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BY EMAIL AND RESS

October 7, 2026

Mr. Ritchie Murray
Registrar
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Mr. Murray,

EB-2026-0164 – Hydro One Networks Inc. and Hydro One Sault Ste. Marie LP – 2028-2032 Custom Incentive Rate-Setting Application for Transmission Revenue Requirements and Distribution Rates

Hydro One Networks Inc. (Hydro One) has filed a combined Custom Incentive Rate-Setting (Custom IR) application, together with supporting materials, electronically using the Ontario Energy Board's (OEB) Regulatory Electronic Submission System.

The application seeks approval of Hydro One's transmission revenue requirement and distribution rates for the five-year period from January 1, 2028 to December 31, 2032, and approval of Hydro One Sault Ste. Marie LP's (HOSSM) transmission revenue requirements, on a final basis for 2027 and under a Custom IR framework for the five-year period from January 1, 2028 to December 31, 2032 (the Application).

A request for the confidential treatment of certain information included in the Application will be submitted under separate cover by Hydro One's legal counsel, Torys LLP.

Where generative artificial intelligence (AI) was used to generate content in the Application, it was also verified by the relevant party or Hydro One witness without the assistance of AI.

Please contact me if you have any questions.

Sincerely,

Elise Andrey
Director, Applications Delivery
Hydro One Networks Inc.

cc: Arlen Sternberg, Jonathan Myers and Daliana Coban, Torys LLP
Kathleen Burke, Vice President, Regulatory Affairs, Hydro One Networks Inc.

hydro one

Connecting power and possibility™

Transmission and Distribution Joint Rate Application 2028-2032

EB-2026-0164

EXHIBIT LIST

An asterisk (*) identifies Exhibits and attachments that are provided as a Microsoft Excel file.

Exhibit	Tab	Schedule	Attachment	Contents
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A	2	1	2	Certifications for Application – Hydro One Sault Ste. Marie LP (HOSSM)
A	2	1	3	Letter From the Governing Body Certifying Approval of Application Submission – Hydro One Networks Inc.
A	2	1	4	Letter From the Governing Body Certifying Approval of Application Submission – Hydro One Sault Ste. Marie LP
A	2	2		Glossary
A	2	3		Compliance with OEB Filing Requirements for Electricity Transmitters and Distributors
A	2	3	1	Transmission Filing Requirement Checklist*
A	2	3	2	Distribution Filing Requirement Checklist*
A	2	3	3	HOSSM Filing Requirement Checklist*
A	2	3	4	Hydro One Distribution Updates to Conditions of Service
A	2	4		Summary of Board Directives and Undertakings from Previous Proceedings
A	3	1		Executive Summary
A	3	1	1	Business Plan Underpinning the Application; Approved by the Board on September 16, 2026, with draft bill impacts. Updated with final bill impacts on October 6, 2026
A	4	1		Custom IR Application Summary
A	4	1	1	Benchmarking, Productivity, and Incentive Regulation Parameter Study for Hydro One Networks' Joint Rate Application – Clearspring Energy Advisors, dated: August 2026
A	4	2		Components of Custom IR Formula - Transmission
A	4	3		Components of Custom IR Formula - Distribution
A	5	1		Distribution Electricity Service Quality Requirements
A	5	1	1	Chapter 2 Appendix 2-G - Service Reliability and Quality Indicators*
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Exhibit	Tab	Schedule	Attachment	Contents	
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A	6	2	1	2024 Hydro One Networks Transmission Financial Statements	
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A	7	1	1	Corporate Organizational Structure for the Hydro One Group of Companies	
A	7	1	2	Organization Structure - Executive and Senior Management Positions	
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B	1	1		Section 1.1	SPF – System Plans Framework Overview

[1] As discussed in Exhibit A-06-01, Section 5.0, Hydro One intends to file the report during the course of this proceeding once it becomes available.

Exhibit	Tab	Schedule	Attachment	Contents	
B	1	1		Section 1.2	SPF – Coordination Through Regional Planning • Attachment 1 - Integrated Energy Plan (IEP) • Attachment 2 - Long Term Capital Plan Information- ESource; June 2026 • Attachment 3 - IESO Update Letter on Regional Planning- Guidehouse; July 27, 2026 • Attachments 4 to 52 - Regional Infrastructure Plan Reports/ Needs Assessment Reports/ Integrated Regional Resource Plan Reports/ Study Reports
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B	3	1		Section 3.5	DSP – Performance Measurement and Outcomes • Attachments 1 – 3 Scorecard and MD&A 2023 to 2025

Exhibit	Tab	Schedule	Attachment	Contents	
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[2] GSP Sections 4.4 and 4.5 are placeholders to maintain structure alignment with the TSP and DSP.

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H	9	1		Transmission Bill Impacts
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L	2	1	2	2028-2032 Revenue Reconciliation*
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APPLICATION REQUESTS

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an application by Hydro One Networks Inc. for an order or orders made pursuant to section 78 of the Act, approving or fixing just and reasonable rates for the transmission and distribution of electricity;

AND IN THE MATTER OF an application by Hydro One Sault Ste. Marie LP for an order or orders made pursuant to section 78 of the Act, approving or fixing just and reasonable rates for the transmission of electricity.

APPLICATION

1. This is a combined application by Hydro One Networks Inc. (Hydro One or the Company) for approval of transmission revenue requirement and distribution rates, and related matters, and by Hydro One Sault Ste. Marie LP (HOSSM) for approval of transmission revenue requirement and related matters, each made pursuant to section 78 of the *Ontario Energy Board Act, 1998* (the Act) and as further set out below.

2. Hydro One is an Ontario corporation with its head office in Toronto. Hydro One carries on the business, among other things, of owning and operating electricity transmission and distribution facilities in Ontario pursuant to licences (ET-2003-0035 and ED-2003-0043) issued by the Ontario Energy Board (the OEB).

3. This is Hydro One's Application for approval of revenue requirement and rates under Custom Incentive Rate-Setting (Custom IR) frameworks, for five-year test periods commencing January 1, 2028 and ending December 31, 2032, for its transmission and distribution businesses.

4. In this Application, Hydro One's transmission business is referred to as Hydro One Transmission, and Hydro One's distribution business is referred to as Hydro One Distribution. Hydro One is an indirect subsidiary of Hydro One Ltd., which is publicly traded on the Toronto Stock Exchange. There are several affiliates of the Company that are separately regulated by the OEB. Hydro One's corporate structure is shown in Exhibit A-07-01 Attachment 1.

5. In the OEB's Decision for Hydro One's previous Custom IR Application (EB-2021-0110), the OEB approved the Settlement Proposal for the 2023-2027 period and the proposed Custom IR methodology to be used to establish Hydro One's transmission and distribution revenue requirements for the years 2024 through to 2027 inclusive.

6. Hydro One's proposed revenue requirements for the 2028 test year have been determined separately for the transmission and distribution businesses using a cost of service, forward test year approach. The transmission and distribution revenue requirements for 2029-2032 will be determined formulaically using the proposed Custom IR frameworks, with parameters specific to each business. For its transmission business, Hydro One requests approval of a revenue requirement and an amendment to Uniform Transmission Rates to allow for recovery of its proposed rates revenue requirement. For its distribution business, Hydro One requests approval of distribution rates and charges, as set out below.

7. HOSSM is an Ontario limited partnership with its head office in Toronto. HOSSM's general partner is Hydro One Sault Ste. Marie Inc., a subsidiary of Hydro One Inc. The limited partner of HOSSM is Hydro One Sault Ste. Marie Holdings LP, which is held by Hydro One.

8. HOSSM carries on the business of owning and operating electricity transmission facilities in the Sault Ste. Marie area of Ontario pursuant to licence ET-2007-0649 from the OEB.

9. In the OEB's Decision and Order in EB-2016-0050, the OEB approved the acquisition of HOSSM[1] by Hydro One Inc. as well as a ten-year deferred rebasing period. In the same decision, the OEB determined that HOSSM would continue with its 2016 revenue requirement and could bring forward a separate rate application, proposing a revenue cap index for the deferral period. In its decision in EB-2018-0218, the OEB approved HOSSM's proposed revenue cap index (RCI) methodology and determined that this methodology would be used to determine HOSSM's base transmission revenue requirement for the years 2019 to 2026 inclusive.

10. In its decision in EB-2026-0170, the OEB approved HOSSM's request to use its 2026 base revenue requirement on an interim basis effective January 1, 2027 for one year. In that application, HOSSM indicated its intention to apply to retroactively rebase its 2027 revenue requirement and to rebase its 2028 revenue requirement on a forecast basis to align with Hydro One Transmission's rate period, as part of the current Application with Hydro One Transmission. Therefore, this is HOSSM's Application for approval of rates under a Custom IR framework, for a six-year test period commencing January 1, 2027 and ending December 31, 2032.

11. HOSSM's proposed revenue requirements for the 2027 and 2028 test years have been determined using a cost of service, forward test year approach. HOSSM's revenue requirements for 2029-2032 will be determined formulaically using the proposed Custom IR framework, with parameters specific to HOSSM. HOSSM requests approval of its 2027 and 2028 rates revenue requirements, and an amendment to Uniform Transmission Rates to allow for recovery of its 2028 rates revenue requirement which will be adjusted to refund to customers the difference between the

[1] HOSSM was named Great Lakes Power Transmission LP at the time of the acquisition; a name change took place on January 16, 2017.

proposed 2027 total revenue requirement once approved and the current interim 2027 revenue requirement (approved on an interim basis in EB-2026-0170).

RELIEF SOUGHT

12. Hydro One and HOSSM hereby apply to the OEB for orders approving:

Hydro One Transmission

a) A total transmission revenue requirement of $2,726.6M for the 2028 test year, as outlined in Exhibit D-01-01, to be effective and implemented on January 1, 2028, and an amendment to the 2028 Uniform Transmission Rates to allow for recovery of the proposed transmission rates revenue requirement of $2,592.6M for 2028 as outlined in Exhibit H-01-01;

b) The proposed Custom IR framework, including the applicable transmission-related parameters, to set Hydro One Transmission's annual revenue requirement during the period from January 1, 2029, through December 31, 2032, as described in Exhibits A-04-01 and A-04-02;

c) The proposed charge determinants by rate pool over the 2028 to 2032 period, as outlined in Exhibit H-07-01;

d) The proposed revenue offsets for each of the test years (2028 to 2032) as shown in Exhibit H-01-01, including external revenues (outlined in Exhibit D-02-01), Export Transmission Service (ETS) revenues (outlined in Exhibit H-08-01), and funding for the LV switchgear credit (outlined in Exhibit H-01-03 and updated annually);

e) The continuation and discontinuation of Hydro One Transmission's current regulatory accounts, as described in Exhibit G-01-03;

f) Accounting orders for new or modified regulatory accounts for Hydro One Transmission, as set out in Exhibit G-01-03;

g) The disposition of a total credit balance for transmission regulatory accounts of $295.3M as of December 31, 2025, inclusive of projected carrying charges to December 31, 2027, as outlined in Exhibit G-01-05. Hydro One seeks approval to refund this balance to customers in the amount of $59.1M per year over a five-year period commencing January 1, 2028, as proposed in Exhibit G-01-06, which will be applied as a revenue offset each year, as shown in Exhibit H-01-01; and,

h) Other items or amounts that may be requested by Hydro One Transmission in the course of this proceeding, and as may be granted by the OEB.

HOSSM

i) A total transmission revenue requirement of $46.1M for the 2027 test year, as outlined in Exhibit D-01-01A, to be effective on a final basis as of January 1, 2027, and an adjustment to the 2028 total transmission revenue requirement to allow for the refund to customers of the difference between the proposed final 2027 transmission revenue requirement of $46.1M, and the interim 2027 transmission revenue requirement of $49.2M approved by the OEB in EB-2026-0170;

j) A total transmission revenue requirement of $50.0M for the 2028 test year, as outlined in Exhibit D-01-01A, to be effective and implemented on January 1, 2028, and an amendment to the 2028 Uniform Transmission Rates to allow for recovery of the proposed transmission rates revenue requirement of $49.1M for 2028 as outlined in Exhibit H-01-01;

k) The proposed Custom IR framework, including the applicable HOSSM-related parameters, to set HOSSM's annual transmission revenue requirement during the period from January 1, 2029, through December 31, 2032, as described in Exhibits A-04-01 and A-04-02;

l) The proposed charge determinants by rate pool over the test period, as outlined in Exhibit H-07-01;

m) The continuation and discontinuation of HOSSM's current transmission regulatory accounts, as described in Exhibit G-01-04;

n) Accounting orders for new or modified regulatory accounts for HOSSM, as set out in Exhibit G-01-04;

o) The disposition of a total credit balance for HOSSM regulatory accounts of $4.3M as of December 31, 2025, inclusive of projected carrying charges to December 31, 2027, as outlined in Exhibit G-01-05. HOSSM seeks approval to refund this balance to customers in the amount of $0.9M per year over a five-year period commencing January 1, 2028, as proposed in Exhibit G-01-06, which will be applied as a revenue offset each year, as shown in Exhibit H-01-01; and,

p) Other items or amounts that may be requested by HOSSM in the course of this proceeding, and as may be granted by the OEB.

Hydro One Distribution

q) Electricity distribution rates as identified in the proposed Tariff of Rates and Charges in Exhibit L-07-02, to be effective January 1, 2028, calculated to support Hydro One Distribution's 2028 base revenue requirement of $2,640.7M (i.e., total revenue requirement of $2,694.8M outlined in Exhibit D-01-01 minus external revenues, outlined in Exhibit D-02-02) as further outlined in Exhibit L-02-01 Attachment 1;

r) The proposed Custom IR framework, including applicable distribution-related parameters, to set Hydro One Distribution's annual revenue requirement, during the period from January 1, 2029, through December 31, 2032, as described in Exhibits A-04-01 and A-04-03, and the inclusion of the Orillia and Peterborough

Rate Zone revenue requirements during the period effective January 1, 2031, through December 31, 2032, as described in Exhibit A-04-03;

s) The proposed external revenues for each of the test years (2028 to 2032) as outlined in Exhibit D-02-01;

t) The proposed Specific Service Charges, as described in Exhibit L-04-01;

u) The continuation and discontinuation of Hydro One Distribution's current regulatory accounts, as described in Exhibit G-01-03;

v) Accounting orders for new or modified regulatory accounts for Hydro One Distribution, as set out in Exhibit G-01-03;

w) The disposition of a total credit balance for distribution regulatory accounts of $224.0M as of December 31, 2025, inclusive of projected carrying charges to December 31, 2027, as outlined in Exhibit G-01-05. This balance is comprised of $209.8M for the Group 1 accounts, and $14.2M for the Group 2 accounts. Hydro One Distribution seeks approval to refund the Group 1 balance to customers over a one-year period, effective January 1, 2028, and to refund the Group 2 balance to customers in the amount of $2.8M per year over a five-year period commencing January 1, 2028, as proposed in Exhibit G-01-06, and approval of the rate riders as proposed in Exhibit L-05-01;

x) The proposed harmonization of rates for former OPDC and PDI customers into Hydro One Distribution's rate structure effective January 1, 2031, as outlined in Exhibits L-01-02, L-01-03, and L-02-01; and

y) Other items or amounts that may be requested by Hydro One Distribution in the course of this proceeding, and as may be granted by the OEB.

CUSTOMERS AFFECTED

13. Hydro One's transmission and distribution service territories are described in TSP Section 2.1 and DSP Section 3.1, respectively and HOSSM's service territory is described in TSP Section 2.10. The persons affected by this Application are Ontario transmission ratepayers and the ratepayers of Hydro One Distribution.

NOTICE AND FORM OF HEARING REQUESTED

14. Given Hydro One Transmission's and HOSSM's revenue requirements will be paid for by all Ontario customers through UTRs, and Hydro One Distribution's vast distribution service territory, notice of this Application is recommended to be published by the OEB in newspapers with wide circulation in Ontario, including The Toronto Star, Sudbury Star, Thunder Bay Chronicle Journal, Ottawa Citizen, Hamilton Spectator and Windsor Star. Hydro One also has active social media accounts on Twitter, Facebook, Instagram and LinkedIn platforms.

15. The Application may be viewed on the Internet at the following addresses:
https://www.hydroone.com/about/regulatory
https://www.hydroone.com/about/regulatory/hydro-one-sault-ste-marie

16. Hydro One and HOSSM request that this Application be heard by way of an oral hearing, consistent with prior proceedings to review Hydro One's multi-year revenue requirement and rate applications for Transmission, Distribution and HOSSM.

17. The written evidence filed with the OEB may be amended from time to time prior to the OEB's final decision on the Application.

PROPOSED EFFECTIVE DATE

18. Hydro One requests that the OEB's Orders for Hydro One Transmission's 2028 rates revenue requirement and amendment to the 2028 Uniform Transmission Rates, and Hydro One Distribution's 2028 rates and charges, be effective January 1, 2028.

19. In the event the requested Orders cannot be made effective by such date, Hydro One requests Interim Orders making its current transmission revenue requirement and charge determinants, as well as Hydro One's current distribution rates and charges, effective on an interim basis as of January 1, 2028, and for the ability to recover any differences between the interim transmission and distribution amounts, and the final amounts effective January 1, 2028, based on the OEB's final Decision and Order herein.

20. HOSSM requests that the OEB's Orders for its final 2027 revenue requirement be effective January 1, 2027.

21. HOSSM requests that the OEB's Orders for its 2028 rates revenue requirement and amendment to the 2028 Uniform Transmission Rates, be effective January 1, 2028.

22. In the event the requested Order for 2028 rates revenue requirement cannot be made effective by January 1, 2028, HOSSM requests Interim Orders making its current transmission rates revenue requirement and charge determinants effective on an interim basis as of January 1, 2028, and that the final 2028 rates revenue requirement be made effective January 1, 2028, based on the OEB's final Decision and Order herein.

BILL IMPACTS

Hydro One Transmission

23. Approval of the Hydro One Transmission portion of this Application results in the following bill impacts:
    - For a typical Hydro One medium density residential (R1) customer consuming 750 kWh per month, the estimated total monthly bill impact in 2028 is an increase of 0.3% or $0.50 and an average annual increase of 0.8% or $1.14 on monthly bills over the 2028-2032 period.

- For a typical Hydro One General Service <50 kW (GSe) customer consuming 2,000 kWh per month, the estimated total monthly bill impact in 2028 is an increase of 0.2% or $1.12 and an average annual increase of 0.5% or $2.54 on monthly bills over the 2028-2032 period.

Total Monthly Bill Impact from Transmission Rates	Impacts	2028	2029	2030	2031	2032	5-year Average
R1 Residential (750 kWh)	$	$0.50	$1.28	$1.49	$0.89	$1.53	$1.14
	%	0.3%	0.9%	1.0%	0.6%	1.0%	0.8%
GSe (2,000 kWh)	$	$1.12	$2.84	$3.32	$1.98	$3.41	$2.54
	%	0.2%	0.6%	0.7%	0.4%	0.7%	0.5%

HOSSM

24. Approval of the HOSSM portion of this Application results in the following bill impacts:[2]

- For a typical Hydro One medium density residential (R1) customer consuming 750 kWh per month, the estimated total monthly bill impact in 2028 is an increase of 0.02% or $0.02, and an average annual increase of 0.01% or $0.02 on monthly bills over the 2028-2032 period.
- For a typical Hydro One General Service <50 kW (GSe) customer consuming 2,000 kWh per month, the estimated total monthly bill impact in 2028 is an increase of 0.01% or $0.05, and an average annual increase of 0.01% or $0.04 on monthly bills over the 2028-2032 period.

Total Monthly Bill Impact from HOSSM Rates	Impacts	2028	2029	2030	2031	2032	5-year Average
R1 Residential (750 kWh)	$	$0.02	$0.01	$0.04	$0.00	$0.01	$0.02
	%	0.02%	0.01%	0.02%	0.00%	0.01%	0.01%
GSe (2,000 kWh)	$	$0.05	$0.03	$0.08	$0.00	$0.02	$0.04
	%	0.01%	0.01%	0.02%	0.00%	0.00%	0.01%

[2] HOSSM's 2028 rates revenue requirement and associated bill impacts do not include the adjustment/refund that will be applied for the difference between the 2027 interim rates revenue requirement approved in EB-2026-0170 and the final 2027 rates revenue requirement proposed for approval in this Application, as further described in Exhibit A-08-01.

Hydro One Distribution

25. Approval of the Hydro One Distribution portion of this Application results in the following bill impacts:
    - For a typical Hydro One medium density residential (R1) customer consuming 750 kWh per month with Distribution Rate Protection (DRP) per O. Reg. 198/17, the estimated total monthly bill impact in 2028 is a decrease of 2.1% or $3.31, and an average annual decrease of 0.1% or $0.10 on monthly bills over the 2028-2032 period.
    - For a typical Hydro One General Service <50 kW (GSe) customer consuming 2,000 kWh per month, the estimated total monthly bill impact in 2028 is an increase of 7.2% or $34.63, and an average annual increase of 3.9% or $20.00 on monthly bills over the 2028-2032 period.

Bill Impacts from Distribution Rates	Impacts	2028	2029	2030	2031	2032	5-year average
R1 Residential (750 kWh) – with DRP	Sub-Total A ($)	-$0.10	$0.00	$0.00	$0.00	$0.00	-$0.02
	Sub-Total A (%)	-0.2%	0.0%	0.0%	0.0%	0.0%	0.0%
	Total Bill ($)	-$3.31	$3.22	$0.00	-$0.43	$0.00	-$0.10
	Total Bill (%)	-2.1%	2.1%	0.0%	-0.3%	0.0%	-0.1%
GSe (2,000 kWh)	Sub-Total A ($)	$49.39	$26.34	$20.40	$8.44	$8.89	$22.69
	Sub-Total A (%)	24.3%	10.4%	7.3%	2.8%	2.9%	9.5%
	Total Bill ($)	$34.63	$32.17	$18.26	$6.97	$7.96	$20.00
	Total Bill (%)	7.2%	6.2%	3.3%	1.2%	1.4%	3.9%

CONDITIONS OF SERVICE

26. Hydro One Distribution's Conditions of Service have changed since its last rebasing application in EB-2021-0110. A summary of key changes and the rationale for the changes are included at Exhibit A-02-03 Attachment 4.

27. There are no rates and charges linked in the Conditions of Service that are not in Hydro One's Tariff of Rates and Charges, except as described in Exhibit L-04-01. The current Conditions of Service can be found on Hydro One's website at: https://www.hydroone.com/about/conditions-of-service

CONFIDENTIAL FILINGS CONTAINED IN APPLICATION

28. Hydro One and HOSSM have identified and redacted personal information within this Application in accordance with Rule 9A of the OEB's *Rules of Practice and Procedure* and Section 10 of the OEB's *Practice Direction on Confidential Filings*. A certification regarding personal information has been filed at Exhibit A-02-01, Attachment 1 and 2.

29. Hydro One and HOSSM have filed confidential information pursuant to Rule 10 of the OEB's *Rules of Practice and Procedure.* Hydro One and HOSSM have filed this information in accordance with the OEB's *Practice Direction on Confidential Filings*, and will be filing its request for confidential treatment of such information under separate cover shortly after filing.

CONTACT INFORMATION

30. Hydro One requests that copies of all documents filed with or issued by the OEB in connection with this Application be served on Hydro One and its Counsel as follows:

Hydro One:

Ms. Eryn MacKinnon
Regulatory Advisor
Hydro One Networks Inc.
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Tel: 416-865-7526
dcoban@torys.com

DATED at Toronto, Ontario, this 7th day of October, 2026.

HYDRO ONE NETWORKS INC. (INCLUDING ON BEHALF OF HYDRO ONE SAULT STE. MARIE LP)

By its Counsel, Torys LLP

Arlen Sternberg

Jonathan Myers

D. Coban

Daliana Coban

Witness: Kathleen Burke

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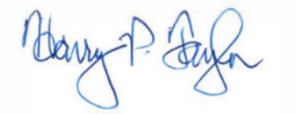
CERTIFICATIONS FOR APPLICATION – HYDRO ONE NETWORKS INC.

TO: ONTARIO ENERGY BOARD

The undersigned, Harry Taylor, being Hydro One Networks Inc.'s (Hydro One) Executive Vice President, Chief Financial and Regulatory Officer, hereby certifies on behalf of Hydro One that:

1. I am a senior officer of Hydro One;
2. This certificate is given pursuant to Chapter 1 of the *Filing Requirements for Electricity Transmission Applications* (last revised on August 11, 2026), and *Filing Requirements for Electricity Distribution Applications* (last revised on August 11, 2026);
3. The evidence submitted in support of Hydro One's 2028-2032 combined transmission revenue requirement and distribution rate application (EB-2026-0164) is accurate, consistent and complete to the best of my knowledge;
4. The evidence submitted does not contain any personal information filed herein (as that phrase is defined in the Freedom of Information and Protection of Privacy Act), that is not otherwise redacted in accordance with rule 9A of the OEB's *Rules of Practice and Procedure*; and
5. Hydro One Transmission and Distribution have the appropriate processes and internal controls for the preparation, review, verification and oversight of all deferral and variance accounts being disposed.

DATED this 7th day of October, 2026.



HARRY TAYLOR

CERTIFICATIONS FOR APPLICATION - HOSSM

TO: ONTARIO ENERGY BOARD

Harry Taylor, being Hydro One Networks Inc.'s (Hydro One) Executive Vice President, Chief Financial and Regulatory Officer and the sole director of Hydro One Sault Ste. Marie Inc. (HOSSM GP), which is the general partner of Hydro One Sault Ste. Marie LP (HOSSM)., certifies in those capacities on behalf of Hydro One Sault Ste. Marie LP (HOSSM), and not in a personal capacity, that:

1. I am a senior officer of Hydro One;
2. I am the sole director of HOSSM GP;
3. This certificate is given pursuant to Chapter 1 of the Ontario Energy Board's *Filing Requirements for Electricity Transmission Applications* (last revised on August 11, 2026), and *Filing Requirements for Electricity Distribution Applications* (last revised on August 11, 2026); and,
4. The evidence submitted in support of HOSSM's revenue requirement application (EB-2026-0164) is accurate, consistent and complete to the best of my knowledge.
5. The evidence submitted does not contain any personal information filed herein (as that phrase is defined in the Freedom of Information and Protection of Privacy Act (Ontario)), that is not otherwise redacted in accordance with rule 9A of the OEB's *Rules of Practice and Procedure*.
6. Hydro One on behalf of HOSSM has the appropriate processes and internal controls for the preparation, review, verification and oversight of all deferral and variance accounts being disposed.

DATED this 7th Day of October, 2026.

HARRY TAYLOR

Hydro One Networks Inc.

483 Bay Street
8th Floor South Tower
Toronto, Ontario M5G 2P5

HydroOne.com

September 16, 2026

Mr. Ritchie Murray
Registrar
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

RE: Board of Directors' Support for EB-2026 – 0164 - Custom IR Application (2028-2032) for Hydro One Networks Inc. Transmission and Distribution

Dear Mr. Murray,

I am the Chair of Board of Directors of Hydro One Networks Inc. This letter is to provide confirmation that the Board of Directors of Hydro One Networks Inc. approves the submission of the 2028-2032 Custom Incentive Rate-Setting Application for Hydro One Networks Inc. Transmission and Distribution (EB – 2026-0164).

Sincerely,

Melissa Sonberg

Chair of the Board of Directors

Hydro One Sault Ste. Marie LP

483 Bay Street
8th Floor South Tower
Toronto, Ontario M5G 2P5

October 7, 2026

Mr. Ritchie Murray
Registrar
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

RE: Board of Directors' Support for EB-2026-0164 – 2027-2032 Custom IR Application for Hydro One Sault Ste. Marie LP (HOSSM)

Dear Mr. Murray,

I am the sole Director of Hydro One Sault Ste. Marie Inc. (HOSSM GP), which is the general partner of Hydro One Sault Ste. Marie LP (HOSSM). This letter is to provide confirmation that the Board of Directors of HOSSM GP is aware of and supports the submission of the 2027-2032 Revenue Requirement Application for HOSSM (EB-2026-0164).

Sincerely,

Harry Taylor
Director
Hydro One Sault Ste. Marie Inc., general partner of Hydro One Sault Ste. Marie LP

GLOSSARY

"$B" refers to billions of dollars.

"$M" refers to millions of dollars.

"ADMS" refers to "Advanced Distribution Management System".

"AMI" refers to "Advanced Metering Infrastructure".

"AODA" refers to *Accessibility for Ontarians with Disabilities Act, 2005*.

"APB" refers to "Activity and Performance-based Benchmarking" report and results.

"Application" refers to this application EB-2026-0164 by Hydro One Networks Inc. and Hydro One Sault Ste. Marie's to the OEB for an order or orders made pursuant to section 78 of the *Act* approving rates for the transmission and distribution of electricity.

"ARV" refers to "Asset Replacement Value".

"ATP" refers to "Affiliate Transmission Project".

"BCA" refers to "Building Condition Assessment" or "Benefit Cost Analysis".

"BES" refers to "Bulk Electric System".

"BESS" refers to "Battery Energy Storage System(s)".

"BTM" refers to "Behind-the-Meter".

"BTM BESS" refers to "Behind-the-Meter Battery Energy Storage System".

“BU-OGCC” refers to “Back-Up Ontario Grid Control Centre”.

“Bulk System Planning” refers to the IESO-led planning used to identify provincial or bulk-system transmission expansion and reinforcement solutions required to address reliability or operability needs.

“C” refers to “Custom Capital Factor”.

“Capital Expenditures” or **“CAPEX”** refers to expenditures relating to property, plant and equipment and intangible assets.

“CALR” refers to “Condition Adjusted Life Remaining”.

“CCA” refers to “capital cost allowance”.

“CCFS” refers to “common corporate functions and services”.

“CCRA” refers to “Connection Cost Recovery Agreements”, which are based on Hydro One's connection procedures that outline a customer's capital contribution towards connection.

“CDM” refers to “conservation and demand management”.

“CIA” refers to “Customer Impact Assessment”.

“CIP” refers to “Critical Infrastructure Protection.”

“CIR” refers to the “Custom Incentive Rate-setting” option.

“CISA” refers to “Cybersecurity and Infrastructure Security Agency”.

"CMI" refers to "Customer Minutes of Interruption".

"Commissioning" refers to the phase in which installed facilities are inspected and tested, confirmed ready for service, and formally transferred for system monitoring and control.

"COTI" refers to "Common Operating Technology Infrastructure".

"CPD" refers to "Capital Project Delivery".

"CRIS" refers to "Climate Risk Intelligence System."

"CSA" refers to the "Canadian Standards Association".

"CWIP" refers to "construction work in progress".

"DCAI" refers to "Distribution Capital Program Work Composite Index".

"DERs" refers to "Distributed Energy Resources".

"DERMS" refers to "Distributed Energy Resource Management System".

"DESN" refers to "Dual Element Spot Network".

"Distribution Filing Requirements" refers to the OEB's Filing Requirements for Electricity Distribution Rate Applications Chapters 1 (August 11, 2026), 2 (December 16, 2025) and 5 (December 16, 2025).

"DGA" refers to "Dissolved Gas Analysis".

"DMS" refers to "Distribution Management System".

"DRO" refers to "Draft Rate Order"

"DS" refers to "Distribution Station".

"DSC" refers to the "Distribution System Code", which is the OEB document outlining the obligations of a distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum technical operating standards of distribution systems.

"DSP" refers to the "Distribution System Plan", which provides a detailed explanation of Hydro One's proposed capital investment plan for its distribution system in respect of the 5-year planning period from 2028 to 2032.

"DTS" refers to "Digital & Technology Solutions."

"DVA" refers to "Deferral and Variance Account".

"EDWA" refers to "Externally Driven Work Account".

"Electricity Act" refers to the *Electricity Act, 1998.*

"ELT" refers to the "Executive Leadership Team", which is Hydro One's most senior level of management.

"EMS" refers to "Energy Management System".

"ESA" refers to "Electrical Safety Authority".

"ESL" refers to "Expected Service Life".

"ESM" refers to "Earnings Sharing Mechanism".

“ETS” refers to the “Export Transmission Service”.

“FCI” refers to “Facility Condition Index”.

“FERC” refers to the American “Federal Energy Regulatory Commission”.

“FRE” refers to “Facilities & Real Estate”.

“FRS” refers to the “Fair Return Standard”.

“**FTE**” refers to “Full-Time Equivalent”.

“FTM BESS” refers to “Front-of-the-Meter Battery Energy Storage System”.

“G” refers to “Growth Factor”.

“GIS’’ refers to “Geographic Information Systems”.

“GSP” refers to “General Plant System Plan”, which presents proposed investments in the General Plant assets and functions that are relied on and shared by the Transmission and Distribution businesses, in respect of the 5-year planning period from 2028 to 2032.

“Handbook” refers to the OEB's *Handbook for Utility Rate Applications* (October 13, 2016).

“Hosting Capacity” refers to the amount of new distributed energy resources that can be connected to a distribution system without adversely affecting system reliability or power quality.

“HOI” refers to “Hydro One Inc.”

"HOL" refers to "Hydro One Limited".

"Hydro One Distribution" refers to the distribution business of "Hydro One Networks Inc."

"Hydro One Remotes" refers to "Hydro One Remote Communities Inc.", a subsidiary of Hydro One Inc. that supplies electricity to remote communities in Ontario's far north.

"HOSSM" refers to "Hydro One Sault Ste. Marie LP" which is the lead transmitter for East Lake Superior Region.

"Hydro One Telecom Inc." refers to a subsidiary company of Hydro One Ltd. that sells high bandwidth telecommunication services to carriers, Internet service providers, and large public and private sector organizations.

"Hydro One Transmission", refers to the transmission business of "Hydro One Networks Inc."

"Hydro One", "HONI" or the "Company" refers to the transmission and distribution business of "Hydro One Networks Inc.", which is the subsidiary of Hydro One Inc. that owns and operates the province-wide transmission system and rural distribution system in Ontario.

"I" refers to "Inflation Factor".

"ICI" refers to the "Industrial Conservation Initiative", which is a policy that incentivizes large customers to reduce their consumption during peak hours.

"ICM" refers to "Incremental Capital Module".

"IESO" refers to the "Independent Electricity Systems Operator".

“INAC” refers to the Federal Department of “Indigenous and Northern Affairs, Canada".

“INPO” refers to the “Institute of Nuclear Power Operations”.

“IPD” refers to “Input Price Differential”

“IPO” refers to the “Initial Price Offering” of Hydro One Limited shares to public markets in 2015.

“IR” refers to “Incentive Rate-Setting”.

“IRRP” refers to “Integrated Regional Resource Plan”.

“IRU” refers to “Indefeasible Right of Use”.

“ISA” refers to “In-Service Addition(s)”.

“ISD” refers to “Investment Summary Documents”, which detail specifics for each material capital investment with spending greater than $4M in any one year for Hydro One Transmission, $1M in any one year for Hydro One Distribution, and $0.29M in any one year for HOSSM.

“ISOC” refers to “Integrated System Operations Centre”.

“ISP” refers to “Internet Service Provider”.

“IT” refers to “Information Technology”.

“IVMS” refers to “Intelligent Vegetation Management System”.

“LDA” refers to the large distribution end-use customers with peak demand above a 2 MW demand threshold.

“LDCs” refers to “Local Distribution Companies”, which own and operate distribution systems that transmit electricity to end-use customers.

“LTC” refers to “Leave to Construct”.

“LTEP” refers to the “Long-Term Energy Plan”, a document created by the Ontario Government that directs long-term planning of the Province's electricity system.

“MACD” refers to the “Market Assessment and Compliance Division”, a ring-fenced business unit of the IESO that performs monitoring and enforcement of Market Participants’ compliance including compliance with applicable reliability standards.

“MECP” refers to the “Ministry of the Environment, Conservation and Parks”.

“MFA” refers to “Minor Fixed Assets”.

“MPLS” refers to “Multiprotocol Label Switching”.

“MW” refers to ‘Megawatt”.

“MUS” refers to “Mobile Unit Substation”.

“NBV” refers to “Net Book Value”.

“NEB” refers to the “National Energy Board”, which is the Federal energy regulator.

"NERC" refers to the "North American Reliability Corporation", which sets the reliability standards that ensure the integrity of the interconnected North American Bulk Electricity Systems. NERC standards are enforced by the IESO.

"NPCC" refers to the "Northeast Power Coordinating Council", which develops regional reliability standards, monitors and enforces compliance, and coordinates regional system planning, design and operations, and assessments of reliability.

"NPV" refers to "Net Present Value".

"NRC" refers to the "National Research Council Transmission Station".

"NWS" refers to "Non-Wires Solutions".

"OC" refers to "Operating Centre".

"OCSF" refers to "Ontario Cyber Security Framework".

"OEB Act" refers to the *Ontario Energy Board Act, 1998.*

"OEB" refers to the "Ontario Energy Board", which is the regulator of electricity and natural gas in Ontario.

"OEFC" refers to the "Ontario Electricity Financial Corporation", which was established following the dissolution of Ontario Hydro and is primarily responsible for Ontario Hydro's debt and other financial obligations.

"OIC" refers to "Order in Council".

"OM&A" refers to "Operations, Maintenance and Administration".

"OMS" refers to "Outage Management System".

"OPEBs" refers to "Other Post-Employment Benefit Costs".

"OPG" refers to "Ontario Power Generation".

"OPGW" refers to "Optical Ground Wire".

"OT" refers to "Operating Technology".

"P&C" refers to "Protection and Control".

"PILs" refers to "Payment in Lieu of Taxes".

"Planning period" refers to the five-year period from 2028 to 2032 for which Hydro One's Application is requesting approval of its transmission and distribution revenue requirements, and the 6-year period from 2027 to 2032 for which HOSSM is requesting approval.

"PSWHA" refers to the *Public Service Works on Highways Act, 1990.*

"R1 customers" refers to medium density residential customers of Hydro One's distribution business.

"R2 customers" refers to low density residential customers of Hydro One's distribution business.

"RCI" refers to "Revenue Cap Index".

"RFP" refers to "Request for Proposal".

“RIP” refers to “Regional Infrastructure Plan”.

“ROE” refers to “Return on Equity”.

“ROW” refers to “right of way” areas where Hydro One assets are granted a legal right to pass along uninhibited.

“RRF” refers to the “Renewed Regulatory Framework”, which is the OEB framework introduced in 2012 to balance investment needs of the sector with customer cost concerns.

“RRR” refers to the “Reporting and Record-keeping Requirements” which are the OEB’s reporting requirements for the utilities that it regulates.

“RSCC” refers to the “Reliability Standards Compliance Committee”, which oversees Hydro One's compliance with reliability standards.

“RTSR” refers to the “Retail Transmission Service Rates”.

“RZ” refers to “Rate Zone”.

“SAIDI” refers to “System Average Interruption Duration Index”.

“SAIFI” refers to “System Average Interruption Frequency Index”.

“SCADA” refers to “Supervisory Control and Data Acquisition”.

“SF6” refers to “Sulfur Hexafluoride”, which is a common and effective dielectric medium used in a large portion of the breaker fleet.

“SIA” refers to “System Impact Assessment”.

"SONET" refers to "Synchronous Optical Network".

"SPF" refers to "System Plan Framework".

"TFP" refers to "total factor productivity".

"Transmission Filing Requirements" refers to the OEB's Filing Requirements for Electricity Transmission Applications Chapters 1 (August 11, 2026), and 2 (October 30, 2025) together with further guidance from Chapter 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (December 16, 2025).

"TL" refers to "Transmission Licence".

"TS" refers to "Transmission Station".

"T-SAIDI" refers to "Transmission System Average Interruption Duration Index".

"TSC" refers to the "Transmission System Code", which is the OEB document outlining conditions, obligations and codes of transmission service in Ontario.

"TSP" refers to the "Transmission System Plan", which provides a detailed explanation of Hydro One's proposed capital investment plan for its transmission system in respect of the 5-year planning period from 2028 to 2032, and the 6-year planning period from 2027 to 2032 for HOSSM's proposed capital investment plan.

"TWE" refers to "Transport and Work Equipment".

"UCC" refers to "undepreciated capital costs."

"US GAAP" refers to the "United States Generally Accepted Accounting Principles", which Hydro One adopted under the OEB's orders.

“USofA” refers to “Uniform System of Accounts”.

“UTR” refers to “Uniform Transmission Rates”.

“VASH” refers to “Vulnerability Assessment and System Hardening”.

“X” refers to the “Productivity Factor”.

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COMPLIANCE WITH OEB FILING REQUIREMENTS FOR ELECTRICITY TRANSMITTERS AND DISTRIBUTORS

1.0 OVERVIEW OF FILING REQUIREMENTS

The Filing Requirements for Electricity Transmission and Distribution Rate Applications have been developed by the OEB to ensure that a utility's rate application contains complete and consistent information to justify its proposed rates. The Filing Requirements are underpinned by the principles of the Renewed Regulatory Framework (RRF) articulated in the *Handbook to Utility Rate Applications* (Handbook) dated October 13, 2016. The Handbook and Filing Requirements have guided the development of this Application.

2.0 COMPLIANCE WITH FILING REQUIREMENTS

Hydro One and Hydro One Sault Ste. Marie (HOSSM) have prepared evidence in accordance with the following filing requirements:

- Filing Requirements for Electricity Transmission Applications (the Transmission Filing Requirements)
  - Chapter 1 - Overview (August 11, 2026)
  - Chapter 2 - Revenue Requirement Applications (October 30, 2025)

- Filing Requirements for Electricity Distribution Rate Applications (the Distribution Filing Requirements)
  - Chapter 1 - Overview (August 11, 2026)
  - Chapter 2 - Cost of Service (December 16, 2025)
  - Chapter 5 - Distribution System Plan (December 16, 2025)

Hydro One and HOSSM have complied with the OEB's policies and expectations contained in the filing requirements and filed a certification on the accuracy of the evidence at Exhibit A-02-01, Attachment 1.

Attachments 1 and 3 of this Exhibit include checklists based on the Transmission Filing Requirements, prepared to demonstrate completeness of the Transmission components of the Application. Attachment 2 of this Exhibit includes a checklist for the Distribution Filing Requirements prepared to demonstrate completeness of the Distribution component of the Application.

Hydro One also created a Table of Concordance in TSP Section 2.0 (Appendix A), DSP Section 3.0 (Appendix A) and GSP Section 4.0 (Appendix A) to map all filing requirements to the System Plans evidence.

Hydro One's Conditions of Service may be found at www.hydroone.com/about/conditions-of-service. Attachment 4 of this Exhibit includes a summary of changes in the Conditions of Service since the last Distribution rate application was filed.

In this Application, Hydro One and HOSSM used the OEB's models to prepare their evidence, which include but are not limited to the following:

- OEB's Revenue Requirement Workform (RRWF) (Tabs 1 to 9) for Hydro One Transmission, Distribution and HOSSM, filed at Exhibit D-01-01, Attachments 1 to 5 for Transmission, Attachments 5-10 for Distribution, and at Exhibit D-01-01A, Attachments 1 to 6 for HOSSM. Tab 13 of RRWF is filed at Attachment 1 and Attachment 2 of Exhibit L-02-01;[1]
- OEB's Chapter 2 Appendices for Hydro One Transmission, Distribution and HOSSM filed with the related exhibits of the evidence, with exceptions noted in the filing requirement checklists therein (Attachments 1 through 3 of this Exhibit).
- PEG Benchmarking Model: instead of this model, see the Benchmarking, Productivity, and Incentive Regulation Parameter Study for Hydro One Networks' Joint Rate Application prepared by Clearspring Energy Advisors and filed as Exhibit A-04-01, Attachment 1;

[1] Exhibit D-05-01-02 is used in place of Tab 10. In regards to Tab 11 of the workform, the template does not allow the flexibility needed for Hydro One's cost allocation and rate design requirements. Information equivalent to that requested in the workform is provided in Exhibits L-01-03 and L-02-01.

- OEB's Cost Allocation Models for Hydro One Distribution's 2028 and 2031 test years, filed at Exhibit L-01-03, Attachments 1 and 2, respectively;
- OEB's Deferral and Variance Account Continuity Schedules for Hydro One Transmission, Distribution and HOSSM, filed at Exhibit G-01-07, Attachments 1 to 3, with certain tabs for Hydro One Distribution filed as separate attachments, as follows:
  - Derivation of Group 1 DVA Rate Riders, filed at Exhibit L-05-01, Attachment 1; and
  - Derivation of Group 2 DVA Rate Riders, filed at Exhibit L-05-01, Attachment 2.
- Consolidated Commodity Accounts Analysis Workform, filed at Exhibit G-01-05, Attachment 3

In addition, Hydro One and HOSSM have custom Excel models that are filed with the following Exhibits, including:

- Custom income tax calculation spreadsheets for Hydro One Transmission and Distribution, in lieu of using the OEB's PILS workform, filed at Exhibit E-09-02, Attachments 1 to 8;
- Custom[2] bill impacts model for Hydro One Distribution, in lieu of using the OEB's Tariff Schedule and Bill Impacts Model, filed at Exhibit L-06-01, Attachments 1 to 5;
- Custom[3] tariff schedules, in lieu of using the OEB's Tariff Schedule and Bill Impacts Model, filed at Exhibit L-07-01, Attachment 1;
- Custom[4] Retail Transmission Services Rates (RTSR) models for derivation of Hydro One Distribution's 2028 and 2031 RTSRs, in lieu of using the OEB's RTSR Workform, filed at Exhibit L-02-01, Attachments 4 and 5.

[2] Hydro One's bill impact model is consistent with the requirements of the OEB's Bill Impacts Model, and the bill impact sheets for all rate classes in all years are provided as Attachments 1 to 5 of Exhibit L-06-01. Hydro One has used this format for bill impacts in all prior applications.
[3] Hydro One's tariff schedules align with the OEB's Tariff Schedule and Bill Impacts Model.
[4] Hydro One does not calculate RTSRs per the OEB's RTSR Workform as noted in Exhibit L-02-01, section 8.3. Rather, Hydro One uses the methodology that has been reviewed and approved by the OEB for Hydro One's distribution rate filings since 2008, which more accurately reflects the share of transmission charges incurred by each class.

Data has been filed in the OEB's workforms in live Microsoft Excel format and ensured that the data reconciles between the models.

A summary of how OEB directions from prior application decisions have been addressed is provided in this Application in Exhibit A-02-04.

3.0 NON-APPLICABILITY OF OEB WORKFORMS

OEB Appendix 2-C – Hydro One Transmission and Distribution

Under section 2.2.3 of the Chapter 2 Distribution Filing Requirements, *Appendix 2C – Depreciation and Amortization Expense* is intended to support the OEB's assessment of whether a distributor's depreciation and amortization expense is reasonable.[1] This Exhibit is not applicable to Hydro One, as the required information is prepared on a Modified IFRS (MIFRS) basis and reflects the OEB's regulatory accounting framework for distributors reporting under IFRS.

Hydro One prepares its financial statements in accordance with U.S. GAAP, where the use of composite or group depreciation for utility assets (ASC 360) does not track individual asset retirements or remaining book values at a granular level. Accordingly, Hydro One is not able to readily identify individual assets that are fully depreciated within its asset classes. Instead, depreciation is applied across pooled asset groups, where accumulated depreciation reflects the overall group rather than specific asset units.

In addition, because remaining life techniques are applied at the group level, estimating the remaining life of individual existing assets is inherently complex and imprecise, as it depends on the aggregate age distribution, historical retirement patterns, and replacement assumptions embedded in the overall depreciation study rather than asset-specific tracking. As a result, the detailed MIFRS-based reporting requirements set out in this appendix, including identification of fully depreciated assets and asset-specific remaining lives, are not aligned with Hydro One's accounting framework and depreciation practices.

Appendix A of the Alliance Study provided at Exhibit E-08-01, Attachment 1 supports the reasonableness of Hydro One's depreciation calculations by demonstrating the application of the broad group depreciation methodology. The study develops depreciation rates based on the expected service lives of asset groups and provides a reasonable basis for allocating asset costs over the periods in which those assets provide service.

Appendix 2-D – HOSSM

Under section 2.5.6.2 of the Chapter 2 Transmission Filing Requirements, Appendix 2-D – Overhead Expense is intended to be filed to identify the burden rates related to the capitalization of costs of self-constructed assets. As HOSSM reports on IFRS, it does not capitalize overhead costs. Therefore, this workform is not applicable to HOSSM.

Entity-Specific Commodity Accounts Analysis Workform – Hydro One Distribution

Pursuant to the OEB's 2024 Decision and Rate Order (EB-2023-0030 and EB-2023-0059), Hydro One was approved to file a Consolidated GA Analysis Workform (now, the Consolidated Commodity Accounts Analysis Workform) for all of its RZs. Hydro One receives one consolidated invoice from the settlement of commodity, bulk transmission and wholesale settlements for all its service territories from the Independent Electricity System Operator (IESO).[5] As such, the reasonability test for Accounts 1588 and 1589 is determined on a consolidated basis.

4.0 COMPLIANCE WITH CUSTOM IR FRAMEWORK EXPECTATIONS

Hydro One's Custom IR Application includes the following key components which align with the expectations for a Custom IR framework set out in the Handbook:

1. <u>Term:</u> Hydro One and HOSSM's Custom IR terms are both over a 5-year term, from 2028-2032, consistent with the guidance in the Handbook.

2. <u>Index for the Annual Rate Adjustment:</u> The proposed Revenue Cap Index includes specific financial incentives for continuous improvement through a custom

[5] EB-2023-0030 and EB-2023-0059, Decision and Rate Orders, June 13, 2024, p. 4

productivity factor for Transmission, Distribution and HOSSM that is supported by third-party empirical evidence (including a supplemental stretch factor on capital). See Exhibits A-04-01, A-04-02, and A-04-03.

3. Benchmarking: The Application is supported by an extensive number of benchmarking studies along with reviews of processes, asset condition analyses and lifecycle studies. See SPF Section 1.3 for details on third-party studies filed with this Application.

4. Performance Metrics: Hydro One has prepared transmission and distribution scorecards in TSP Section 2.5 and DSP Section 3.5, and HOSSM has prepared a scorecard in TSP Section 2.10 Attachment 3. The metrics align with the RRF outcomes of customer focus, operational effectiveness, financial performance, and public policy responsiveness. The proposed targets demonstrate Hydro One and HOSSM's commitment to continuous improvement.

5. Updates: The Application contains updates limited to those described in Exhibits A-04-02 and A-04-03 for Hydro One Transmission, HOSSM, and Hydro One Distribution, respectively.

6. Protecting Customers: Hydro One Transmission and Distribution, and HOSSM continue to propose an Earnings Sharing Mechanism. This will enable the sharing of the benefits of productivity improvements with customers during the plan term and provide ratepayers with protection from utility earnings that become excessive, see Exhibit A-04-01.

4.1 MATERIALITY THRESHOLDS

The following materiality thresholds have been used in this Application:

- $1M for Hydro One Distribution, as defined in section 2.0.8 of the Chapter 2 Filing Requirement for Electricity Distributors, applicable to distributors with a revenue requirement of more than $200M;

- $4M for Hydro One Transmission, as defined in section 2.1.5 of the Chapter 2 Filing Requirement for Electricity Transmitters, applicable to transmitters with a revenue requirement of more than $200M; and
- $0.29M for HOSSM as defined in section 2.1.5 of the Chapter 2 Filing Requirement for Electricity Transmitters, applicable to transmitters with a revenue requirement of $10M and less than or equal to $200M. The materiality threshold has been calculated as 0.65% of HOSSM's approved 2026 revenue requirement of $44.4M.[6]

4.2 FILING OF COMPREHENSIVE SYSTEM PLANS

Hydro One and HOSSM have filed comprehensive system plans in support of forecast capital needs, including a System Plan Framework (SPF), Transmission System Plan (TSP), Distribution System Plan (DSP), and General Plant System Plan (GSP). Hydro One adopted Distribution Filing Requirements[7] to guide the content and structure of its SPF, TSP, and GSP to ensure that all the considerations for a DSP filing are included in the design of its system plans.

5.0 CUSTOMER ENGAGEMENT PROCESS

Hydro One and HOSSM's plans reflect customer needs and preferences, which were identified through a comprehensive two-phase customer engagement process, as detailed in SPF Section 1.6. Hydro One and HOSSM's investment planning, business planning, regulatory process and customer engagement process were fully integrated, allowing Hydro One and HOSSM to develop System Plans that are truly responsive to customer needs.

6.0 HOST & EMBEDDED DISTRIBUTOR FILING REQUIREMENTS

Hydro One is both a host distributor and a partially embedded distributor.

[6] OEB Decision EB-2025-0158, p.1.
[7] Section 2.4 of Chapter 2 Transmission Filing Requirement noting that transmitters may wish to refer to Chapter 5 of the OEB's *Filing Requirements for Electricity Distribution Rate Applications* (DSP Filing Requirements)

Hydro One is partially embedded in Canadian Niagara Power Inc., E.L.K Energy Inc., GrandBridge Energy Inc., ERTH Power Corporation, Essex Powerlines Corporation, Halton Hills Hydro Inc., Hydro Ottawa Limited, InnPower Corporation, Newmarket-Tay Power Distribution Ltd., Niagara Peninsula Energy Inc., North Bay Hydro Distribution Ltd., Elexicon Energy Inc., Enova Power Corp., and Westario Power Inc. Approximately 1% of customer load is supplied through host distributors.

Hydro One is also a host distributor for Alectra Utilities Corporation, Bluewater Power Distribution Corporation, Canadian Niagara Power Inc., Centre Wellington Hydro Ltd., EPCOR Electricity Distribution Ontario Inc., Cooperative Hydro Embrun Inc., E.L.K. Energy Inc., Eastern Ontario Power Inc., GrandBridge Energy Inc., Entegrus Powerlines Inc., ERTH Power Corporation, Essex Powerlines Corporation, Festival Hydro Inc., Greater Sudbury Hydro Inc., Grimsby Power Inc., Halton Hills Hydro Inc., Hearst Power Distribution Company Limited, Hydro 2000 Inc., Hydro Hawkesbury Inc., Hydro Ottawa Limited, InnPower Corporation, Kingston Hydro Corporation, Lakefront Utilities Inc., Lakeland Power Distribution Ltd., London Hydro Inc., Milton Hydro Distribution Inc., Newmarket-Tay Power Distribution Ltd., Niagara Peninsula Energy Inc., North Bay Hydro Distribution Ltd., Northern Ontario Wires Inc., Oakville Hydro Electricity Distribution Inc., Orangeville Hydro Limited, Ottawa River Power Corporation, Renfrew Hydro Inc., Rideau St. Lawrence Distribution Inc., Sioux Lookout Hydro Inc., Toronto Hydro-Electric System Limited, Elexicon Energy Inc., Wasaga Distribution Inc., Enova Power Corp., Wellington North Power Inc., and Westario Power Inc.

Exhibit L-01-02 describes Hydro One’s sub-transmission (ST) rate class. The ST rate class applies to all distributors embedded in Hydro One’s distribution system.

Embedded distributors were engaged as part of Hydro One's customer engagement described in SPF Section 1.6. As detailed in Exhibit L-02-01, section 5.2, the methodology used for the allocation of costs to the ST rate class, as well as the design of ST rates, has not changed from the methodology that was used in Hydro One’s previous distribution rate applications. Hydro One has had approved ST rates applicable to its embedded

distributors since 2008. As such, a statement of support for embedded distributor cost allocation is not applicable because embedded distributors have had the opportunity to review the cost allocation and rate design of the rate applicable to them as part of the regulatory approval process for Hydro One's previous rate applications.

7.0 DEVIATION FROM FILING REQUIREMENTS

Hydro One and HOSSM have complied with the OEB's policies and guidelines set out in the Handbook and Filing Requirements. Where modifications to the OEB's workforms were necessary as noted above, they are noted in the checklists therein, filed at Attachments 1 through 3 of this Exhibit.

8.0 CHANGES TO METHODOLOGY & DESCRIPTION OF WHAT CHANGED

Hydro One included a list of major changes to its methodology compared to previous applications as it impacts the revenue requirement, for which it seeks approval in this Application:

- Change in the revenue cap index for Transmission, Distribution and HOSSM. For changes to Hydro One and HOSSM's revenue requirement framework, please see Exhibits A-04-01, A-04-02 and A-04-03.
- Recovery of Prepaid Cloud Computing Amortization in the capital related revenue requirement to enable cost recovery of amortized cloud amounts during the 2028-2032 rate term as costs for Transmission and Distribution, discussed in Exhibit A-04-01, A-04-02 and E-08-01.

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Hydro One Networks Inc. (Transmission)

EB-2026-0164

Adopted from 2025 Filing Requirement For Electricity Transmitters (issued October 30, 2025)

Transmission Filing Requirements Checklist	Filing Requirement (Page #, Reference)		Yes/No/N/A	Evidence Reference, Notes
2.1 GENERAL REQUIREMENTS				
	Ch 1, p 2	Certification by a senior officer of the transmitter that the evidence filed is accurate, consistent and complete to the best of their knowledge. The applicant is required to provide a similar certification when interrogatory responses or other evidence are filed in a proceeding.	**Yes**	Exhibit A-02-01, Attachment 1
	Ch 1, p 3-4	Confidential Information - Practice Direction has been followed	**Yes**	Exhibit A-02-01
	Ch 1, p 2	Certification by a senior officer stating that the application and any evidence filed in support of the application does not include any personal information unless it is filed in accordance with Rule 9A of the OEB's Rules (and the Practice Direction on Confidential Filings, as applicable). The applicant is required to provide a similar certification when interrogatory responses or other evidence are filed in a proceeding.	**Yes**	Exhibit A-02-01, Attachment 1
	Ch 1, p 2	The certification filed with an application must include that the applicant has the appropriate processes and internal controls for the preparation, review, verification and oversight of account balances being disposed.	**Yes**	Exhibit A-02-01, Attachment 1
	Ch 1, p 6	The OEB also requires a letter from the governing body (e.g. Board of Directors) certifying that it is aware of and approves the submission of the application.	**Yes**	Exhibit A-02-01, Attachment 3
	Ch 1, p 6	Where generative artificial intelligence (AI) is used to generate content in a filing, the applicant must: (1) disclose that generative AI was used to generate content in the filing; and (2) confirm that the accuracy of the filing generated by AI has been verified by the party or representative without the assistance of generative AI. Disclosure must be made either in the certification of evidence section of the application, at the beginning of the document created by generative AI, or in the cover letter to a multi-document package.	**Yes**	Application Cover Letter
	Ch 2, p 4	Provide Chapter 2 appendices that are applicable to their transmission applications	**Yes**	Applicable Chapter 2 appendices are filed under each of the respective exhibits: TSP Section 2.5 Attachment 4 (App 2-G) TSP Section 2.8 Attachment 1 (App 2-AA) TSP Section 2.9 Attachment 1 (App 2-AB) GSP Section 4.8 Attachment 1 (App 2-AA) GSP Section 4.9 Attachment 1 (App 2-AB) Exhibit C-04-04 (App 2-BA) Exhibit E-08-01, Attachment 3 (App 2-BB) Exhibit C-08-02, Attachment 1 (App 2-D) Exhibit D-02-01, Attachment 1 (App 2-H) Exhibit E-02-01, Attachment 1 (App 2-JA, JB, JC, L) Exhibit E-06-01, Attachment 1 (App 2-K) Exhibit E-07-01, Attachment 3 (App 2-KA) Exhibit E-10-01, Attachment 1 (App 2-M) Exhibit E-04-01, Attachment 1 (App 2-N) Exhibit F-01-03 (App 2-OA) Exhibit F-01-04 (App 2-OB) Appendices not provided and reason: - Appendix 2-A and 2-AC a not applicable because it's optional; information is provided in SPF Section 1.6 - Appendix 2-C is not applicable as described in Exhibit A-02-03 -Appendix 2-JD not applicable -Appendices 2-FA, 2- FB, 2-FC, 2-IA, 2-IB, 2 -Q , 2 -R, 2-ZA, 2-ZB are not applicable as they are for Distribution

	Ch 2, p 4	Written direct evidence is to be included before data schedules	Yes	Confirmed
	Ch 2, p 4	Average of the opening and closing fiscal year balances must be used for items in rate base, unless an alternative method is documented and justified.	Yes	Exhibit C-01-01 Exhibit C-04-01
	Ch 2, p 4	Total capitalization (debt and equity) must equate to total rate base	Yes	Confirmed; Exhibit F-01-03 (App 2-OA) Exhibit C-01-01
	Ch 2, p 4	Data for the following years, at a minimum, must be provided unless explicitly stated otherwise: Test year = prospective year (year during which new rate term commences); Bridge year = current year (or the year immediately preceding the test year); Four most recent historical years (or number of years necessary to provide actuals back to and including the most recent OEB-approved test year, but not less than four years); Most recent OEB-approved test year	Yes	Confirmed; Hydro One has provided the required data in its evidence exhibits and its custom spreadsheets
	Ch 2, p 4	Custom IR applicants must include in their evidence forecasts for revenue, costs and inflation for each year of the proposed rate term, and benchmarking evidence supporting the cost forecasts	Yes	Exhibit A-04-01 Exhibit A-04-01, Attachment 1 Exhibit A-04-02
	Ch 2, p 4	Documents must include page numbers and are to be provided in bookmarked and text-searchable PDF format	Yes	Confirmed
	Ch 2, p 5	Tables must also be provided in working Microsoft Excel spreadsheet format where available and practical	Yes	Confirmed
	Ch 2, p 6	Materiality threshold; The applicant must provide justification for material amounts and material annual variances described in its application. The transmitter-specific thresholds are: $65,000 for a transmitter with a transmission revenue requirement less than or equal to $10 million; 0.65% of transmission revenue requirement for a transmitter with a transmission revenue requirement greater than $10 million and less than or equal to $200 million; $4 million for a transmitter with a transmission revenue requirement of more than $200 million	Yes	Exhibit A-02-03 TSP Section 2.12 GSP Section 4.11
2.2 ACCOUNTING STANDARDS				
	Ch 2, p 7	State accounting standard(s) used in historical, bridge and test years and summarize changes since last filing.	Yes	Exhibit A-06-01
2.3 EXHIBIT 1 – APPLICATION OVERVIEW AND ADMINISTRATIVE DOCUMENTS				
2.3.1 Application Executive Summary and Business Plan				
	Ch 2, p 9	Overview of past and expected future performance, business plan and objectives and how they align with RRFE objectives	Yes	Exhibit A-03-01
	Ch 2, p 9	Summary identifying key elements of the proposals and the Business Plan underpinning application, as guided by RRFE including customer feedback reflected in the transmitter's objectives	Yes	Exhibit A-02-01 Exhibit A-03-01 Exhibit A-03-01, Attachment 1
	Ch 2, p 9	Revenue Requirement - request, changes from previous revenue requirement and schedule of drivers of change from last OEB-approved year	Yes	Exhibit A-03-01
	Ch 2, p 9	Budgeting Assumptions - Economic overview. Budget Directives and Guidelines. Budget directives and guidelines (capital and operating budgets), including economic assumptions used; Budget Assumptions: economic overview (such as growth and inflation)	Yes	Exhibit A-03-01
	Ch 2, p 9	Load Forecast Summary - Load growth (% change from last OEB-approved application) and description of forecasting methods used	Yes	Exhibit A-03-01
	Ch 2, p 9	TSP - Summary of drivers and elements of plan, details of investment planning process, capital expenditures requested for test years, changes in capital expenditures from OEB approved	Yes	Exhibit A-03-01 Summary of drivers and elements of plan - TSP Section 2.8, GSP Section 4.8; Details of Investment Planning Process - SPF Section 1.7, TSP Section 2.7, GSP Section 4.7; Capital Expenditures - TSP Section 2.8, GSPE Section 4.8; Changes in Capital Expenditures - TSP Section 2.9, GSP Section 4.9
	Ch 2, p 10	Rate Base and Capital Plan: Summary of the main drivers of the capital plan and cost trends; rate base requested for the test year(s); Change in rate base from last OEB-approved ($ and %); Capital expenditures requested for the test year; Change in capital expenditures from last OEB-approved ($ and %)	Yes	Exhibit A-03-01 TSP Section 2.8 TSP Section 2.9, Appendix 2-AB GSP Section 4.8 GSP Section 4.9 Exhibit C-01-01 (Rate Base)

	Ch 2, p 13	Performance and Reporting - Proposed scorecard	**Yes**	SPF Section 1.5 TSP Section 2.5
	Ch 2, p 10	OM&A - Request for test years and change from last OEB-approved; summary of overall drivers and cost trends; total compensation for the test years and the change from the last OEB-approved ($ and %); Service Level Agreement (SLA) fee allocation structure and summary	**Yes**	Exhibit A-03-01 (Executive Summary) Exhibit E-02-01 (OM&A) Exhibit D-02-03 (Affiliate Services) Exhibit E-04-01 (Common and Other OM&A)
	Ch 2, p 10	Cost of Capital - Whether the OEB's cost of capital parameters are being used and rationale for deviations from OEB's methodology (note: OEB decision issued March 27, 2025 outlines updated methodology for future mechanistic updates); A summary table showing the proposed capital structure and cost of capital parameters resulting in the Weighted Average Cost of Capital (WACC). A statement as to whether or not the applicant is using the OEB's cost of capital parameters Summary and rationale of any deviations from the OEB's cost of capital methodology	**Yes**	Exhibit A-03-01 Exhibit F-01-01
	Ch 2, p 10	Cost Allocation and Rate Design - Summary of how costs are allocated to the three rate pools	**Yes**	Exhibit A-03-01
	Ch 2, p 10	Deferral and Variance Accounts - Accounts requested for disposition, total disposition ($) and disposition period(s) and any new DVAs requested and any discontinuation of existing DVAs	**Yes**	Exhibit A-03-01 Exhibit G-01-01
	Ch 2, p 10	Bill Impacts - Summary of impacts ($ and %) at wholesale level (i.e. change in UTR) and for typical retail customers (750 kWh/month for residential and 2000 kWh/month for GS < 50 kWh)	**Yes**	Exhibit A-03-01
	Ch 2, p 10	Summary of any proposed mitigation plans to address rate impacts on specific customer classes or overall	*N/A*	Transmission rates are uniform
2.3.2 Transmission System Overview				
	Ch 2, p 11	Description of transmitter's service area, including a general description and map(s) showing where the transmitter operates within the province and the communities (if any) serviced by the transmitter	**Yes**	TSP Section 2.1 TSP Section 2.8
	Ch 2, p 11	Details of the investment planning process, including asset condition assessment, identification and prioritization of capital investments, trade- offs with the operations, maintenance and administration expenditures	**Yes**	SPF Section 1.7 TSP Section 2.2 (Asset Condition) TSP Section 2.7 TSP Section 2.8 TSP Section 2.12 GSP Section 4.2 GSP Section 4.7 GSP Section 4.8 GSP Section 4.11
	Ch 2, p 11	Transmission System Plan and relevant policy context and changes, including current issues identified through Ontario's Regional Planning exercise	Yes	SPF Section 1.7 TSP Section 2.6 TSP Section 2.7 TSP Section 2.8
	Ch 2, p 11	Summary of the major drivers and elements of the transmitter's capital plan	**Yes**	TSP Section 2.1 TSP Section 2.8 GSP Section 4.1 GSP Section 4.7
	Ch 2, p 11	Capital expenditures requested for the test year(s)	**Yes**	TSP Section 2.8 TSP Section 2.8, Attachment 1 (Appendix 2-AA) GSP Section 4.8 GSP Section 4.8, Attachment 1 (2-AA)
	Ch 2, p 11	Change in capital expenditures from last OEB-approved ($ and %)	**Yes**	TSP Section 2.9, TSP Section 2.9, Attachment 1 (Appendix 2-AB) GSP Section 4.9 GSP Section 4.9, Attachment 1 (2-AB)
2.3.3 Customer Engagement				
	Ch 2, p 11	Customer engagement process and activities	**Yes**	SPF Section 1.6 and Attachment 1 TSP Section 2.6 TSP Section 2.7 GSP Section 4.6 GSP Section 4.7

	Ch 2, p 11	Customer needs including end-use load customers and generator customers	**Yes**	SPF Section 1.6 and Attachment 1 TSP Section 2.6 TSP SEction 2.7 GSP Section 4.6 GSP Section 4.7
	Ch 2, p 12	How the application responds to customer needs	**Yes**	SPF Section 1.6 SPF Section 1.7 TSP Section 2.7 GSP Section 4.7
	Ch 2, p 12	Customer satisfaction surveys engagement activities	**Yes**	SPF Section 1.6 SPF Section 1.6 , Attachment 1
	Ch 2, p 12	Appendix 2AC in the Distribution Filing Requirements helpful in structuring this evidence	*N/A*	Note: Appendix 2-AC is not filed as it is optional SPF Section 1.6 (customer- engagement)
	Ch 2, p 12	Responses to letters of comment	*N/A*	Hydro One has not yet received letters of comment filed with the OEB
2.3.4 Financial Information				
	Ch 2, p 12	Non-consolidated audited financial statements of the utility (excluding operations of affiliated companies that are not rate-regulated) for which the application has been made, for the most recent three historical years (i.e. two years' statements must be filed).	**Yes**	Exhibit A-06-02, Attachments 1 & 2 (HONI Tx)
	Ch 2, p 12	Where the regulated entity conducts more than one activity regulated by the OEB, the transmitter shall disclose information separately about each of its operating segments in accordance with the Segment Disclosure provisions which corporate entities are encouraged to adopt by the CPA Canada Handbook	**Yes**	Exhibit A-06-03
	Ch 2, p 12	If the most recent final audited financial statements are not available at the time of filing the application, the draft financial statements must be filed and the final audited financial statements, together with a summary of the main changes from the draft statements (if there are any) must be provided as soon as they are available. Alternatively, if the transmitter publishes its financial statements publicly, a link to the website may be provided.	*N/A*	Not Applicable. See Exhibit A-06-02, Attachments 1 & 2 (HONI Tx)
	Ch 2, p 12	A detailed reconciliation of the financial results shown in the audited financial statements with the regulatory financial results filed in the application. The reconciliation must include: o The separation of non-utility businesses, for example the fixed assets. o The identification of any deviations that are being proposed between the audited financial statements and the regulatory financial statements including the identification of any prior OEB approvals for such deviations	**Yes**	Exhibit A-06-03
	Ch 2, p 13	Annual Report and Management's Discussion and Analysis for the most recent year of the parent company, as available and applicable. If a transmitter also files an Annual Information Form publicly, a link to this Form should be provided.	**Yes**	Exhibit A-06-04 Exhibit A-06-04, Attachment 1
	Ch 2, p 13	Rating Agency Reports	**Yes**	Exhibit F-01-05, Attachments 1A - 3
	Ch 2, p 13	Prospectuses & information circulars for recent and planned public offerings	**Yes**	Exhibit F-01-06, Attachments 1 & 2
	Ch 2, p 13	Any change in tax status (e.g., from a corporation to a limited partnership). A description of existing accounting orders and list of any departures from these orders. Any departures from the Uniform System of Accounts (USoA). The accounting standards used for general purpose financial statements and when those standards were adopted.	**Yes**	Exhibit E-09-01 (Tax Exhibit) Exhibit G-01-01, Attachment 1 (Accounting Orders) Exhibit G-01-03 Exhibit A-06-01 (Accounting Standard and Changes to Accounting Policies)
2.3.5 Performance Measurement and Reporting				
	Ch 2, p 13	A proposed scorecard - measure and monitor transmitter's performance including key RRF objectives of public policy responsiveness, financial performance, operational effectiveness and customer focus	**Yes**	SPF Section 1.5 TSP Section 2.5
	Ch 2, p 13	Demonstrate how the proposed scorecard meets the requirements for performance standards set out in section 4.5.1 of the TSC	**Yes**	TSP Section 2.5 TSP Section 2.4 TSP Section 2.4, Attachments 2, 3, and 5
	Ch 2, p 13	Discuss any outstanding areas of non-compliance and the effect they have had on the application, including any relief sought	*N/A*	There are no outstanding areas of non-compliance, and no relief has been requested.

2.3.6 Administration				
	Ch 2, p 13	Table of Contents	**Yes**	Exhibit A-01-01
	Ch 2, p 13	Statement identifying customers materially affected by the application	**Yes**	Exhibit A-02-01
	Ch 2, p 13	Internet address for viewing of application; and any social media accounts (with addresses) used by the applicant to communicate with its customers.	**Yes**	Exhibit A-02-01
	Ch 2, p 13	Primary contact information (name, address, phone, fax, email)	**Yes**	Exhibit A-02-01
	Ch 2, p 14	Identification of legal representation	**Yes**	Exhibit A-02-01
	Ch 2, p 14	Requested effective date	**Yes**	Exhibit A-02-01
	Ch 2, p 14	A statement of where the notice of hearing should be published and the rationale for why the stated publication(s) is/are appropriate. The OEB has implemented a publication process that no longer requires that the applicant publish the notice of hearing. However, the OEB still requires the applicant's recommendation(s) regarding publication media.	**Yes**	Exhibit A-02-01
	Ch 2, p 14	Bill impacts for typical Ontario residential customer and Ontario General Service customer	**Yes**	Exhibit A-02-01
	Ch 2, p 14	Form of hearing requested (written or oral)	**Yes**	Exhibit A-02-01
	Ch 2, p 14	List of approvals requested including accounting orders	**Yes**	Exhibit A-02-01
	Ch 2, p 14	Proposed length of the term and proposed method for establishing revenue requirement for each year of the term	**Yes**	Exhibit A-02-01 Exhibit A-02-03 Exhibit A-04-01 Exhibit A-04-02
	Ch 2, p 13	Changes in tax status	**Yes**	Exhibit E-09-01
	Ch 2, p 13	Existing Accounting Orders	**Yes**	Exhibit G-01-01 Exhibit G-01-01, Attachment 1 Exhibit G-01-03
	Ch 2, p 14	Map of assets and operations showing where the utility operates within the province, and the communities serviced by the utility.	**Yes**	TSP Section 2.1
	Ch 2, p 14	Corporate and utility organizational structure, planned changes, rationale for changes and cost impact	**Yes**	Exhibit A-07-01 Exhibit A-07-01, Attachment 1: Corporate entities relationship chart (organizational structure)
	Ch 2, p 13	The Accounting Standard used and when it was adopted	**Yes**	Exhibit A-06-01
	Ch 2, p 14	Deviations from filing requirements, if any	**Yes**	Exhibit A-02-03
	Ch 2, p 14	Changes to methodologies used in previous applications: A statement identifying and describing any changes to the methodologies as used in previous applications	**Yes**	Exhibit A-02-03
	Ch 2, p 14	Confirmation that accounting treatment is segregated for non-regulated business	**Yes**	Exhibit A-06-03
	Ch 2, p 14	Indication of how prior OEB Decisions or Orders have been satisfied and impact on current application Identification of OEB directions from any previous OEB Decisions and/or Orders, this includes any commitments made as part of an approved settlement. The applicant must clearly indicate how these are being addressed in the current application	**Yes**	Exhibit A-02-04
	Ch 2, p 15	All responses to matters raised in letters of comment filed with the OEB during the course of the proceeding.	*N/A*	No letters have been filed
2.4 EXHIBIT 2 – TRANSMISSION SYSTEM PLAN				
General - Transmission System Overview				
	Ch 2, p 15	Transmitters may refer to Chapter 5 of the Distribution Filing Requirements for guidance on content and structure of the TSP.	**Yes**	TSP Section 2.0 GSP Section 4.0
2.4.1 TSP Overview		*TSP Overview must include a high-level summary of the investment planning process including:*		
	Ch 2, p 15	The strategic plan for the utility and overall strategy for investments	**Yes**	SPF Section 1.7 TSP Section 2.7 GSP Section 4.7

	Ch 2, p 15	The longer term economic and planning assumptions	**Yes**	SPF Section 1.7
	Ch 2, p 15	The asset management plan	**Yes**	SPF Section 1.7 TSP Section 2.7 GSP Section 4.7
	Ch 2, p 15	A description of how investments are prioritized and selected	**Yes**	SPF Section 1.7 TSP Section 2.7 GSP Section 4.7
	Ch 2, p 15	A discussion of transmission investments identified in the regional planning process	**Yes**	SPF Section 1.2 TSP Section 2.12
	Ch 2, p 15	Highlights of recent and proposed investments and their fit with the strategic plan	**Yes**	TSP Section 2.8
	Ch 2, p 15	A description of how the needs of customers and overall system planning policy objectives are being reflected	**Yes**	SPF Section 1.6 SPF Section 1.7 TSP Section 2.7 GSP Section 4.7
	Ch 2, p 15	Consideration of public policy objectives, including the OEB's statutory objectives such as facilitating the maintenance of a financially viable electricity industry, promoting electricity conservation and demand management, and facilitating the implementation of a smart grid and the connection of renewable energy generation.	**Yes**	TSP Section 2.5 TSP Section 2.6
	Ch 2, p 15	The linkages and trade-offs between certain capital projects and ongoing OM&A spending	**Yes**	TSP Section 2.8 GSP Section 4.8
	Ch 2, p 15-16	A transmitter's investment projects and programs must be grouped for filing purposes into one of the four investment categories listed below: System access investments are modifications (including asset relocation) to a transmission system that a transmitter is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the transmission system. System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the transmitter's system to provide customers with electricity services. System service investments encompass modifications to ensure that a transmitter's system continues to meet operational objectives while addressing anticipated future customer electricity service requirements. General plant investments encompass modifications, replacements or additions to a transmitter's assets that are not part of its transmission system including land and buildings, tools and equipment, rolling stock and electronic devices and software used to support day to day business and operations activities. A project or program involving two or more drivers associated with different categories should be placed in the category corresponding to the trigger driver. For example, a project triggered by the need to replace end of service life components in a transmission station should be considered a system renewal investment, even if in anticipation of future system requirements (a system service driver) the project includes assets rated for a higher voltage.	**Yes**	TSP Section 2.8 TSP Section 2.12 GSP Section 4.8 GSP Section 4.11
2.4.2 Asset Management Plan				
	Ch 2, p 16	Asset management plan, including the utility's asset management policy, strategy and objectives	**Yes**	SPF Section 1.7 TSP Section 2.2 TSP Section 2.7 GSP Section 4.2 GSP Section 4.7
	Ch 2, p 16	Inventory and assessment of the condition of capital assets whose net book value is material to the transmitter (by class and inclusion in BES); and how this inventory informs plan for capital expenditures and maintenance expenditures	**Yes**	TSP Section 2.2
	Ch 2, p 17	Identify NERC exemptions, planned or in progress NERC exemption requests and associated costs if exemption denied	**Yes**	There are no exemptions being sought from NERC or any material costs expected
2.4.2.1 Planning Process				
	Ch 2, p 16	A transmitter should provide the processes used to identify, select, prioritize (including reprioritizing investments over the five-year term), optimize and pace the execution of investments over the term of the TSP. A transmitter should also demonstrate that it has considered the potential risks of proceeding/not proceeding with individual capital expenditures. Transmitters that have connected customers should be able to demonstrate that they have considered the correlation between their capital plan and customer feedback and needs.	**Yes**	SPF Section 1.6 SPF Section 1.7 TSP Section 2.7 TSP Section 2.12 GSP Section 4.7 GSP Section 4.11

	Ch 2, p 17	A transmitter should demonstrate how it undertakes system optimization using an approach that considers the transmitter's whole system. This should include, where applicable, assessing the use of non-wires solutions, cost-effective implementation of transmission improvements, and other innovative technologies.	**Yes**	SPF Section 1.7 TSP Section 2.7 TSP Section 2.12 GSP Section 4.7 GSP Section 4.11
	Ch 2, p 17	A transmitter must also demonstrate that it has a planning process for future capacity needs of its system. Transmitters should consider the guidance provided in the OEB's publication "Load Forecast Guideline for Ontario" provided by the Regional Planning Process Advisory Group (RPPAG).	**Yes**	SPF Section 1.2 TSP Section 2.7 GSP Section 4.7
	Ch 2, p 17	Single-asset transmitters may utilize another transmitter's asset management process, rather than develop their own, but should explain how it is ensuring that the other transmitter's asset management process is cost-effective, and provide a summary of how the applicant's assets were considered in the other transmitter's most recent investment planning activities.	*N/A*	Not Applicable
	Ch 2, p 17	A transmitter should identify, describe, and summarize the data used in the processes above.	**Yes**	SPF Section 1.6 SPF Section 1.7 TSP Section 2.2 TSP Section 2.7 GSP Section 4.2 GSP Section 4.7
2.4.2.2 Overview of Assets Managed				
	Ch 2, p 17	A transmitter should provide an overview of its service area (e.g., system configuration; urban/rural; temperate/extreme weather) pertinent for supporting its capital expenditures over the forecast period.	**Yes**	TSP Section 2.1
	Ch 2, p 17	A transmitter should provide asset information (e.g., asset capacity and utilization; asset condition; asset failures/performance; asset risks; and asset demographics), by major asset type, that may help explain the specific need for the capital expenditures and demonstrate that a transmitter has considered all economic alternatives.	**Yes**	TSP Section 2.1 TSP Section 2.2 GSP Section 4.1 GSP Section 4.2
	Ch 2, p 17	The inventory should identify in which pool each class of asset belongs, and identify which of these are part of the BES as defined by applicable NERC Standards	**Yes**	TSP Section 2.1 TSP Section 2.2 Exhibit H-02-01 Exhibit H-02-02
	Ch 2, p 17	The transmitter shall identify any exemptions received from NERC, including any such requests that are planned or in progress, and a discussion of any associated costs in the event that the exemption is denied.	*N/A*	There are no exemptions being sought from NERC or any material costs expected
2.4.2.3 Asset Lifecycle Optimization Policies and Practices				
	Ch 2, p 18	The information provided should be sufficient to show the trade-off between spending on new capital (i.e. replacement) and life-extending refurbishment. A transmitter should also be able to demonstrate that it has carried out cost-effective system operations and maintenance (O&M) activities to sustain an asset to the end of its service life (and can include references to the TSC).	**Yes**	TSP Section 2.2 TSP Section 2.8 TSP Section 2.12 Exhibit E-02-02 GSP Section 4.7
	Ch 2, p 18	A transmitter should explain the processes and tools it uses to forecast, prioritize, and optimize system renewal spending and how it intends to operate within budget envelopes. For prioritizing capital expenditures, a transmitter should explain the approaches it uses to balance a customer's need for reliability and capital expenditure costs.	**Yes**	SPF Section 1.7 TSP Section 2.2 TSP Section 2.7 GSP Section 4.2 GSP Section 4.7
	Ch 2, p 18	A transmitter should also be able to demonstrate that in planning the lifecycle of an asset, it has considered the future capacity requirements of the asset such that it does not need to be replaced prematurely due to capacity constraints.	**Yes**	SPF Section 1.7 TSP Section 2.2 TSP Section 2.7 GSP Section 4.2 GSP Section 4.7
	Ch 2, p 18	A transmitter should provide a summary of any important changes to its asset life optimization policies, processes, and tools since the last TSP filing.	**Yes**	TSP Section 2.2 - there have been no material changes to the overarching asset lifecycle framework
2.4.3 Regional Planning Considerations				
	Ch 2, p 18	Information on the regional planning processes in which it participates and demonstrating that regional considerations have been considered and addressed	**Yes**	SPF Section 1.2 TSP Section 2.6
	Ch 2, p 18	Final Regional Infrastructure Plan (RIP) describing investments in transmission or distribution facilities set out in the TSP	**Yes**	SPF Section 1.2 and Attachments

	Ch 2, p 18	Identify any investments from the RIP for which the applicant will be seeking approval The applicant shall also provide a copy of the final Integrated Regional Resource Plan, where applicable	**Yes**	SPF Section 1.2 TSP Section 2.12 in Investment Summary Documents where applicable
	Ch 2, p 18	Where regional planning is underway but a RIP is not yet complete, the applicant shall submit a letter form the IESO identifying the status of the regional planning process and potential impacts on the applicant's investment plans.	**Yes**	SPF Section 1.2 and Attachments
	Ch 2, p 18	Where the applicant is not required to participate in regional planning, the applicant shall submit its needs assessment report documenting that regional planning is not required	**Yes**	SPF Section 1.2 and Attachments
	Ch 2, p 18	Identify investments spanning more than one region and identify the relationship between the planning process	**Yes**	SPF Section 1.2 and Attachments
2.4.3.1 Coordinated Planning with Third Parties				
	Ch 2, p 19	Description of the consultation including: the purpose of the consultation; whether the transmitter initiated the consultation or was an invitee; participants in the consultation; deliverables and impact on plan	**Yes**	SPF Section 1.2 TSP Section 2.6
	Ch 2, p 19	Where a final deliverable of the regional planning process is expected but not available at the time of filing, the transmitter must provide information indicating: The role of the transmitter in the consultation ; The status of the consultation process ;Where applicable, the expected date(s) on which final deliverables are expected to be issued	**Yes**	TSP Section 1.2
2.4.4 Capital Expenditures				
	Ch 2, p 20	Capital expenditure plan overview including proposed capital expenditures over the five-year planning period.	**Yes**	TSP Section 2.8 GSP Section 4.8
	Ch 2, p 20	The capital expenditure plan should set out and comprehensively justify a transmitter's proposed capital expenditures over a five-year planning period, including investment and asset-related O&M expenditures.	**Yes**	TSP Section 2.8 TSP Section 2.12 GSP Section 4.8 GSP Section 4.11 Exhibit E-02-01 Exhibit E-04-01
	Ch 2, p 20	Investments justified in whole or in part by reference to specific aspects of the planning process.	**Yes**	SPF Section 1.7 TSP Section 2.7 TSP Section 2.8 TSP Section 2.12 GSP Section 4.7 GSP Section 4.8 GSP Section 4.11
2.4.4.1 Capital Expenditure Summary				
	Ch 2, p 20	Summary of capital expenditure performance over the past four historical years, plus the bridge year including the bridge year and five future years including the test year(s), showing treatment of contributed capital and additions and deductions from Construction Work in Progress	**Yes**	Exhibit C-04-01 (Continuity Schedule) Exhibit C-04-05 (CWIP) TSP Section 2.1 TSP Section 2.8 and Attachment 1 TSP Section 2.9 and Attachments 1-5 GSP Section 4.1 GSP Section 4.8 and Attachment 1 GSP Section 4.9 and Attachments 1-5
	Ch 2, p 20	An analysis of capital expenditure performance over the past four historical years, plus the bridge year. The analysis should include an explanation of variances between actual and OEB-approved/planned costs and volume of work for each investment.	**Yes**	TSP Section 2.9 and Attachments 1-5 GSP Section 4.9 and Attachments 1-5
	Ch 2, p 20	An analysis of capital expenditures for the five future years if electing a five-year term, including the test year(s). The analysis should show capital expenditures, treatment of contributed capital and additions and deductions from Construction Work in Progress.	**Yes**	TSP Section 2.8 and Attachment 1 GSP Section 4.8 and Attachment 1 Exhibit C-04-01 (Continuity Schedule) Exhibit C-04-05 (CWIP)
	Ch 2, p 20	A comparison of capital expenditures in the five future years versus the five historical years.	**Yes**	TSP Section 2.8 TSP Section 2.12 GSP Section 4.8 GSP Section 4.11
	Ch 2, p 20	A summary of any important modifications to typical capital programs since the last TSP (e.g., changes to individual asset strategies).	**Yes**	TSP Section 2.2

	Ch 2, p 20	The proposed accounting treatment, including the treatment of cost of funds, for investments spanning more than one year	**Yes**	Exhibit C-08-01
	Ch 2, p 20	A description of the impacts of capital expenditures on O&M for each year, or a statement that the capital plans did not impact O&M costs.	**Yes**	TSP Section 2.8 GSP Section 4.8
2.4.4.2 Justifying Capital Expenditures				
	Ch 2, p 20-21	Provide information to enable OEB's assessment of how a transmitter's TSP controls costs through identification, optimization, prioritization, pacing of capital-related expenditures and how overall capital budget envelope was developed.	**Yes**	SPF Section 1.7 TSP Section 2.7 GSP Section 4.7
	Ch 2, p 21	Discuss how the application keeps pace with technological changes and integrates cost-effective innovative investments and traditional planning needs such as load growth, asset condition and reliability	**Yes**	TSP Section 2.2 TSP Section 2.6 TSP Section 2.8 TSP Section 2.12 GSP Section 4.2 GSP Section 4.6 GSP Section 4.8 GSP Section 4.11
	Ch 2, p 21	Justify the total amount of proposed capital expenditures and explain how the expenditures over the next five years will achieve its objectives	**Yes**	TSP Section 2.8 TSP Section 2.12 GSP Section 4.8 GSP Section 4.11
	Ch 2, p 21	Comment on lumpy investment years and rate impacts of capital investments in the long-term.	**Yes**	TSP Section 2.8 GSP Section 4.8 Exhibit C-02-01 Exhibit A-04-02 (the C-factor)
	Ch 2, p 21	On a project specific basis, grouped appropriately, or by program including similar projects across a portfolio of assets: Drivers of capital expenditure increases for the test year(s)	**Yes**	TSP Section 2.8 TSP Section 2.12 GSP Section 4.8 GSP Section 4.11
	Ch 2, p 21	On a project specific basis, grouped appropriately, or by program including similar projects across a portfolio of assets: The basis for the estimated budget for the project or program; (e.g. historical cost, preliminary engineering estimates, request for proposals)	**Yes**	TSP Section 2.8 TSP Section 2.12 GSP Section 4.8 GSP Section 4.11
	Ch 2, p 21	On a project specific basis, grouped appropriately, or by program including similar projects across a portfolio of assets: identification of any project that has been undertaken in compliance with a condition included in the transmitter's licence as a reuslt of a directive issued by the Minister of Energy to the OEB or has been declared a priority project by the Lieutenant Governor in Council	**Yes**	TSP Section 2.8 TSP Section 2.12 GSP Section 4.8 GSP Section 4.11
	Ch 2, p 21	For projects / programs with a value greater than the materiality threshold and not subject to a leave to construct application, provide the following capital expenditure information: a description of the need, scope and purpose of the project or program customer attachments load and capital costs cost-benefit analysis discussion of other capital and non-capital alternatives which were considered and rejected in favour of the proposed project or program detailed information on the priority of the project or program relative to other investments and risks of not proceeding with the project / program for sustainment / renewal, details on the condition or life expectancy of the asset(s) being improved through reinvestment detailed breakdown of starting dates and in-service dates for each project / program	**Yes**	SPF Section 1.7 TSP Section 2.12 GSP Section 4.11
	Ch 2, p 21-22	For any projects or programs that requires leave to construct approval under the OEB Act, where construction is to commence in a test year: (i) a summary of the evidence for the leave to construct application; and (ii) the OEB case number, if a leave to construct application has been filed with the OEB	**Yes**	TSP Section 2.8, Attachment 2 TSP Section 2.12
	Ch 2, p 22	For all other capital expenditures (those not already addressed above): describe components of capital expenditure and provide a reconciliation of capital components to total capital budget	**Yes**	TSP Section 2.8 TSP Section 2.12 GSP Section 4.8 GSP Section 4.11
	Ch 2, p 22	Cost benchmarking studies (internal or external) or utility cost comparisons (mandatory for Custom IR applications)	**Yes**	Exhibit A-04-01 , Attachment 1 SPF Section 1.3 summary of all benchmarking studies TSP Section 2.3 GSP Section 4.3

	Ch 2, p 22	Description of quantifiable continuous improvement or efficiency gains, how they will be achieved and benefit customers	**Yes**	Exhibit A-04-01 Exhibit A-04-02 SPF Section 1.4 TSP Section 2.11 GSP Section 4.10 Exhibit E-02-05
	Ch 2, p 22	A proposal to mitigate the potential for any significant earning by the transmitter above the regulatory net income supported by the approved ROE, using such tools as a capital variance account or an ESM	**Yes**	Exhibit A-04-01 Exhibit G-01-03 (continuance of ESM with modification)
2.5 EXHIBIT 3 – RATE BASE				
	Ch 2, p 22	This section must include the following: 1) Rate Base 2) Fixed Asset Continuity Schedule 3) Depreciation, Amortization and Depletion 4) Allowance for Working Capital 5) Customer Connection and Cost Recovery Agreements 6) Capitalization Policy		
2.5.1 Rate Base				
	Ch 2, p 23	State whether capital expenditures are equivalent to in-service additions. If so, variance explanations are only required once. If not, the applicant should specify whether it is explaining variances based on capital expenditures or in-service additions (both are not required).	**Yes**	Exhibit C-02-01
	Ch 2, p 23	Opening and closing balances and the averages thereof for gross assets and accumulated depreciation. Rate base may include an allowance for working capital. Rate base must be supported by historical actuals, bridge year (actuals to date and balance of year as budgeted) and test years. This section must include a table showing the components of the last OEB-approved rate base, the proposed test year rate base and the variances.	**Yes**	Exhibit C-01-01 (Rate Base) Exhibit C-04-01 to C-04-03 (Continuity Schedules) Exhibit C-05-01 (Working Capital Allowance)
2.5.2 Fixed Asset Continuity Schedule				
	Ch 2, p 23-24	Continuity statements (year end balance, including any capitalized interest during construction and any capitalized overhead costs). Explanation for any restatement (e.g. due to change in accounting standards) Year over year variance analysis required, including written explanation where variance greater than materiality threshold Hist. OEB-Approved vs Hist. Actual (most recent historical OEB-approved year) Hist. Act. vs. preceding Hist. Act. (for relevant number of years) Hist. Act. vs. Bridge Bridge vs. Test	**Yes**	Exhibit C-01-01 Exhibit C-04-02 (Gross Fixed Assets) Exhibit C-04-03 (Accumulated Depreciation) Exhibit C-04-04 (Appendix 2-BA) Exhibit C-04-05 (CWIP)
	Ch 2, p 24	Opening and closing balances of gross assets and accumulated depreciation must correspond to fixed asset continuity statements. Otherwise explanation and reconciliation required. Reconciliation must be between the last actual year, bridge year and test years net book value balances reported on a fixed aset continuity schedule (Appendix 2-BA) and the balances included in the rate base calculation.	**Yes**	Exhibit C-01-01 Exhibit C-04-02 and C-04-03 Exhibit C-04-04 (Appendix 2-BA)
	Ch 2, p 24	Continuity statements must be reconcilable to the calculated depreciation expenses and presented by asset account.	**Yes**	Exhibit C-04-04 (Appendix 2-BA) Exhibit E-08-01, Attachment 2
	Ch 2, p 24	Information outlined in the fixed asset continuity schedule is provided for each year, in both the application material and in working Microsoft Excel format.	**Yes**	Exhibit C-01-01 Exhibit C-04-04 (Appendix 2-BA)
2.5.3 Depreciation, Amortization and Depletion Gross Assets - PP&E and Accumulated Depreciation				
	Ch 2, p 24	Proposed levels of depreciation / amortization expense must appropriately reflect the useful lives of the applicant's assets and the OEB's policies	**Yes**	Exhibit E-08-01 Exhibit E-08-01, Attachment 3
	Ch 2, p 19	Detailed breakdown of the in-service capital additions for the test year(s)	**Yes**	Exhibit C-02-01
	Ch 2, p 24	Details for depreciation, amortization and depletion by asset group for historical, bridge and test years, including asset amount and rates of depreciation or amortization.	**Yes**	Exhibit E-08-01, Attachment 2
	Ch 2, p 24	Any Asset Retirement Obligations (AROs) and any associated depreciation or accretion expenses related to the AROs identified, including the basis for and calculation of these amounts.	**Yes**	Exhibit E-08-01

	Ch 2, p 24	Capital additions normally attract six months of depreciation expense when they enter service in the test year ("half-year" rule). The OEB may consider a different approach but applicants must identify their historial practices and must support any variance from the half-year rule whether that variance applies to the test year, subsequent years or both.	**Yes**	Exhibit E-08-01
	Ch 2, p 25	A copy of the depreciation/amortization policy or a written description of the depreciation practices followed and used in preparing the application.	**Yes**	Exhibit E-08-01, Attachment 1
	Ch 2, p 25	A summary of changes to its depreciation/amortization policy made since the last rebasing application filing.	**Yes**	Exhibit E-08-01
	Ch 2, p 25	If filing under MFIRS accounting standards, signifiant components of each capital asset must be depreciated separately. Deviations from this practice must be explained.	*N/A*	Not Applicable - Hydro One Transmission is not under MFIRS accounting standards
	Ch 2, p 25	State if any changes have been made to the depreciation/amortization policy or asset service lives since last rebasing.	**Yes**	Exhibit E-08-01
	Ch 2, p 25	If changes have been made to the depreciation/amortization policy or asset service lives since last rebasing: Identify the changes and provide a detailed explanation for the causes of the changes Provide a study to justify changes in useful lives, if applicable Provide a list detailing all asset service lives and reconcile to the USoA	**Yes**	Exhibit E-08-01 Exhibit E-08-01, Attachment 3
2.5.4 Allowance for Working Capital				
	Ch 2, p 25	Working Capital - Lead/Lag Study for two time periods: the time between the date customers receive service and the date the customers' paymets are vaailable to the transmitter (the lag); and the time between the date when the transmitter receives goods and the date they are paid for (the lead)	**Yes**	Exhibit C-05-01, Attachment 1 (Hydro One Transmission - Lead/Lag Study)
	Ch 2, p 25	Lead/Lag Study - leads and lags measured in days, dollar-weighted; WCA = dollar-weighted net lag (lag - lead) / 365 (366 in a leap year) x annual test year cash expenses	**Yes**	Exhibit C-05-01, Attachment 1 (Hydro One Transmission - Lead/Lag Study)
	Ch 2, p 25	For transmitters in Ontario, the lead/lag study should reflect the fact that the IESO provides the bulk of the revenue to the transmitter, with minimal contributions from other sources.	**Yes**	Exhibit C-05-01, Attachment 1 (Hydro One Transmission - Lead/Lag Study)
2.5.5 Customer Connection and Cost Recovery Agreements				
	Ch 2, p 26	The transmitter should show customer contribution amounts separately as an offset to rate base.	**Yes**	Exhibit C-07-01. Capital / in-service additions included in rate base are net of customer contributions
	Ch 2, p 26	Provide the number of CCRAs executed with Ontario rate-regulated Dx due to be reviewed during the rate period because they will reach a fifth anniversary and provide aggregated estimate of total expected true-up contributions and proceeds from bypass agreements	*N/A*	Exhibit C-07-01 - Hydro One expects the forecasts will be accurate, and does not expect further capital contributions in the future
	Ch 2, p 26	Detail on financial and regulatory accounting treatment of true-up and bypass agreement proceeds.	**Yes**	Exhibit C-07-01
2.5.6 Capitalization Policy				
	Ch 2, p 26	Capitalization policy, including changes since the last revenue requirement application. Identify changes and causes of changes, explain reasons for changes and and state whether changes are the result of adhering to to an accounting requirement.	**Yes**	Exhibit C-08-02, Attachment 2
	Ch 2, p 26	Overhead costs on self-constructed assets	**Yes**	Exhibit C-08-02
	Ch 2, p 26	Identification of burden rates and burden rates prior to changes, if any	**Yes**	Exhibit C-09-01
2.5.7 Capital Module				
	Ch 2, p 26-27	Revenue Cap index applicants may request a capital increment for discrete projects being placed in service after the rebasing year that are part of the TSP; are intended to come into service during the index rate plan period; and involve costs that the transmitter cannot manage through the revenue established through the index rate plan period	*N/A*	Not Applicable - Hydro One is not requesting ACM
	Ch 2, p 27	The request must address proposed approval criteria (materiality, need, prudence) and the process for implementation of the recovery of the capital increment.	*N/A*	Not Applicable - Hydro One is not requesting ACM

2.6 EXHIBIT 4 – SERVICE QUALITY AND RELIABILITY PERFORMANCE AND REPORTING				
2.6.1 Proposed Scorecard				
	Ch 2, p 27-28	Propose a five-year scorecard including measures for public policy responsiveness, operational effectiveness, customer focus, financial performance and other relevant relevant performance categories believed to be meaningful: Some examples of metrics proposed by transmitters in previous applications are as follows: Average System Availability System Average Interruption Frequency Contribution System Average Interruption Duration Contribution NERC Vegetation Compliance OM&A Cost ($K) per circuit kilometer	**Yes**	TSP Section 2.5
2.6.2 Reliability Performance				
	Ch 2, p 28	Reliability performance measures (developed by Electricity Canada): transmission frequency of delivery point interruptions, transmission duration of delivery point interruptions, unsupplied energy in minutes, transmission system unavailability (percentage of system unavailable)	**Yes**	TSP Section 2.4 TSP Section 2.5
	Ch 2, p 28	Address performance standards for transmitters as set out in Chapter 4 of the TSC.	**Yes**	TSP Section 2.4
	Ch 2, p 28	Compare system performance with other systems both nationally and internationally	**Yes**	TSP Section 2.4
2.6.3 Compliance Matters				
	Ch 2, p 28	Discuss any outstanding areas of non-compliance which have had an effect on the application, including any relief sought through this application to resolve the non-compliance	*N/A*	There are no outstanding areas of non-compliance that have had a direct effect on the application
2.7 EXHIBIT 5 – OPERATING REVENUE				
2.7.1 Load and Revenue Forecasts				
	Ch 2, p 29	Explanation of causes, assumptions and adjustments for volume forecast. Economic assumptions and data sources for customer and load forecasts	**Yes**	Exhibit D-03-01 Exhibit D-04-01
	Ch 2, p 29	Explanation of weather normalization methodology. Describe economic models, econometric models, end-use models customer forecast surveys and load shape analyses	**Yes**	Exhibit D-04-01
	Ch 2, p 29	Detailed CDM electricity demand side management (eDSM) forecast, with impact of CDM eDSM shown on the load forecast for each of the three rate pools (Network, Line Connection, Transformation Connection). The applicant must also indicate how the forecast reflects IESO CDM eDSM forecasts and targets in the load forecast	**Yes**	Exhibit D-04-01
	Ch 2, p 29	Impact of forecast embedded generation on the transmission system load accounted for. Explain assumptions and methodology.	**Yes**	Exhibit D-04-01
2.7.2 Accuracy of Load Forecast and Variance Analysis		***A comparison of the forecast versus actual loads for the historical years; an explanation for any significant variances; and evidence of how variance analysis has been used to improve the transmitter's load forecasting methodology.***		
	Ch 2, p 29	Demonstrate five year historical accuracy by providing schedule of volumes (in kW for those rate pools that use this charge determinant), revenues, customer/connections count by rate pool and total system load in kWh) for: Historical OEB-approved; Historical actual for the past 5 years; Historical actual for the past 5 years – weather normalized; Bridge year; Bridge year – weather normalized; Test year	**Yes**	Exhibit D-04-01, Table 6 & Appendix E

	Ch 2, p 29	Analyses and discussion for volumes, revenues, customer/connections count and total system load: Comparison with the latest applicable provincial forecast(s) from the IESO, including a discussion of significant differences; Historical OEB-approved vs. historical actual; Historical OEB-approved vs. historical actual – weather normalized; Historical actual – weather-normalized vs. preceding year's historical actual –weather-normalized (for the necessary number of years); Historical actual – weather normalized vs. bridge year – weather-normalized; Bridge year – weather-normalized vs. test year(s)	**Yes**	Comparison with IESO forecast: Exhibit D-04-01, Appendix F; Year-over-year comparisons: Exhibit D-04-01, Appendix G
	Ch 2, p 29	All data used to determine the forecasts must be presented and filed in live MS Excel spreadsheet format	**Yes**	Exhibit D-04-01, Attachment 1 Exhibit D-03-01, Attachment 1
2.7.3 Other Revenue		***Details of other revenue sources and their treatment in the revenue requirement calculation.***		
	Ch 2, p 30	Comparison of actual revenues for historical years to forecast revenue for bridge and test year(s), including explanations for significant variances in year-over-year comparisons	**Yes**	Exhibit D-02-01
	Ch 2, p 30	How costing and pricing for other revenues is determined, any new proposed service charges, and/or changes to rates or new rules for applying existing charges	**Yes**	Exhibit D-02-01
	Ch 2, p 30	Revenue from affiliate transactions, shared services, corporate cost allocation. For each affiliate transaction, identification of the service, the nature of the service provided to affiliate entities, accounts used to record the revenue and associated costs	**Yes**	Exhibit D-02-03 (Affiliate Services) Exhibit E-04-01, Attachment 1 (Corporate Cost Allocation)
	Ch 2, p 30	Revenues or costs (including interest) associated with deferral and variance accounts must not be included in other revenue.	**Yes**	Confirmed
2.8 EXHIBIT 6 – OPERATING COST		**Operating cost evidence including OM&A, depreciation/amortization, and taxes.**		
	Ch 2, p 30	Exhibit must include the following sections: 1) Overview, 2) Summary and Cost Driver Tables, 3) Program Delivery Costs with Variance Analysis, 4) Workforce Planning and Employee Compensation, 5) Shared Services and Corporate Cost Allocation, 6) Purchases of Non-Affiliate Services, 7) Regulatory and One-Time Costs, 8) Charitable and Political Donations, 9) Taxes or Payments in Lieu of Taxes (PILs) and Property Taxes	**Yes**	Exhibit E-02-01 (Transmission OM&A) Exhibit E-06-01, Attachment 1, 1A, 1B, 2, and 3 (Compensation) Exhibit E-06-02 (Workforce Strategy) Exhibit D-02-03 (Affiliate Services) Exhibit E-04-08 (Common Corporate Costs & Allocation Methodology) Exhibit E-05-01 (Procurement Management) Exhibit E-10-01 (Regulatory One-Time Costs) Exhibit E-10-02 (One Time Costs) Exhibit E-10-03 (Charitable and Political Donations) Exhibit E-09-01 (Income Taxes) Exhibit E-09-06 (Property Taxes)
2.8.1 Overview		***Overview of operating costs including summary of main cost drivers and trends.***		
	Ch 2, p 30	Brief explanation of: test year OM&A levels how the transmitter developes its OM&A budget (e.g. zero based budgeting, inflationary increase or some combination), and the transmitter's internal approval process, cost drivers and significant changes relative to historical and bridge years, trends in costs and relevant metrics such as OM&A per customer and OM&A per km of transmission line (and its components) for the histrical, bridge and test years, inflation rate assumed, with a full explanation if different from the OEB's sector-specific inflation factor business environment changes, benchmarking studies (internal and external) or utility cost comparisons, description of the continuous improvement or efficiency gains over the term and the means by which those gains and savings will be acheved and the benefits assured for customers	**Yes**	Exhibit E-02-01
2.8.2 Summary and Cost Driver Tables		***Summary tables showing OM&A costs by function and cost driver analysis.***		
	Ch 2, p 30	Summary of recoverable OM&A expenses	**Yes**	Exhibit E-02-01, Attachment 1A (App 2-JA)
	Ch 2, p 30	OM&A cost drivers	**Yes**	Exhibit E-02-01, Attachment 1A (App 2-JB)
	Ch 2, p 30	OM&A by programs or OM&A by USoA	**Yes**	Exhibit E-02-01, Attachment 1A (App 2-JC)
	Ch 2, p 30	OM&A cost per customer and per FTE (if applicable)	**Yes**	Exhibit E-02-01, Attachment 1A (App 2-L)
	Ch 2, p 31	Change in OM&A in test year attributable to a change in capitalized overhead	**Yes**	Exhibit C-08-02, Attachment 1 (App 2-D)
	Ch 2, p 31	OM&A variance analysis for test year with respect to bridge and historical years	**Yes**	Exhibit E-02-01
2.8.3 Program Delivery Costs with Variance Analysis		***Program delivery costs with variance analysis comparing actual to approved/planned costs.***		

	Ch 2, p 31	The variance analysis will apply the 2.1.5. Materiality Thresholds and include the following: Test year vs historical OEB-approved Historical OEB-approved vs historical actuals (for the 5 most recent historical OEB-approved years including the bridge year) Test year vs most recent historical actuals	**Yes**	Exhibit E-02-01
	Ch 2, p 31	Details of O&M Costs for: workforce planning and employee compensation shared services and corporate cost allocation purchase of non-affiliate services regulatory and one-time costs Charitable and political donations PILs and Property Taxes	**Yes**	Exhibit E-06-01, Attachment 1, 1A, 1B, 2, and 3 (Compensation) Exhibit E-06-02 (Workforce Strategy) Exhibit D-02-03 (Affiliate Services) Exhibit E-04-02 (Common Corporate Functions and Services and Other OM&A) Exhibit E-04-08 (Common Corporate Costs & Allocation Methodology) Exhibit E-05-01 (Procurement Management) Exhibit E-04-08 (Common Corporate Costs & Allocation Methodology) Exhibit E-10-01 (Regulatory One-Time Costs) Exhibit E-10-02 (One Time Costs) Exhibit E-10-03 (Charitable and Political Donations) Exhibit E-09-01 (Income Taxes) Exhibit E-09-06 (Property Taxes) Exhibit E-04-04 (Common Corporate OM&A- DTS) Exhibit E-04-05 (Operations OM&A)
2.8.4 Workforce Planning and Employee Compensation		***Workforce planning and employee compensation details including FTE counts, compensation philosophy, and benchmarking.***		
	Ch 2, p 31	Employee complement, compensation and benefits	**Yes**	Exhibit E-06-01, Attachments 1A, 1B, 2, 3 Exhibit E-06-02
	Ch 2, p 31	The OEB expects that transmitters will provide a description of their proposed workforce plans, including compensation strategy and any changes from the previous plan. Transmitters must discuss the outcomes of previous plans and how those outcomes have impacted their proposed plans including an explanation of the reasons for all material changes to FTE numbers and compensation. Explanation for all years includes: -Year over year variances with an explanation of contributing factors, inflation rates used for forecasts, and hiring the plans for any new employees -Basis for performance pay, eligible employee groups, goals, measures and review processes for pay-for-performance plans -Any relevant studies (i.e. compensation benchmarking)	**Yes**	Exhibit E-06-01, Attachments 1A, 1B, 2, 3 Exhibit E-06-02
	Ch 2, p 31	Employee benefit programs including pensions, OPEBs, and other costs charged to OM&A. A breakdown of the pension and OPEBs amounts included in OM&A and capital must be provided for the last OEB-approved rebasing application, and for historical, bridge and test years	**Yes**	Exhibit E-07-01 (Pensions & OPEBs) Exhibit E-06-01 (Compensation) Exhibit E-07-01, Attachment 3 (App 2-KA)
	Ch 2, p 31	Most recent actuarial reports must be included and be reconciled with the pension and OPEBs amounts (as applicable). The basis on which pension and OPEBs amounts are forecast for the bridge and test years must also be explained. What is documented in the tax section of the evidence must agree with this analysis	**Yes**	Exhibit E-07-01, Attachment 1 (Pension Valuation) Exhibit E-07-01, Attachment 2 (OPEBs forecast)
	Ch 2, p 31	The transmitter must clearly indicate if pension and OPEB costs are proposed to be recovered using the default accrual basis or the cash basis. If a transmitter is proposing to calculate pension and OPEB expenses based on the cash method, it must provide sufficient supporting rationale and evidence for doing so. If a transmitter is proposing to change the basis in which pension and OPEB costs are included in OM&A from its last rebasing application (e.g., from cash to accrual), it must quantify the impact of the change. For all circumstances, the transmitter must file the evidence required by the OEB to support the quantum of pension and OPEB costs in the test year.	**Yes**	Exhibit E-07-01 Exhibit E-07-01, Attachment 3 (App 2-KA)
2.8.5 Shared Services and Corporate Cost Allocation		***Shared services and corporate cost allocation methodology, amounts allocated, and basis for allocation.***		
	Ch 2, p 34	Identification of shared services and justify its proposed shared services and corporate allocation in detail For shared services among affiliated entities, a transmitter must provide at a minimum: The type of service provided or received. The fee allocation structure and the pricing methodology (e.g., cost-base, market-base, tendering, etc.).	**Yes**	Exhibit D-02-03 Exhibit E-04-01, Attachment 1 (App 2-N)

	Ch 2, p 34	Allocation methodology for corporate and shared services, a list of costs and allocators, and any 3rd party review of the corporate cost allocation methodoogy used	**Yes**	Exhibit E-04-08 Exhibit E-04-08, Attachment 1
	Ch 2, p 34	Details for services provided or received for historical, bridge and test years. Reconciliation of revenue arising from transactions must be included in other revenue in Operating Revenue section. If applicable, the same service provider who provides services to multiple transmitters, including new entrants, needs to provide evidence that there is no double-accounting on the service fee allocation to the various service receivers, given the different timing that these transmitters (service receivers) are either placed in-service and/or when these transmitters they file revenue requirement applications individually.	**Yes**	Exhibit D-02-03 Exhibit E-04-02
	Ch 2, p 35	Variance analysis with explanations - test year vs last OEB approved and most recent actual	**Yes**	Exhibit E-04-02
	Ch 2, p 35	Identification of any Board of Director costs for affiliates included in applicant's costs	**Yes**	Exhibit E-04-08
2.8.6 Purchase of Non-Affiliate Services		***Details of services purchased from non-affiliates including procurement practices and cost justification.***		
	Ch 2, p 31	Procurement Policy - includes level of signing authority, description of competitive tendering process and confirmation that its non-affiliate services comply with the policy	**Yes**	Exhibit E-05-01, Attachment 1 & 3
	Ch 2, p 31	Material transactions not in compliance with procurement policy or without a competitive tender - Give reasons for procurement, summarize nature and cost of product or service (confidentiality procedures should be followed if there are concerns with dosclosing cost) and describe how vendor was selected	*N/A*	Not Applicable - all material transactions are in compliance Exhibit E-05-01 (procurement management)
2.8.7 One-time Costs		***One-time costs included in the revenue requirement with justification for inclusion.***		
	Ch 2, p 35	One-time costs - historical, bridge, test year costs. Explanation of cost recovery in test years. An explanation must also be provided if a transmitter is not proposing to recover the one-time costs	*N/A*	Exhibit E-10-02
2.8.8 Regulatory Costs		***Regulatory costs including OEB cost assessments, hearing costs, and intervenor costs.***		
	Ch 2, p 35-36	Regulatory costs - breakdown of actual and forecast costs (OEB cost assessments, legal fees, consultant fees, costs awards, etc.) and supporting informaiton for level of costs associated with preparaiton and review of the current application.	**Yes**	Exhibit E-10-01 E-10-01, Attachment 1 (App 2-M)
	Ch 2, p 36	Identify period over which costs are to recovered and explanation if different from rate term	**Yes**	Exhibit E-10-01 Exhibit E-10-01, Attachment 1 (App 2-M)
	Ch 2, p 36	Costs claimed on an amortized basis - not included in historic / bridge years	*N/A*	Exhibit E-10-01 Exhibit E-10-01, Attachment 1 (App 2-M)
2.8.9 Charitable and Political Donations	***Ch 2, p 36***	***Charitable and political donations policy and amounts, confirming exclusion from revenue requirement.***		
	Ch 2, p 36	File the amounts paid in charitable donations (per year) from the last OEB-approved rebasing application up to and including the test year(s).	*N/A*	Exhibit E-10-03
	Ch 2, p 36	Detailed information for all charitable donations claimed for recovery (recovery of charitable donations is generally not allowed for the purpose of setting revenue requirement)	*N/A*	Exhibit E-10-03
	Ch 2, p 36	Non-recoverable contributions identified, disclosed and removed from the revenue requirement calculation	*N/A*	Exhibit E-10-03
	Ch 2, p 36	Charitable Donations - confirmation that political contributions not included	*N/A*	Exhibit E-10-03
2.8.10 Taxes or PILs and Property Taxes		***Taxes or Payments in Lieu of Taxes (PILs) and property taxes calculation and methodology.***		
	Ch 2, p 36	Income tax or PILs calculations, derivation of adjustments for historical, bridge, test years (regulatory assets and liabilities generally excluded)	**Yes**	Exhibit E-09-02, Attachments 1 - 8
	Ch 2, p 36	Supporting schedules and calculations identifying reconciling items	**Yes**	Exhibit E-09-02, Attachments 1 - 4, 7 and 8
	Ch 2, p 36	Most recent federal and provincial tax returns	**Yes**	Exhibit E-09-05, Attachment 1
	Ch 2, p 36	Financial Statements included with tax returns if different from those filed with application	*N/A*	Not Applicable; Exhibit A-06-02 (financial statements) Exhibit E-09-05 (tax returns)

	Ch 2, p 36	Calculation of Tax Credits; redact where required (filing of unredacted versions is not required)	Yes	Exhibit E-09-02, Attachments 5 & 6
	Ch 2, p 36	Supporting schedules, calculations and explanations for other additions and deductions	Yes	Exhibit E-09-01
	Ch 2, p 36	Taxes other than PILs (property taxes) clearly identified where included	Yes	Exhibit E-09-06
2.8.10.1 Non-recoverable and Disallowed Expenses		***Non-recoverable and disallowed expenses identified and excluded from revenue requirement.***		
	Ch 2, p 37	Exclude from regulatory tax calculation any non-recoverable or disallowed expenses	Yes	Exhibit E-09-01
2.8.10.2 Integrity Checks		***Integrity checks confirming consistency between revenue requirement components.***		
	Ch 2, p 37	Depreciation and amortization added back in the application's PILs/tax model agree with the numbers disclosed in the rate base section of the application	Yes	Exhibit E-09-02, Attachment 1
	Ch 2, p 37	The capital additions and deductions in the UCC/CCA Schedule 8 agree with the rate base section for historic, bridge and test years	Yes	Exhibit E-09-02, Attachments 7 & 8 Exhibit C-04-01
	Ch 2, p 37	Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31st historic year UCC that agrees with the opening bridge year UCC at January 1st	No	These Exhibit explain the "No"; Exhibit E-09-05, Attachment 1 Exhibit E-09-02, Attachment 4 (Tx CCA Historical)
	Ch 2, p 37	The CCA deductions in the application's PILs/tax model for historic, bridge and test years agree with the numbers in the UCC schedules for the same years filed	Yes	Exhibit E-09-02, Attachment 4 (Tx CCA Historical) Exhibit E-09-02, Attachment 3 (Tx Taxes Historical Years) Exhibit E-09-02, Attachment 1 (Tx CCA Test Years) Exhibit E-09-02, Attachment 2 (Tx Taxes Test Years)
	Ch 2, p 37	Loss carry-forwards, if any, from the tax returns (Schedule 4) agree with those disclosed in the application	*N/A*	Exhibit E-09-01
	Ch 2, p 37	CCA is maximized even if there are tax loss carry-forwards	Yes	Exhibit E-09-01
	Ch 2, p 37	A statement is included in the application as to when the losses, if any, will be fully utilized	*N/A*	Exhibit E-09-01
	Ch 2, p 37	Accounting OPEB and pension amounts added back on Schedule 1 reconciliation of accounting income to net income for tax purposes, must agree with the OM&A analysis for compensation	Yes	Exhibit E-09-02, Attachment 1
	Ch 2, p 37-38	The income tax rate used to calculate the tax expense must be consistent with the utility's actual tax facts and evidence filed in the proceeding.	Yes	Exhibit E-09-01
2.8.11 Z-Factor Claims		***Z-factor claims eligibility criteria and any claims being made, including causation, materiality, prudence, and notification requirements.***		
	Ch 2, p 38	Evidence that z-factor costs incurred meet eligibility criteria (causation, materiality, prudence); materiality threshold proposed that exceeds OEB-defined materiality threshold, amount recorded in deferral account, allocation of incremental revenue requirements to rate pools, calculation of incremental revenue requirement	*N/A*	Hydro One is not requesting a z-factor claim in its Application. See Exhibit E-10-04
	Ch 2, p 38	Z-factor events must be: (1) caused by an event outside of the transmitter's control; (2) must not be a reasonably foreseeable event that could have been anticipated at the time of the rate application; (3) must have a material impact on the transmitter's costs; and (4) must not be recoverable through any other mechanism.	*N/A*	Hydro One is not requesting a z-factor claim in its Application. See Exhibit E-10-04
	Ch 2, p 38	Z-factor claims must demonstrate causation - a clear and direct link between the external event and the incremental costs incurred by the transmitter.	*N/A*	Hydro One is not requesting a z-factor claim in its Application. See Exhibit E-10-04
	Ch 2, p 38	Z-factor materiality threshold must exceed the OEB-defined materiality threshold. The transmitter must propose and justify the materiality threshold to be applied to any Z-factor claim.	*N/A*	Hydro One is not requesting a z-factor claim in its Application. See Exhibit E-10-04
	Ch 2, p 39	Z-factor notification requirements: transmitters must notify the OEB within 180 days of the event giving rise to a potential Z-factor claim. The notification must include a description of the event, estimated costs, and the proposed recovery mechanism.	*N/A*	Hydro One is not requesting a z-factor claim in its Application. See Exhibit E-10-04
EXHIBIT 7 – COST OF CAPITAL AND CAPITAL STRUCTURE		**Cost of capital and capital structure evidence.**		
2.9.1 Capital Structure		***Capital structure including debt/equity ratio and comparison to OEB-deemed structure.***		
	Ch 2, p 39	OEB's cost of capital parameters used; subject to an update if new parameters are available prior to the issuance of the OEB's decision for a specific transmitter's application.	Yes	Exhibit F-01-01

	Ch 2, p 39	Multi-year revenue requirement approvals must indicate whether cost of capital will be updated annually or fixed for all test years	**Yes**	Exhibit F-01-01
	Ch 2, p 40	Long-term debt; Short-term debt; Preference shares and Common equity must be presented with the appropriate schedules	**Yes**	Exhibit F-01-03 (App 2-OA) Exhibit F-01-04 (App 2-OB)
	Ch 2, p 40	Explanation for any material changes in actual capital structure or material differences between actual and deemed capital structure are required including: Retirements of debt or preference shares and buy-back of common shares Short-term debt, long-term debt, preference shares and common share offerings	**Yes**	Exhibit F-01-01
	Ch 2, p 40	Rate regulated utilities are expected to demonstrate that they have been prudent in their management of debt. Utilities are required to file evidence to explain how they manage their long-term debt, including actual debt and the forecast for future debt.	**Yes**	Exhibit F-01-02
	Ch 2, p 40	For utilities incurring transactions/issuance costs to secure financing from the market, the transaction/issuance costs should be incorporated into the debt interest rate used to set rates, so that the transaction costs are amortized over the term of the debt instrument using the effective interest rate methodology.	**Yes**	Exhibit F-01-04 (App 2-OB)
2.9.2 Cost of Capital (Return on Equity and Cost of Debt)		***Return on equity and cost of debt parameters, including comparison to OEB's cost of capital methodology.***		
	Ch 2, p 40	Calculation of cost for each capital component	**Yes**	Exhibit F-01-03
	Ch 2, p 40	Profit or loss on redemption of debt	**Yes**	Exhibit F-01-02
	Ch 2, p 40	Copies of promissory notes or other debt arrangements with affiliates. Note that this is not required for third 3rd party debt, e.g., with commercial banks.	**Yes**	Exhibit F-02-05 Exhibit F-02-06
	Ch 2, p 41	Explanation of debt rate for each existing debt instrument	**Yes**	Exhibit F-01-02
	Ch 2, p 41	Forecast of new debt in bridge and test year - details including estimate of rate	**Yes**	Exhibit F-01-02
	Ch 2, p 41	If proposing any rate that is different from the OEB guidelines, a justification of the proposed rate(s), including key assumptions	**Yes**	Exhibit F-01-02
	Ch 2, p 41	Historical ROE achieved.	**Yes**	Exhibit F-01-01 TSP Section 2.5
	Ch 2, p 41	An applicant should provide an overview of its financing strategy.	**Yes**	Exhibit F-01-01
2.9.3 Not-for-Profit Corporations		***For not-for-profit corporations: alternative approaches to cost of capital if applicable.***		
	Ch 2, p 41	Not for Profit Corporations - Evidence that excess revenue is used to build up operating and capital reserves	*N/A*	Not Applicable - Hydro One is not a not-for-profit corporation
2.10 EXHIBIT 8 – DEFERRAL AND VARIANCE ACCOUNTS		**Deferral and variance accounts evidence including balances and proposed dispositions.**		
	Ch 2, p 41	List of all outstanding DVA and sub-accounts; provide description of DVAs	**Yes**	Exhibit G-01-01
	Ch 2, p 42	Completed DVA continuity schedule for period following last disposition to present - live Excel format	**Yes**	Exhibit G-01-07, Attachment 1 (HONI Tx Continuity Schedule)
	Ch 2, p 42	Confirm use of interest rates established by the OEB by month or by quarter for each year	**Yes**	Exhibit G-01-01
	Ch 2, p 42	Explanation if account balances in continuity schedule differs from trial balance in RRR and AFS	**Yes**	Exhibit G-01-07, Attachment 1
	Ch 2, p 42	A proposal for an allocator based on the proposed cost driver(s) and included in the continuity schedule	**Yes**	Exhibit H-01-03
	Ch 2, p 43	Statement as to any new accounts, and justification.	**Yes**	Exhibit G-01-03
	Ch 2, p 43	Statement whether any adjustments made to DVA balances previously approved by OEB on final basis; explanation, amount of adjustment and supporting documents	*N/A*	Exhibit G-01-05
	Ch 2, p 43	A proposal of a different carrying charge on a DVA involving long-term expenditures, if any, with evidence to justify the departure from standard DVA carrying charges.	*N/A*	Not Applicable ; Exhibit G-01-01 (regulatory accounts)
	Ch 2, p 43	Any additional mechanisms proposed for rate-regulated infrastructure investment by Indigenous business ventures in the transmission sector. Utilities can make applications for consideration by the OEB on a case-by-case basis for alternative cost recovery mechanisms for significant new infrastructure investments.	*N/A*	Not Applicable
2.10.1 Disposition of Deferral and Variance Accounts		***Disposition of deferral and variance accounts including methodology and proposed rate riders.***		
	Ch 2, p 43	Identify accounts for which disposition is sought	**Yes**	Exhibit G-01-01

	Ch 2, p 43	Identify accounts for which disposition is not sought and the reasons	**Yes**	Exhibit G-01-01
	Ch 2, p 43	Propose the method to be used for recovery or refund of balances that are proposed for disposition	**Yes**	Exhibit G-01-06 Exhibit H-01-03
	Ch 2, p 43	Provide a statement that the balances proposed for disposition before forecasted interest are consistent with the last Audited Financial Statements	**Yes**	Exhibit G-01-05
	Ch 2, p 43	Show all relevant calculations, including the rationale for the allocation of each account, the proposed billing determinants and the length of the disposition period	**Yes**	Exhibit H-01-01 Exhibit H-01-03
2.10.2 Earnings Sharing Mechanism (ESM)				
	Ch 2, p 44	The transmitter must provide supporting evidence showing how the balance is derived. The calculation and disposition of the ESM should follow the transmitter's approved accounting order.	**Yes**	Exhibit G-01-01, Section 3.19
2.10.2.1 Disposition of ESM				
	Ch 2, p 44	Transmitters should include a description of the methodology to calculate excess earnings. At a minimum, the actual ROE shall be based on: Regulatory net income derived from regulated transmission operations, excluding non-regulated revenues and costs Adjustments for extraordinary, non-recurring items. A description of these adjustments should be included or excluded. Regulatory earnings determined in accordance with OEB-approved principles	**Yes**	Exhibit G-01-01, Section 3.19
	Ch 2, p 44	The approved ROE from the transmitter's most recent OEB rate decision should be used as the baseline.	**Yes**	Exhibit F-01-01
	Ch 2, p 44	In addition to the above, the applicant must include: - Amount recorded in the ESM – a reconciliation of the balance recorded in the deferral account, including the interest applied. -Proposed disposition methodology – the proposed method for refunding excess earnings to ratepayers.	**Yes**	Exhibit G-01-01 Exhibit G-01-03
2.11 EXHIBIT 9 – COST ALLOCATION TO UNIFORM TRANSMISSION RATE POOLS: CHARGE DETERMINANTS		**Cost allocation to Uniform Transmission Rate pools and charge determinants.**		
	Ch 2, p 45	Identify the cost allocation methodology that is proposed to allocate costs to the three transmission rate pools: Network, Line Connection and Transformation Connection	**Yes**	Exhibit H-01-01 Exhibit H-01-03
	Ch 2, p 45	Steps taken to functionalize the assets in the functional categories	**Yes**	Exhibit H-01-02
	Ch 2, p 45	Allocation of revenue requirement to the rate pools and allocation factors for each asset or groups of assets	**Yes**	Exhibit H-05-01 Exhibit H-03-01 Exhibit H-03-02 Exhibit H-03-03 Exhibit H-04-01
	Ch 2, p 45	Assignment of depreciation, return on capital, taxes and OM&A costs to rate pools and non-standard rate pools	**Yes**	Exhibit H-04-02 Exhibit H-04-03 Exhibit H-04-04
2.12 EXHIBIT 10 – RATE DESIGN FOR UNIFORM TRANSMISSION RATES		**Rate design for Uniform Transmission Rates.**		
2.12.1 Bill Impact Information		***Bill impact information for typical residential and general service customers.***		
	Ch 2, p 46	Provide bill impact of the application including the dollar and percentage impact on the average customer's total bill and the percentage impact on transmission rates	**Yes**	Exhibit H-09-01
	Ch 2, p 46	Bill impacts for typical customers and consumption levels (residential customers consuming 750 kWh/month and GS < 50 kW consuming 2000 kWh/month, typical direct-connected non-LDC customer)	**Yes**	Exhibit H-09-01
2.12.1 Setting the Uniform Transmission Rates		***Setting the Uniform Transmission Rates including calculation methodology and proposed rates.***		
	Ch 2, p 46	Overview of how the UTR are established in Ontario and how these rates are determined	**Yes**	Exhibit H-06-01

	Ch 2, p 46	The revenue requirement and load forecast data (from each transmitter) that is used to compile the transmission charge determinants for each rate pool	**Yes**	Exhibit H-10-01, Attachment 2
	Ch 2, p 46	A table explaining and documenting the determination of the UTR including: - previously approved revenue requirements and load forecast charge determinants for all other transmitters in the pool; - OEB file number of each decision approving each revenue requirement and charge determinant; -applicant's proposed revenue requirements and charge determinants as proposed in the application; -the calculation of the UTRs for each pool; - the transmission revenue allocator for each of the Ontario transmitters in the pool; -an explanation of any changes to terms and conditions of service and the rationale behind those changes if the changes affect the application of the rates -If applicable, the determination of the Export Transmission Service rates and the treatment of revenues generated through these rates	**Yes**	Exhibit H-08-01 Exhibit H-10-01, Attachments 1 & 2 Not Applicable re: explanation of any changes to terms and conditions of service

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GENERAL REQUIREMENTS		
Ch1, p4	If third-party documentation is filed and the documentation has been labelled as "confidential" (e.g., in the header or footer of the document), and if the distributor is not seeking confidential treatment, confirmation provided that the documentation does not contain confidential information as defined in the Practice Direction on Confidential Filings, and the distributor is providing it for the public record	Exhibit A-02-01, Attachment 1
Ch1, p4	Confidential Information - Practice Direction has been followed	Exhibit A-02-01, Attachment 1
Ch1, p5	Certification by a senior officer that the application and any evidence filed in support of the application does not include any personal information unless it is filed in accordance with Rule 9A of the OEB's Rules (and the Practice Direction Confidential Filings, as applicable)	Exhibit A-02-01, Attachment 1
Ch1, p5	Certification by a senior officer that the evidence filed is accurate, consistent and complete to the best of their knowledge	Exhibit A-02-01, Attachment 1
Ch1, p5	Certification by senior officer that the distributor has appropriate processes and internal controls for the preparation, review, verification and oversight of deferral and variance account balances being disposed	Exhibit A-02-01, Attachment 1
Ch1, p6	A letter from the governing body (e.g., Board of Directors) certifying that it is aware of and approves the submission of the application	Exhibit A-02-01, Attachment 3
Ch1, p6	Where generative artificial intelligence (AI) is used to generate content in a filing in a proceeding, distributor must: - disclose generative AI was used to generate content in a filing; and - confirm that the accuracy of the filing generated by AI has been verified by the party or rep. without the assistance of generative AI Disclosure made either: in the certification of evidence section of application, at the beginning of the document created by generative AI, or in the cover letter to a multi-document package	Application Cover Letter
2	COS checklist filed and statement identifying all deviations from Filing Requirements	Exhibit A-02-03 Exhibit A-02-03, Attachment 2
2	Chapter 2 appendices in live Excel format; PDF and Excel copy of current tariff sheet	Applicable Chapter 2 appendices are filed under each of the respective exhibits: DSP Section 3.8, Attachment 1 (App 2-AA) DSP Section 3.9, Attachment 1 (App 2-AB) GSP Section 4.8, Attachment 1 (App 2-AA) GSP Section 4.9, Attachment 1 (App 2-AB) Exhibit C-04-04 (App 2-BA) Exhibit E-08-01, Attachment 3 (App 2-BB) Exhibit C-08-02, Attachment 1 (App 2-D) DSP Section 3.4, Attachment 7 (App 2-FA, FB, FC) Exhibit A-05-01, Attachment 1 (App 2-G) Exhibit D-02-02, Attachment 1 (App 2-H) Exhibit D-05-01, Attachment 2 (App 2-IB) Exhibit E-03-01, Attachment 1A (App 2-JA, 2-JB, 2-JC,2-L) Exhibit E-06-01, Attachment 1A (App 2-K) Exhibit E-07-01, Attachment 3 (App 2-KA) Exhibit E-10-01, Attachment 1 (App 2-M) Exhibit E-04-01, Attachment 1 (App 2-N) Exhibit F-01-03 (App 2-OA) Exhibit F-01-04 (App 2-OB) Exhibit C-05-01, Attachment 1 (App 2-ZA, ZB) Exhibit L-06-02, Attachment 1 (App 2-R) Appendices not provided and reason: - Appendix 2-A and AC a not applicable because it's optional; information is provided in SPF Section 1.6 - Appendix 2-C is not applicable as described in Exhibit A-02-03 -Appendix 2-JD is optional and not applicable; refer to App 2-JC -Appendix 2-Q is not applicable as embedded distributors are covered by Hydro One's ST class. -Appendix 2-IA is not applicable as it is replaced by Appendix 2-IB

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3	If distributor updates/amends an OEB model, reference made in corresponding exhibit re: what was updated/amended	Exhibit A-02-03
3	Regulated entity shown separately from parent company or any other affiliates	Confirmed - All Exhibits
3	If applicable, if cost of service filed earlier than scheduled, justify why an early rebasing is required by demonstrating why and how distributor cannot adequately manage resources and financial needs during IRM period	Not Applicable
4	If applicable, late applications filed after the commencement of the rate year for which the application is intended to set rates is converted to the following rate year	Not Applicable
4-5	All of the following exhibits filed: Application Overview and Administrative Documents, Rate Base and Capital (including DSP), Customer and Load Forecast, Operating Expenses, Cost of Capital and Capital Structure, Revenue Requirement and Revenue Deficiency/Sufficiency, Cost Allocation, Rate Design, Deferral and Variance Accounts	Confirmed
5	General requirements applicable throughout application: -written evidence included before data schedules -avg. of opening and closing fiscal year balances used for items in rate base (unless alternative method justified) -debt + equity = total rate base -data for test year, bridge year, three most recent historicals (or as many needed to provide actuals back to last OEB-approved), most recent OEB-approved test	Confirmed
5	Documents include page numbers and are provided in text searchable and bookmarked PDF format	Confirmed
6	Links within Excel models are broken and models named so that they can be identified (e.g. RRWF instead of Attachment A)	Confirmed
6	Materiality threshold: Explanation with supporting evidence for material amounts pertaining to CAPEX, capital variances, rate base variances, OM&A, and DVAs; additional details below the threshold if helpful to the OEB	Exhibit A-02-03 Variance explanations have been provided throughout the application based on materiality threshold outlined in Exhibit A-02-03.
EXHIBIT 1 - APPLICATION OVERVIEW AND ADMINISTRATIVE DOCUMENTS		
Table of Contents		
7	Table of Contents listing major sections and subsections of the application	Exhibit A-01-01
Application Summary and Business Plan		
7	Distributor with less than 30k customers: Business or Strategic Plan. If no Business or Strategic plan: key planning assumptions, description of materia factors (internal and external) that may affect the operation of the utility and major goals of the distributor in the test year and remaining years of the five year term Distributor with 30k or more customers: Business Plan underpinning application - can be augmented by plain language summary of distributor's goals that informed the application if this is not otherwise in the Business Plan. Also provide Strategic Plan, if available	Exhibit A-03-01, Attachment 1
7	Brief, plain language summary of the application which includes the main requests with section references and rationale behind each request. Must include:	Exhibit A-03-01
	Revenue requirement (service revenue requirement requested for test year, increase/decrease ($ and %) from most recent approved, main drivers of revenue requirement changes from last OEB-approved	Exhibit A-03-01
7	Load forecast summary (load and customer growth (% change in kWh, kW and change in customer #s from last OEB-approved))	Exhibit A-03-01
7-8	Rate base and DSP (major drivers of DSP and cost trends, rate base requested, change in rate base from last OEB-approved ($ and %), CAPEX for test year, change in CAPEX from last OEB-approved ($ and %)	Exhibit A-03-01
8	OM&A requested for test and change from last OEB-approved ($ and %), drivers and cost trends	Exhibit A-03-01
8	Cost of capital (table showing proposed capital structure and parameters resulting in WACC, statement confirming use of OEB's cost of capital parameters, summary and rational of deviations from OEB methodology)	Exhibit A-03-01

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8	Cost allocation and rate design (proposed new customer classes and/or customer definition changes, new proposed charges, significant changes proposed to rev. cost ratios and fixed/variable split, mitigation plans)	Exhibit A-03-01 Exhibit L-01-02 Exhibit L-01-03 Exhibit L-02-01
8	DVAs (total disposition ($) including split between customer classes and between RPP and non-RPP (if applicable), disposition period(s), new DVAs and requested	Exhibit A-03-01 Exhibit L-05-01 Exhibit L-05-01, Attachment 1 & 2
8-9	Bill Impacts ($ and %) for residential customer at 750kWh, and typical customers for all other classes (based on commodity rates on TOU with regulatory charges held constant; bill impacts to be used for Notice (Sub-total A) for residential customer at 750kWh and GS<50 at 2000kWh as well as a typical consumer for a distributor's service area for all customer classes, and bill impacts based on alternative consumption profiles and customer groups as appropriate	Exhibit A-03-01 Exhibit L-06-01
Administration		
9	Primary contact information (name, address, phone, email)	Exhibit A-02-01
9	Identification of legal (or other) representation	Exhibit A-02-01
9	Applicant's internet address for viewing of application and any social media accounts, with addresses, used by the applicant to communicate with customers	Exhibit A-02-01
9	Statement identifying where notice should be published and why	Exhibit A-02-01
9	Form of hearing requested and why	Exhibit A-02-01
9	Requested effective date	Exhibit A-02-01
9	Statement identifying and describing any changes to methodologies used vs previous applications	Exhibit A-02-03
9	Identification of OEB directions from any previous OEB Decisions and/or Orders, including commitments made as part of approved settlements. Indication of how these are being addressed in the current application	Exhibit A-02-04
9	Reference to Conditions of Service - provide reference to website and confirm version is current; identify if there are changes to Conditions of Service (a) since last CoS application and/or (b) as a result of the current application. Confirmation that there are no rates and charges linked in the Conditions of Service that are not in the distributor's Tariff of Rates and Charges must be provided	Exhibit A-02-01 Exhibit A-02-03, Attachment 4
10	Description of the corporate and utility organizational structure showing the main units and executive and senior management positions within the organization; corporate entities relationship chart, showing the extent to which the parent company is represented on the distributor company's Board of Directors; description of the reporting relationships between distributor and management of the parent company. Also include any planned changes in corporate or operational structure, including any changes in legal organization and control	Exhibit A-07-01 Exhibit A-07-01, Attachment 1: Corporate entities relationship chart (organizational structure) Exhibit A-07-01, Attachment 2: Hydro One organization structure
10	List of approvals requested (and relevant section of legislation). All approvals including accounting orders, new rate classes, revised specific service charges or retail service charges which the distributor is seeking, must be documented. Appendix 2-A**may** be used to list requested approvals	Exhibit A-02-01
Small Distributor Process Eligibility (between 5k and 30k customers)		
10	If applicable, if a very small distributor wishes to opt out of using the one-day Issues Meeting, the distributor should make that known in its application	Not Applicable - Hydro One is not eligible to apply for VSU Guidelines
11	If applicable, a small distributor seeking to use the Small Distributor Process must make that known in its application	Not Applicable - Hydro One is not eligible to apply for VSU Guidelines
Distribution System Overview		
11	Description of Service Area - general description and map showing where distributor operates and communities served	DSP Section 3.1

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Customer Engagement		
11	Provide information regarding its customer engagement activities, activities that occur on an on-going basis, and specific activities pertaining to application. **May** use Appendix 2-AC to assist in listing customer engagement activities	SPF Section 1.6 and Attachment 1; DSP Section 3.6, 3.7; GSP Section 4.6, 4.7 (NOTE: Appendix 2-AC is not filed as it's optional)
11-12	Ongoing Customer Engagement - Describe methods used to communicate and engage with each customer class regularly, summarize pertinent feedback received through regular customer communications, and explain how feedback informs operations and rate application, where applicable	SPF Section 1.6 SPF Section 1.6, Attachment 2
12	Application-Specific Customer Engagement - Explain customer engagement process specific to application (tailor customer engagement activities to distributor's circumstances and the proposals in application). Demonstrate how customer needs and priorities were factored into the decision-making process	SPF Section 1.6 SPF Section 1.6, Attachment 1 DSP Section 3.7 GSP Section 4.6 GSP Section 4.7
12	Customer engagement with customers who would be affected by proposals related to new rate classes, changes in to existing rate classes and change in charges such as RSCs, Specific Service Charges, standby rates, and unmetered-load customers	Not Applicable - no new rate classes or significant changes determined appropriate for consultation
12	All responses to matters raised in letters of comment filed on public record	Hydro One has not yet received letters of comment filed with the OEB
Performance Measurement		
13	Link to most recent scorecard	DSP Section 3.5
13	Identification of performance improvement targets	DSP Section 3.5
13	OEB approved benchmarking model for the test year showing efficiency assessment, discussion on how the results obtained from the OEB approved forecasting model and Activity and Program-based Benchmarking (APB) have informed the distributor's business plan and application	Exhibit A-04-01, Attachment 1 DSP Section 3.5 (APB)
13	Distributors **may** provide table showing respective OEB-approved IRM increases for each of the last historical years from last rebasing, and assigned cohort as per the OEB approved model	Not Applicable- Hydro One is under Custom IR
13-14	Activity and Performance-based Benchmarking (APB) results - at least provide the following unit cost variance analysis: - Year-over-year Historical Actuals (for most recent APB results) - Forecast Bridge Year vs Historical Actuals, to extent possible - Test Year vs Historical Actuals, to extent possible - An explanation of significant change (greater than 20% from previous year or five-year average) - A plan to drive down unit costs if five-year average is 25% greater than industry five-year average	DSP Section 3.5
14	Explain variances in cost performance, whether changes in unit costs are within distributor's control, and discuss relevant actions planned or underway Discuss econometric results to extent possible	DSP Section 3.5
Facilitating Innovation		
14-15	Distributors are encouraged to include a description of the ways their approach to innovation has shaped the application. Could include explanations of approach to innovation or keeping up with innovation in their business more generally; of specific projects or technologies for enhancing the provision o distribution services; and of enabling characteristics or constraints in their ability to undertake innovative solutions	DSP Section 3.1 DSP Section 3.4 DSP Section 3.8 DSP Section 3.11, D-SS-10, D-SS-05, D-SS-08, D-SS-07, D-SR-16, D-SS-09 GSP Section 4.8 GSP Section 4.11, DTS related ISDs
15	Explain how innovative alternatives have been considered in place of traditional investments. Include information about the costs, expected benefits and associated risks of innovative alternatives. An innovative approach the OEB has emphasized is for distributors to consider the use of non-wires solutions (NWSs) to address distribution system needs	DSP Section 3.4 DSP Section 3.6 DSP Section 3.6, Attachment 1 DSP Section 3.11, D-SS-04

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15	If distributor is applying for margin on payments (MoP) incentive related to the use of third-party DERs as NWSs, eligibility criteria and filing requirements as set out in section 11 of the Distribution System Code addressed	Exhibit G-01-03, Section 9.4 (see NWS Implementation Cost Variance Account)
15	If distributor includes a discrete and innovative proposal in its application, the OEB encourages the distributor to review the five considerations set out in the OEB's March 20, 2025 letter	Not Applicable
Financial Information		
16	Audited Financial Statements (excluding operations of affiliated companies that are not rate regulated) for two most recent historical years (i.e. one year's statements must be filed, covering two years of historical actuals); if most recent finals n/a, draft financial statements filed and finals, along with summary of main changes if there are any, provided as soon as they are available. Alternatively, if distributor publishes financial statement on its website, a link may be provided	Exhibit A-06-02, Attachments 5 & 6 (HONI Dx)
16	A detailed reconciliation of the financial results shown in the audited financial statements with the regulatory financial results filed in the application, including a reconciliation of the fixed assets in order to, as one example, separate non distribution businesses. This must include the identification of any deviations that are being proposed between the audited financial statements and the regulatory financial results, including the identification of any prior OEB approvals for such deviations	Exhibit A-06-03
16	Annual Report and MD&A for most recent year of distributor and parent company, as available and applicable. If an Annual Information Form is filed publicly, a link should be provided	Exhibit A-06-04 Exhibit A-06-04, Attachment 1
16	Rating Agency Reports, if available; Prospectuses, information circulars etc. for recent and planned public debt and/or equity offerings	Exhibit F-01-05, Attachments 1A to 3 Exhibit F-01-06, Attachments 1 to 2
16	Any change in tax status	Exhibit E-09-01
16	Description of existing accounting orders and departures from these orders, as well as any departures from the USoA	Exhibit G-01-01 (Description of Existing Accounting Orders) Exhibit G-01-01, Attachment 1 (Accounting Orders) Exhibit A-06-01 (Changes to Accounting Policies)
16	Accounting Standards used for financial statements and when adopted	Exhibit A-06-01
16-17	If distributor conducting non-distribution businesses, confirmation that accounting treatment used has segregated these activities from rate regulated activities	Exhibit A-06-03
Distributor Consolidation		
17	Information filed on the extent to which the distributor has investigated opportunities for consolidation or collaboration/partnerships with other distributors (contained within a dedicated section of the application); conclusions from investigations, including future plans	Exhibit A-08-01
17	If distributor has become party to a proposed or approved MAADs transaction since last rebasing, disclosure of this information in current application	Exhibit A-08-01
	A distributor filing an application to rebase following a consolidation must:	
17	Identify any incentives that formed part of the consolidation transaction if the incentive represents costs that are being proposed to remain or enter rate base and/or revenue requirement - list the exhibits in which incentives are discussed	Exhibit A-08-01
17	Specify whether and which commitments made to shareholders are to be funded through rates	Exhibit A-08-01
17	Detail of realized and projected savings as a result of consolidation compared to what was in the approved consolidation application and explanation of the nature of these savings (e.g. one-time, ongoing etc.)	Exhibit L-03-01
17	Detail of efficacy of any rate plan confirmed as part of MAADs	Exhibit L-03-01

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17	Identify approved ACM or ICM from a previous IRM application it proposes be incorporated into rate base	Not Applicable- HONI did not apply for an ACM or ICM from a previous price cap application
18	Distributor rebasing for the first time following a consolidation that was approved under the 2024 MAADs handbook must also provide additional information: **(Distributors that Deferred Rebasing for Five Years or Less):**	Not applicable - transactions completed under previous MAADs guidelines
18	Achieved efficiencies and savings associated with the various activities where efficiencies were expected (as documented in the consolidation application)	Not applicable - transactions completed under previous MAADs guidelines
18	A qualitative discussion on enhanced reliability and service quality as a consolidated distributor	Not applicable - transactions completed under previous MAADs guidelines
18	A qualitative discussion on enhanced reliability and service quality on a rate zone basis	Not applicable - transactions completed under previous MAADs guidelines
18	Total transaction and transition costs, and whether those have been recovered over the term of the deferred rebasing period through the savings achieved	Not applicable - transactions completed under previous MAADs guidelines
18	A discussion on any obstacles encountered since consolidation and how the distributor managed those obstacles. If applicable, a discussion of how obstacles affected the consolidated entity from reaching its targets should also be included	Not applicable - transactions completed under previous MAADs guidelines
18	**(Distributors that Deferred Rebasing for More than Five Years):** Updates to information filed as part of mid-term report based on achieved results, including for any period not covered by the initial mid-term report	Not applicable - transactions completed under previous MAADs guidelines
18	Regardless of the length of the elected deferred rebasing period, the distributor must provide (on a reasonable efforts basis) an updated version of the revenue requirement analysis provided in the consolidation application based on information known at the time of the filing, and a comparison and discussion of the consolidation application forecasts versus those filed in the post-consolidation rebasing application.	Not applicable - transactions completed under previous MAADs guidelines
EXHIBIT 2 - RATE BASE AND CAPITAL		
Rate Base		
19	Indication of whether capital expenditures are equivalent to in-service additions, and if so, variance explanations only required once. If not, specify whether variance explanations are on CAPEX or in-service additions basis	Exhibit C-02-02 DSP Section 3.9
19	For rate base, opening and closing balances for each year, and the average of the opening and closing balances for gross assets and accumulated depreciation (discussion of methodology if applicant uses an alternative method); working capital allowance	Exhibit C-01-01 (Rate Base) Exhibit C-04-01 to C-04-03 (Continuity Schedules) Exhibit C-05-01 (Working Capital Allowance)
19	Table showing components of the last OEB-approved rate base, the proposed test year rate base and the variances	Exhibit C-01-01
Fixed Asset Continuity Schedule		
19	Completed Appendix 2-BA for each year - in Excel format	Exhibit C-04-04
19-20	Continuity statements and year-over-year variance analysis must be provided (year end balance, including capitalized interest during construction and overhead costs). Explanations provided where there is a year-over-year variance greater than the applicable materiality threshold If applicable, explanation for any restatement (e.g. due to change in accounting standards) and reconciliation to original statements Year over year variance analysis; explanation where variance greater than materiality threshold. The following comparisons must be provided: - Hist. OEB-Approved vs Hist. Actual (for the most recent historical OEB-approved year) - Hist. Act. vs. preceding Hist. Act. (for the relevant number of years) - Hist. Act. vs. Bridge - Bridge vs. Test	Exhibit C-01-01 Exhibit C-04-02 (Gross Fixed Assets) Exhibit C-04-03 (Accumulated Depreciation) Exhibit C-04-04 (Appendix 2-BA) Exhibit C-04-05 (CWIP)

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20	Opening and closing balances of gross assets and accumulated depreciation correspond to fixed asset continuity statements. If not, an explanation and reconciliation must be provided (e.g. CWIP, ARO). Reconciliation must be between net book value balances reported on Appendix 2-BA and balances included in rate base calculation	Exhibit C-01-01 Exhibit C-04-02 Exhibt C-04-03 Exhibit C-04-04 (Appendix 2-BA)
20	Distributor may include in-service balances previously recorded in DVAs, such as renewable generation/smart grid related accounts, in its opening test year property, plant and equipment balances, if these costs have not been previously reviewed and approved for disposition, and if disposition is being requested in this application. In this situation, the distributor must clearly show in its evidence (e.g. Appendix 2-BA) that the addition was included in the opening test year balances and must reconcile the closing bridge year and opening test year figures. Distributors must provide the same reconciliation for accumulated depreciation	Exhibit C-01-01 Exhibit C-04-04 (Appendix 2-BA)
20	Summary of approved and actual costs for any ICM(s) and/ or ACM approved in previous IRM applications	Not applicable No ICMS or ACMs approved from previous IRM applications
20	Continuity statements must reconcile to calculated depreciation expenses and presented by asset account	Exhibit C-04-04 (Appendix 2-BA) Exhibit E-08-01, Attachment 2
20	All asset disposals clearly identified in the Chapter 2 Appendices for all historical, bridge and test years	Exhibit E-08-01, Attachment 2 Exhibit C-04-04 (Appendix 2-BA)
Depreciation, Amortization and Depletion		
21	Explanations for any useful lives of an asset that are proposed that are not within the ranges contained in the Kinectrics Report	Exhibit E-08-01
21	Depreciation, amortization and depletion details by asset group for historical, bridge and test years. Include asset amount and rate of depreciation/amortization. Must complete Appendix 2-C which must agree to accumulated depreciation in Appendix 2-BA under rate base	Exhibit E-08-01, Attachment 2 See Exhibit A-02-03 for rationale on non-applicability of Appendix 2-C (Distribution)
21	Identification of any Asset Retirement Obligations and associated depreciation or accretion expense - includes the basis for and calculation of these amounts	Exhibit E-08-01
21	Identification of historical depreciation practice and proposal for test year. Variances from half year rule must be documented and supporting rationale provided	Exhibit E-08-01
21	Copy of depreciation/amortization policy if available. If not, equivalent written description; summary of changes to depreciation/amortization policy since last CoS	Exhibit E-08-01, Section 1.4 (equivalent written description has been provided) Exhibit E-08-01
21	If filing under MIFRS, explanation of any deviations from the practice of depreciating significant parts or components of PP&E separately	Not Applicable - Hydro One is not filing under MIFRS and does not have different practices of depreciating parts or components of PP&E separately
22	If no changes have been made to depreciation policy or service lives since last rebasing, a statement confirming that this is the case is required. For any depreciation expense policy or asset service lives changes since its last rebasing application: - identification of the changes and detailed explanation for the causes of the changes -use of Kinectrics study or another study to justify changes in useful life - list detailing all asset service lives tied to USoA and reconcile this list to the USoA, detail differences in asset service lives and the TULs from Kinectrics and explain differences outside of minimum and maximum TUL range from Kinectrics; Appendix 2-BB if there have been changes in asset service lives since last rebasing	Exhibit E-08-01 Exhibit E-08-01, Attachment 1

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Filing Requirement (Page #, Reference)		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Allowance for Working Capital		
22	Working Capital - 7.5% allowance or Lead/Lag Study. If previously ordered by OEB as part of last rate application to file Lead/Lag Study, must comply	Exhibit C-05-01 Exhibit C-05-01, Attachment 2 (Hydro One Distribution - Lead/Lag Study)
22	If Lead/Lag Study conducted - leads and lags measured in days, dollar-weighted and reflects the distributor's actual billing and settlement processing timelines and considers relevant changes to operating environment	Exhibit C-05-01, Attachment 2 (Hydro One Distribution - Lead/Lag Study)
23	Cost of Power must be determined by split between RPP and non-RPP Class A and Class B customers based on actual data, use most current RPP (TOU) price. Calculation must include the impact of the most up to date Ontario Electricity Rebate. Distributors must complete Appendix 2-ZA - Commodity Expense and Appendix 2-ZB - Cost of Power	Exhibit C-05-03 (Appendix 2-ZA and 2-ZB)
23	Use most recent approved UTRs, Smart Metering Entity Charge and regulatory charges	Confirmed- Hydro One is using the most recent approved UTRs, Smart Metering Entity Charge and regulatory charges
Distribution System Plan		
23	DSP filed as a stand-alone, self-sufficient element within Exhibit 2	Exhibit B-03-01 (DSP)
Policy Options for the Funding of Capital		
23	Distributor may propose ACM capital project coming into service during Price Cap IR (a discrete project documented in DSP) - provide information on need and prudence. For projects with an expected capital cost of $2 million or more, excluding general plant investments, includes documentation of the consideration of NWSs to meet the identified system need that will be addressed by the project(s) as articulated in the OEB's Benefit-Cost Analysis Framework for Addressing Electricity System Needs (BCA Framework) to assess the economic feasibility of NWSs	Not Applicable; Hydro One is not requesting an ACM
23-24	Identification that distributor is proposing ACM treatment for these future projects and provide the preliminary cost information, and ACM/ICM materiality threshold calculations - ACM Report provides further details on information required	Not Applicable; Hydro One is not requesting an ACM
24	Complete Capital Module Applicable to ACM and ICM	Not Applicable; Hydro One is not requesting an ACM
Addition of Previously Approved ACM and ICM Project Assets to Rate Base		
24	Distributor with previously approved ACM(s) and/or ICM(s) - schedule of ACM/ICM amounts proposed to be incorporated into rate base (i.e. PP&E and associated depreciation). Comparison of actual capital spending with OEB-approved amount and explanation for variances	Not Applicable; Hydro One is not requesting an ACM
25	Balances in Account 1508 sub-accounts; rate of interest prescribed by the OEB for DVAs for the respective quarterly period as published on the OEB's website	Not Applicable; Hydro One is not requesting an ACM
25	True-up calculation if material, comparing the recalculated revenue requirement based on actual capital spending relating to the OEB-approved ACM/ICM project(s) to the rate rider revenues collected in the same period; assumptions used in the calculation noted (e.g., half-year rule)	Not Applicable; Hydro One is not requesting an ACM
25	Accelerated capital cost allowance (CCA) should not be reflected in the ACM/ICM revenue requirement associated with these projects. Distributors should include the impact of the CCA rule change associated with the ACM/ICM project(s) in Account 1592 - PILs and Tax Variances – CCA Changes sub-account for CCA changes	Not Applicable; Hydro One is not requesting an ACM
Capitalization		
25	Statement confirming accounting standard used in application - MIFRS, USGAAP, ASPE	Exhibit A-06-01
26	Capitalization Policy: provide policy including changes since last rebasing application. Confirm if no changes made to capitalization policy since last rebasing application.	Exhibit C-08-02, Attachment 2
26	Overhead Costs: complete Appendix 2-D	Exhibit C-08-02, Attachment 1 (Appendix 2-D)
26	Burden Rates: identification of burden rates, description of how burden rates were derived. If burden rates were changed since last rebasing, identification of the burden rates prior to the change	Exhibit C-08-02, Attachment 1 (Appendix 2-D) Exhibit C-09-01

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Filing Requirement (Page #, Reference)		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Costs of Eligible Investments for the Connection of Qualifying Generation Facilities		
26	See Appendix A	DSP Section 3.4
General & Administrative Matters		
Ch5, p2	Use of terminology and formats set out in Ch. 5	Exhibit B-03-01 (DSP)
Investment Categories		
Ch5, pp2-4	Investment projects and programs grouped into one of four investment categories (i.e. system access, system renewal, system service, general plant)	DSP Section 3.8
Distribution System Plan		
Ch5, p5	If a distributor's application uses alternative section headings and/or arranges the information in a different order, table provided that cross-references the headings/subheadings used in the application to the section headings/subheadings indicated in Ch. 5	DSP Section 3.0 GSP Section 4.0
Ch5, p5	DSP duration minimum of 10 years, comprising of a historical and forecast period. The historical period is the first five years of the DSP duration, consisting of five historical years, ending with the bridge year. For distributors that have not filed a DSP within the past five years, the historical period is from the test year of a distributor's last cost or service application to the bridge year. The forecast period is the last five years of the DSP duration, consisting of five forecast years, beginning with the test year of the current cost of service application	DSP Section 3.1 with further supporting sections from DSP Sections 3.5, 3.6, 3.7. 3.8, 3.9 and 3.11 including all Investment Summary Documents (ISDs).
Distribution System Plan Overview		
Ch5, p6	High-level overview of information filed in DSP which includes capital investment highlights and changes since last DSP; objectives distributor plans to achieve through DSP, which will be used as a baseline comparison in the performance measurement section below	DSP Section 3.1
Coordinated Planning with Third Parties		
Ch5, p6	The distributor must demonstrate that it has coordinated planning with third parties where appropriate. Explanation of whether consultations affected distributor's DSP, and if so, how; for consultations that affected DSP - overview of consultations and relevant material supporting the effects the consultations had on the DSP	SPF Section 1.2 SPF Section 1.6 DSP Section 3.7
Ch5, p6	Overview of consultation should include: purpose, outcome, whether the distributor initiated the consultation or was invited to participate in it, and the other participants in the consultation process	SPF Section 1.6 DSP Section 3.1 DSP Section 3.7
Ch5, p6	Most recent Regional Plan filed. In the absence of a regional plan, a Regional Planning Status Letter from the transmitter filed	SPF Section 1.2 SPF Section 1.2, Attachments DSP Section 3.7 SPF Section 1.2, Attachment 52
Ch5, p6	Identification of any inconsistencies between DSP and any current Regional Plan. If there are any inconsistencies, explanation of the reasons why, particularly where a proposed investment in their DSP is different from the recommended optimal investment identified in the Regional Plan	DSP Section 3.7
Ch5, p7 & OEB Letter, Jan. 11, 2022	Telecommunications Entities: See January 11, 2022 letter for further guidance to the regulation that requires distributors to consult with any telecommunications entity that operates within its service area when preparing a capital plan for submission to the OEB, for the purpose of facilitating the provision of telecommunications services, and include the following information in its capital plan: -number of consultations conducted and a summary of the manner in which the distributor determined with whom to consult; a summary of the results of the consultation; and a statement as to whether the results of the consultations are reflected in the capital plan and, if so, a summary as to how	DSP Section 3.7
Ch5, p7	REG: -confirmation if there are REG investments in region -if there REG investments proposed in DSP, demonstration of coordination with IESO, other distributors/transmitters (as applicable), and that investments proposed are consistent with Regional Infrastructure Plan - IESO letter in relation to REG investments	DSP Section 3.4

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Performance Measurement for Continuous Improvement		
Ch5, p7	Distribution System Plan: Summary of objectives for continuous improvement set out in last DSP and discussion on whether these objectives achieved. For objectives not achieved, explanation of how this affects current DSP and if applicable, improvements implemented to achieve the objectives in Section 5.2.1	DSP Section 3.5
Ch5, p8	Service Quality and Reliability: - 5 historical years of SQRs; explanations for material changes in service quality and reliability and whether and how DSP addresses these issues - for reliability, any declining 5 year SAIDI/SAIFI trends explained - if reliability targets established in last DSP, any under-performance explained	Exhibit A-05-01 DSP Section 3.5
Ch5, p8	Completed Appendix 2-G; confirmation that the data is consistent with scorecard, or explanation of any inconsistencies	Exhibit A-05-01, Attachment 1 (OEB Appendix 2-G)
Ch5, p8	Summary of performance for historical period using methods and measures (metrics/targets) identified and how performance has trended over the period. Summary must include historical period data on: - all interruptions - all interruptions excluding loss of supply - all interruptions excluding major events and loss of supply for: SAIFI, SAIDI	DSP Section 3.5 Exhibit A-05-01, Attachment 1 (OEB Appendix 2-G)
Ch5, p8	Summary of major events that occurred since last cost of service	DSP Section 3.7, Attachment 1
Ch5, pp8-9	For each cause of interruption for last five historical years: number of interruptions that occurred as a result of the cause of interruption, number of customer interruptions that occurred as a result of interruption, number of customer-hours of interruptions that occurred as a result of the cause of interruption	DSP Section 3.7, Attachment 2
Ch5, p9	Distributor-Specific Reliability Targets: - Reliability performance targets calculated based on: (1) baseline for SAIDI and SAFI based on five-year average performance, (2) an adjustment factor based on performance trend, and (3) an adjustment reflecting benchmarking results - if establishing performance expectations based on something other than the default target, evidence provided of capital and operational plan and other factors that justify the reliability performance the distributors plan to deliver - summary of any feedback from customers regarding reliability on distributors' system	DSP Section 3.5
Planning Process		
Ch5, p9	Overview of planning process that has informed five-year capital expenditure plan; flowchart accompanied by explanatory text**may** be helpful	SPF Section 1.7 DSP Section 3.7 GSP Section 4.7
Ch5, p10	Summary of important changes in distributor's AM process since last DSP	DSP Section 3.7
Ch5, p10	Process: - provide processes used to identify, select, prioritize (including reprioritization over 5 year term), optimize, and pace execution of investments - demonstration that distributor has considered correlation between plan and customer's feedback and needs - demonstration that distributor has considered potential risks of proceeding/not proceeding with individual capital expenditures - demonstrate how it undertake grid optimization using an approach that considers the distributor's whole system - consideration, where applicable, of assessing the use of distribution rate-funded NWSs, cost-effective implementation of distribution improvements affecting reliability, and meeting customer needs as acceptable costs to customers, and other innovative technologies - demonstration that distributor has a planning process for future capacity needs, which must include, among other aspects, increased adoption of electric vehicles	DSP Section 3.6 DSP Section 3.7 GSP Section 4.6 GSP Section 4.7

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Ch5, p11	On a best-efforts basis, the distributor should: - describe how its planning processes have been impacted by its multiple demand load forecasts including qualitative and quantitative risk and uncertainty assessments, as appropriate, for each demand load forecast - incorporate cost projections for future investments that reflect reasonable assumptions for cost trends - consider frequent and extreme weather impacts on energy infrastructure resilience and ensure future average, minimum and maximum temperatures are considered (this can be considered in the load forecast described in Chapter 2 Filing Requirements Section 2.3.1.3) - where a system investment, policy, or program is intended to facilitate fuel switching: consider costs and benefits across impacted energy systems	DSP Section 3.6
Ch5, p11	Data - identification, description and summary of data used in processes above to identify, select, prioritize, optimize and pace investments over DSP	DSP Section 3.7 GSP Section 4.7
Overview of Assets Managed		
Ch5, p12	Overview of service area (e.g. system configuration, urban/rural etc.) to support capital expenditures over forecast period; asset information (e.g. capacity, utilization, condition, failures/performance, asset risks, demographics) by major asset type that may help explain the specific need for the capital expenditure and demonstration of consideration of economic alternatives	DSP Section 3.1 DSP Section 3.2
Ch5, p12	Statement as to whether distributor has had any transmission or high voltage assets deemed previously by the OEB as distribution assets, and whethe there are any such assets that the distributor is asking the OEB to deem as distribution assets in the current application	DSP Section 3.1
Ch5, p12	Description of whether distributor is a host and/or embedded distributor; identification of any embedded and/or host distributors; partially embedded status identified (including % of total load supplied through host); if host distributor, identification of whether there is a separate embedded class or if any embedded distributors are included in other classes	Exhibit A-02-03
Asset Lifestyle Optimization Policies and Practices		
Ch5, p13	Demonstration that distributor has carried out cost-effective system O&M activities to sustain as asset to the end of its service life (and can include references to the Distribution System Code)	DSP Section 3.2
Ch5, p13	Explanation of processes and tools used to forecast, prioritize and optimize system renewal spending and how distributor intends to operate within budget envelopes	DSP Section 3.2 DSP Section 3.7
Ch5, p13	Demonstration of consideration of potential risks of proceeding/not proceeding with individual capital expenditures	DSP Section 3.8, DSP Section 3.11 Investment Summary Documents (ISDs)
Ch5, p13	Demonstration that the distributor has considered the future capacity requirements of the asset such that it does not need to be replaced prematurely due to capacity constraints	DSP Section 3.6 DSP Section 3.7
Ch5, p13	Summary of important changes to the distributor's asset life optimization policies, processes, and tools since last DSP	DSP Section 3.2 GSP Section 4.2
System Capability Assessment for REG and DER		
Ch5, p13	Provide list of restricted feeders by name, the feeder designation, the reason for the restriction, number of connected customers, and explain if there are plans to improve the distribution system's ability to connect distributed energy resources	DSP Section 3.4
Ch5, p13	If a distributor has incurred or expects to incur costs to accommodate and connect renewable generation facilities that will be the responsibility of the distributor under the DSC, refer to Appendix A of Chapter 5 Filing Requirements	DSP Section 3.4
Ch5, pp13-14	Where a distributor plans to improve the distribution system's ability to connect additional distributed energy resources in areas with restricted hosting capacity: include an assessment of potential solutions, including infrastructure-based and non-infrastructure-based options	DSP Section 3.4 DSP Section 3.11, D-SS-07
Non-Wires Solutions to Address System Needs		
Ch5, p14	Description of how distributor has taken NWSs into consideration in its planning process	DSP Section 3.6
Ch5, p14	Explanation of proposed activity in the context of the DSP, including providing details on the system need that is being addressed, infrastructure investments that are being avoided or deferred as a result of NWS, and the prioritization of proposed NWS activity relative to other system investments in the DSP	DSP Section 3.6

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Ch5, pp14-15	Evidence why the proposed NWS is the preferred approach (alone or in combination with an infrastructure solution) to meeting a system need, including an assessment of the projected benefits to customers relative to cost impacts, following the requirements of the BCA Framework	DSP Section 3.6
Ch5, p15	Demonstration that distributor has meaningfully explored contracting services from non-utility owned distributed energy resources for any rate funded, distributor-owned NWS proposal	DSP Section 3.11, D-SS-04, Attachment 2
Climate Vulnerability Assessment and System Hardening *These requirements apply on a best-efforts basis for 2027 rate applications* **Ch5, p15**	- Perform Vulnerability Assessment using either the Generic Option or Custom Option - Vulnerability Assessment supported by documented input data sources, rationale for asset and climate peril selection, and justification for any deviations from standard approaches	DSP Section 3.3, Attachment 5
Ch5, p15	Generic Vulnerability Assessment Option: - file completed version of the Vulnerability Assessment Toolkit - include discussion of vulnerability assessment results in DSP	Not Applicable; using custom option DSP Section 3.3, Attachment 5.01
Ch5, p15	Custom Vulnerability Assessment Option: - ensure that the vulnerability assessment methodology meets criteria outlined in VASH policy - file custom vulnerability assessment study including detailed calculations - include discussion of vulnerability assessment results in DSP	DSP Section 3.3, Attachment 5 DSP Section 3.6
Ch5, p16	- After Vulnerability Assessment: perform pre-assessment to determine whether technically and economically feasible system hardening investment exist - Document and explain pre-assessment approach	DSP Section 3.3, Attachment 5 DSP Section 3.6
Ch5, pp16-17	If pre-assessment identifies economically plausible system harding investments: conduct benefit-cost analysis for VASH for those investments - Generic Option: file Benefit-Cost Analysis Toolkit within VASH toolkit - Custom Option: ensure Benefit-Cost Analysis methodology meets VASH policy	DSP Section 3.3, Attachment 5 DSP Section 3.6
Capital Expenditure Summary **Ch5, p17**	Provide capital expenditure plan that sets out proposed expenditures on distribution system and general plant over a five-year planning period, including investment and asset-related operating and maintenance expenditures	DSP Section 3.8 GSP Section 4.8
Ch5, p17	Provide a snapshot of a distributor's capital expenditures over a 10-year period, including five historical years and five forecast years	DSP Section 3.8 GSP Section 4.8
Ch5, p17	The entire cost of individual projects or programs allocated to one of the four investment categories based on the primary driver of the investment	DSP Section 3.8
Ch5, p17	Completed Appendices 2-AA and 2-AB	DSP Section 3.8, Attachment 1 DSP Section 3.9, Attachment 1 GSP Section 4.8, Attachment 1 GSP Section 4.9, Attachment 1
Ch5, p17	Analysis of distributor's capital expenditure performance for the DSPs historical period - should include explanation of variances by investment or category, including actuals v. OEB-approved/planned amounts for the applicant's last OEB-approved CoS or Custom IR application and DSP - explanation of variances between planned and actual volume of work completed and explanation of variances in a given year that are much higher or lower than the historical trend	DSP Section 3.9 GSP Section 4.9
Ch5, p18	Analysis of distributor's capital expenditure performance for the DSPs forecast period; for investments that have a lifecycle >1yr, the proposed accounting treatment, including the treatment of the cost of funds for CWIP	DSP Section 3.8 Exhibit C-08-01 Exhibit C-08-02, Attachment 2 Exhibit C-04-05
Ch5, p18	Analysis of capital expenditures in DSP forecast period v. historical	DSP Section 3.8 GSP Section 4.8

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Ch5, p18	Summary of any important modifications to typical capital programs since the last DSP	DSP Section 3.8, DSP Section 3.11
Ch5, p18	Description of the impacts of capital expenditures on O&M for each year or statement that the capital plans did not impact O&M costs	DSP Section 3.8 GSP Section 4.8
Ch5, p18	Statement that there are no expenditures for non-distribution activities in the applicant's budget	DSP Section 3.8
Justifying Capital Expenditures		
Ch5, pp18-19	Context on how overall capital expenditures over 5 years will achieve distributor's objectives; comment on lumpy investment years and rate impacts of capital investments in long term	DSP Section 3.1 DSP Section 3.7 DSP Section 3.8 GSP Section 4.1 GSP Section 4.7 GSP Section 4.8 Exhibit A-03-01
Material Investments		
For each project that meets materiality threshold set in Ch 2A or deemed by applicant to be distinct for any other reason, guidelines are:		
Ch5, p19	General information on the project or program - Need, scope, volume of work expected to be completed, key project timings (incl. key factors that affect timing), total expenditures (inc. contributions and economic evaluation as per DSC, as applicable), comparative historical expenditures, priority, alternatives considered, benefit-cost analysis results of recommended alternative, description of the innovative nature of investment if applicable. -Where an investment within the five year forecast period involves a Leave to Construct approval, provide summary of the evidence (as available), for that investment consistent with Chapter 4 of the Filing Requirements for Electricity Transmission Applications	DSP Sections 3.11, Investment Summary Documents (ISDs) GSP Section 4.11, Investment Summary Documents (ISDs)
Ch5, pp19-20	Evaluation criteria and information requirements for each project/program - Demonstration of need, and may include the need to address safety, cyber security, grid innovation, environmental, statutory/regulatory obligations - Where investment substantially exceeds materiality - business case justifying expenditure, alternatives (including NWSs,if applicable), benefits for customers, impact on distributor costs - If a distributor is requesting funding for an NWS, additional guidance on evidentiary requirements is provided in the NWS Guidelines - Where distributor assets that a project will support economic growth: provide evidence supporting assertion and indication of economic growth policies of the government of Ontario that are relevant to the project	DSP Sections 3.11: D-SS-09 on grid innovation DSP Section 3.6 Attachments 1 to 5 for NWS Exhibit G-01-03 Section 9.4 GSP Section 4.11: G-GP-10, G-GP-11, G-GP-30 on physical and cybersecurity
Ch5, p20	Explanation of how innovative project is expected to benefit customers, such as improved reliability, enhanced customer services, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate	DSP Sections 3.11, Investment Summary Documents
Benefit-Cost Analysis Framework		
Ch5, p21	The BCA Framework is mandatory when the projected capital cost of the proposed solution to an electricity system need (either NWS or traditional infrastructure) exceeds $2 million (excluding general plant investments)	DSP Section 3.6 DSP Section 3.6, Attachments
Ch5, p21	Conduct pre-assessment to identify whether there is a reasonable expectation that an NWS may be a viable approach to meeting an identified need. Should the pre-assessment conclude that an NWS is a viable approach, a distributor should proceed with completing a BCA. The BCA should be filed along with the pre-assessment results	DSP Section 3.6 DSP Section 3.6, Attachments
Ch5, p21	BCAs are to be prepared for each specific system need	DSP Section 3.6 DSP Section 3.6, Attachments
Ch5, p22	Distribution Service Test (DST) A distributor looking to file a BCA **must** employ the mandatory distribution service BCA and consider the mandatory quantitative/qualitative impacts to benefit/costs as outlined in the BCA Framework, and **must** include the Excel-based quantitative output template, BCA Data Filing Submission Template. The BCA **may** include the permitted DST qualitative impacts as applicable.	DSP Section 3.6 DSP Section 3.6, Attachments

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Ch5, p23	Energy System Test (EST) Distributors **are encouraged** to do an optional EST particularly if they believe an NWS offers significant benefits beyond those of distribution service. When an EST is conducted, the mandatory EST quantitative/qualitative impacts should be included, including the DST impacts as outlined in the BCA Framework.	DSP Section 3.6 DSP Section 3.6, Attachments
Appendix A (if applicable)		
Ch5, Appendix A	Information on the capability of distribution system to accommodate REG investments, including a summary of the distributor's load and renewable energy generation connection forecast by feeder/substation (where applicable); information identifying specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected renewable generation capacity	DSP Section 3.4
Ch5, Appendix A	In relation to renewable or other distributed energy generation connections, the information that must be considered by a distributor and documented in an application (where applicable), includes: applications from renewable generators > 10 kW, number and MW of REG connections for forecast period, information from IESO and any other information about the potential for renewable generation in distributor's service area, capacity of Dx to connect REG, connection constraints	DSP Section 3.4
EXHIBIT 3 - CUSTOMER AND LOAD FORECAST		
Load Forecasts		
26	Weather normal load forecast provided	Exhibit D-05-01
26	Table outlining any factors that influence the load forecast in distributor's service territory (e.g. demographics, customer composition etc.)	Exhibit D-05-01
26-27	Explanation of the causes, assumptions and adjustments for the volume forecast, including all economic assumptions and data sources used (e.g. housing outlook & forecasts, other variables used in forecasting volumes)	Exhibit D-03-01 Exhibit D-05-01
27	Explanation of weather normalization methodology	Exhibit D-05-01
27	Completed Appendix 2-IB; the customer and load forecast for the test year entered on RRWF, Tab 10	Exhibit D-05-01, Attachment 2 Exhibit D-03-01, Attachment 1
Multivariate Regression Model		
27-28	- rationale to support change if the proposed model's methodology differs from the methodology used in the most recent load forecast; discussion of modelling approaches considered and alternative models tested - statistics should include, but not limited to, the regression equations coefficients and intercepts (e.g. t-stats, model statistics including R2, adjusted R2, F-stat, root-mean-squared-error and Durbin-Watson statistic), including explanation for any resulting non-intuitive relationships - explanation of B239weather normalization methodology (including if monthly HDD and/or CDD are used they are based on either: 10 year avg. or proposed alternative approach with supporting evidence - definitions of HDD and CDD including: climatological measurement points and why appropriate as well as identification of base degrees - sources of data for endogenous and exogenous variables. Where a variable has been constructed, explanation of the variable data used and source. Where a distributor has constructed the demand variable to model billed consumption on a class-specific basis, a full explanation of the approach used to pro-rate or interpolate non-interval data (i.e. if billing data are not based on calendar monthly readings as obtained from interval or smart meters) must be provided, including an explanation of why the constructed demand series is suitable for modelling - any binary variables used must be explained and justified - the use of binary variables should be limited and overlap with other variables should be avoided - explanation of any specific adjustments made (e.g. to adjust for loss or gain of major customers or load, significant re-classifications of customers, etc.). Note locally purchased generation should be included in the total for purchased power - description of how CDM and NWS impacts and other exogenous factors have been accounted for in the historical period, and how CDM and NWS impacts, including any targets or forecasts in the bridge and test years, are factored into the test year load forecast - data and regression model and statistics used in customer and load forecast in Excel format	Exhibit D-05-01 Attachment, 2 Exhibit D-05-01; Appendix A, B & C Exhibit D-03-01-, Attachment 1

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NAC Model		
28-29	- rationale to support NAC methodology if the model use differs from the method used in the most recent load forecast - data supporting calculation of NAC values for each rate class - description of how CDM and NWS impacts and other exogenous factors have been accounted for in historical period and how CDM and NWS impacts, including any targets or forecasts in the bridge and test years, are factored into test year forecast - discussion of weather normalization assumptions used	Not Applicable - Hydro One does not use a normalized average use model to forecast load
Integrated Energy Plan		
29	On a best efforts basis, the load forecast should: - incorporate multiple demand scenarios (includes a reference, high, and low scenario) that takes into consideration the electrification of transportation, industry and any other areas that have electrification impacts. The high and low usage scenarios must include appropriate and substantiated assumptions. A distributor may use modelling done by others to assess multiple demand scenarios. - incorporate economic growth projections, including employment, population and housing - consider future average weather impacts and include average, minimum (HDD) and maximum (CDD) temperatures	Exhibit D-03-01, Appendix A Exhibit D-03-06
Incorporating CDM and NWS Impacts in the Load Forecast for Distributors		
29	Refer to NWS Guidelines for guidance, including supporting evidence required regarding incorporating historical and forecast impact of CDM and NWS activities in load forecast	DSP Section 3.3, Attachment 6 DSP Section 3.6 Exhibit D-05-01
Accuracy of Load Forecast and Variance Analyses		
30	Completed Appendix 2-IB (2-IA provides further instructions for filling out 2-IB)	Exhibit D-05-01, Attachment 2
30	For customer/connection counts: -identification as to whether customer/connection count is shown in year end or average format -year-over-year variances in changes of customer/connection counts with explanation for changes in the definition of, or major changes made in the composition of each customer class -explanations of bridge and test year forecasts by rate class -for last rebasing, variance analysis between last OEB-approved and actuals with explanations for material differences	D-05-01 D-05-01, Attachment 1
30	For consumption and demand: -explanation and details to support how kWh are converted to kW for applicable demand-billed classes -year-over-year variances in consumption (kWh) and demand (kW or kVA - the latter for demand billed rate classes) by rate class and for system consumption overall (kWh) with explanations for material changes in the definition of or major changes over time (comparison done for both historical actuals against each other and historical weather-normalized actuals over time) -explanations of the bridge and test year forecasts by rate class (and how these vary from or are trending from both historical actuals and from weather-normalized actuals) -for last rebasing variance analysis between the last OEB-approved and the actual results with explanations for material differences	D-05-01 D-05-01, Attachment 1
30	All data and equations used to determine customers/connections, demand and load forecasts provided in Excel format	Confirmed
EXHIBIT 4 - OPERATING EXPENSES		
Overview		
31	Brief explanation (quantitative and qualitative) of: - test year OM&A levels - how the distributor develops and receives approval of their OM&A budget - cost drivers and significant changes relative to historical and bridge years - trends in costs and relevant metrics including OM&A per customer (and its components) for the historical, bridge and test years - inflation rate assumed (if proposing different rate than IPI - provide explanation supporting proposal) - business environment changes	Exhibit E-03-01

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Filing Requirement (Page #, Reference)		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
OM&A Summary and Cost Driver Tables		
Inclusion of the following tables in evidence and all OM&A appendices filed:		
31	Summary of recoverable OM&A expenses; Appendix 2-JA	Exhibit E-03-01, Attachment 1 (Tab 2-JA)
31	Recoverable OM&A cost drivers; Appendix 2-JB	Exhibit E-03-01, Attachment 1 (Tab 2-JB)
31	OM&A programs table - Appendix 2-JC **or** OM&A by USoA Table - Appendix 2-JD	Exhibit E-03-01, Attachment 1 (Tab 2-JC)
31	Recoverable OM&A Cost per customer and per FTE; Appendix 2-L	Exhibit E-03-01, Attachment 1 (Tab 2-JL)
31	Distributors with 30k or more customers: present OM&A by program; Appendix 2-JC filed to provide OM&A details and variance analysis on a program basis. For each program, provide a definition of the USoA accounts included	Exhibit E-03-01, Attachment 1 (Tab 2-JC)
32	Only distributors with less than 30k customers: option to file OM&A by program or USoA. If USoA chosen, 2-JD filed instead of 2-JC	Not Applicable - do not have less than 30k customers
32	For all distributors, the table provided (2-JC or 2-JD) must reflect the entire OM&A amount proposed to be recovered through rates. Information provided for bridge and test years.	Exhibit E-03-01
32	Appendix 2-JB populated to provide information on the cost drivers of OM&A expenses; 2-JA broken down into major categories; 2-L populated	Exhibit E-03-01, Attachment 1
32	Identification of change in OM&A in test year in relation to change in capitalized overhead	Exhibit C-08-02, Attachment 1 (Appendix 2-D)
OM&A Variance Analysis		
32	Re: 2-JC or 2-JD - variance analysis between: - Test Year vs Historical OEB approved - Historical OEB-Approved vs Historical Actuals (for the most recent historical OEB-approved year) - Test Year vs most recent Historical Actuals	Exhibit E-03-01, Attachment 1
32	If OM&A expense detailed on USoA basis, variance analysis and explanation broken down by the five major OM&A categories as per 2-JA	Not Applicable - OM&A expense is not detailed on USoA basis
32	For all distributors, the variance analysis includes explanation of whether the change was within the distributor's control or not - distributors encouraged to provide explanations for costs above the threshold which have impacted historical trend	Exhibit E-03-01
Workforce Planning and Employee Compensation		
32	Completed Appendix 2-K; information on labour and compensation includes total amount, whether expensed or capitalized	Exhibit E-06-01 Attachment 1A (App 2-K) and 1B
32-33	If there are three or fewer employees in any category, aggregate with the category to which it is most closely related. This higher level of aggregation must be continued, if required, to ensure that no category contains three or fewer employees.	Confirmed
33	Description of proposed workforce plans, including compensation strategy and any changes from previous plan	Exhibit E-06-01. Attachment 1, 1A, 1B, 2, and 3 Exhibit E-06-02
33	Discussion of the outcomes of previous plans and how those outcomes have impacted their proposed plans including an explanation of the reasons for all material changes to FTEs and compensation. Explanation for all years includes: - variances with an explanation of contributing factors, inflation rates used for forecasts, and the plan for any new employees - basis for performance pay, eligible employee groups, goals, measures, and review process for pay-for-performance plans - relevant studies (e.g. compensation benchmarking)	Exhibit E-06-01. Attachment 1, 1A, 1B, 2, and 3 Exhibit E-06-02
33	Details of employee benefit programs including pensions, OPEBs, and other costs charged to OM&A. A breakdown of the pension and OPEBs amounts included in OM&A and capital provided for the last OEB-approved rebasing application, and for historical, bridge and test years	Exhibit E-07-01 Exhibit E-07-01; Attachment 3 (Appendix 2-KA)
33	Most recent actuarial report and be reconciled with pension and OPEBs amounts (as applicable)	Exhibit E-07-01; Attachment 2
33	Explanation of the basis of which pension and OPEBs amounts are forecast for the bridge and test years; what is documented in the tax section agrees with analysis	Exhibit E-07-01 Exhibit E-07-01; Attachment 3 (Appendix 2-KA)

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Filing Requirement (Page #, Reference)		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
33	For virtual distributors - Appendix K completed in relation to the employees of the affiliates who are doing the work of the regulated distributor. Provide the status of pension funding and all assumptions used in the analysis	Not Applicable - Hydro One is not a virtual utility
33-34	Indication if pension and OPEBs to be recovered using cash or accrual method. If cash method, sufficient supporting rationale and evidence for cash method. If proposing to change the basis in which pension and OPEB costs are included in OM&A from last rebasing, quantification of impact of transition provided	Exhibit E-07-01
Shared Services and Corporate Cost Allocation		
34	Identification of all shared services among affiliates, including the extent to which the applicant is a "virtual utility" and justification of proposed shared services and cost allocation	Exhibit D-02-03
34	For shared services among affiliated entities: type of service provided or received, pricing methodology	Exhibit D-02-03 Exhibit E-04-01, Attachment 1 (Appendix 2-N)
34	Allocation methodology for corporate services, list of shared services, list of costs and allocators and how the allocator was derived, any third party review of cost allocation methodology	Exhibit E-04-08 Exhibit E-04-08, Attachment 1
34	Completed Appendix 2-N for service provided or received for historical actuals, bridge and test; including reconciliation with revenue included in Other Revenue	Exhibit E-04-01, Attachment 1 (Appendix 2-N)
34	Shared Service and Corporate Cost Variance analysis - test year vs last OEB approved and test year vs most recent actual	Exhibit E-04-01 Exhibit E-04-02
35	Identification of any Board of Director costs for affiliates included in LDC costs	Exhibit E-04-08
Purchase of Non-Affiliate Services		
35	Copy of procurement policy (including information on signing authority, tendering process, non-affiliate service purchase compliance)	Exhibit E-05-01 Attachment 1 & 3
35	For material transactions not in compliance with procurement policy, or that were undertaken pursuant to exceptions contemplated within the policy, an explanation as to why as well as a summary of the nature and cost of the product, and a description of the specific methodology used for selecting the vendor	Not Applicable - all material transactions are in compliance Exhibit E-05-01 (procurment management)
Regulatory One-Time Costs		
35	Information supporting the incremental costs associated with the preparation and review of the current application	Exhibit E-10-01
35	Identification of one-time costs in historical, bridge, test years. Explanation provided if distributor is not proposing to recover one-time costs over the test year and subsequent IRM term)	Exhibit E-10-02
35	Completed Appendix 2-M	Exhibit E-10-01, Attachment 1 (Appendix 2-M)
35	Ongoing regulatory costs included in the administration costs of OM&A expense and any material change reported in Appendix 2-JB OM&A Cost Drivers.	Exhibit E-03-01, Attachment (Appendix 2-JB)
LEAP, Charitable and Political Donations		
36	LEAP - the greater of 0.12% of forecasted service revenue requirement or $2,000 included in OM&A and recovered from all rate classes. If proposing LEAP funding higher than 0.12%, details of demographics provided	Not Applicable
36	For any charitable contributions claimed for recovery, detailed information provided	Exhibit E-10-03
36	Confirmation that no political contributions have been included for recovery	Exhibit E-10-03
Cost of Non-Wires Solution and Conservation and Demand Management		
37	Statement confirming that no costs for supporting IESO programs funded under the eDSM Framework are included in revenue requirement	E-03-04 Section 5.2
37	Distributor should generally not include any forecast costs associated with partnership in the IESO's Local Initiative Program (LIP) within its revenue requirement; distributor can seek to recover partnership costs at a future date through the LIP deferral account. If distributor plans to partner with the IESO for the LIP at the time of its cost of service application, description of proposed approach to partnership, including a forecast of LIP costs	Confirmed

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Funding Options for Non-Wires Solutions		
37-38	If NWSs included in COS where NWSs expected to come into service during Price Cap IR term, identification of if costs of such NWSs included in the revenue requirement, or if the distributor intends to propose treatment similar to an ACM for these future NWSs	Not Applicable
38	If the latter as noted above, supporting rationale provided (e.g., the preliminary cost information and ACM/ICM materiality threshold calculations to show that a similar capital project would qualify for ACM treatment based on the forecasted information at the time of the DSP and cost of service application)	Not Applicable
EXHIBIT 5 - COST OF CAPITAL AND CAPITAL STRUCTURE		
38	Use of most recent parameters issued by the OEB, subject to update if new parameters available prior to OEB decision	Exhibit F-01-01
38	If applying for distributor specific cost of capital parameters and equity ratios, supporting evidence and justification provided. This evidence must provide strong rationale for departing from the OEB's policy and why the Fair Return Standard cannot be met	Exhibit F-01-01
Capital Structure		
39	Completed Appendix 2-OA for last OEB approved and test years	Exhibit F-01-03: Appendix 2-OA
39	Completed Appendix 2-OB for historical, bridge and test years with respect to long-term debt, short-term debt, preference shares, and common equity	Exhibit F-01-04: Appendix 2-OB
39	Explanation for any material changes in actual capital structure or material differences between actual and deemed capital structure including: retirement of debt or preference shares and buy-back of common shares; short-term debt, long-term debt, preference shares and common share offerings	Exhibit F-01-01 Exhibit F-01-01, Attachment 1
Cost of Capital (Return on Equity and Cost of Debt)		
The following provided for each year:		
39	For affiliated debt held by the holding company, other affiliated company or related party debt of the utility, an explanation of how the debt rate is no higher than it would have been if funds were borrowed directly by the utility through the external markets	Exhibit F-01-02
39	Evidence explaining how distributor manages their long-term debt, including actual debt and the forecast of future debt	Exhibit F-01-02
39	For utilities incurring transactions/issuance costs to secure financing from the market - transaction/issuance costs incorporated into the debt interest rate used to set rates (so that the transaction costs are amortized over the term of the debt instrument using the effective interest rate methodology)	Exhibit F-01-02
40	Calculation of cost for each capital component	Exhibit F-01-03: Appendix 2-OA
40	Profit or loss on redemption of debt, if applicable	Exhibit F-01-02
40	Copies of current promissory notes or other debt arrangements with affiliates	Exhibit F-02-05 Exhibit F-02-06
40	Explanation of debt rate for each existing debt instrument including an explanation on how the debt rate was determined and is in compliance with the policies documented in the Cost of Capital Decision or applicant's proposed approach (including the justification and key assumptions)	Exhibit F-01-02
40	Forecast of new debt in bridge and test year - details including estimate of rate and other pertinent information (e.g. affiliated debt or third party)	Exhibit F-01-02
40	Historical return on equity achieved	Exhibit F-01-01
40	If applicable (only when there are material variances relating to notional debt with material impacts on revenue requirement) - the rate for notional debt is at the lower of the deemed long-term debt rate at the time of issuance and the weighted average cost of actual long-term debt	Exhibit F-01-01

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Filing Requirement (Page #, Reference)		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Not-for-Profit Corporations		
40	Requested capital structure and cost of capital (including the proposed cost of long-term and short-term debt and proposed return on equity)	Not Applicable; not a not-for-profit corporation
40	Statement as to whether the revenues derived from the return on equity component of the cost of capital is to be used to fund reserves or will be used for other purposes	Not Applicable; not a not-for-profit corporation
41	If the revenues derived from the return on equity component will be used to fund reserves, specifications for each proposed reserve fund and a description of the governance (policies, procedures, sign-off authority, etc.) that will be applied	Not Applicable; not a not-for-profit corporation
41	If the revenues derived from the return on equity component will be used for other purposes, statement as to whether these revenues will be used for non-distribution activities (in the situation where the excess revenues are greater than the amounts needed to fund distribution activities); rationale provided supporting the use of the revenues in this manner. Also, governance (policies, procedures, sign-off authority, etc.) that will be applied to the funding of non-distribution activities provided	Not Applicable; not a not-for-profit corporation
41	If there are approved reserves from previous OEB decisions provide the following: -the limits of any capital and/or operating reserves as approved by the OEB, and identifying the decisions establishing these reserve accounts and their limits -the current balances of any established capital and/or operating reserves	Not Applicable; not a not-for-profit corporation
EXHIBIT 6 - REVENUE REQUIREMENT AND REVENUE DEFICIENCY OR SUFFICIENCY		
41	The following information must be provided in this exhibit (with cross references to where in the application further details can be found for each) excluding energy costs and revenues and unregulated costs and revenues: -determination of net income, statement of rate base, actual return on rate base, indicated rate of return, requested rate of return, deficiency or sufficiency in revenue, gross deficiency or sufficiency in revenue	Exhibit D-01-01, Attachments 6-10 (Dx RRWF)
41-42	Revenue deficiency or sufficiency calculations net of electricity price differentials captured in the Retail Settlement Variance Accounts (RSVAs) and also net of any cost associated with low voltage (LV) charges or DVA balances of distribution expenditures/revenues being tracked through approved deferral and variance accounts for certain distribution assets (e.g. ICM and ACM capital projects) and for which disposition is not being sought in the application.	Exhibit D-01-01, Attachments 6-10 (Dx RRWF)
42	Summary of drivers for test year deficiency/sufficiency, how much each driver contributes; references in application evidence mapped to drivers	Exhibit D-01-01
42	Impacts of any changes in methodologies on deficiency/sufficiency and on individual cost drivers contributing to it	Not Applicable - No change methodolgy to deficiency/sufficiency
Revenue Requirement Work Form		
42	Completed RRWF. Revenue requirement, def/sufficiency, data entered in RRWF must correspond with other exhibits	Confirmed; Exhibit D-01-01, Attachments 6-10 (Dx RRWF)
42	If the enhanced RRWF cannot reflect a distributor's proposed rates accurately, the distributor must file its rate generator model	Exhibit L-02-01, Attachment 1 Exhibit L-02-01, Attachment 2
43	For revenues - calculation of bridge year forecast of revenues at existing rates; calculation of test year forecasted revenues at each of existing rates and proposed rates	Exhibit D-01-01, Attachments 6-10 (Dx RRWF)
Income Tax or PILs		
43	Detailed calculations of income tax or PILS. Must include a completed Excel version of the PILs model available on the OEB's website, including derivation of adjustments for historical, bridge and test years. Regulatory assets and liabilities must excluded from PILs calculations when they were created and when they were disposed, regardless of the actual tax treatment accorded those amounts	Exhibit E-09-02, Attachment 1 - 8 Exhibit A-02-03 - Hydro One completed custom spreadsheets rather than using OEB's PILs model
43	Supporting schedules and calculations identifying reconciling items	Exhibit E-09-02, Attachments 1 - 4, 7 & 8
43	Most recent federal and provincial tax returns	Exhibit E-09-05A
43	Financial Statements included with tax returns if different from those filed with application	Not Applicable
43-44	Calculation of tax credits; redact where required (filing of unredacted versions is not required)	Exhibit E-09-02; Attachments 5 & 6

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Filing Requirement (Page #, Reference)		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
44	Supporting schedules, calculations and explanations for other additions and deductions	Exhibit E-09-01
44	Completion of the integrity checks in the PILs Model	Exhibit E-09-01
44	Accelerated CCA - confirm whether Accelerated Investment Incentive Program (AIIP) was applied to eligible capital additions in tax filings. If distributor committed to applying (or not applying) AIIP through the previous IRM term, it is expected to maintain that approach unless the OEB has approved otherwise - Confirm whether a smoothing mechanism was applied to the PILs expense and approved in the last cost of service decision and order. If yes, the use of Account 1592 to record the specific CCA changes during the rate term contemplated in the smoothing proposal is no longer applicable - full revenue requirement impact recorded in Account 1592 and the balance sought for review and disposition, detailed calculations by year for the full revenue requirement impact recorded in Account 1592 in Excel format	Exhibit G-01-01, Attachment 2
44-45	If applying accelerated CCA to the PILs in the test year, proposal for a smoothing mechanism to reduce the test year's PILs expense	Not Applicable
Other Taxes		
45	Account 6105 is not an OM&A account and should be excluded from all OM&A totals. Applicant should provide an explanation of how these tax amounts are derived	Exhibit E-03-01, Attachment 1 (App 2-JA, JB, JC) E-09-06
Non-recoverable and Disallowed Expenses		
45	Exclude from regulatory tax calculation any non-recoverable or disallowed expenses	Confirmed; Exhibit E-09-01
Other Revenue		
45-46	Completed Appendix 2-H, including the breakdown of each account showing the components of each	Exhibit D-02-02, Attachment 1
45-46	For each other distribution revenue account: -comparison of actual revenues for historical years to forecast revenue for bridge and test year, including explanations for significant variances year-over-year -revenue from any new proposed specific service charges, changes to rates, or new rules for applying existing specific service charges (incl. any credits to customers) -revenue from affiliate transactions, shared services, or corporate cost allocation. For each affiliate transaction identification of service, the nature of service provided, accounts used to record revenue, and costs to provide service -revenue from affiliate transactions recorded in Account 4375 -expenses from affiliate transactions recorded in Account 4380	Exhibit D-02-02
46	Balances recorded in Account 4375 and Account 4380 reconcile to the balances recorded in Appendix 2-N – Shared Services and Corporate Allocation for the three historical years, the bridge year and the test year. Any differences must be reconciled	Exhibit D-02-02, Attachment 1 Exhibit E-04-01, Attachment 1
46	Revenue related to microFIT recorded as revenue offset in Account 4235	Exhibit D-02-02 Exhibit D-02-02, Attachment 1
46	Transfer pricing and allocation of cost methods do not result in cross-subsidization between regulated and non-regulated lines of business and compliance with article 340 of APH; explanations for any deviations	Exhibit C-03-01 Exhibit E-04-08, Attachment 1
46	Identification of any discrete customer groups that may be materially impacted by changes to other rates and charges	Not applicable - no customer groups to be materially impacted by the changes
47	Revenues or costs (including interest) associated with deferral and variance accounts not included in other revenues	Exhibit D-02-02, Attachment 1

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Filing Requirement (Page #, Reference)		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
EXHIBIT 7 - COST ALLOCATION		
Cost Allocation Study Requirements		
47	Completed cost allocation study using the OEB-approved methodology or the distributor's study and model reflecting forecasted test year loads and costs and supported by appropriate explanations and live Excel spreadsheets; sheets 11 and 13 of the RRWF complete	Exhibit L-01-03, Attachment 1 Exhibit L-01-03, Attachment 2
47	Description of weighting factors, rationale for use of default values (if applicable)	Exhibit L-01-03
47	If distributor is choosing to use the same weightings as its previous rebasing application (on the condition that these were accepted by the OEB and there have been no significant changes in the distributor's policies or practices that would impact the weightings), a reference to the previous application provided	Exhibit L-01-03
48	Complete live Excel cost allocation model, whether using the OEB-issued one or a different model. If using the OEB-issued model, Input sheet I.2, cells c15 and c17 must be used to identify the final run of the model on each sheet. If using another model, the distributor must file equivalent information	Exhibit L-01-03, Attachment 1 Exhibit L-01-03, Attachment 2
Load Profiles and Demand Allocators		
48	Updated load profiles for all classes and update demand allocators	Exhibit L-01-03, Attachment 1 (Demand Allocators) Exhibit L-01-03, Attachment 2 (Demand Allocators) Exhibit L-01-03, Attachment 7 (Load Profiles)
48	Discussion of how load profiles have been normalized for weather and any notable events impacting usage patterns	Exhibit D-05-01
48	If multivariate regression model is used, the following must be provided: -statistics and statistical tests related to regression equation(s) coefficients and intercept, results of tests for autocorrelation and multicollinearity -explanation of the weather-normalization methodology including: relationship between demand and Heating and/or Cooling requirements, determination of normal weather: the hourly for daily Heating and/or Cooling required -sources of data used for both endogenous and exogenous variables. Where a variable has been constructed, explanation of the variable, data used and the source of the data provided -explanation of any specific adjustments made (e.g. to address gaps in historical meter data)	Exhibit D-05-01 Exhibit D-05-01, Attachments 1-3 Exhibit D-03-01 Exhibit D-03-01, Attachment 1
48	Data and regression model and statistics used in the weather normalization of load profiles provided in Excel format (includes showing the derivation of any constructed variables)	Exhibit D-05-01 Exhibit D-03-01 Exhibit D-03-01, Attachment 1
49	Spreadsheet and a description with calculations to show how demand allocators are derived from the historical weather normal or weather actual load profiles	Exhibit D-05-01
49	Historical Average: Where the annual demand allocators are based on weather actual load profiles, at least three, and ideally five years of historical data should be used to perform weather normalization. Where the annual demand allocators are based on weather normalized load profiles, fewer years may be used	Exhibit D-05-01
49-50	Host Distributor only - evidence of consultation with embedded Dx prior to rate filing - statement regarding embedded Dx support for approach to allocation of costs - if embedded Dx is separate class - class in cost allocation study and RRWF - if new embedded Dx class - rationale and supporting evidence (cost of serving, load served, asset ownership information, distribution charges levied); include in cost allocation study and RRWF - if embedded Dx billed as GS customer - include with the GS class in cost allocation model and the RRWF. Provide cost of serving, load served, asset ownership information, distribution charges levied, appropriateness of rates for the GS class recovering costs of providing low voltage dx services to embedded distributor(s). Completed Appendix 2-Q - Cost of Serving Embedded Distributors	Please refer to Exhibit A-02-03, section 4 re: consultation with embedded distributors and support for allocation of costs. Embedded distributors are part of Hydro One's sub-transmission (ST) rate class, which is included in the cost allocation model (L-01-03-01). Appendix 2-Q is not applicable as embedded distributors are covered by Hydro One's ST class.
50	microFIT - if the applicant believes that it has unique circumstances which would justify a different rate than the generic rate, documentation to support rate must be provided	Not Applicable - Hydro One is adopting the OEB's microFIT charge
50	Standby Rates - distributors with interim standby rates to request approval for final standby rates and provide evidence confirming that they have advised all affected customers of the proposal	Not Applicable - Hydro One is not requesting a standby charge

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51	Standby Rates - distributor that seeks to establish new standby rates or changes to standby charges, including a change in the methodology on which these rates are based, must provide full documentation supporting its proposal, and confirm that all affected customers have been notified of the proposed change(s)	Not Applicable - Hydro One is not requesting a standby charge
51	If new customer class or changing definition of existing classes, rationale and restatement of revenue requirement from previous cost of service	Exhibit L-01-02
51	If eliminating or combining customer classes, rationale and restatement of revenue requirement from previous cost of service, where possible	Exhibit L-01-02
Class Revenue Requirements		
51-52	To support a proposal to rebalance rates, information on the revenue by class that would apply if all rates were changed by a uniform percentage provided. Ratios compared with the ratios that will result from the rates being proposed by the distributor	Not Applicable - no proposal to rebalance rates
Revenue to Cost Ratios		
52	If R:C ratios outside dead band - cost allocation proposal to bring them within the OEB-approved ranges provided. In making any such adjustments, potential mitigation measures addressed if the impact of the adjustments on the rates of any particular class or classes is significant	Exhibit L-02-01
53	If distributor proposes to continue rebalancing rates after the cost of service test year, the ratios proposed for subsequent year(s) must be provided	Exhibit L-02-01
53	If Cost Allocation Model other than OEB model used - exclude LV and exclude DVA balances and that revenues exclude rate riders, rate adders and the Smart Metering Entity Charge. Distributor must also ensure that information relevant to customer charge unit costs, microFIT unit costs and revenue is consistent with the output from the OEB's model	Not Applicable - the OEB's Cost Allocation Model was used
EXHIBIT 8 - RATE DESIGN		
53	Monthly fixed charges - 2 decimal places; variable charges - 4 decimal places; if departing from this approach, explanation provided as to why necessary and appropriate	Exhibit L-02-01
Fixed Variable Proportion		
53	The following is to be provided in relation to the fixed/variable proportion of proposed rates: -Current F/V for each rate class with supporting info -Proposed F/V for each rate class with explanation for any changes from current proportions -Table comparing current and proposed monthly fixed charges with the floor and ceiling as in cost allocation study Analysis must be net of rate adders, funding adders, and rate riders	Exhibit L-02-01 Exhibit L-02-01, Attachment 1
RTSRs		
54	Completed RTSR Model in Excel	Exhibit L-02-01, Attachment 4 & 5
54	Identification of the quantity of load (energy and demand) used by EV charging facilities. EV charging volume only counted in the rows pertaining to EV charging and not be included in the volume for the remainder of the applicable rate class	Exhibit L-02-01
54	If proposing to update RTSRs to reflect updated cost causation data: provide additional tables beyond RTSR model	Exhibit L-02-01
54	RTSR information consistent with working capital allowance calculation; explanation for any differences	Exhibit L-02-01
Retail Service Charges		
55	Use of current approved generic retail service rates and charges per most recent rate order	Confirmed; Exhibit L-07-02
Regulatory Charges		
55	If applying for a rate other than the generic rate set by the OEB, distributors must provide justification as to why their specific circumstances would warrant a different rate, in addition to a detailed derivation of their proposed rate	Not Applicable - Hydro One is not applying for changes to the generic regulatory charges set by the OEB

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Specific Service Charges		
55-56	If requesting new specific service charge or a change to the level of an existing charge, description of the purpose of charge, or reason for change to an existing charge; calculations to support charges	Exhibit L-04-01 Exhibit L-04-01, Attachment 1
56	Identification in the Application Summary all proposed changes that will have an impact on customers, including changes to other rates and charges that may affect a discrete group; identification of specific customers or customer groups impacted by each proposal	Not applicable - see Exhibit A-03-01
56	Calculation of charge includes: direct labour, labour rate, burden rate, incidental, other	Not applicable - see Exhibit L-04-01
56	Identification of any rates and charges in Conditions of Service that do not appear on tariff sheet. Explain nature of costs, provide schedule outlining revenues or capital contributions recovered from these rates from last OEB-approved year to most recent actuals and the revenue or capital contributions forecasted for the bridge and test years. A proposal and explanation as to whether these charges should be included on tariff sheet	Exhibit L-04-01
56	Revenue from specific service charges corresponds with Other Revenue evidence	Exhibit D-02-02, Attachment 1 Exhibit D-01-01, Attachments 6-10
Wireline Pole Attachment Charge		Confirmed; Exhibit G-01-01 Exhibit L-07-02 Exhibit L-07-02, Attachment 1
56-57	Use of most recent charge per OEB generic order	
Low Voltage Service Rates		
If the distributor is fully or partially embedded, information on the following must be provided:		
57	Forecast LV Cost	Not Applicable to Hydro One
57	Actual LV Cost for the last three historical years along with bridge and test year forecasts; year-over-year variances and explanations for substantive changes in costs over time up to and including test year forecast	Not Applicable to Hydro One
57	Support for forecast LV, e.g. Hydro One Sub-Transmission charges	Not Applicable to Hydro One
57	Allocation of forecasted LV cost to customer classes (typically proportional to Tx connection revenue)	Not Applicable to Hydro One
57	Proposed LV rates by customer class	Not Applicable to Hydro One
Smart Meter Entity Charge		Confirmed
58	Current OEB-approved Smart Metering Entity Charge until the OEB approves any updated charge	
Loss Factors		
58	Proposed SFLF and Total Loss Factor for test year	Exhibit L-06-02
58	Statement as to whether LDC is embedded including whether fully or partially	Exhibit A-02-03, Section 6
58	Study of losses if required by previous decision	Exhibit L-06-02
58	3-5 years of historical loss factor data - Completed Appendix 2-R	Exhibit L-06-02, Attachment 1 (App 2-R)
58	If proposed distribution loss factor >5% or is showing an increasing trend, explanation for level of losses, details of actions taken to reduce losses in the previous five years, and actions planned to reduce losses going forward	Exhibit L-06-02 Exhibit L-06-02, Attachment 1 (App 2-R)
58	Explanation of SFLF if not standard	Exhibit L-06-02
58	Reconciliation between the application and RRR filing	Confirmed; Exhibit L-06-02, Attachment 1 (App 2-R)

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Filing Requirement (Page #, Reference)		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Tariff of Rates and Charges		
59	Current and proposed Tariff of Rates and Charges -**must be filed in Excel format and PDF format** Explanation and support of each change in the appropriate section of the application	Exhibit L-07-01, Attachments 1-4 Exhibit L-07-02, Attachments 1 & 2
59	Completed Tariff Schedule and Bill Impacts Model	Exhibit L-06-01, Attachments 1-5 Exhibit L-07-01, Attachments 1-4 Exhibit L-07-02, Attachments 1-2
59	Explanation of changes to terms and conditions of service if changes affect application of rates and rationale behind those changes	Not Applicable - no changes to the Conditions of Service that affect the Application of the rates and charges to be approved by the OEB. Following the OEB's decision on this Application, Hydro One's Conditions of Service will be updated as needed in order to implement the OEB's decision on this Application.
59	Proposed tariffs must include applicable regulatory charges, and any other generic rates as ordered by the OEB	Exhibit L-07-02, Attachments 1 & 2
Revenue Reconciliation		
59	Calculations of revenue per class under current and proposed rates; reconciliation of rate class revenue and other revenue to total revenue requirement (i.e. breakout volumes, rates and revenues by rate component etc.)	Exhibit L-02-01, Attachments 1 & 2
59	Completed RRWF - Sheet 13 (table reconciling base revenue requirement against revenues recovered through proposed rates)	Exhibit L-07-02, Attachments 1 & 2
Bill Impact Information		
59	Bill impacts filed for all customer classes on a representative sample of end-users, which identifies existing rates, proposed changes to rates, and detailed bill impacts (including % change in distribution excluding pass through costs - Sub-Total A, % change in distribution - Sub-Total B, % change in delivery - Sub-Total C, and $ change in total bill)	Exhibit L-06-01, Attachments 1-5
60	Bill impacts provided for typical customers and consumption levels. Must provide residential 750 kWh and GS<50 2,000 kWh. Bill impacts must be provided for a range of consumption levels relevant to the service territory for each class	Exhibit L-06-01
60	If applicable, for certain classes where one or more customers have unique consumption and demand patterns, the distributor must show a typical impact and provide an explanation	Exhibit L-06-01, Attachments 1-5
Rate Mitigation		
60	Mitigation plan if total bill increase for any customer class is >10% including: specification of class and magnitude of increase, description of mitigation measures, justification for mitigation measure including reasons if no mitigation proposed, other relevant information. The Tariff Schedule and Bill Impacts Model must reflect any mitigation plan proposed.	Exhibit L-06-01
Rate Harmonization Mitigation Issues		
61	If part of a MAADs transaction, and rate harmonization plan not yet approved by the OEB, a rate harmonization plan must be filed	Exhibit L-01-02 Exhibit L-02-01 Exhibit L-03-01
61	Plan includes a detailed explanation and justification for the implementation plan, and an impact analysis	Exhibit L-01-02 Exhibit L-01-03 Exhibit L-03-01 Exhibit L-06-01
61	If consolidated distributor does not intend to undertake rate harmonization: explanation for not doing so	Not Applicable- Hydro One is proposing to harmonize acquired utilities
61	If impact of COS increases and harmonization effects result in total bill increases for any customer class exceeding 10%, discussion on of proposed measures to mitigate increases in its mitigation plan, or justification provided as to why mitigation is not required	Exhibit L-06-01
61	Migration plan that includes fully harmonizing rates that is to be accomplished over more than one year must be supported by a detailed plan for accomplishing this during the subsequent Price Cap IR period	Exhibit L-06-01

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Filing Requirement (Page #, Reference)		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
EXHIBIT 9 - DEFERRAL AND VARIANCE ACCOUNTS		
61	Summary table showing all active DVAs not disposed of yet, showing principal and interest/carrying charges, total balance for each account, whether account being proposed for disposition and (for Group 2 DVAs) whether the account is proposed to be continued or discontinued	Exhibit G-01-01, Section 1.0
61	In a separate section under the summary table: - For any account identified in the summary table as not being proposed for disposition, provide an explanation as to why it is not being proposed for disposition - For any Group 2 account identified in the summary table that are proposed to be discontinued, provide an explanation as to why it is being discontinued	Exhibit G-01-01, Section 6.0
61	If applicable, description of DVAs that were used differently than as described in the APH, relevant accounting order or other OEB document	Exhibit G-01-01 Exhibit G-01-01, Attachment 1
62	Completed DVA continuity schedule for period from last disposition to present - live Excel format. Continuity schedule must show separate itemization of opening balances, annual adjustments, transactions, dispositions, interest and closing balances for all active DVAs. The opening principal amounts and interest amounts for Group 1 and 2 balances, shown in the DVA Continuity Schedule, must reconcile with the last applicable approved closing balances.	Exhibit G-01-07 Exhibit G-01-05, Attachment 1 (Consolidated DVA Continuity Schedule) Exhibit G-01-07, Attachment 2 (HONI Dx Continuity Schedule)
62	Explanation if account balances in continuity schedule differs from trial balance reported through RRR and documented in AFS - included in tab Appendix A of DVA schedule. This includes all Account 1508 sub-accounts. A reconciliation of all the Account 1508 sub-accounts to the Account 1508 control account reported in the RRR is to be provided in the DVA continuity schedule	Exhibit G-01-05 Exhibit G-01-07, Attachment 2 (HONI Dx Continuity Schedule)
62	Statement whether any adjustments made to DVA balances previously approved by OEB on final basis - the OEB expects that no adjustment will be made to any deferral and variance account balances previously approved by the OEB on a final basis. If any adjustments have been made, explanation for the nature and the amount of the adjustment(s), and appropriate supporting documentation, under a section titled "Adjustments to Deferral and Variance Accounts"	Exhibit G-01-05
62	Confirmation of use of interest rates established by the OEB by month or by quarter for each year; most recently published rate used as a placeholder for future periods	Exhibit G-01-01
62	If requesting proposal for a differing carrying charge on a DVA involving long-term expenditures: include evidence justifying departure from standard practice.	Not Applicable - Hydro One has not made such proposal Exhibit G-01-01
Disposition of Deferral and Variance Accounts		
63	Refer to DVA Continuity Schedule Instructions for instructions on completing the DVA Continuity Schedule, annual updates and discussions on default treatments and expectations for DVAs	Confirmed
63	Confirmation that distributor is allocating DVAs using an approved allocator. If proposing to allocate a DVA which the OEB has not established an allocator, proposed allocation based on cost driver must be provided with justification; indication of proposed billing determinants, including charge type for recovery purposes and included in cont. schedule	Confirmed
63	Propose rate riders that dispose of the balances. If the distributor is proposing an alternative recovery period other than one year, explanation provided	Exhibit G-01-06 Exhibit L-05-01 Exhibit L-05-01, Attachments 1 & 2
63	Support (e.g., explanations, calculations) on how each material Group 2 balance is determined. For distributor-specific Group 2 accounts that are not material, provide a brief explanation of the account balance	Exhibit G-01-01
Disposition of Accounts 1588 and 1589		
63	If a distributor has not implemented OEB's February 21, 2019 accounting guidance, indication that this is the case	Exhibit G-01-05
63	Indication of the year in which Account 1588 and Account 1589 balances were last approved for disposition, and whether the balances were approved on an interim or final basis. If the balances were last disposed on an interim basis, indicate the year in which balances were last disposed on a final basis	Exhibit G-01-05
64	Transactions recorded in Accounts 1588 and 1589 are accounted for in accordance with the respective year's accounting guidance	Confirmed; Exhibit G-01-05, Attachment 1 (Consolidated DVA Continuity Schedule)

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Filing Requirement (Page #, Reference)		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
64-65	**Commodity Accounts Analysis Workform (Formerly GA Analysis Workform)** - filed in in live Excel format for each year that has not previously been approved by the OEB for disposition - If the distributor is adjusting the Account 1588 and 1589 balance that was previously approved on an interim basis, Commodity Account Analysis Workform completed from the year after the distributor last received final disposition for Account 1588 and1589 - If the distributor is proposing adjustments to final disposed balances in Account 1588 and 1589, completed Workform from the year(s) that contain the error(s) and the associated adjustment(s) to the year the balance is being requested - for any unexplained discrepancy between the actual and expected balance (i.e., greater than +/- 1% of the total annual IESO GA charges), further analysis and supporting evidence - completed reasonability test for the balance in Account 1588. The reasonability test is included in the Commodity Accounts Analysis Workform.	Exhibit G-01-05, Attachment 3 (Consolidated Commodity Accounts Analysis Workform)
65-66	**Two-Year Limitation Period** - if seeking OEB approval of exception from the limitation period for a payment or adjustment, detailed justification for seeking approval - explanation of the actions taken to resolve the issue to avoid the need for an exception to the limitation period, and why the applicant was not successful in its efforts to resolve the issue - consideration of factors per OEB's October 31, 2019 letter - accounting adjustments recorded in the continuity schedule of the related commodity variance accounts and include these accounting adjustments in the Commodity Accounts Analysis Workform for the purpose of reasonability tests in Accounts 1588 and 1589.	Not Applicable - not seeking approval of exception from 2-year limitation period
Disposition of Account 1580, Sub-account CBR Class B Variance		
66	Proposed disposition of Account 1580 sub-account CBR Class B in accordance with the CBR Accounting Guidance. Must be disposed over one year.	Exhibit G-01-05
66	Account 1580 sub-account CBR Class A is not to be disposed through rates proceedings but rather follow the OEB's accounting guidance	Exhibit G-01-01, Section 5.3
Disposition of Account 1595		
66	Distributors are expected to request disposition of residual balances in Account 1595 Sub-accounts for each vintage year once, on a final basis	Exhibit G-01-05 Exhibit G-01-07, Attachment 2 (HONI Dx Continuity Schedule)
67	Explanation for any material residual balances being proposed for disposition, including quantifying significant drivers of the residual balance	Exhibit G-01-05
Disposition of Retail Service Charges Related Accounts		
67	Distributors that have not yet disposed of Accounts 1508 sub-account Retail Service Charges Incremental Revenue, 1518 or 1548 may forecast balances up to the end of the incentive rate-setting period, provided it can do so with reasonable accuracy, and the OEB may consider disposing of the forecast amounts and then closing the accounts	Exhibit G-01-01
67	Provide cost drivers for any material balances for disposition in Accounts 1518, 1548 or 1508 (sub-account Retail Service Charges Incremental Revenue)	Exhibit G-01-01
Disposition of Account 1592, Sub-account CCA Changes		
67	Provide full revenue requirement impact recorded in Account 1592, Sub-account CCA Changes and the balance sought for review and disposition	Exhibit G-01-01
68	Calculations for accelerated CCA differences per year, based on actual capital additions. Calculations include: underpreciated capital cost continuity schedules for each year itemized by CCA class, calculated PILs/tax differences, grossed-up PILs/tax differences, other applicable information	Exhibit G-01-01 Exhibit G-01-01, Attachment 5
68	Confirmation that Account 1592 amounts related to ICM/ACM have been included in the account, if applicable	Not Applicable - No ICM/CM has been requested
68	Reconciliation of these amounts to the amounts presented in Account 1592 sub-account CCA changes in the DVA continuity schedule	Exhibit G-01-01, Attachment 2 Exhibit G-01-07, Attachment 2
68	If a distributor does not have a balance in this sub-account, the distributor must explain why	Not Applicable; see Exhibit G-01-01

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Filing Requirement (Page #, Reference)		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
Disposition of Account 1509 Impacts Arising from the COVID-19 Emergency		
68	If requesting disposition of any amounts related to the COVID-19 Account, filing requirements as set out in the Filing Requirements for Electricity Distribution Rate Applications, 2025 Edition for 2026 Rate Applications has been provided	Not Applicable - Hydro One is not requesting disposition of COVID account
Disposition of Account 1508, Sub-account Pole Attachment Revenue Variance		
68-69	A table showing the calculation of the account balance, the annual balance broken down customer type, if applicable and: - the number of poles used in the calculation - the pole attachment charge incorporated in rates - the updated charge May also forecast the balance to the effective date of its new rates	Exhibit G-01-01, Section 5.21
Disposition of Account 1508, Sub-account Getting Ontario Connected Act		
69-70	Distributors requesting disposition of any amounts recorded are to file, at a minimum, the following information: - statement confirming that distributor has reflected the GOCA impact in the locate costs of the test year's revenue requirement - supporting calculations for the amounts recorded in the sub-accounts, including the methodology used to measure incremental costs - proposed disposition of the GOCA Variance account under Account 1508 Sub-Account GOCA Variance Account and discontinuance of the account after the rebasing application - rationale if the distributor proposes to continue the GOCA Variance account in the rate term	Exhibit G-01-01, Section 5.12
Disposition of Account 1511 Incremental Cloud Computing Implementation Costs		
	Distributors requesting disposition of any amounts recorded in the Cloud Computing Implementation Account are to file, at a minimum, the following information:	
70	Discussion and supporting explanation for the annual amounts recorded, including the methodology used to measure incremental costs and offsetting savings, as applicable. If there are no offsetting savings, explanation provided	Exhibit G-01-01, Sections 3.9 & 5.18
70	List of the cloud solution(s), actual or forecast amount(s), type(s) of expenditure, and nature of costs	Exhibit G-01-01, Sections 3.9 & 5.18
70	List of costs requested by projects (each with the business purpose of the projects) and a statement for each project regarding whether the cost associated for each project is material	Exhibit G-01-01, Sections 3.9 & 5.18
70	Discussion of whether the distributor would be able to reasonably forecast any further entries in the account, up to the effective data of new rates, so that the account may be disposed in its entirety in the current proceeding (and whether the distributor would be amenable to such an approach)	Exhibit G-01-01, Sections 3.9 & 5.18
70-71	Proposal for disposition of balance - the nature of the cloud solution considered in determining disposition methodology. Recovery would generally be expected to be over the remaining contract term unless the distributor has a strong rationale for doing otherwise	Exhibit G-01-01, Sections 3.9 & 5.18
71	If applicable, proposed treatment of any future cloud solutions during the rate term. If no proposal is made in a rebasing rate application, the Cloud Computing Deferral Account will be closed	Exhibit G-01-03, Section 6.13
71	Use of prescribed interest rate for DVAs	Exhibit G-01-07, Attachment 2 (HONI Dx Continuity Schedule)
71	If applicable, proposal for the rate treatment of the unamortized balance of cloud-based solutions and for any future projects which considers the risk profile of cloud computing solutions versus on-premise solutions and different options that are available for the rate treatment	Exhibit G-01-03, Section 6.13
Disposition of Account 1508, Sub Account Extended Horizons Variance Account		
	If requesting disposition, the following must be filed at a minimum:	
71	Details of the forecasted connections embedded in rates as of the last cost of service application	Exhibit G-01-01, Section 5.16 - due to immateriality of balance disposed, an explanation has been provided in accordance with Chapter 2 Filing Requirement
71	Statement confirming that the forecasted connections were eligible for the extension of connection and revenue horizons	Exhibit G-01-01,Section 5.16
71	Supporting calculations for the amounts recorded in the account, including methodology used to determine those customer connections eligible for extension	Exhibit G-01-01, Section 5.16 - due to immateriality of balance disposed, an explanation of methodology has been provided in accordance with Chapter 2 Filing Requirement

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Filing Requirement (Page #, Reference)		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
72	Statement confirming that distributor has reflected the impact of the expansions of the horizons into its forecast for the test year and beyond	Exhibit G-01-01, Section 5.16
72	Proposed disposition of the account and discontinuance after the rebasing application	Exhibit G-01-03, Section 8.12
Disposition of Account 1508, Sub-Account Electric Vehicle Charging Rate (EVC Rate)		
72	If requesting disposition: supporting calculations for the amounts recorded, including methodology used to measure incremental costs; proposed disposition of the account and discontinuance after the rebasing application	Not Applicable; refer to Exhibit G-01-01, Section 6.11 Exhibit G-01-03, Section 8.13
Disposition of Distributor-Specific Accounts		
72	For any material, distributor-specific accounts requested for disposition (e.g., Account 1508 sub-accounts), supporting evidence showing how the annual balance is derived and relevant accounting order provided. For distributor-specific accounts requested for disposition that are not material, provide a brief explanation for the account balance	Exhibit G-01-01, Section 5.0
Establishment of New Deferral and Variance Accounts		
72-73	If new DVA - evidence provided which demonstrates that the requested DVA meets the following criteria: causation, materiality, prudence; include draft accounting order with description of the mechanics of the account, provide examples of general journal entries and the proposed account duration	Exhibit G-01-03, Exhibit G-01-03, Attachments 10 - 17
Lost Revenue Adjustment Mechanism Variance Account for NWS Activities		
73-74	Indication of whether distributor is requesting an LRAMVA for one or more activities related to distribution rate-funded NWS activities or LIP activities if this request has not been addressed in a previous application	Not Applicable - Hydro One is not requesting use of LRAMVA related to NWS or LIP activities
74	If applicable, where a distributor is requesting access to, and the use of, an LRAMVA for a distribution rate-funded NWS activity or a LIP activity, the distributor should refer to the NWS Guidelines for the nature of the evidence the OEB requires to assess such a proposal	Not Applicable - Hydro One is not requesting use of LRAMVA related to NWS or LIP activities
Appendix A Cost of Eligible Investments for the Connection of Qualifying Generation Facilities		
Appendix A	If applicable, proposal to divide the costs of eligible investments between the distributor's ratepayers and all Ontario ratepayers per O.Reg. 330/09	DSP Section 3.4, Attachment 7
Appendix A	Appendices 2-FA through 2-FC identifying all eligible investments for recovery	DSP Section 3.4, Attachment 7 (HONI RGCRP Model) DSP Section 3.4, Attachment 7 (Peterborough RZ RGCRP Model)
Appendix A	For distributors that are already receiving rate protection as a result of a previous application the new (current) cost of service application should include an update to include the actual costs incurred for the investments as well as a depreciation adjustment to calculate a new capital amount for input into Appendices 2-FA through 2-FC. This would generate a new up-to-date rate protection amount for the test year and beyond, which will be subject to the materiality threshold	DSP Section 3.4, Attachment 7 (HONI RGCRP Model) DSP Section 3.4, Attachment 7 (Peterborough RZ RGCRP Model)

HOSSM

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Adopted from 2025 Filing Requirement For Electricity Transmitters (issued October 30, 2025)

Transmission Filing Requirements Checklist	Filing Requirement (Page #, Reference)	Filing Requirement	Yes/No/N/A	Evidence Reference, Notes
2.1 GENERAL REQUIREMENTS				
	Ch 1, p 2	Certification by a senior officer of the transmitter that the evidence filed is accurate, consistent and complete to the best of their knowledge. The applicant is required to provide a similar certification when interrogatory responses or other evidence are filed in a proceeding.	**Yes**	Exhibit A-02-01, Attachment 1
	Ch 1, p 3-4	Confidential Information - Practice Direction has been followed	**Yes**	Exhibit A-02-01
	Ch 1, p 2	Certification by a senior officer stating that the application and any evidence filed in support of the application does not include any personal information unless it is filed in accordance with Rule 9A of the OEB's Rules (and the Practice Direction on Confidential Filings, as applicable). The applicant is required to provide a similar certification when interrogatory responses or other evidence are filed in a proceeding.	**Yes**	Exhibit A-02-01, Attachment 2
	Ch 1, p 2	The certification filed with an application must include that the applicant has the appropriate processes and internal controls for the preparation, review, verification and oversight of account balances being disposed.	**Yes**	Exhibit A-02-01, Attachment 2
	Ch 1, p 6	The OEB also requires a letter from the governing body (e.g. Board of Directors) certifying that it is aware of and approves the submission of the application.	**Yes**	Exhibit A-02-01, Attachment 4
	Ch 1, p 6	Where generative artificial intelligence (AI) is used to generate content in a filing, the applicant must: (1) disclose that generative AI was used to generate content in the filing; and (2) confirm that the accuracy of the filing generated by AI has been verified by the party or representative without the assistance of generative AI. Disclosure must be made either in the certification of evidence section of the application, at the beginning of the document created by generative AI, or in the cover letter to a multi-document package.	**Yes**	Application Cover Letter
	Ch 2, p 4	Provide Chapter 2 appendices that are applicable to their transmission applications	**Yes**	Applicable Chapter 2 appendices are filed under each of the respective exhibits: TSP Section 2.10 Attachment 1 (App 2-AA) TSP Section 2.10 Attachment 2 (App 2-AB) TSP Section 2.10 Attachment 4 (App 2-G) Attachment C-04-04A (App 2-BA) Exhibit E-08-02, Attachment 2 (App 2-BB and 2-C) Exhibit E-02-06-01, Attachment 1 (App 2-JA, JB, JC, JL) Exhibit E-07-02, Attachment 3 (App 2-KA) Exhibit F-02-03 (App 2-OA) Exhibit F-02-04 (App 2-OB) Appendices not provided and reason: - Appendix 2-A and 2-AC are not applicable because it's optional; information is provided in SPF Section 1.6 - Appendix 2-D is not applicable as described in Exhibit A-02-03 -Appendix 2-JD not applicable -Appendices 2-FA, 2- FB, 2-FC, 2-IA, 2-IB, 2 -Q , 2 -R, 2-ZA, 2-ZB are not applicable as they are for Distribution -Appendix 2-H not applicable (HOSSM does not have other external revenue)
	Ch 2, p 4	Written direct evidence is to be included before data schedules	**Yes**	Confirmed
	Ch 2, p 4	Average of the opening and closing fiscal year balances must be used for items in rate base, unless an alternative method is documented and justified.	**Yes**	Exhibit C-01-01 Exhibit C-04-01
	Ch 2, p 4	Total capitalization (debt and equity) must equate to total rate base	**Yes**	Confirmed; Exhibit F-02-03 (App 2-OA) Exhibit C-01-02

	Ch 2, p 4	Data for the following years, at a minimum, must be provided unless explicitly stated otherwise: Test year = prospective year (year during which new rate term commences); Bridge year = current year (or the year immediately preceding the test year); Four most recent historical years (or number of years necessary to provide actuals back to and including the most recent OEB-approved test year, but not less than four years); Most recent OEB-approved test year	**Yes**	Confirmed; Hydro One has provided the required data in its evidence exhibits, Chapter 2 appendices applicable to HOSSM, and in its custom spreadsheets
	Ch 2, p 4	Custom IR applicants must include in their evidence forecasts for revenue, costs and inflation for each year of the proposed rate term, and benchmarking evidence supporting the cost forecasts	**Yes**	Exhibit A-04-01 Exhibit A-04-01, Attachment 1 Exhibit A-04-02
	Ch 2, p 4	Documents must include page numbers and are to be provided in bookmarked and text-searchable PDF format	**Yes**	Confirmed
	Ch 2, p 5	Tables must also be provided in working Microsoft Excel spreadsheet format where available and practical	**Yes**	Confirmed
	Ch 2, p 6	Materiality threshold; The applicant must provide justification for material amounts and material annual variances described in its application. The transmitter-specific thresholds are: $65,000 for a transmitter with a transmission revenue requirement less than or equal to $10 million; 0.65% of transmission revenue requirement for a transmitter with a transmission revenue requirement greater than $10 million and less than or equal to $200 million; $4 million for a transmitter with a transmission revenue requirement of more than $200 million	**Yes**	Exhibit A-02-03 TSP Section 2.12
2.2 ACCOUNTING STANDARDS				
	Ch 2, p 7	State accounting standard(s) used in historical, bridge and test years and summarize changes since last filing.	**Yes**	Exhibit A-06-05
2.3 EXHIBIT 1 – APPLICATION OVERVIEW AND ADMINISTRATIVE DOCUMENTS				
2.3.1 Application Executive Summary and Business Plan				
	Ch 2, p 9	Overview of past and expected future performance, business plan and objectives and how they align with RRFE objectives	**Yes**	Exhibit A-03-01
	Ch 2, p 9	Summary identifying key elements of the proposals and the Business Plan underpinning application, as guided by RRFE including customer feedback reflected in the transmitter's objectives,	**Yes**	Exhibit A-02-01 Exhibit A-03-01, Attachment 1
	Ch 2, p 9	Revenue Requirement - request, changes from previous revenue requirement and schedule of drivers of change from last OEB-approved year	**Yes**	Exhibit A-03-01
	Ch 2, p 9	Budgeting Assumptions - Economic overview. Budget Directives and Guidelines. Budget directives and guidelines (capital and operating budgets), including economic assumptions used; Budget Assumptions: economic overview (such as growth and inflation)	**Yes**	Exhibit A-03-01
	Ch 2, p 9	Load Forecast Summary - Load growth (% change from last OEB-approved application) and description of forecasting methods used	**Yes**	Exhibit A-03-01
	Ch 2, p 9	TSP - Summary of drivers and elements of plan, details of investment planning process, capital expenditures requested for test years, changes in capital expenditures from OEB approved	**Yes**	Exhibit A-03-01 Summary of drivers and elements of plan - TSP Section 2.10; Details of Investment Planning Process - SPF Section 1.7, TSP Section 2.7 and TSP Section 2.10; Capital Expenditures - TSP Section 2.10; Changes in Capital Expenditures - TSP Section 2.10
	Ch 2, p 10	Rate Base and Capital Plan: Summary of the main drivers of the capital plan and cost trends; rate base requested for the test year(s); Change in rate base from last OEB-approved ($ and %); Capital expenditures requested for the test year; Change in capital expenditures from last OEB-approved ($ and %)	**Yes**	Exhibit A-03-01 (Executive Summary) TSP Section 2.10 (Capital Plan) Exhibit C-01-02 (Rate Base)
	Ch 2, p 13	Performance and Reporting - Proposed scorecard	**Yes**	SPF Section 1.5 TSP Section 2.10, Attachment 3
	Ch 2, p 10	OM&A - Request for test years and change from last OEB-approved; summary of overall drivers and cost trends; total compensation for the test years and the change from the last OEB-approved ($ and %); Service Level Agreement (SLA) fee allocation structure and summary	**Yes**	Exhibit A-03-01 (Executive Summary) Exhibit E-02-06 (OM&A) Exhibit D-02-03 (Affiliate Services)

	Ch 2, p 10	Cost of Capital - Whether the OEB's cost of capital parameters are being used and rationale for deviations from OEB's methodology (note: OEB decision issued March 27, 2025 outlines updated methodology for future mechanistic updates); A summary table showing the proposed capital structure and cost of capital parameters resulting in the Weighted Average Cost of Capital (WACC). A statement as to whether or not the applicant is using the OEB's cost of capital parameters Summary and rationale of any deviations from the OEB's cost of capital methodology	**Yes**	Exhibit A-03-01 (Executive Summary) Exhibit F-02-01 (Cost of Capital)
	Ch 2, p 10	Cost Allocation and Rate Design - Summary of how costs are allocated to the three rate pools	**Yes**	Exhibit A-03-01
	Ch 2, p 10	Deferral and Variance Accounts - Accounts requested for disposition, total disposition ($) and disposition period(s) and any new DVAs requested and any discontinuation of existing DVAs	**Yes**	Exhibit A-03-01
	Ch 2, p 10	Bill Impacts - Summary of impacts ($ and %) at wholesale level (i.e. change in UTR) and for typical retail customers (750 kWh/month for residential and 2000 kWh/month for GS < 50 kWh)	**Yes**	Exhibit A-03-01
	Ch 2, p 10	Summary of any proposed mitigation plans to address rate impacts on specific customer classes or overall	NA	Transmission rates are uniform
2.3.2 Transmission System Overview				
	Ch 2, p 11	Description of transmitter's service area, including a general description and map(s) showing where the transmitter operates within the province and the communities (if any) serviced by the transmitter	**Yes**	TSP Section 2.10
	Ch 2, p 11	Details of the investment planning process, including asset condition assessment, identification and prioritization of capital investments, trade- offs with the operations, maintenance and administration expenditures	**Yes**	SPF Section 1.7 TSP Section 2.2 (Asset Condition) TSP Section 2.7 TSP Section 2.10
	Ch 2, p 11	Transmission System Plan and relevant policy context and changes, including current issues identified through Ontario's Regional Planning exercise	Yes	SPF Section 1.7 TSP Section 2.6 TSP Section 2.7 TSP Section 2.10
	Ch 2, p 11	Summary of the major drivers and elements of the transmitter's capital plan	**Yes**	TSP Section 2.10
	Ch 2, p 11	Capital expenditures requested for the test year(s)	**Yes**	TSP Section 2.10 TSP Section 2.10, Attachment 1
	Ch 2, p 11	Change in capital expenditures from last OEB-approved ($ and %)	**Yes**	TSP Section 2.10 TSP Section 2.10, Attachment 2
2.3.3 Customer Engagement				
	Ch 2, p 11	Customer engagement process and activities	**Yes**	SPF Section 1.6 SPF Section 1.6, Attachment 1 TSP Section 2.10
	Ch 2, p 11	Customer needs including end-use load customers and generator customers	**Yes**	SPF Section 1.6 SPF Section 1.6, Attachment 1 TSP Section 2.10
	Ch 2, p 12	How the application responds to customer needs	**Yes**	SPF Section 1.7 TSP Section 2.7 TSP Section 2.10
	Ch 2, p 12	Customer satisfaction surveys engagement activities	**Yes**	SPF Section 1.6 SPF Section 1.6, Attachment 1
	Ch 2, p 12	Appendix 2AC in the Distribution Filing Requirements helpful in structuring this evidence	*N/A*	Note: Appendix 2-AC is not filed as it is optional. SPF Section 1.6 (customer-engagement)
	Ch 2, p 12	Responses to letters of comment	*N/A*	Hydro One has not yet received letters of comment filed with the OEB
2.3.4 Financial Information				
	Ch 2, p 12	Non-consolidated audited financial statements of the utility (excluding operations of affiliated companies that are not rate-regulated) for which the application has been made, for the most recent three historical years (i.e. two years' statements must be filed).	**Yes**	Exhibit A-06-02, Attachments 3 & 4 (HOSSM)

	Ch 2, p 12	Where the regulated entity conducts more than one activity regulated by the OEB, the transmitter shall disclose information separately about each of its operating segments in accordance with the Segment Disclosure provisions which corporate entities are encouraged to adopt by the CPA Canada Handbook	**Yes**	Exhibit A-06-03
	Ch 2, p 12	If the most recent final audited financial statements are not available at the time of filing the application, the draft financial statements must be filed and the final audited financial statements, together with a summary of the main changes from the draft statements (if there are any) must be provided as soon as they are available. Alternatively, if the transmitter publishes its financial statements publicly, a link to the website may be provided.	*N/A*	Not Applicable See Exhibit A-06-02; Attachments 3 & 4 (HOSSM)
	Ch 2, p 12	A detailed reconciliation of the financial results shown in the audited financial statements with the regulatory financial results filed in the application. The reconciliation must include: o The separation of non-utility businesses, for example the fixed assets. o The identification of any deviations that are being proposed between the audited financial statements and the regulatory financial statements including the identification of any prior OEB approvals for such deviations	**Yes**	Exhibit A-06-03
	Ch 2, p 13	Annual Report and Management's Discussion and Analysis for the most recent year of the parent company, as available and applicable. If a transmitter also files an Annual Information Form publicly, a link to this Form should be provided.	**Yes**	Exhibit A-06-04 Exhibit A-06-04, Attachment 1
	Ch 2, p 13	Rating Agency Reports	**Yes**	Exhibit F-01-05, Attachments 1A - 3
	Ch 2, p 13	Prospectuses & information circulars for recent and planned public offerings	**Yes**	Exhibit F-01-06, Attachments 1 & 2
	Ch 2, p 13	Any change in tax status (e.g., from a corporation to a limited partnership). A description of existing accounting orders and list of any departures from these orders. Any departures from the Uniform System of Accounts (USoA). The accounting standards used for general purpose financial statements and when those standards were adopted.	**Yes**	Exhibit E-09-01 (Tax Exhibit) Exhibit G-01-02 (Accounting Orders) Exhibit G-01-04 Exhibit A-06-01 (Accounting Standard and Changes to Accounting Policies) Exhibit A-06-05
2.3.5 Performance Measurement and Reporting				
	Ch 2, p 13	A proposed scorecard - measure and monitor transmitter's performance including key RRF objectives of public policy responsiveness, financial performance, operational effectiveness and customer focus	**Yes**	TSP Section 2.10, Attachment 3
	Ch 2, p 13	Demonstrate how the proposed scorecard meets the requirements for performance standards set out in section 4.5.1 of the TSC	**Yes**	TSP Section 2.10, Attachment 3 TSP Section 2.4 TSP Section 2.4, Attachments 2, 3, and 5
	Ch 2, p 13	Discuss any outstanding areas of non-compliance and the effect they have had on the application, including any relief sought	*N/A*	There are no outstanding areas of non-compliance that have had a direct effect on the application
2.3.6 Administration				
	Ch 2, p 13	Table of Contents	**Yes**	Exhibit A-01-01
	Ch 2, p 13	Statement identifying customers materially affected by the application	**Yes**	Exhibit A-02-01
	Ch 2, p 13	Internet address for viewing of application; and any social media accounts (with addresses) used by the applicant to communicate with its customers.	**Yes**	Exhibit A-02-01
	Ch 2, p 13	Primary contact information (name, address, phone, fax, email)	**Yes**	Exhibit A-02-01
	Ch 2, p 14	Identification of legal representation	**Yes**	Exhibit A-02-01
	Ch 2, p 14	Requested effective date	**Yes**	Exhibit A-02-01
	Ch 2, p 14	A statement of where the notice of hearing should be published and the rationale for why the stated publication(s) is/are appropriate. The OEB has implemented a publication process that no longer requires that the applicant publish the notice of hearing. However, the OEB still requires the applicant's recommendation(s) regarding publication media.	**Yes**	Exhibit A-02-01
	Ch 2, p 14	Bill impacts for typical Ontario residential customer and Ontario General Service customer	**Yes**	Exhibit A-02-01
	Ch 2, p 14	Form of hearing requested (written or oral)	**Yes**	Exhibit A-02-01
	Ch 2, p 14	List of approvals requested including accounting orders	**Yes**	Exhibit A-02-01

	Ch 2, p 14	Proposed length of the term and proposed method for establishing revenue requirement for each year of the term	**Yes**	Exhibit A-02-01 Exhibit A-02-03 Exhibit A-04-01 Exhibit A-04-02
	Ch 2, p 13	Changes in tax status	**Yes**	Exhibit E-09-01
	Ch 2, p 13	Existing Accounting Orders	**Yes**	Exhibit G-01-02 Exhibit G-01-04
	Ch 2, p 14	Map of assets and operations showing where the utility operates within the province, and the communities serviced by the utility.	**Yes**	TSP Section 2.10
	Ch 2, p 14	Corporate and utility organizational structure, planned changes, rationale for changes and cost impact	**Yes**	Exhibit A-07-01 Exhibit A-07-01, Attachment 1: Corporate entities relationship chart (organizational structure)
	Ch 2, p 13	The Accounting Standard used and when it was adopted	**Yes**	Exhibit A-06-01
	Ch 2, p 14	Deviations from filing requirements, if any	**Yes**	Exhibit A-02-03
	Ch 2, p 14	Changes to methodologies used in previous applications: A statement identifying and describing any changes to the methodologies as used in previous applications	**Yes**	Exhibit A-02-03
	Ch 2, p 14	Confirmation that accounting treatment is segregated for non-regulated business	**Yes**	Exhibit A-06-03
	Ch 2, p 14	Indication of how prior OEB Decisions or Orders have been satisfied and impact on current application Identification of OEB directions from any previous OEB Decisions and/or Orders, this includes any commitments made as part of an approved settlement. The applicant must clearly indicate how these are being addressed in the current application	**Yes**	Exhibit A-02-04
	Ch 2, p 15	All responses to matters raised in letters of comment filed with the OEB during the course of the proceeding.	*N/A*	No letters have been filed
2.4 EXHIBIT 2 – TRANSMISSION SYSTEM PLAN				
General - Transmission System Overview				
	Ch 2, p 15	Transmitters may refer to Chapter 5 of the Distribution Filing Requirements for guidance on content and structure of the TSP.	**Yes**	TSP Section 2.0
2.4.1 TSP Overview		***TSP Overview must include a high-level summary of the investment planning process including:***		
	Ch 2, p 15	The strategic plan for the utility and overall strategy for investments	**Yes**	SPF Section 1.7 TSP Section 2.7 TSP Section 2.10
	Ch 2, p 15	The longer term economic and planning assumptions	**Yes**	SPF Section 1.7
	Ch 2, p 15	The asset management plan	**Yes**	SPF Section 1.7 TSP Section 2.7 TSP Section 2.10
	Ch 2, p 15	A description of how investments are prioritized and selected	**Yes**	SPF Section 1.7 TSP Section 2.7 TSP Section 2.10
	Ch 2, p 15	A discussion of transmission investments identified in the regional planning process	**Yes**	SPF Section 1.2 TSP Section 2.10 TSP Section 2.12
	Ch 2, p 15	Highlights of recent and proposed investments and their fit with the strategic plan	**Yes**	TSP Section 2.10
	Ch 2, p 15	A description of how the needs of customers and overall system planning policy objectives are being reflected	**Yes**	SPF Section 1.6 SPF Section 1.7 TSP Section 2.7 TSP Section 2.10
	Ch 2, p 15	Consideration of public policy objectives, including the OEB's statutory objectives such as facilitating the maintenance of a financially viable electricity industry, promoting electricity conservation and demand management, and facilitating the implementation of a smart grid and the connection of renewable energy generation.	**Yes**	TSP Section 2.6 TSP Section 2.10 TSP Section 2.10, Attachment 3
	Ch 2, p 15	The linkages and trade-offs between certain capital projects and ongoing OM&A spending		TSP Section 2.10

	Ch 2, p 15-16	A transmitter's investment projects and programs must be grouped for filing purposes into one of the four investment categories listed below: System access investments are modifications (including asset relocation) to a transmission system that a transmitter is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the transmission system. System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the transmitter's system to provide customers with electricity services. System service investments encompass modifications to ensure that a transmitter's system continues to meet operational objectives while addressing anticipated future customer electricity service requirements. General plant investments encompass modifications, replacements or additions to a transmitter's assets that are not part of its transmission system including land and buildings, tools and equipment, rolling stock and electronic devices and software used to support day to day business and operations activities. A project or program involving two or more drivers associated with different categories should be placed in the category corresponding to the trigger driver. For example, a project triggered by the need to replace end of service life components in a transmission station should be considered a system renewal investment, even if in anticipation of future system requirements (a system service driver) the project includes assets rated for a higher voltage.	**Yes**	TSP Section 2.10 TSP Section 2.12 in respective Investment Summary Documents
2.4.2 Asset Management Plan				
	Ch 2, p 16	Asset management plan, including the utility's asset management policy, strategy and objectives	**Yes**	SPF Section 1.7 TSP Section 2.2 TSP Section 2.7 TSP Section 2.10
	Ch 2, p 16	Inventory and assessment of the condition of capital assets whose net book value is material to the transmitter (by class and inclusion in BES); and how this inventory informs plan for capital expenditures and maintenance expenditures	**Yes**	TSP Section 2.2
	Ch 2, p 17	Identify NERC exemptions, planned or in progress NERC exemption requests and associated costs if exemption denied	**Yes**	There are no exemptions being sought from NERC or any material costs expected
2.4.2.1 Planning Process				
	Ch 2, p 16	A transmitter should provide the processes used to identify, select, prioritize (including reprioritizing investments over the five-year term), optimize and pace the execution of investments over the term of the TSP. A transmitter should also demonstrate that it has considered the potential risks of proceeding/not proceeding with individual capital expenditures. Transmitters that have connected customers should be able to demonstrate that they have considered the correlation between their capital plan and customer feedback and needs.	**Yes**	SPF Section 1.6 SPF Section 1.7 TSP Section 2.7 TSP Section 2.10
	Ch 2, p 17	A transmitter should demonstrate how it undertakes system optimization using an approach that considers the transmitter's whole system. This should include, where applicable, assessing the use of non-wires solutions, cost-effective implementation of transmission improvements, and other innovative technologies.	**Yes**	SPF Section 1.7 TSP Section 2.7 TSP Section 2.10 TSP Section 2.12 in Investment Summary Documents if applicable
	Ch 2, p 17	A transmitter must also demonstrate that it has a planning process for future capacity needs of its system. Transmitters should consider the guidance provided in the OEB's publication "Load Forecast Guideline for Ontario" provided by the Regional Planning Process Advisory Group (RPPAG).	**Yes**	SPF Section 1.2 TSP Section 2.7 TSP Section 2.10
	Ch 2, p 17	Single-asset transmitters may utilize another transmitter's asset management process, rather than develop their own, but should explain how it is ensuring that the other transmitter's asset management process is cost-effective, and provide a summary of how the applicant's assets were considered in the other transmitter's most recent investment planning activities.	*N/A*	Not Applicable
	Ch 2, p 17	A transmitter should identify, describe, and summarize the data used in the processes above.	**Yes**	SPF Section 1.6 SPF Section 1.7 TSP Section 2.2 TSP Section 2.7 TSP Section 2.10

2.4.2.2 Overview of Assets Managed				
	Ch 2, p 17	A transmitter should provide an overview of its service area (e.g., system configuration; urban/rural; temperate/extreme weather) pertinent for supporting its capital expenditures over the forecast period.	**Yes**	TSP Section 2.10
	Ch 2, p 17	A transmitter should provide asset information (e.g., asset capacity and utilization; asset condition; asset failures/performance; asset risks; and asset demographics), by major asset type, that may help explain the specific need for the capital expenditures and demonstrate that a transmitter has considered all economic alternatives.	**Yes**	TSP Section 2.2 TSP Section 2.10
	Ch 2, p 17	The inventory should identify in which pool each class of asset belongs, and identify which of these are part of the BES as defined by applicable NERC Standards	**Yes**	TSP Section 2.1 TSP Section 2.2 Exhibit H-02-01 Exhibit H-02-02
	Ch 2, p 17	The inventory should identify which of these are part of the bulk electricity system as defined by applicable North American Electric Reliability Corporation (NERC) standards. The transmitter shall identify any exemptions received from NERC, including any such requests that are planned or in progress, and a discussion of any associated costs in the event that the exemption is denied.	**Yes**	There are no exemptions being sought from NERC or any material costs expected
2.4.2.3 Asset Lifecycle Optimization Policies and Practices				
	Ch 2, p 18	An understanding of a transmitter's asset lifecycle optimization policies and practices will support the regulatory assessment of system renewal investments and decisions to refurbish rather than replace system assets. The information provided should be sufficient to show the trade-off between spending on new capital (i.e. replacement) and life-extending refurbishment. A transmitter should also be able to demonstrate that it has carried out cost-effective system operations and maintenance (O&M) activities to sustain an asset to the end of its service life (and can include references to the TSC).	**Yes**	TSP Section 2.2 TSP Section 2.10 TSP Section 2.12 Exhibit E-02-06
	Ch 2, p 18	A transmitter should explain the processes and tools it uses to forecast, prioritize, and optimize system renewal spending and how it intends to operate within budget envelopes. For prioritizing capital expenditures, a transmitter should explain the approaches it uses to balance a customer's need for reliability and capital expenditure costs.	**Yes**	SPF Section 1.7 TSP Section 2.2 TSP Section 2.7 TSP Section 2.10
	Ch 2, p 18	A transmitter should also be able to demonstrate that in planning the lifecycle of an asset, it has considered the future capacity requirements of the asset such that it does not need to be replaced prematurely due to capacity constraints.	**Yes**	SPF Section 1.7 TSP Section 2.2 TSP Section 2.7 TSP Section 2.10
	Ch 2, p 18	A transmitter should provide a summary of any important changes to its asset life optimization policies, processes, and tools since the last TSP filing.	**Yes**	TSP Section 2.2 - there have been no material changes to the overarching asset lifecycle framework that Hydro One uses however these are now being used for HOSSM
2.4.3 Regional Planning Considerations				
	Ch 2, p 18	Information on the regional planning processes in which it participates and demonstrating that regional considerations have been considered and addressed	**Yes**	SPF Section 1.2
	Ch 2, p 18	Final Regional Infrastructure Plan (RIP) describing investments in transmission or distribution facilities set out in the TSP	**Yes**	SPF Section 1.2 and Attachments
	Ch 2, p 18	Identify any investments from the RIP for which the applicant will be seeking approval The applicant shall also provide a copy of the final Integrated Regional Resource Plan, where applicable	**Yes**	SPF Section 1.2 TSP Section 2.12 in Investment Summary Documents where applicable
	Ch 2, p 18	Where regional planning is underway but a RIP is not yet complete, the applicant shall submit a letter form the IESO identifying the status of the regional planning process and potential impacts on the applicant's investment plans.	**Yes**	SPF Section 1.2 and Attachments
	Ch 2, p 18	Where the applicant is not required to participate in regional planning, the applicant shall submit its needs assessment report documenting that regional planning is not required	**Yes**	SPF Section 1.2 and Attachments
	Ch 2, p 18	Identify investments spanning more than one region and identify the relationship between the planning process	**Yes**	SPF Section 1.2 and Attachments
2.4.3.1 Coordinated Planning with Third Parties				

	Ch 2, p 19	Description of the consultation including: the purpose of the consultation; whether the transmitter initiated the consultation or was an invitee; participants in the consultation; deliverables and impact on plan	**Yes**	SPF Section 1.2 TSP Section 2.6 TSP Section 2.10
	Ch 2, p 19	Where a final deliverable of the regional planning process is expected but not available at the time of filing, the transmitter must provide information indicating: The role of the transmitter in the consultation ; The status of the consultation process ;Where applicable, the expected date(s) on which final deliverables are expected to be issued	**Yes**	SPF Section 1.2
2.4.4 Capital Expenditures				
	Ch 2, p 20	Capital expenditure plan overview including proposed capital expenditures over the five-year planning period.	**Yes**	TSP Section 2.10 TSP Section 2.12 in respective Investment Summary Documents
	Ch 2, p 20	The capital expenditure plan should set out and comprehensively justify a transmitter's proposed capital expenditures over a five-year planning period, including investment and asset-related O&M expenditures.	**Yes**	TSP Section 2.10 TSP Section 2.12 in respective Investment Summary Documents Exhibit E-02-06
	Ch 2, p 20	Investments justified in whole or in part by reference to specific aspects of the planning process.	**Yes**	SPF Section 1.7 TSP Section 2.7 TSP Section 2.10 TSP Section 2.12 in respective Investment Summary Documents
2.4.4.1 Capital Expenditure Summary				
	Ch 2, p 20	Summary of capital expenditure performance over the past four historical years, plus the bridge year including the bridge year and five future years including the test year(s), showing treatment of contributed capital and additions and deductions from Construction Work in Progress	**Yes**	Exhibit C-01-02 (Rate Base) Exhibit C-04-01 (Continuity Schedule) Exhibit C-04-05 (CWIP) TSP Section 2.10 TSP Section 2.10, Attachment 1
	Ch 2, p 20	An analysis of capital expenditure performance over the past four historical years, plus the bridge year. The analysis should include an explanation of variances between actual and OEB-approved/planned costs and volume of work for each investment.	**Yes**	TSP Section 2.10
	Ch 2, p 20	An analysis of capital expenditures for the five future years if electing a five-year term, including the test year(s). The analysis should show capital expenditures, treatment of contributed capital and additions and deductions from Construction Work in Progress.	**Yes**	TSP Section 2.10, Attachments 1-2 TSP Section 2.12 in respective Investment Summary Documents Exhibit C-04-01 (Continuity Schedule) Exhibit C-04-05 (CWIP)
	Ch 2, p 20	A comparison of capital expenditures in the five future years versus the five historical years.	**Yes**	TSP Section 2.10 TSP Section 2.10, Attachments 1 & 2
	Ch 2, p 20	A summary of any important modifications to typical capital programs since the last TSP (e.g., changes to individual asset strategies).	**Yes**	TSP Section 2.2 TSP Section 2.10
	Ch 2, p 20	The proposed accounting treatment, including the treatment of cost of funds, for investments spanning more than one year	**Yes**	Exhibit C-08-01
	Ch 2, p 20	A description of the impacts of capital expenditures on O&M for each year, or a statement that the capital plans did not impact O&M costs.	**Yes**	TSP Section 2.10
2.4.4.2 Justifying Capital Expenditures				
	Ch 2, p 20-21	Provide information to enable OEB's assessment of how a transmitter's TSP controls costs through identification, optimization, prioritization, pacing of capital-related expenditures and how overall capital budget envelope was developed.	**Yes**	SPF Section 1.7 TSP Section 2.7 TSP Section 2.10
	Ch 2, p 21	Discuss how the application keeps pace with technological changes and integrates cost-effective innovative investments and traditional planning needs such as load growth, asset condition and reliability	**Yes**	TSP Section 2.2 TSP Section 2.6 TSP Section 2.10 TSP Section 2.12 in respective Investment Summary Documents
	Ch 2, p 21	Justify the total amount of proposed capital expenditures and explain how the expenditures over the next five years will achieve its objectives	**Yes**	TSP Section 2.10
	Ch 2, p 21	Comment on lumpy investment years and rate impacts of capital investments in the long-term	**Yes**	TSP Section 2.10 Exhibit C-02-01 A-04-02 (the C-factor)
	Ch 2, p 21	On a project specific basis, grouped appropriately, or by program including similar projects across a portfolio of assets: Drivers of capital expenditure increases for the test year(s)	**Yes**	TSP Section 2.10 TSP Section 2.12 in respective Investment Summary Documents

	Ch 2, p 21	On a project specific basis, grouped appropriately, or by program including similar projects across a portfolio of assets: The basis for the estimated budget for the project or program; (e.g. historical cost, preliminary engineering estimates, request for proposals)	**Yes**	TSP Section 2.10 TSP Section 2.12 in respective Investment Summary Documents
	Ch 2, p 21	On a project specific basis, grouped appropriately, or by program including similar projects across a portfolio of assets: identification of any project that has been undertaken in compliance with a condition included in the transmitter's licence as a reuslt of a directive issued by the Minister of Energy to the OEB or has been declared a priority project by the Lieutenant Governor in Council	**Yes**	TSP Section 2.10 TSP Section 2.12 in respective Investment Summary Documents
	Ch 2, p 21	For projects / programs with a value greater than the materiality threshold and not subject to a leave to construct application, provide the following capital expenditure information: a description of the need, scope and purpose of the project or program customer attachments load and capital costs cost-benefit analysis discussion of other capital and non-capital alternatives which were considered and rejected in favour of the proposed project or program detailed information on the priority of the project or program relative to other investments and risks of not proceeding with the project / program for sustainment / renewal, details on the condition or life expectancy of the asset(s) being improved through reinvestment detailed breakdown of starting dates and in-service dates for each project / program	**Yes**	SPF Section 1.7 TSP Section 2.12 in respective Investment Summary Documents
	Ch 2, p 21-22	For any projects or programs that requires leave to construct approval under the OEB Act, where construction is to commence in a test year: (i) a summary of the evidence for the leave to construct application; and (ii) the OEB case number, if a leave to construct application has been filed with the OEB	**Yes**	TSP Section 2.8, Attachment 2 in conjunction with TSP Section 2.12
	Ch 2, p 22	For all other capital expenditures (those not already addressed above): describe components of capital expenditure and provide a reconciliation of capital components to total capital budget	**Yes**	TSP Section 2.10
	Ch 2, p 22	Cost benchmarking studies (internal or external) or utility cost comparisons (mandatory for Custom IR applications)	**Yes**	Exhibit A-04-01, Attachment 1 SPF Section 1.3 summary of all benchmarking studies TSP Section 2.3
	Ch 2, p 22	Description of quantifiable continuous improvement or efficiency gains, how they will be achieved and benefit customers	**Yes**	Exhibit A-04-01 Exhibit A-04-02 SPF Section 1.4 TSP Section 2.10 TSP Section 2.11 Exhibit E-02-05
	Ch 2, p 22	A proposal to mitigate the potential for any significant earning by the transmitter above the regulatory net income supported by the approved ROE, using such tools as a capital variance account or an ESM	**Yes**	Exhibit A-04-01 Exhibit G-01-04 (continuance of ESM with modification)
2.5 EXHIBIT 3 – RATE BASE				
	Ch 2, p 22	This section must include the following: 1) Rate Base 2) Fixed Asset Continuity Schedule 3) Depreciation, Amortization and Depletion 4) Allowance for Working Capital 5) Customer Connection and Cost Recovery Agreements 6) Capitalization Policy		
2.5.1 Rate Base				
	Ch 2, p 23	State whether capital expenditures are equivalent to in-service additions. If so, variance explanations are only required once. If not, the applicant should specify whether it is explaining variances based on capital expenditures or in-service additions (both are not required).	**Yes**	Exhibit C-02-03
	Ch 2, p 23	Opening and closing balances for each year and the averages thereof for gross assets and accumulated depreciation. Rate base may include an allowance for working capital. Rate base must be supported by historical actuals, bridge year (actuals to date and balance of year as budgeted) and test years. This section must include a table showing the components of the last OEB-approved rate base, the proposed test year rate base and the variances.	**Yes**	Exhibit C-01-02 (Rate Base) Exhibit C-04-01 to C-04-03 (Continuity Schedules) Exhibit C-05-01 (Working Capital Allowance)

2.5.2 Fixed Asset Continuity Schedule				
	Ch 2, p 23-24	Continuity statements (year end balance, including any capitalized interest during construction and any capitalized overhead costs). Explanation for any restatement (e.g. due to change in accounting standards) Year over year variance analysis required, including written explanation where variance greater than materiality threshold Hist. OEB-Approved vs Hist. Actual (most recent historical OEB-approved year) Hist. Act. vs. preceding Hist. Act. (for relevant number of years) Hist. Act. vs. Bridge Bridge vs. Test	**Yes**	Exhibit C-01-02 Exhibit C-04-02 (Gross Fixed Assets) Exhibit C-04-03 (Accumulated Depreciation) Exhibit C-04-04A (Appendix 2-BA) Exhibit C-04-05 (CWIP)
	Ch 2, p 24	Opening and closing balances of gross assets and accumulated depreciation must correspond to fixed asset continuity statements. Otherwise explanation and reconciliation required. Reconciliation must be between the last actual year, bridge year and test years net book value balances reported on a fixed aset continuity schedule (Appendix 2-BA) and the balances included in the rate base calculation.	**Yes**	Exhibit C-01-02 Exhibit C-04-02 Exhibit C-04-03 Exhibit C-04-04A (Appendix 2-BA)
	Ch 2, p 24	Continuity statements must be reconcilable to the calculated depreciation expenses and presented by asset account.	**Yes**	Exhibit C-04-04A (Appendix 2-BA) Exhibit E-08-02, Attachments 1 & 2
	Ch 2, p 24	Information outlined in the fixed asset continuity schedule is provided for each year, in both the application material and in working Microsoft Excel format.	**Yes**	Exhibit C-01-02 Exhibit C-04-04A (Appendix 2-BA)
2.5.3 Depreciation, Amortization and Depletion Gross Assets - PP&E and Accumulated Depreciation				
	Ch 2, p 24	Proposed levels of depreciation / amortization expense must appropriately reflect the useful lives of the applicant's assets and the OEB's policies	**Yes**	Exhibit E-08-02 Exhibit E-08-02, Attachment 2
	Ch 2, p 19	Detailed breakdown of the in-service capital additions for the test year(s)	**Yes**	Exhibit C-02-03
	Ch 2, p 24	Details for depreciation, amortization and depletion by asset group for historical, bridge and test years, including asset amount and rates of depreciation or amortization.	**Yes**	Exhibit E-08-02, Attachment 2
	Ch 2, p 24	Any Asset Retirement Obligations (AROs) and any associated depreciation or accretion expenses related to the AROs identified, including the basis for and calculation of these amounts.	**Yes**	Exhibit E-08-02
	Ch 2, p 24	Capital additions normally attract six months of depreciation expense when they enter service in the test year ("half-year" rule). The OEB may consider a different approach but applicants must identify their historial practices and must support any variance from the half-year rule whether that variance applies to the test year, subsequent years or both.	**Yes**	Exhibit E-08-02
	Ch 2, p 25	A copy of the depreciation/amortization policy or a written description of the depreciation practices followed and used in preparing the application.	**Yes**	Exhibit E-08-02, section 1.2 (equivalent written description has been provided)
	Ch 2, p 25	A summary of changes to its depreciation/amortization policy made since the last rebasing application filing.	*N/A*	Not Applicable - see Exhibit E-08-02, Section 1.2
	Ch 2, p 25	If filing under MFIRS accounting standards, signifiant components of each capital asset must be depreciated separately. Deviations from this practice must be explained.	**Yes**	Exhibit E-08-02
	Ch 2, p 25	State if any changes have been made to the depreciation/amortization policy or asset service lives since last rebasing.	*N/A*	Not Applicable - see Exhibit E-08-02, Section 1.2
	Ch 2, p 25	If changes have been made to the depreciation/amortization policy or asset service lives since last rebasing: Identify the changes and provide a detailed explanation for the causes of the changes provide a study to justify changes in useful lives, if applicable Provide a list detailing all asset service lives and reconcile to the USoA	*N/A*	Not Applicable - see Exhibit E-08-02, Section 1.2
2.5.4 Allowance for Working Capital				
	Ch 2, p 25	Working Capital - Lead/Lag Study for two time periods: the time between the date customers receive service and the date the customers' paymets are vaailable to the transmitter (the lag); and the time between the date when the transmitter receives goods and the date they are paid for (the lead)	*N/A*	Exhibit C-05-04

	Ch 2, p 25	Lead/Lag Study - leads and lags measured in days, dollar-weighted; WCA = dollar-weighted net lag (lag - lead) / 365 (366 in a leap year) x annual test year cash expenses	*N/A*	Exhibit C-05-04
	Ch 2, p 25	For transmitters in Ontario, the lead/lag study should reflect the fact that the IESO provides the bulk of the revenue to the transmitter, with minimal contributions from other sources.	**Yes**	Exhibit C-05-04
2.5.5 Customer Connection and Cost Recovery Agreements				
	Ch 2, p 26	The transmitter should show customer contribution amounts separately as an offset to rate base.	*N/A*	Exhibit C-07-01. Capital / in-service additions included in rate base are net of customer contributions
	Ch 2, p 26	Provide the number of CCRAs executed with Ontario rate-regulated Dx due to be reviewed during the rate period because they will reach a fifth anniversary and provide aggregated estimate of total expected true-up contributions and proceeds from bypass agreements	*N/A*	Exhibit C-07-01 - Hydro One expects the forecasts will be accurate, and does not expect further capital contributions in the future
	Ch 2, p 26	Detail on financial and regulatory accounting treatment of true-up and bypass agreement proceeds.	*N/A*	Exhibit C-07-01
2.5.6 Capitalization Policy				
	Ch 2, p 26	Capitalization policy, including changes since the last revenue requirement application. Identify changes and causes of changes, explain reasons for changes and and state whether changes are the result of adhering to to an accounting requirement.	*N/A*	HOSSM does not have its own capitalization policy. It uses the same capitalization policy as Hydro One Networks Exhibit C-08-02, Attachment 2
	Ch 2, p 26	Overhead costs on self-constructed assets	*N/A*	Not Applicable; Exhibit C-08-02, Attachment 1
	Ch 2, p 26	Identification of burden rates and burden rates prior to changes, if any	*N/A*	HOSSM does not have burden rates; Exhibit A-02-03
2.5.7 Capital Module				
	Ch 2, p 26-27	Revenue Cap index applicants may request a capital increment for discrete projects being placed in service after the rebasing year that are part of the TSP; are intended to come into service during the index rate plan period; and involve costs that the transmitter cannot manage through the revenue established through the index rate plan period	*N/A*	HOSSM is not requesting ACM
	Ch 2, p 27	The request must address proposed approval criteria (materiality, need, prudence) and the process for implementation of the recovery of the capital increment.	*N/A*	HOSSM is not requesting ACM
2.6 EXHIBIT 4 – SERVICE QUALITY AND RELIABILITY PERFORMANCE AND REPORTING				
2.6.1 Proposed Scorecard				
	Ch 2, p 27-28	Propose a five-year scorecard including measures for public policy responsiveness, operational effectiveness, customer focus, financial performance and other relevant relevant performance categories believed to be meaningful: Some examples of metrics proposed by transmitters in previous applications are as follows: Average System Availability System Average Interruption Frequency Contribution System Average Interruption Duration Contribution NERC Vegetation Compliance OM&A Cost ($K) per circuit kilometer	**Yes**	TSP Section 2.10 Attachment 3
2.6.2 Reliability Performance				
	Ch 2, p 28	Reliability performance measures (developed by Electricity Canada): transmission frequency of delivery point interruptions, transmission duration of delivery point interruptions, unsupplied energy in minutes, transmission system unavailability (percentage of system unavailable)	**Yes**	TSP Section 2.4 TSP Section 2.10, Attachment 3 TSP Section 2.10, Attachment 4
	Ch 2, p 28	Address performance standards for transmitters as set out in Chapter 4 of the TSC.	**Yes**	TSP Section 2.4
	Ch 2, p 28	Compare system performance with other systems both nationally and internationally	**Yes**	TSP Section 2.4

2.6.3 Compliance Matters				
	Ch 2, p 28	Discuss any outstanding areas of non-compliance which have had an effect on the application, including any relief sought through this application to resolve the non-compliance	*N/A*	There are no outstanding areas of non-compliance that have had a direct effect on the application
2.7 EXHIBIT 5 - OPERATING REVENUE				
2.7.1 Load and Revenue Forecasts				
	Ch 2, p 29	Explanation of causes, assumptions and adjustments for volume forecast. Economic assumptions and data sources for customer and load forecasts	**Yes**	Exhibit D-03-01 Exhibit D-04-01
	Ch 2, p 29	Explanation of weather normalization methodology. Describe economic models, econometric models, end-use models customer forecast surveys and load shape analyses	**Yes**	Exhibit D-04-01
	Ch 2, p 29	Detailed CDM electricity demand side management (eDSM) forecast, with impact of CDM eDSM shown on the load forecast for each of the three rate pools (Network, Line Connection, Transformation Connection). The applicant must also indicate how the forecast reflects IESO CDM eDSM forecasts and targets in the load forecast	**Yes**	Exhibit D-04-01
	Ch 2, p 29	Impact of forecast embedded generation on the transmission system load accounted for. Explain assumptions and methodology.	**Yes**	Exhibit D-04-01
2.7.2 Accuracy of Load Forecast and Variance Analysis		***A comparison of the forecast versus actual loads for the historical years; an explanation for any significant variances; and evidence of how variance analysis has been used to improve the transmitter's load forecasting methodology.***		
	Ch 2, p 29	Demonstrate five year historical accuracy by providing schedule of volumes (in kW for those rate pools that use this charge determinant), revenues, customer/connections count by rate pool and total system load in kWh) for: Historical OEB-approved; Historical actual for the past 5 years; Historical actual for the past 5 years – weather normalized; Bridge year; Bridge year – weather normalized; Test year	**Yes**	Exhibit D-04-01, Table 6 and Appendix E
	Ch 2, p 29	Analyses and discussion for volumes, revenues, customer/connections count and total system load: Comparison with the latest applicable provincial forecast(s) from the IESO, including a discussion of significant differences; Historical OEB-approved vs. historical actual; Historical OEB-approved vs. historical actual – weather normalized; Historical actual – weather-normalized vs. preceding year's historical actual –weather-normalized (for the necessary number of years); Historical actual – weather normalized vs. bridge year – weather-normalized; Bridge year – weather-normalized vs. test year(s)	**Yes**	Comparison with IESO forecast: Exhibit D-04-01, Appendix F; Year-over-year comparisons: Exhibit D-04-01, Appendix G
	Ch 2, p 29	All data used to determine the forecasts must be presented and filed in live MS Excel spreadsheet format	**Yes**	Exhibit D-04-01, Attachment 1 Exhibit D-03-01, Attachment 1
2.7.3 Other Revenue		***Details of other revenue sources and their treatment in the revenue requirement calculation.***		
	Ch 2, p 30	Comparison of actual revenues for historical years to forecast revenue for bridge and test year(s), including explanations for significant variances in year-over-year comparisons	*N/A*	Not Applicable- HOSSM has no external revenue
	Ch 2, p 30	How costing and pricing for other revenues is determined, any new proposed service charges, and/or changes to rates or new rules for applying existing charges	*N/A*	Not Applicable- HOSSM has no external revenue
	Ch 2, p 30	Revenue from affiliate transactions, shared services, corporate cost allocation. For each affiliate transaction, identification of the service, the nature of the service provided to affiliate entities, accounts used to record the revenue and associated costs	**Yes**	Exhibit D-02-03 (Affiliate Services) Exhibit E-04-01, Attachment 1 (Corporate Cost Allocation)
	Ch 2, p 31	Revenues or costs (including interest) associated with deferral and variance accounts must not be included in other revenue.	**Yes**	Confirmed
2.8 EXHIBIT 6 – OPERATING COST		**Operating cost evidence including OM&A, depreciation/amortization, and taxes.**		

	Ch 2, p 31	Exhibit must include the following sections: 1) Overview, 2) Summary and Cost Driver Tables, 3) Program Delivery Costs with Variance Analysis, 4) Workforce Planning and Employee Compensation, 5) Shared Services and Corporate Cost Allocation, 6) Purchases of Non-Affiliate Services, 7) Regulatory and One-Time Costs, 8) Charitable and Political Donations, 9) Taxes or Payments in Lieu of Taxes (PILs) and Property Taxes	**Yes**	Costs incurred by HOSSM are charged through Service Level Agreements. HOSSM has no FTEs The applicable sections are provided, including: Exhibit E-02-06 (HOSSM OM&A) Exhibit D-02-03 (Affiliate Services) Exhibit E-04-08 (Common Corporate Costs & Allocation Methodology) Exhibit E-10-01 (Regulatory One-Time Costs) Exhibit E-09-01 (Income Taxes)
2.8.1 Overview		***Overview of operating costs including summary of main cost drivers and trends.***		
	Ch 2, p 31	Brief explanation of: -test year OM&A levels -how the transmitter developes its OM&A budget (e.g. zero based budgeting, inflationary increase or some combination), and the transmitter's internal approval process, -cost drivers and significant changes relative to historical and bridge years, -trends in costs and relevant metrics such as OM&A per customer and OM&A per km of transmission line (and its components) for the histrical, bridge and test years, - inflation rate assumed, with a full explanation if different from the OEB's sector-specific inflation factor -business environment changes, - benchmarking studies (internal and external) or utility cost comparisons, -description of the continuous improvement or efficiency gains over the term and the means by which those gains and savings will be acheved and the benefits assured for customers	**Yes**	Exhibit E-02-06
2.8.2 Summary and Cost Driver Tables		***Summary tables showing OM&A costs by function and cost driver analysis.***		
	Ch 2, p 32	Summary of recoverable OM&A expenses	**Yes**	Exhibit E-02-06, Attachment 1 (App 2-JA)
	Ch 2, p 32	OM&A cost drivers	**Yes**	Exhibit E-02-06, Attachment 1 (App 2-JC)
	Ch 2, p 32	OM&A by programs or OM&A by USoA	**Yes**	Exhibit E-02-06, Attachment 1 (App 2-JC)
	Ch 2, p 32	OM&A cost per customer and per FTE (if applicable)	**Yes**	Exhibit E-02-06, Attachment 1 (App 2-JL)
	Ch 2, p 32	Change in OM&A in test year attributable to a change in capitalized overhead	*N/A*	Exhibit C-08-02, Attachment 1 (App D) there is no capitalized overhead for HOSSM
	Ch 2, p 32	OM&A variance analysis for test year with respect to bridge and historical years	**Yes**	Exhibit E-02-06
2.8.3 Program Delivery Costs with Variance Analysis		***Program delivery costs with variance analysis comparing actual to approved/planned costs.***		
	Ch 2, p 32	The variance analysis will apply the 2.1.5. Materiality Thresholds and include the following: -Test year vs historical OEB-approved -Historical OEB-approved vs historical actuals (for the 5 most recent historical OEB-approved years including the bridge year) -Test year vs most recent historical actuals	**Yes**	Exhibit E-02-06
	Ch 2, p 32	Details of O&M Costs for: -workforce planning and employee compensation -shared services and corporate cost allocation -purchase of non-affiliate services -regulatory and one-time costs OEB costs -Charitable and political donations -PILs and Property Taxes	**Yes**	Exhibit E-06-02 (Workforce Strategy) Exhibit D-02-03 (Affiliate Services) Exhibit E-04-02 (Common Corporate Functions and Services and Other OM&A) Exhibit E-04-08 (Common Corporate Costs & Allocation Methodology) Exhibit E-05-01 (Procurement Management) Exhibit E-04-08 (Common Corporate Costs & Allocation Methodology) Exhibit E-10-01 (Regulatory One-Time Costs) Exhibit E-10-03 (Charitable and Political Donations) Exhibit E-09-01 (Income Taxes) Exhibit E-02-06 (HOSSM OM&A)
2.8.4 Workforce Planning and Employee Compensation		***Workforce planning and employee compensation details including FTE counts, compensation philosophy, and benchmarking.***		
	Ch 2, p 33	Employee complement, compensation and benefits	*N/A*	HOSSM has no FTEs

	Ch 2, p 33	The OEB expects that transmitters will provide a description of their proposed workforce plans, including compensation strategy and any changes from the previous plan. Transmitters must discuss the outcomes of previous plans and how those outcomes have impacted their proposed plans including an explanation of the reasons for all material changes to FTE numbers and compensation. Explanation for all years includes: -Year over year variances with an explanation of contributing factors, inflation rates used for forecasts, and hiring the plans for any new employees -Basis for performance pay, eligible employee groups, goals, measures and review processes for pay-for-performance plans -Any relevant studies (i.e. compensation benchmarking)	*N/A*	HOSSM has no FTEs
	Ch 2, p 33	Employee benefit programs including pensions, OPEBs, and other costs charged to OM&A. A breakdown of the pension and OPEBs amounts included in OM&A and capital must be provided for the last OEB-approved rebasing application, and for historical, bridge and test years	**Yes**	Exhibit E-07-02 (Pensions & OPEBs) Exhibit E-06-01 (Compensation) Exhibit E-07-02, Attachment 3 (App 2-KA)
	Ch 2, p 33	Most recent actuarial reports must be included and be reconciled with the pension and OPEBs amounts (as applicable). The basis on which pension and OPEBs amounts are forecast for the bridge and test years must also be explained. What is documented in the tax section of the evidence must agree with this analysis	**Yes**	Exhibit E-07-02, Attachment 1 (Pension Valuation) Exhibit E-07-02, Attachment 2 (OPEBs forecast)
	Ch 2, p 34	The transmitter must clearly indicate if pension and OPEB costs are proposed to be recovered using the default accrual basis or the cash basis. If a transmitter is proposing to calculate pension and OPEB expenses based on the cash method, it must provide sufficient supporting rationale and evidence for doing so. If a transmitter is proposing to change the basis in which pension and OPEB costs are included in OM&A from its last rebasing application (e.g., from cash to accrual), it must quantify the impact of the change. For all circumstances, the transmitter must file the evidence required by the OEB to support the quantum of pension and OPEB costs in the test year.	**Yes**	Exhibit E-07-02 Exhibit E-07-02, Attachment 3 (App 2-KA)
2.8.5 Shared Services and Corporate Cost Allocation		***Shared services and corporate cost allocation methodology, amounts allocated, and basis for allocation.***		
	Ch 2, p 34	Identification of shared services and justify its proposed shared services and corporate allocation in detail For shared services among affiliated entities, a transmitter must provide at a minimum: The type of service provided or received. The fee allocation structure and the pricing methodology (e.g., cost-base, market-base, tendering, etc.).	**Yes**	Exhibit D-02-03 Exhibit E-04-01, Attachment 1 (App 2-N)
	Ch 2, p 34	Allocation methodology for corporate and shared services, a list of costs and allocators, and any 3rd party review of the corporate cost allocation methodoogy used	**Yes**	Exhibit E-04-08 Exhibit E-04-08, Attachment 1
	Ch 2, p 34	Details for services provided or received for historical, bridge and test years. Reconciliation of revenue arising from transactions must be included in other revenue in Operating Revenue section. If applicable, the same service provider who provides services to multiple transmitters, including new entrants, needs to provide evidence that there is no double-accounting on the service fee allocation to the various service receivers, given the different timing that these transmitters (service receivers) are either placed in-service and/or when these transmittersthey file revenue requirement applications individually.	**Yes**	Exhibit D-02-03 Exhibit E-04-02
	Ch 2, p 35	Variance analysis with explanations - test year vs last OEB approved and most recent actual	**Yes**	Exhibit E-04-02
	Ch 2, p 35	Identification of any Board of Director costs for affiliates included in applicant's costs	**Yes**	Exhibit E-04-08
2.8.6 Purchase of Non-Affiliate Services		***Details of services purchased from non-affiliates including procurement practices and cost justification.***		
	Ch 2, p 31	Procurement Policy - includes level of signing authority, description of competitive tendering process and confirmation that its non-affiliate services comply with the policy	**Yes**	Exhibit E-05-01, Attachment 1 & 3
	Ch 2, p 31	Material transactions not in compliance with procurement policy or without a competitive tender - Give reasons for procurement, summarize nature and cost of product or service (confidentiality procedures should be followed if there are concerns with dosclosing cost) and describe how vendor was selected	*N/A*	Not Applicable - all material transactions are in compliance Exhibit E-05-01 (procurement management)

2.8.7 One-time Costs		***One-time costs included in the revenue requirement with justification for inclusion.***		
	Ch 2, p 35	One-time costs - historical, bridge, test year costs. Explanation of cost recovery in test years. An explanation must also be provided if a transmitter is not proposing to recover the one-time costs	*N/A*	Exhibit E-10-02
2.8.8 Regulatory Costs		***Regulatory costs including OEB cost assessments, hearing costs, and intervenor costs.***		
	Ch 2, p 35-36	Regulatory costs - breakdown of actual and forecast costs (OEB cost assessments, legal fees, consultant fees, costs awards, etc.) and supporting informaiton for level of costs associated with preparaiton and review of the current application.	**Yes**	Exhibit E-10-01 Exhibit E-10-01, Attachment 1 (App 2-M)
	Ch 2, p 36	Identify period over which costs are to recovered and explanation if different from rate term	*N/A*	Exhibit E-10-01
	Ch 2, p 36	Costs claimed on an amortized basis - not included in historic / bridge years	*N/A*	Exhibit E-10-01
2.8.9 Charitable and Political Donations		***Charitable and political donations policy and amounts, confirming exclusion from revenue requirement.***		
	Ch 2, p 36	File the amounts paid in charitable donations (per year) from the last OEB-approved rebasing application up to and including the test year(s).	*N/A*	Exhibit E-10-03
	Ch 2, p 36	Detailed information for all charitable donations claimed for recovery (recovery of charitable donations is generally not allowed for the purpose of setting revenue requirement)	*N/A*	Exhibit E-10-03
	Ch 2, p 36	Non-recoverable contributions identified, disclosed and removed from the revenue requirement calculation	*N/A*	Exhibit E-10-03
	Ch 2, p 36	Charitable Donations - confirmation that political contributions not included	*N/A*	Exhibit E-10-03
2.8.10 Taxes or PILs and Property Taxes		***Taxes or Payments in Lieu of Taxes (PILs) and property taxes calculation and methodology.***		
	Ch 2, p 36	Income tax or PILs calculations, derivation of adjustments for historical, bridge, test years (regulatory assets and liabilities generally excluded) Detailed calculations of income tax or PILs, as applicable, including derivation of adjustments (e.g., tax credits, CCA adjustments) for the historical, bridge and test years. Note: regulatory assets (and regulatory liabilities) must generally be excluded from PILs calculations both when they were created, and when they were collected, regardless of the actual tax treatment accorded those amounts.	**Yes**	Exhibit E-09-04, Attachments 1 - 4
	Ch 2, p 36	Supporting schedules and calculations identifying reconciling items	**Yes**	Exhibit E-09-04, Attachments 1 - 4
	Ch 2, p 36	Most recent federal and provincial tax returns	**Yes**	Exhibit E-09-05A, Attachment 1
	Ch 2, p 36	Financial Statements included with tax returns if different from those filed with application	*N/A*	Not Applicable; Exhibit A-06-02 (financial statements) Exhibit E-09-05A (tax returns)
	Ch 2, p 36	Calculation of Tax Credits; redact where required (filing of unredacted versions is not required)	*N/A*	Not Applicable; HOSSM did not claim any tax credits (HOSSM did not hire any apprentices/co-ops directly and had no SRED activity)
	Ch 2, p 36	Supporting schedules, calculations and explanations for other additions and deductions	**Yes**	Exhibit E-09-04, Attachments 2 & 4
	Ch 2, p 36	Taxes other than PILs (property taxes) clearly identified where included	**Yes**	Exhibit E-02-06
2.8.10.1 Non-recoverable and Disallowed Expenses		***Non-recoverable and disallowed expenses identified and excluded from revenue requirement.***		
	Ch 2, p 37	Exclude from regulatory tax calculation any non-recoverable or disallowed expenses	**Yes**	Exhibit E-09-03
2.8.10.2 Integrity Checks		***Integrity checks confirming consistency between revenue requirement components.***		
	Ch 2, p 37	Depreciation and amortization added back in the application's PILs/tax model agree with the numbers disclosed in the rate base section of the application	**Yes**	Exhibit E-09-04, Attachment 1
	Ch 2, p 37	The capital additions and deductions in the UCC/CCA Schedule 8 agree with the rate base section for historic, bridge and test years	**Yes**	Exhibit E-09-04, Attachment 2 Exhibit C-05-04
	Ch 2, p 37	Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31st historic year UCC that agrees with the opening bridge year UCC at January 1st	**No**	The following Exhibits provide rationale for "No"; Exhibit E-09-05A, Attachment 1 Exhibit E-09-04, Attachment 4 (HOSSM CCA Historical)

	Ch 2, p 37	The CCA deductions in the application's PILs/tax model for historic, bridge and test years agree with the numbers in the UCC schedules for the same years filed	**Yes**	Exhibit E-09-04, Attachment 4 (HOSSM CCA Historical) Exhibit E-09-04, Attachment 3 (HOSSM Taxes Historical Years) Exhibit E-09-04, Attachment 2 (HOSSM CCA Test Years) Exhibit E-09-04, Attachment 1 (HOSSM Taxes Test Years)
	Ch 2, p 37	Loss carry-forwards, if any, from the tax returns (Schedule 4) agree with those disclosed in the application	*N/A*	No losses if it is a partnership
	Ch 2, p 37	CCA is maximized even if there are tax loss carry-forwards	**Yes**	Exhibit E-09-03
	Ch 2, p 37	A statement is included in the application as to when the losses, if any, will be fully utilized	*N/A*	No losses if it is a partnership
	Ch 2, p 37	Accounting OPEB and pension amounts added back on Schedule 1 reconciliation of accounting income to net income for tax purposes, must agree with the OM&A analysis for compensation	*N/A*	No OPEB adjustments for HOSSM
	Ch 2, p 37-38	The income tax rate used to calculate the tax expense must be consistent with the utility's actual tax facts and evidence filed in the proceeding.	**Yes**	Exhibit E-09-03
2.8.11 Z-Factor Claims		***Z-factor claims eligibility criteria and any claims being made, including causation, materiality, prudence, and notification requirements.***		
	Ch 2, p 38	Evidence that z-factor costs incurred meet eligibility criteria (causation, materiality, prudence); materiality threshold proposed that exceeds OEB-defined materiality threshold, amount recorded in deferral account, allocation of incremental revenue requirements to rate pools, calculation of incremental revenue requirement	*N/A*	HOSSM is not requesting a z-factor claim in its Application. See Exhibit E-10 04
	Ch 2, p 38	Z-factor events must be: (1) caused by an event outside of the transmitter's control; (2) must not be a reasonably foreseeable event that could have been anticipated at the time of the rate application; (3) must have a material impact on the transmitter's costs; and (4) must not be recoverable through any other mechanism.	*N/A*	HOSSM is not requesting a z-factor claim in its Application. See Exhibit E-10 04
	Ch 2, p 38	Z-factor claims must demonstrate causation - a clear and direct link between the external event and the incremental costs incurred by the transmitter.	*N/A*	HOSSM is not requesting a z-factor claim in its Application. See Exhibit E-10 04
	Ch 2, p 38	Z-factor materiality threshold must exceed the OEB-defined materiality threshold. The transmitter must propose and justify the materiality threshold to be applied to any Z-factor claim.	*N/A*	HOSSM is not requesting a z-factor claim in its Application. See Exhibit E-10 04
	Ch 2, p 39	Z-factor notification requirements: transmitters must notify the OEB within 180 days of the event giving rise to a potential Z-factor claim. The notification must include a description of the event, estimated costs, and the proposed recovery mechanism.	*N/A*	HOSSM is not requesting a z-factor claim in its Application. See Exhibit E-10 04
EXHIBIT 7 - COST OF CAPITAL AND CAPITAL STRUCTURE		**Cost of capital and capital structure evidence.**		
2.9.1 Capital Structure		***Capital structure including debt/equity ratio and comparison to OEB-deemed structure.***		
	Ch 2, p 39	OEB's cost of capital parameters used; subject to an update if new parameters are available prior to the issuance of the OEB's decision for a specific transmitter's application.	**Yes**	Exhibit F-02-01
	Ch 2, p 39	Multi-year revenue requirement approvals must indicate whether cost of capital will be updated annually or fixed for all test years	**Yes**	Exhibit F-02-01
	Ch 2, p 40	Long-term debt; Short-term debt; Preference shares and Common equity must be presented with the appropriate schedules	**Yes**	Exhibit F-02-03 (App 2-OA) Exhibit F-02-04 (App 2-OB)
	Ch 2, p 40	Explanation for any material changes in actual capital structure or material differences between actual and deemed capital structure are required including: Retirements of debt or preference shares and buy-back of common shares Short-term debt, long-term debt, preference shares and common share offerings	**Yes**	Exhibit F-02-01
	Ch 2, p 40	Rate regulated utilities are expected to demonstrate that they have been prudent in their management of debt. Utilities are required to file evidence to explain how they manage their long-term debt, including actual debt and the forecast for future debt.	**Yes**	Exhibit F-02-02
	Ch 2, p 40	For utilities incurring transactions/issuance costs to secure financing from the market, the transaction/issuance costs should be incorporated into the debt interest rate used to set rates, so that the transaction costs are amortized over the term of the debt instrument using the effective interest rate methodology.	**Yes**	Exhibit F-02-02
2.9.2 Cost of Capital (Return on Equity and Cost of Debt)		***Return on equity and cost of debt parameters, including comparison to OEB's cost of capital methodology.***		

	Ch 2, p 40	Calculation of cost for each capital component	**Yes**	Exhibit F-02-03
	Ch 2, p 40	Profit or loss on redemption of debt	**Yes**	Exhibit F-02-02
	Ch 2, p 40	Copies of promissory notes or other debt arrangements with affiliates. Note that this is not required for third 3rd party debt, e.g., with commercial banks.	**Yes**	Exhibit F-02-05 Exhibit F-02-06
	Ch 2, p 41	Explanation of debt rate for each existing debt instrument	**Yes**	Exhibit F-02-02
	Ch 2, p 41	Forecast of new debt in bridge and test year - details including estimate of rate	**Yes**	Exhibit F-02-02
	Ch 2, p 41	If proposing any rate that is different from the OEB guidelines, a justification of the proposed rate(s), including key assumptions	**Yes**	Exhibit F-02-02
	Ch 2, p 41	Historical ROE achieved.	**Yes**	Exhibit F-02-01 TSP Section 2.10, Attachment 3
	Ch 2, p 41	An applicant should provide an overview of its financing strategy.	**Yes**	Exhibit F-02-01
2.9.3 Not-for-Profit Corporations		***For not-for-profit corporations: alternative approaches to cost of capital if applicable.***		
	Ch 2, p 41	Not for Profit Corporations - evidence that excess revenue is used to build up operating and capital reserves	*N/A*	Not Applicable - HOSSM is not a not-for-profit corporation
2.10 EXHIBIT 8 – DEFERRAL AND VARIANCE ACCOUNTS		**Deferral and variance accounts evidence including balances and proposed dispositions.**		
	Ch 2, p 42	List of all outstanding DVA and sub-accounts; provide description of DVAs	**Yes**	Exhibit G-01-02
	Ch 2, p 42	Completed DVA continuity schedule for period following last disposition to present - live Excel format A continuity schedule in Excel format for the period following the last disposition to the present, showing separate itemization of opening balances, annual adjustments, transactions, interest and closing balances	**Yes**	Exhibit G-01-07, Attachment 3 (HOSSM Continuity Schedule)
	Ch 2, p 42	Confirm use of interest rates established by the OEB by month or by quarter for each year	**Yes**	Exhibit G-01-02
	Ch 2, p 42	Explanation if account balances in continuity schedule differs from trial balance in RRR and AFS	*N/A*	See Exhibit G-01-07, Attachment 3
	Ch 2, p 42	A proposal for an allocator based on the proposed cost driver(s) and included in the continuity schedule	**Yes**	Exhibit H-01-01 Exhibit H-01-03
	Ch 2, p 43	Statement as to any new accounts, and justification.	**Yes**	Exhibit G-01-04
	Ch 2, p 43	Statement whether any adjustments made to DVA balances previously approved by OEB on final basis; explanation, amount of adjustment and supporting documents	*N/A*	Exhibit G-01-05
	Ch 2, p 43	A proposal of a different carrying charge on a DVA involving long-term expenditures, if any, with evidence to justify the departure from standard DVA carrying charges.	*N/A*	Not proposing different carrying charges for DVA involving long term expenditures Exhibit G-01-02
	Ch 2, p 43	Any additional mechanisms proposed for rate-regulated infrastructure investment by Indigenous business ventures in the transmission sector. Utilities can make applications for consideration by the OEB on a case-by-case basis for alternative cost recovery mechanisms for significant new infrastructure investments.	*N/A*	Not Applicable
2.10.1 Disposition of Deferral and Variance Accounts		***Disposition of deferral and variance accounts including methodology and proposed rate riders.***		
	Ch 2, p 44	Identify accounts for which disposition is sought	**Yes**	Exhibit G-01-02, section 2.0
	Ch 2, p 44	Identify accounts for which disposition is not sought and the reasons	**Yes**	Exhibit G-01-02, section 3.0
	Ch 2, p 44	Propose the method to be used for recovery or refund of balances that are proposed for disposition	**Yes**	Ehibit G-01-06 Exhibit H-01-03
	Ch 2, p 44	Provide a statement that the balances proposed for disposition before forecasted interest are consistent with the last Audited Financial Statements	**Yes**	Exhibit G-01-05
	Ch 2, p 44	Show all relevant calculations, including the rationale for the allocation of each account, the proposed billing determinants and the length of the disposition period	**Yes**	Exhibit H-01-01 Exhibit H-01-03
2.10.2 Earnings Sharing Mechanism (ESM)				
	Ch 2, p 44	The transmitter must provide supporting evidence showing how the balance is derived. The calculation and disposition of the ESM should follow the transmitter's approved accounting order.	**Yes**	Exhibit G-01-02, Section 2.7

2.10.2.1 Disposition of ESM				
	Ch 2, p 44	Transmitters should include a description of the methodology to calculate excess earnings. At a minimum, the actual ROE shall be based on: Regulatory net income derived from regulated transmission operations, excluding non-regulated revenues and costs Adjustments for extraordinary, non-recurring items. A description of these adjustments should be included or excluded. Regulatory earnings determined in accordance with OEB-approved principles	**Yes**	Exhibit G-01-02, Section 2.7
	Ch 2, p 44	The approved ROE from the transmitter's most recent OEB rate decision should be used as the baseline.	**Yes**	Exhibit F-02-01
	Ch 2, p 44	In addition to the above, the applicant must include: - Amount recorded in the ESM – a reconciliation of the balance recorded in the deferral account, including the interest applied. -Proposed disposition methodology – the proposed method for refunding excess earnings to ratepayers.	**Yes**	Exhibit G-01-02 Exhibit G-01-04
2.11 EXHIBIT 9 – COST ALLOCATION TO UNIFORM TRANSMISSION RATE POOLS: CHARGE DETERMINANTS		**Cost allocation to Uniform Transmission Rate pools and charge determinants.**		
	Ch 2, p 45	Identify the cost allocation methodology that is proposed to allocate costs to the three transmission rate pools: Network, Line Connection and Transformation Connection	**Yes**	Exhibit H-01-01 Exhibit H-01-03
	Ch 2, p 45	Steps taken to functionalize the assets in the functional categories including the criteria used to define each asset category and, how costs are apportioned to the functional categories and rate pools. Allocation factors for dual function assets must be explained.	*N/A*	Reasoning explained in Exhibit H-01-01
	Ch 2, p 45	Allocation of revenue requirement to the rate pools and allocation factors for each asset or groups of assets	*N/A*	Reasoning explained in Exhibit H-01-01 & Exhibit H-05-01
	Ch 2, p 45	Assignment of depreciation, return on capital, taxes and OM&A costs to rate pools and non-standard rate pools	*N/A*	Reasoning explained in Exhibit H-01-01
2.12 EXHIBIT 10 – RATE DESIGN FOR UNIFORM TRANSMISSION RATES		**Rate design for Uniform Transmission Rates.**		
2.12.1 Bill Impact Information		***Bill impact information for typical residential and general service customers.***		
	Ch 2, p 46	Provide bill impact of the application including the dollar and percentage impact on the average customer's total bill and the percentage impact on transmission rates	**Yes**	Exhibit H-09-01
	Ch 2, p 46	Bill impacts for typical customers and consumption levels (residential customers consuming 750 kWh/month and GS < 50 kW consuming 2000 kWh/month, typical direct-connected non-LDC customer)	**Yes**	Exhibit H-09-01
2.12.2 Setting the Uniform Transmission Rates		***Setting the Uniform Transmission Rates including calculation methodology and proposed rates.***		
	Ch 2, p 46	Overview of how the UTR are established in Ontario and how these rates are determined	**Yes**	Exhibit H-06-01
	Ch 2, p 46	The revenue requirement and load forecast data (from each transmitter) that is used to compile the transmission charge determinants for each rate pool	**Yes**	Exhibit H-10-02
	Ch 2, p 46	A table explaining and documenting the determination of the UTR including: - previously approved revenue requirements and load forecast charge determinants for all other transmitters in the pool; - OEB file number of each decision approving each revenue requirement and charge determinant; -applicant's proposed revenue requirements and charge determinants as proposed in the application; -the calculation of the UTRs for each pool; - the transmission revenue allocator for each of the Ontario transmitters in the pool; -an explanation of any changes to terms and conditions of service and the rationale behind those changes if the changes affect the application of the rates -If applicable, the determination of the Export Transmission Service rates and the treatment of revenues generated through these rates	**Yes**	Exhibit H-10-01, Attachment 2 Exhibit H-10-02, Attachment 2 Not Applicable re: explanation of any changes to terms and conditions of service

Updates to Conditions of Service

Hydro One's Conditions of Service document describes how the company will conduct business with our Customers, and the terms of services provided. We have recently updated our Conditions of Service to address the Ontario Energy Board's (OEB's) (December 18, 2025) Notice of Amendments to the Distribution System Code (EB-2019-0207), to facilitate policy changes and updates, effective May 1, 2026.

The following is a summary of the key changes to Hydro One's Conditions of Service and where to find the updates in the document.

Key Changes	Old Section	New Section	Section Title
Amendments made to reflect Hydro One's process changes. Section numbering has also been updated to reflect the additions.	- - 2.1 D. to 2.1 K.	2.1 B 2.1 C 2.1 D 2.1 E 2.1 F. to 2.1 M.	Connections - Primary Service Connections - Secondary Service Connections - Common Service Taps Connections - Temporary Connections
Amendments reflecting inclusion of Embedded Distributors and change of revenue horizon from 25 to 40 years to be consistent with changes made to the Distribution System Code.	2.1.2	2.1.2	Expansions / Offer to Connect
Reference to Residential and Energy Billed General Service Customer expansion deposit was removed to be consistent with current practice.	2.1.2.1	2.1.2.1	Expansion Deposits
Reference to agreements prior to March 18, 2019, has been removed.	2.1.2.2	2.1.2.2	Capital Cost Recovery Agreement / Customer Service Contract / Connection Cost Agreement
This section was removed and relocated to Section 2.1.2.7 Ownership of New Lines	2.1.2.5 D	2.1.2.7	Ownership of Alternative Bids
Amendments reflect the inclusion of Other Land Rights throughout the section to be consistent with Hydro One's processes	2.1.6 B	2.1.6 B	Easements
Land Owner or Owner is replaced with landlord/owner to be consistent throughout the Conditions of Service document	2.1 C	2.1 C	Landlord and Tenant Agreements

This section now aligns with the Distribution System Code. 6.1.2.1, 6.2.2.2 and 6.1.2.3	2.1.7 B	2.1 7 B	Implied Contracts
Amendments reflect inclusion of house moves as part of large vessel moves	2.1.7 I	2.1. 7 I	Special Contracts
Amendments include clarity on the calculation for the bypass compensation amount	2.1 8	2.1 8	Bypass of Distribution Facilities
The section was updated to provide more details about capital contribution calculations tied to Transmission System Code 6.3.17. Replaced “TX” with “Transmission” to align with our processes	2.1.10	2.1.10	Cost Responsibility for Investments in Transmission Facilities
Amendments made to clarify that approvals are required not only for individual motor sizes, but also for combinations of motors that may start simultaneously	2.3.2 F	2.3.2 F	Power Quality - Motors and Welders
Replaced the word compliance to complies as continued throughout the Conditions of Service terminology	2.3.3	2.3.3	Electrical Disturbances
Meter-mounting device has replaced 'meter base' throughout the entire Conditions of Service for consistency	2.3.7	2.3.7	Meter Installation and Meter Reading
Removed the words DER Facility owners to clarify responsibility of the customer. Updated hyperlink	2.3.7.1	2.3.7.1	General
Correction of a typographical error	2.3.7.1 E	2.3.7.1 E	Totalized Metering
The section now removes any ambiguity about whether NGRs can be used on utility-owned transformers (they cannot) and explicitly ties permission to customer ownership.	2.3.7.1 D	2.3.7.1 D	Secondary Metering - Neutral Ground Resistor
Correction of a typographical error	2.5.1 A	2.5.1 A	Current Usage Data
Amendments made to clarify the use of customer information to determine listed financial protections / credits.	2.5.2 B	2.5.2 B	Hydro One’s Collection, Use and Disclosure of Customer Information

The section has been updated to replace the previous metering-based criteria with a clear threshold for determining residential classification in mixed-use service locations	3.1.1	3.1.1	Customer Class Specific - Residential
Section has been reorganized for clarity and flow with the inclusion that a capital contribution in accordance with section 2.1.2 of the Conditions of Service may be required (if an expansion is required).	3.1.5	3.1.5	Residential - Connection and Upgrade Charges
Removed section and added to section 2.1.C.1	3.1.7	2.1.C.1	Customer-Supplied Secondary Wire
Section has been reorganized for clarity and flow with the inclusion that a capital contribution in accordance with section 2.1.2 of the Conditions of Service may be required (if an expansion is required).	3.2.1	3.2.1	General Service (Below and Above 50kW) - Connection and Upgrade Charges
The section has been updated to clearly define ownership and operational demarcation points for both Hydro One–owned and customer-owned secondary services, adding detailed guidance on responsibilities for maintenance, repair, and associated site work. This includes replacing references to "meter base" with "meter mounting devices".	3.2.2	3.2.2	GS - Ownership Demarcation Point and Operational Demarcation Point
Amendments reflecting Hydro One's process changes which had been implemented or missed as part of the last Conditions of Service update. The section numbering has also been updated to reflect the additions. Including a change in cable size criteria from 500MCM to 750MCM.	3.2.4	3.2.4	GS - Metering - Metering Equipment
Section has been reorganized for clarity and flow with the inclusion that a capital contribution in accordance with section 2.1.2 of the Conditions of Service may be required (if an expansion is required).	3.3.1	3.3.1	Sub-Transmission - Connection and Upgrade Changes
Rearranging of word “material to provide further clarity	3.4.1	3.4.1	Technical Requirements - Equipment Deemed Compliant

Updated Conditions of Service to reflect DER Connection Procedure changes that come into force May 1, 2026, for MicroDER from 10kW to 12kW.	3.4	3.4	Various – DER Facilities
Section was amended to include that a capital contribution in accordance with section 2.1.2 of the Conditions of Service may be required (if an expansion is required).	3.6	3.6	Embedded Distributors
Section has been updated to clarify the treatment of new and existing mobile home parks, land leased communities, trailer parks and campgrounds."	Appendix F	Appendix F	Appendix F- Mobile Home Parks, Land Lease Community Homes and Intermittent/Seasonal use sites
Definition updated to reflect DER Connection Procedure changes that come into force May 1, 2026, from 10kW to 12kW. “Micro-DER Facility” means a DER Facility with a name-plate rated capacity of 12 kW or less and for greater certainty, includes a Micro-Embedded Generation Facility; “Micro-Embedded Generation Facility” means an Embedded Generation Facility with a name-place rated capacity of 12 kW or less;	Definitions	Definitions	Various to address MicroDER DSC Changes.
Removing reference to CSA Standard C22.3 No.9 throughout the Conditions of Service document	3.4	3.4	Various – DER Facilities
Added References and Links to Hydro One Technical Interconnection Requirements (TIR) documents for clarity	References	References	Various to address MicroDER DSC Changes
Updated language for “Customer Connection Horizon” and “Technical Interconnection Requirements” (TIR) to reflect current procedures	Glossary of Terms	Glossary of Terms	Various to address MicroDER DSC Changes

Updates to Conditions of Service

Hydro One's Conditions of Service document describes how the company will conduct business with our Customers, and the terms of services provided. We have recently updated our Conditions of Service to address the Ontario Energy Board's (OEB's) February 16, 2024 Notice of Amendments to the Distribution System Code (EB-2019-0207), to facilitate connection of electric vehicle charging infrastructure, effective May 27, 2024.

The following is a summary of the key changes to Hydro One's Conditions of Service and where to find the updates in the document.

Key Changes	Old Section	New Section	Section Title
Added a reference to new Appendix G "Distributor Specific Electric Vehicle Charging Connection Requirements"	--	--	Table of Contents
Updated with a reference to the new Appendix G for customers interested in connecting Electric Vehicle Supply Equipment ("EVSE")	1.4	1.4	Amendments and Changes
Added the definition of "Electric Vehicle Supply Equipment"	4	4	Glossary of Terms
Outline of process and requirements for connecting non-residential electric vehicle charging equipment, with references to specific sections in the main body of the Conditions of Service, as needed.	--	Appendix G	"Distributor Specific Electric Vehicle Charging Connection Requirements"

Updates to Conditions of Service

Hydro One's Conditions of Service document describes how the company will conduct business with our Customers, and the terms of services provided. We have recently updated our Conditions of Service to address the Ontario Energy Board's (OEB's) Decision and Order (EB-2020-0246), effective January 1, 2023 and updates to corporate practice.

The following is a summary of the key changes to Hydro One's Conditions of Service and where to find the updates in the document.

Key Changes	Old Section	New Section	Section Title
These sections are updated to reflect the Seasonal Rate Class elimination and subsequent re-classification of affected customers.	2.1.1	2.1.1	Distribution Activities - General, Connections, Connection / Building that Lies Along
	2.4.1.1	2.4.1.1	Tariff and Charges, Service Connection, Rate Classifications
	2.4.3	2.4.3	Tariff and Charges, Deposits
	2.4.4	2.4.4	Tariff and Charges, Billing
	3.1.1	3.1.1	Customer Class Specific, Residential Customers, Residential
	3.1.2	This section has been removed	Customer Class Specific, Residential Services, Seasonal Residential
	3.1.3	3.1.4	Rural and Remote Electricity Rate Protection
	3.2	3.2	Customer Class Specific, General Service (below and above 50 kW)
	4.0	4.0	Glossary of Terms
These sections are updated to reflect the implementation of the new rate classifications for customers in the former service areas of Norfolk Power Distribution Inc., Haldimand County Hydro Inc., and Woodstock Hydro Services Inc.	New section	3.1.2	Customer Class Specific, Residential Services, Acquired Residential
	3.2	3.2	Customer Class Specific, General Service (below and above 50 kW)
	3.3	3.3	Customer Class Specific, Sub-Transmission
	4.0	4.0	Glossary of Terms
These sections are updated to reflect the revision to the Sub-Transmission rate class eligibility criteria, and the increase in maximum pad-mounted transformer sizes supplied by Hydro One.	2.1 H	2.1 H	Connections, Transformation - Pad-Mounted Transformers (underground type)
	3.3	3.3	Customer Class Specific, Sub-Transmission
	3.3.1	3.3.1	Customer Class Specific, Sub-Transmission, Connection and Upgrade charges
	3.3.2	3.3.2	Customer Class Specific, Sub-Transmission, Ownership Demarcation Point and Operational Demarcation Point
	4.0	4.0	Glossary of Terms

These sections are updated to reflect the integration of customers in the former service areas of Peterborough Distribution Inc. and Orillia Power Distribution Corporation.	New section	3.1.3	Customer Class Specific, Residential Services, Peterborough and Orillia Residential
	3.2	3.2	Customer Class Specific, General Service (below and above 50 kW)
This section is updated to exclude the former Debt Retirement Charge for all users.	2.4.1.3	2.4.1.3	Rural and Remote Electricity Rate Protection
This section is updated to reflect the Customer Choice Initiative for Regulated Price Plan (RPP) customers.	2.4.2	2.4.2	Tariff and Charges, Energy (Electricity) Supply
These section numbers are updated	3.1.3 to 3.1.8	3.1.4 to 3.1.9	Customer Class Specific, Residential Customers
These sections are updated to reflect amendments related to the connection of distributed energy resources ("DERs") to local electricity distribution systems. The majority of changes involve updated terminology. The most material changes are to Section 2.3.6 "Emergency Backup Facilities", from which the previous Section B. "Load Displacement Generation and Energy Storage Facilities" is moved to Section 3.4, as these facilities are not intended for use as backup facilities. Section 3.4 (previously titled "Embedded Generation Facilities") now contains information and requirements associated with all DER facilities and has been re-named, accordingly.	1.4	1.4	Amendments and Changes
	2.1.2	2.1.2	Expansions / Offer to Connect
	2.1.2.4	2.1.2.4	Offer to Connect
	2.1.2.6	2.1.2.6	Rebates
	2.1.7	2.1.7	Contracts G. Connection Cost Agreement
	2.1.7	2.1.7	Contracts H2. DER Facilities
	2.3.6	2.3.6	A. Emergency Backup Facilities
	2.3.6	3.4	B. Load Displacement Generation and/or Energy Storage Facilities
	2.3.7	2.3.7	Meter Installation and Meter Reading
	2.4.5	2.4.5	Gross Load Billing
	3.4	3.4	DER Facilities (previously "Embedded Generation Facilities")
	3.5	3.5	Embedded Wholesale Market Participants
	4	4	Glossary of Terms
Hydro One's treatment of disconnection and reconnection charges in the previous Section 2.2.7, was moved to Section 2.2.6 (as a condition of re-connection) and Section 2.2.7 was eliminated.	2.2.1	2.2.1	Disconnection/Load Control for Reasons of Non-Payment
	2.2.6	2.2.6	Reconnection
	2.2.7	2.2.6	Disconnection and Reconnection Related Charges
	2.4.6	2.4.6	Payments and Overdue Account Interest Charges B. Late Payment Charges
These sections are updated to include the requirement for large Sub-Transmission customers and embedded distributors that contribute to the need for a new or modified transmission connection facility to make a capital contribution toward these investments.	3.3	3.3	Sub-Transmission 3.3.1 Connection and Upgrade Charges

The requirement was already stated in the Conditions of Service's Section 2.1.10, this update is to repeat it within the section or appendix specific to these customers as well, for clarity.	Appendix C	Appendix C	Embedded Distributor Overview
Corrections or Minor Clean-up: Section 2.2 was amended to correct the previous reference. Section 2.1.2.2 confirms that Hydro One did not apply expansion deposits in situations where customers had received contracts without that requirement prior to March 18, 2019, if they followed Hydro One's instructions at the time.	2.2	2.2	Disconnection / Load Control
	2.1.2.2	2.1.2.2	Capital Cost Recovery Agreement / Customer Service Contract / Connection Cost Agreement

SUMMARY OF BOARD DIRECTIVES AND UNDERTAKINGS FROM PREVIOUS PROCEEDINGS

1.0 INTRODUCTION (OEB FILING REQUIREMENTS SECTION 2.3.6 (TX), 2.1.3 (DX))

This Exhibit provides a summary of directions and settlement commitments from past Ontario Energy Board (OEB) proceedings and explains the steps Hydro One has taken to address them as part of this Application. Section 2.0 summarizes the status of the terms of the Settlement Agreement (EB-2021-0110) and Section 3.0 addresses OEB directions from other proceedings.

2.0 EB-2021-0110 DECISION ON SETTLEMENT PROPOSAL AND ORDER ON RATES, REVENUE REQUIREMENT, AND CHARGE DETERMINANTS

In Hydro One's Application for Transmission Revenue Requirement and Distribution Rates for 2023 to 2027 (EB-2021-0110), Hydro One reached a settlement with all parties (the Settlement Agreement) which was approved by the OEB on November 29, 2022. Under the terms of the Settlement Agreement, Hydro One committed to undertake several actions, which are summarized below, together with the steps Hydro One has taken to address them.

2.1 REPORTING

Under the terms of the Settlement Agreement, Parties agreed that Hydro One would prepare the following reports.

2.1.1 ALTERNATIVE APPROACH(ES) FOR ESTABLISHING THE REVENUE REQUIREMENT

2.1.1.1 SETTLEMENT AGREEMENT ISSUE 5 AND 6

Hydro One will consider potential alternative approach(es) for establishing the revenue requirement and/or rates for the years following the base year, while meeting OEB RRF objectives and striking an appropriate balance of risk between customers and the utility. If Hydro One applies for another Custom IR in its next cost-based rate application, it will

provide evidence regarding potential alternative approach(es) that were considered and why they were rejected.[1]

2.1.1.2 HYDRO ONE ACTIONS

As discussed in Exhibit A-04-01, Hydro One reviewed and considered several alternative approaches for establishing a revenue requirement. As a result, Hydro One is proposing to continue certain rate-setting elements and is introducing new or revised components.

2.1.2 CAPITAL PROGRAM PERFORMANCE REPORTS

2.1.2.1 SETTLEMENT AGREEMENT TERM A1

For each of Distribution and Transmission, Hydro One will prepare a Capital Program Performance Report (similar to those which are filed in EB-2021-0110 at Exhibit B-02-01, TSP Section 2.9, Attachment 2 and at Exhibit B-03-01, DSP Section 3.9, Attachment 3). Either as part of these reports, or through separate reports, Hydro One will report on General Plant execution. The Capital Program Performance Reports will be prepared subject to the following conditions: i) they will be prepared annually after Audited Financial Statements are published, and no earlier than April 30th for the previous year; ii) upon completion they will be published on Hydro One's website; iii) they will be prepared for the purposes of Hydro One's next Distribution and Transmission cost-based rate application and will not form part of Hydro One's annual update applications during the 2023-2027 Custom IR term; and iv) they may be redacted if necessary.[2]

2.1.2.2 HYDRO ONE ACTIONS

Hydro One has prepared 2023-2025 Capital Program Performance Reports for Transmission, Distribution, and General Plant according to the Settlement Agreement. The reports may be found as attachments to TSP Section 2.9, DSP Section 3.9, and GSP Section 4.9. The 2023 - 2024 reports are available on Hydro One's website (the 2025 report will be published shortly after this Application is filed).

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[1] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A – Settlement Proposal – Settlement by Issue, 2.0. Custom Application, Issues 5 and 6, p. 55 and 56 of 117.
[2] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A – Settlement Proposal – Appendix A, p.106 of 117.

2.1.3 SCORECARDS

2.1.3.1 SETTLEMENT AGREEMENT TERM A2

For Distribution and Transmission, Hydro One will prepare and publish its scorecard approved under Issue 8, subject to the following conditions: i) they will be prepared annually, no earlier than September 30th each year to align with OEB Reporting and Record Keeping Requirements ("RRR") scorecards; ii) upon completion they will be published on Hydro One's website; iii) they will be prepared for the purposes of Hydro One's next Distribution and Transmission cost-based rate application and will not form part of Hydro One's annual update applications during the 2023-2027 Custom IR term; iv) they will include discussion sections similar to the OEB Distribution RRR Scorecard; and v) they may be redacted if necessary.[3]

2.1.3.2 HYDRO ONE ACTIONS

Hydro One has prepared 2023-2025 Scorecards and accompanying Management Discussion and Analysis. The scorecards may be found as attachments to TSP Section 2.5 and DSP Section 3.5. The 2023 - 2024 scorecards are available on Hydro One's website (the 2025 report will be published shortly after this Application is filed).

2.1.4 DER REPORTING

2.1.4.1 SETTLEMENT AGREEMENT TERM A3

Hydro One Distribution will publish an update of the information in the table on page 2 of JT-3.22 in EB-2021-0110 and provide a breakdown between behind-the-meter and front-of-the-meter resources. This information will be prepared subject to the following conditions: i) it will be published on an annual basis at the time the Capital Program Performance Report for Distribution is published; ii) upon completion it will be published on Hydro One's website; and iii) it will be prepared for the purposes of Hydro One's next Distribution cost-based rate application and will not form part of Hydro One Distribution's annual update application during the 2023-2027 Custom IR term.[4]

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[3] Ibid.
[4] Ibid.

2.1.4.2 HYDRO ONE ACTIONS

Hydro One has prepared 2023-2025 DER reports consistent with the settlement commitment. The DER reports may be found as attachments to DSP Section 3.4. The 2023 - 2024 reports are available on Hydro One's website (the 2025 reports will be published shortly after this Application is filed).

2.1.5 INDIGENOUS RELIABILITY REPORTING

2.1.5.1 SETTLEMENT AGREEMENT TERM A4

Hydro One Distribution will prepare and provide an Indigenous Reliability Report as part of its next cost-based rate application.[5]

2.1.5.2 HYDRO ONE ACTIONS

The First Nations Reliability Report - 2025 may be found at DSP Section 3.11, D-SS-04 Attachment 1.

2.1.6 US GAAP TO IFRS TRANSITION IMPACTS

2.1.6.1 SETTLEMENT AGREEMENT: REPORTING TERM A5

Subject to the accounting system limitations identified by Hydro One during the proceeding (A-Staff-13, A-Staff-14, A-Staff-15) and the issuance by the IASB of a final IFRS Standard applicable to rate regulated utilities, Hydro One will provide in its next cost-based rate application, on a best efforts basis and without prejudice to its submissions in future applications as to the most appropriate accounting standard to be applied to Hydro One for regulatory purposes, estimated impacts (directional, and ranges where reasonably practical) of an initial transition from USGAAP to IFRS for regulatory purposes as at the beginning of the next rate term, as well as estimated impacts on the annual revenue requirements for the remainder of the rate term. To the extent reasonably possible, the impacts will be broken down based on the areas of potential revenue requirement impacts identified in the PwC US GAAP to IFRS Conversion Impact Review Report (Exhibit A/Tab 6/Schedule 1/Attachment 1/p. 9). Hydro One will also, on a best effort and without

[5] Ibid., p.107 of 117.

prejudice basis, quantify the incremental costs of transitioning and maintaining IFRS for regulatory purposes.[6]

2.1.6.2 HYDRO ONE ACTIONS

Hydro One re-engaged PwC for the current Application to fulfill this settlement commitment. As outlined in Exhibit A-06-01, due to the timing of the issuance of a new IFRS standard, it is Hydro One's intention to file PwC's report during the course of this proceeding once it becomes available.

2.1.7 DENSITY INFORMATION

2.1.7.1 SETTLEMENT AGREEMENT: REPORTING TERM A6

In addition to updating the information provided in response to L-VECC-117, Hydro One Distribution will provide, by filing on RESS under EB-2021-0110 no later than December 31, 2022, the aggregate numbers of assets by geographic density area (low, medium and high-density) for the following types of assets:

- Poles
- Line transformers
- Overhead devices count total (the total number of switches, fuses, reclosers/sectionalizers, capacitors and voltage regulators).[7]

2.1.7.2 HYDRO ONE ACTIONS

Hydro One Distribution provided the requested density information by letter dated December 23, 2022, which was submitted using the OEB's Regulatory Electronic Submission System under EB-2021-0110.

[6] Ibid.
[7] Ibid.

2.2 INDEPENDENT THIRD-PARTY STUDIES

Under the terms of the Settlement Agreement, Parties agreed that Hydro One would engage independent third parties to prepare studies and they would be filed by Hydro One in its next cost-based rate application[8]:

2.2.1 SETTLEMENT AGREEMENT TERM B1A

Transmission and Distribution Total Factor Productivity and total cost econometric benchmarking studies;

2.2.1.1 HYDRO ONE ACTIONS

Total Factor Productivity and Total Cost Econometric Benchmarking studies may be found at Exhibit A-04-01, Attachment 1.

2.2.2 SETTLEMENT AGREEMENT TERM B1B

Distribution vegetation management cost benchmarking study and an assessment of vegetation management practices;

2.2.2.1 HYDRO ONE ACTIONS

Hydro One engaged CNUC to carry out a benchmarking study of Hydro One's Utility Vegetation Management program against industry comparators. The study may be found at DSP Section 3.3, Attachment 1.

2.2.3 SETTLEMENT AGREEMENT TERM B1C

Assessment of Hydro One's fleet asset strategy, management, and costs;

2.2.3.1 HYDRO ONE ACTIONS

Hydro One engaged Utilimarc to complete an assessment of the Fleet Investment Strategy. The report may be found at GSP Section 4.3, Attachment 4.

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[8] Ibid., p.107 and 108.

Witness: Uri Akselrud, Mark Brodie, Kathleen Burke, Gianni DiFilippo, Peter Faltaous, Lyndsay Fulton, Spencer Gill, Chris Iveson, Donna Jablonsky, Kevin Marcotte, Anthony Nava, Aimee Oabel, Ogbomah Osiemi, Scott Vicary

2.2.4 SETTLEMENT AGREEMENT TERM B1D

Common Corporate Costs Benchmarking Study;

2.2.4.1 HYDRO ONE ACTIONS

Hydro One has filed an updated Common Corporate Costs Benchmarking Study, which may be found at Exhibit E-04-02, Attachment 1.

2.2.5 SETTLEMENT AGREEMENT TERM B1E

Corporate Cost Allocation Review;

2.2.5.1 HYDRO ONE ACTIONS

Hydro One has filed an updated Corporate Cost Allocation Review, which may be found at Exhibit E-04-08, Attachment 1.

2.2.6 SETTLEMENT AGREEMENT TERM B1F

Compensation Benchmarking Study using similar/same methodology as the Mercer report filed in EB-2021-0110;

2.2.6.1 HYDRO ONE ACTIONS

Hydro One has filed an updated benchmarking study using the Mercer methodology, which may be found at Exhibit E-06-01, Attachment 2

2.2.7 SETTLEMENT AGREEMENT TERM B1G

Management and Non-Represented Role Benchmarking and Compensation Study using same/similar methodology as Willis Towers Watson report;

2.2.7.1 HYDRO ONE ACTIONS

Hydro One has filed an updated benchmarking study using a similar methodology, which may be found in Exhibit E-06-01, Attachment 3.

2.2.8 SETTLEMENT AGREEMENT TERM B1H

Actuarial Pension Valuation for Hydro One's defined benefit pension plan**;**

2.2.8.1 HYDRO ONE ACTIONS

Hydro One has filed an updated Actuarial Pension Valuation for Hydro One's defined benefit pension plan, which may be found at Exhibit E-07-01, Attachment 1.

2.2.9 SETTLEMENT AGREEMENT TERM B1I

Projected Benefit Costs for its Pension Plans and Post-Employment Benefit Plans;

2.2.9.1 HYDRO ONE ACTIONS

Hydro One has filed an updated Projected Benefit Costs for its Pension Plans and Post-Employment Benefit Plans, which may be found at Exhibit E-07-01, Attachment 2.

2.2.10 SETTLEMENT AGREEMENT TERM B1J

Depreciation Study, which for greater certainty will be conducted based on the most recent actuals available at the relevant time. As such, it will only be conducted based on existing assets and not future assets. Therefore, to the extent that the regulated Transmission or Distribution businesses have DER assets, those assets will be included in the study. On a best-efforts basis, as part of the next study, Hydro One will request that the third-party depreciation expert develop useful lives for DERs to the extent that Hydro One is able to provide asset information for those assets.

2.2.10.1 HYDRO ONE ACTIONS

Hydro One has filed an updated Depreciation Study, which may be found at Exhibit E-08-01, Attachment 1.

2.3 PLANNING

2.3.1 LONG-TERM CAPITAL PLAN INFORMATION

2.3.1.1 SETTLEMENT AGREEMENT TERM C1

At its next cost-based rate application, Hydro One will provide a summary of long-term (10-20 years) forecast information for Hydro One Transmission and Distribution that is available in Regional Planning Reports and IESO Bulk planning. The information will be consistent with the framework being developed by the Regional Planning Process Advisory Group (RPPAG). The Parties acknowledge that this would represent a comprehensive long-term plan since it will incorporate the areas of regional planning that Hydro One is responsible for, the distribution components that are reflected within the regional plans, and the IESO's Bulk plan (which is the sole responsibility of the IESO).[9]

2.3.1.2 HYDRO ONE ACTIONS

Hydro One has prepared a long-term load forecast summary for a 10–20-year forecast drawing from Regional Planning Reports and IESO planning information. The forecast is summarized at SPF Section 1.2, Attachment 2.

2.3.2 ELECTRIFICATION PLANNING

2.3.2.1 SETTLEMENT AGREEMENT TERM C2 AND C3

As part of its next cost-based rate application, Hydro One Distribution will arrange for a study to be prepared by an independent consultant to examine general electrification scenarios for the 2030-2050 timeframe. The study will provide the directional distribution needs and recommendations for potential cost-effective solutions for electrification to minimize unit distribution costs. The consultant will invite input from the intervenors in EB-2021-0110. This study will not be a substitute for the Regional Planning process, and the specific facilities required for electrification in each Region / LDC territory will continue to be identified as part of the Regional Planning process.

[9] Ibid., p.108 of 117.

For greater certainty, the words "recommendations for potential cost-effective solutions for electrification" in the above paragraph is not meant to be narrow such that it necessarily excludes consideration in the study of (a) how to size equipment to ensure it can handle potential electrification scenarios without replacement before end-of-life; (b) how to use electrification to flatten the overall load profile, improve the load factor and increase revenue to lower unit costs; (c) how to time system upgrades to match demand increases and revenue therefrom; (d) whether/how to encourage/incent efficient use of the distribution system by EVs; (e) whether/how to encourage/incent customers to utilize smart switches to "share" circuit breakers and thus avoid panel upgrades; or (f) other similar topic areas.[10]

2.3.2.2 HYDRO ONE ACTIONS

Hydro One engaged Environmental Resources Management (ERM) to prepare an independent study to understand how electrification could shape energy use and peak load on its distribution network between 2030 and 2050, and to identify how cost-effective non-wires solutions, such as energy efficiency (EE), behind-the-meter distributed energy resources (DERs), and demand-side flexibility (DSF), can mitigate reinforcement needs. The study may be found at DSP Section 3.3, Attachment 6 and is discussed in DSP Section 3.6.

2.3.3 NON-WIRES SOLUTIONS – PLANNING PROCESS

2.3.3.1 SETTLEMENT AGREEMENT TERM C4

Hydro One Distribution will develop and implement a robust planning process that appropriately considers non-wires solutions ("NWS"), including CDM, to meet system service needs, which (a) includes capital and O&M cost assumptions for NWSs, (b) requires examination of NWSs in a timely fashion such that alternatives are not dismissed simply because of lack of time, and (c) includes appropriate stakeholder engagement.

Hydro One Distribution will leverage its existing procurement processes in respect of projects greater than a $5M threshold. Distribution projects will be considered for NWSs

[10] Ibid., p. 108 and 109.

in accordance with the most recent CDM guideline, subject to a $5M threshold. This will apply on a best-efforts basis only, beginning with projects planned to commence construction in 2025. This is because the development and implementation of a robust planning process, that appropriately considers NWSs, including CDM, to meet system service needs must be developed, tested and proven to be effective and Hydro One Distribution has no experience in doing so. Once developed, tested and proven to be effective, Hydro One Distribution will apply the process in the ordinary course.[11]

2.3.3.2 HYDRO ONE ACTIONS

Hydro One has developed and implemented, as part of its planning process, a comprehensive approach to assessing NWS for distribution system needs over the 2028-2032 period, consistent with the OEB's NWS Guidelines and BCA Framework. The approach to assess NWS builds on practical experience gained through initiatives such as mobile battery storage, commercial and industrial flexibility, and residential demand response programs. During the current rate period, Hydro One applied NWS on a targeted basis as methodologies, tools, and organizational capabilities continued to mature. Lessons learned supported the refinement of Hydro One's NWS process as outlined in DSP Section 3.6, Attachment 1.

Hydro One subsequently applied this process to its 2028-2032 capital plan and identified NWS projects that are expected to defer capital investments and achieve peak demand reduction during the 2028–2032 period, as discussed in DSP Section 3.6.

2.3.4 MUNICIPAL ENERGY PLANS

2.3.4.1 SETTLEMENT AGREEMENT TERM C5

Hydro One will meaningfully consider the goals of municipal energy and emission plans with a view to pursuing cost efficiencies, reduced emissions, and enhanced energy outcomes for consumers in Ontario served by Hydro One. Hydro One will include these

[11] Ibid., p. 109 of 117.

elements in its next Transmission and Distribution System Plans, and the supporting Business Plan, where relevant and feasible.[12]

2.3.4.2 HYDRO ONE ACTIONS

Hydro One has considered and included relevant elements from municipalities regarding their electricity demand and emission reduction plans in the regional planning (RP) process. Specifically, since February 2023, Hydro One has facilitated the collection of this information from municipalities via annual outreach for newly triggered regional planning stages. In December 2024, Hydro One improved this information gathering process by preparing and providing municipalities with a standardized template that is aligned with the OEB Regional Planning Process Advisory Group (RPPAG) Guideline, "Improving the Electricity Planning Process in Ontario: Enhanced Coordination between Municipalities and Entities in the Electricity Sector". This template aims to ensure municipalities provide sufficiently detailed input in a consistent manner so that LDCs, including Hydro One Distribution, can translate it into their load forecasts used in regional planning. A well-informed load forecast is pivotal in developing the appropriate scale and timing of electricity infrastructure and/or non-wires plans to support growth within municipalities while maintaining reliability.

In addition to Hydro One's annual email outreach to over 250 municipalities, the company has actively worked to enhance municipal awareness and engagement in the regional planning process. This has included presenting at webinars that cover municipal input opportunities in regional planning, as well as holding targeted discussions with municipalities about community growth and their role in upcoming regional planning cycles.

Based on feedback from municipalities, and members of the regional planning Technical Working Group, Hydro One also accelerated Regional Planning in certain areas to address emerging growth in those communities (e.g., St. Lawrence, Peterborough to Kingston, Toronto, Greater Ottawa, and London regions).

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[12] Ibid.

In addition to participating in Regional Planning, Hydro One Distribution also considers municipal input to inform load forecasts used for on-going distribution planning. The forecast is evaluated against the planning limits of various assets to identify needs, alternatives, and recommended investments which inform the proposed investment plan.

2.3.5 CLIMATE CHANGE AND INVESTMENT PLANNING

2.3.5.1 SETTLEMENT AGREEMENT TERM C6

Hydro One will include, in future operational and capital investments plans, discussion of how the proposed spending will directly support the achievement of Hydro One's climate change policy commitments by 2030 and 2050.[13]

2.3.5.2 HYDRO ONE ACTIONS

Hydro One strives to mitigate the impacts of climate change through GHG reduction efforts, working towards a long-term, sustainable carbon footprint reduction of 30% in operations-driven emissions by 2030 and striving towards net zero carbon emissions in 2050. To this end, Hydro One is proposing several operational and capital investments that will reduce its GHG footprint, specifically, replacing Internal Combustion Engines (ICE) with electric, hybrid, smaller engine vehicles and other alternative fuels (see GSP Section 4.11, G-GP-01), implementing energy savings initiatives at Operations and Service Centres (see GSP Section 4.11, G-GP-03) and working to repair and replace defective or leaking SF6 and gas-insulated equipment (see TSP Section 2.2, Exhibit E-02-02).

As reported in the 2025 Sustainability Report, Hydro One has already reduced its operations driven emissions (Scope 1 and Scope 2 – purchased electricity) by approximately 27% compared to its baseline year of 2018. The initiatives listed will allow Hydro One to continue to move towards its 2050 goal as it evaluates other opportunities to progress in a cost-effective manner.

[13] Ibid.

2.3.6 NON-WIRES ALTERNATIVE SOLUTIONS – BI-DIRECTIONAL CHARGER STUDY

2.3.6.1 SETTLEMENT AGREEMENT TERM C7

Hydro One Distribution, as part of its next Distribution cost-based rate application, will provide a summary of the bi-directional charger pilot program engagement results (see Interrogatory B3-ED-028, part d): the pilot project with Peak Power and the IESO) and, if possible, viable use cases.[14]

2.3.6.2 HYDRO ONE ACTIONS

The proposed Grid Innovation Fund project, led by Peak Power with Hydro One support, was intended to demonstrate the feasibility and cost-effectiveness of Vehicle-to-Home (V2H) technology for improving customer reliability and supporting grid operations. The project would have assessed the ability of Electric Vehicles (EVs) to provide backup power during outages, participate in IESO-administered markets where economically viable, and potentially support reliability for rural customers. The project was terminated due to challenges obtaining Canadian-certified bi-directional charging infrastructure and suitable bi-directional capable EVs

Through its participation, Hydro One identified several important considerations for V2H applications: i) market readiness was limited, with limited availability of compatible vehicles and bi-directional charging infrastructure; ii) the practical grid value of V2H is likely to be significantly lower than its theoretical potential due to customer participation, vehicle availability, and operational limitations; and iii) the benefits remain uncertain given high technology costs, evolving technical and regulatory standards, and unresolved interoperability challenges.

While V2H technologies may offer future reliability, flexibility, and non-wires benefits, at this time, they are not considered sufficiently mature, scalable, or cost-effective to be relied upon as a planning solution on the Hydro One distribution system.

[14] Ibid., p.110 of 117.

2.3.7 CAPACITY RESTRICTIONS FOR DERS

2.3.7.1 SETTLEMENT AGREEMENT TERM C8

Hydro One will review and assess options to mitigate capacity restrictions on its Distribution system and will recommend next steps (if any) to be considered for its next DSP and TSP (or sooner for any next steps that do not have significant costs, can be accommodated within existing funding envelopes, or can be funded through other means).[15]

2.3.7.2 HYDRO ONE ACTIONS:

DSP Section 3.4 sub-section 6 describes Hydro One's plans to mitigate capacity restrictions as well as actions taken within the current rate period to increase DER connection capacity.

2.4 LINE LOSSES

2.4.1 UPDATED DISTRIBUTION LINE LOSS STUDY

2.4.1.1 SETTLEMENT AGREEMENT TERM D1

Hydro One Distribution will conduct an analysis of its overall distribution losses, similar to what it filed in EB-2017-0049. Should Hydro One observe a material change in overall losses, Hydro One will conduct a detailed distribution line loss study.[16]

2.4.1.2 HYDRO ONE ACTIONS

Hydro One conducted an analysis of its overall distribution losses. This analysis is provided in Exhibit L-06-02, Attachment 1 and shows that there has been no material change in terms of the 5-year average of losses over the 2021-2025 period compared to earlier studies submitted to OEB. Consequently, there is no need to conduct a new detailed distribution line loss study in this regard.

[15] Ibid.
[16] Ibid.

2.4.2 TRANSMISSION SYSTEM LINE LOSS GUIDELINE UPDATE

2.4.2.1 SETTLEMENT AGREEMENT D2

Hydro One Transmission will continue participating in the IESO's transmission losses engagement process. Within six months of the final IESO guideline being published as part of the IESO stakeholder process, Hydro One will review and, if necessary, update its transmission line loss guideline.[17]

2.4.2.2 HYRDO ONE ACTIONS

Hydro One Transmission participated in the IESO's transmission losses engagement process and updated its Transmission Line Loss Guideline within six months of the June 2023 IESO guideline being published.

2.4.3 DISTRIBUTION SYSTEM ELECTRICITY LOSSES

2.4.3.1 SETTLEMENT AGREEMENT TERM D3

Hydro One Distribution will prepare a review of utility practices for mitigating distribution system losses. The review will consider best practices of other distributors (where applicable) and provide recommendations (if any) to cost-effectively reduce losses, including details on when and how those recommendations would be implemented. The review will be provided part of Hydro One's next distribution cost-based rate application and Hydro One will include information discussing its response to any recommendations.[18]

2.4.3.2 HYDRO ONE ACTIONS

Hydro One engaged Electrical Power Research Institute (EPRI) to undertake a comprehensive review of distribution loss reduction practices. The EPRI report may be found at DSP Section 3.3, Attachment 4.

[17] Ibid.
[18] Ibid.

2.4.4 LOSS STUDIES FOR PROJECTS NOT REQUIRING LEAVE TO CONSTRUCT

2.4.4.1 SETTLEMENT AGREEMENT TERM D4

Hydro One Distribution will review relevant planning standards to confirm that they will capture all cost-effective opportunities to reduce line losses when replacing infrastructure.

Hydro One Transmission will prepare line loss assessments for material investments that do not require a leave to construct application and include such assessments in its TSP ISDs according to Hydro One's Transmission line loss guideline at the design phase of the project. The assessments will be filed as part of Hydro One Transmission's next cost-based rate application.[19]

2.4.4.2 HYDRO ONE ACTIONS

Hydro One Distribution reviewed planning standards and guidelines for cost-effective opportunities to reduce system losses and made applicable changes. The changes include:

- Overhead Distribution Standards: Included minimum conductor sizing for all newly constructed 3-phase overhead distribution feeders.
- Developed a planning guide for optimal capacitor bank placement in distribution system modeling tool to meet system voltage needs while minimizing losses.

At the time of filing this Application, none of the identified Transmission Lines investments have completed the design phase. Consequently, no line loss assessments are available as they will be prepared when these investments reach the design phase.

2.5 SPECIFIC PROGRAM REQUIREMENTS

2.5.1 ENERGY STORAGE – GRID SCALE (D-SS-04)

2.5.1.1 SETTLEMENT AGREEMENT TERM E1

Hydro One Distribution shall undertake competitive procurement processes for reliability services from energy storage solution providers for projects over the 2025-2027 period

[19] Ibid., p. 110 and 111 of 117.

and, in this regard, shall actively seek economic participation or equity investment opportunities from First Nations as part of its standard procurement practice. The terms of the procurements shall not prevent third parties from lowering the cost to Hydro One by participating in the IESO-administered markets (e.g., real-time price arbitrage, capacity services, ancillary services, etc.) as long as that participation would not unduly detract from the reliability services to Hydro One customers (i.e. the market participation could reduce the reliability benefits only by a small degree). Furthermore, Hydro One will record in a new variance account any variances in accounting treatment resulting from any third-party ownership, with disposition to be determined in the next rebasing.[20]

2.5.1.2 HYDRO ONE ACTIONS

Hydro One undertook a competitive procurement process and issued Requests for Proposals for reliability services from energy storage solution providers for grid-scale BESS, as discussed in DSP Section 3.11, D-SS-04, Attachment 2.

2.5.2 ENERGY STORAGE – RESIDENTIAL (D-SS-04)

2.5.2.1 SETTLEMENT AGREEMENT TERM E2

Hydro One confirms that the purpose of the Energy Storage – Residential (D-SS-04) investment is to improve reliability at the lowest cost to ratepayers. Parties agree that the agreement to the 2023-2027 system service capital expenditures and in-service-additions shall not be construed as the Intervenor Parties necessarily agreeing that it is appropriate for Hydro One to own and operate behind-the-meter assets.

The Framework for Energy Innovation consultation (EB-2021-0118) is expected to provide regulatory clarity on the treatment of innovative technologies, including the use of third-party DERs to provide reliability improvements. Following regulatory clarity from the OEB, if there is a reputable third-party aggregator for residential battery storage units in Ontario that enables improved reliability, and that third-party aggregator expresses an interest in providing this service on reasonable terms and conditions and appropriate scale to Hydro One, then Hydro One will consider this and, if appropriate, will leverage Hydro One's

[20] Ibid., p. 111 of 117.

existing procurement processes. In the event that this does arise, and the units are used to participate in the IESO administered markets, Hydro One will record in a new deferral account, to the benefit of ratepayers, any net revenue derived by Hydro One from the third-party's participation in the IESO administered markets, with disposition to be determined in the next rebasing.[21]

2.5.2.2 HYDRO ONE ACTIONS (PETER)

To evaluate the potential use of third-party aggregators of residential battery storage units to improve customer reliability, Hydro One undertook a competitive procurement process and issued Requests for Proposals for reliability services from energy storage solution providers for residential BESS, as discussed in DSP Section 3.11, D-SS-04, Attachment 2.

2.5.3 ENERGY STORAGE – REPORTING (D-SS-04)

2.5.3.1 SETTLEMENT AGREEMENT TERM E3

Hydro One Distribution will prepare, and file as part of its next Distribution cost-based rate application, a baseline reliability assessment for the target customers and communities to assess the success in achieving the expected outages. The assessment will include:

- Outage frequency on a monthly basis over an historical 3-year period; and
- Outage duration on a monthly basis over an historical 3-year period.

For Grid Scale energy storage, Hydro One will provide performance data on an annual basis such as number and duration of outages experienced as well as availability of the BESS system. For residential storage, Hydro One will require the vendor's solution to be able to provide performance data on an annual basis, and Hydro One will provide the vendor's performance data on an annual basis.

The performance data will be published on the Hydro One website at the time the Capital

[21] Ibid.

Performance Report is published. The performance data are prepared for the purposes of Hydro One's future cost-based rate applications and will not form part of Hydro One Distribution's annual update application during the 2023-2027 Custom IR term.[22]

2.5.3.2 HYDRO ONE ACTIONS

Hydro One has prepared 2023-2025 reports on Grid Scale Front of the Meter Battery Energy Storage Systems and Residential Behind the Meter Battery Energy Storage Systems according to the Settlement Agreement. The reports may be found as attachments to DSP Section 3.11, D-SS-04, Attachments 3 - 8. The 2023 - 2024 reports are available on Hydro One's website (the 2025 report will be published shortly after this Application is filed).

2.5.4 EXPLORE VALUE FROM RIGHT-OF-WAYS

2.5.4.1 SETTLEMENT AGREEMENT TERM E4

Hydro One Transmission will explore the feasibility of using the land in transmission corridors for solar power generation facilities in a way that would result in net revenues for ratepayers and address all operational and safety concerns.[23]

2.5.4.2 HYDRO ONE ACTIONS

Hydro One Transmission assessed whether solar generation within transmission rights-of-way (ROWs) could feasibly generate net revenues for ratepayers while satisfying operational and safety requirements.

Hydro One determined that material constraints preclude feasibility at a systemwide or programmatic level. These constraints include limited usable land area due to mandatory clearance and access requirements, low energy output relative to corridor length, shading from transmission infrastructure, grounding and induction risks, and ongoing impacts to maintenance access and future transmission expansion. Even where minimum clearance

[22] Ibid., p. 112 of 117
[23] Ibid.

and access standards could be achieved, residual operational and safety risks would remain that cannot be fully mitigated or controlled.

From a financial perspective, Hydro One determined, under current conditions, there is insufficient evidence to support the expectation of net revenue generation from solar installations within transmission ROWs. Land values vary significantly across the Province, land use permissions must be evaluated on a parcel specific basis, and substantial portions of transmission ROWs are subject to easements or Crown ownership that limit Hydro One's authority to permit third-party infrastructure. As a result, any estimate of system level revenue potential would necessarily rely on assumptions that cannot be substantiated.

Currently, the use of transmission ROWs for solar generation does not present a feasible opportunity to generate net revenues for ratepayers while fully meeting safety, reliability, operational, and asset management obligations. Accordingly, Hydro One has not adopted an approach to permitting solar development within transmission ROWs.

2.6 OTHER

2.6.1 ELECTRONIC BILLING

2.6.1.1 SETTLEMENT AGREEMENT TERM F1

During the course of this proceeding parties became aware that Hydro One had implemented a program to transition paper billed customers to e-billing where customers had provided Hydro One with an email address during a prior transaction. Hydro One confirmed that it had implemented an electronic billing ("e-billing") pilot program which had since ended. Its current and standard process for transitioning customers from paper billing to electronic billing is as follows:

Step 1: Customers on paper billing receive a paper insert with their bill advising them that they will be moved to e-billing. The insert includes the following language that describes how to remain on paper-billing: "We respect your preferences. If you don't want a

paperless bill, you can switch back to paper billing at any time. Change your preferences by logging into HydroOne.com/KeepPaper.

Step 2: Seven to 10 days prior to their first e-bill, customers receive an email reminding them that they are being switched over to e-billing. It also includes the above language describing how to remain on paper-billing.

Step 3: If the customer does not pay their first e-bill, Hydro One automatically un-enrolls them from e-billing and places them back on paper billing, and no late payment charges or other penalties are incurred.

While the standard procedure does transition customers without their explicit consent it also assumes that any transition customer who fails to pay their first e-bill has declined to continue with this service and thereby reverts to the former paper billing option and without penalty. The “non-payment return to paper” element was also part of the pilot program. The standard process differed from the pilot in that, for the standard process, Hydro One sends a notice to the customer advising them that they have been enrolled in e-billing, explains that e-billing is optional and provides the customer with instructions on how to decline e-billing using a simple and convenient method. The pilot was different in that it did not include language stating that e-billing was optional and did not include a description of the process to decline e-billing.

The Parties agree that to address concerns arising from the e-billing pilot program, Hydro One will take the following steps:

1. it will not charge for providing paper bills;
2. it will contact every customer who was contacted as part of the pilot and inform them that they are not required to be on e-billing and may return to paper bill at no cost;
3. it will reverse (return) any late payment charge to a customer who incurred such a charge after being converted to e-billing as part of the pilot;

4. it will confirm with any customer who was converted to e-billing and who wishes to remain on e-billing after (2) that the email provided is the correct one to use;
5. it will ensure that no customer who has switched to e-billing as part of the pilot is reported to credit agencies based on late payments; and
6. if a customer who has been auto-enrolled on e-billing does not pay their first e-bill, Hydro One will continue its practice of automatically un-enrolling that customer from e-billing and will place the customer back on paper billing without penalty or charge.[24]

2.6.1.2 HYDRO ONE ACTIONS

Hydro One confirms that it does not charge for providing paper bills. Hydro One confirms that it contacted every customer who was contacted as part of the pilot and informed them that they were not required to be on e-billing and may return to paper bill at no cost.

Hydro One confirms it reversed (returned) any late payment charge to a customer who incurred such a charge after being converted to e-billing as part of the pilot. Hydro One confirms that it confirmed with any customer who was converted to e-billing and who wished to remain on e-billing after step 2 (above) that the email provided was the correct one to use.

Hydro One confirms that it ensured that no customer who was switched to e-billing as part of the pilot was reported to credit agencies based on late payments.

Hydro One confirms that Hydro One continued its practice of automatically un-enrolling customers from e-billing and placed the customer back on paper billing without penalty or charge if a customer who had been auto-enrolled on e-billing did not pay their first e-bill.

[24] Ibid., p. 112 and 113 of 117.

3.0 OEB DIRECTIONS FROM OTHER PROCEEDINGS

3.1 EB-2023-0291 DECISION AND ORDER FOR RENEWABLE GENERATION CONNECTION RATE PROTECTION COMPENSATION AMOUNT

3.1.1 OEB DIRECTION

At the time of rebasing for the Haldimand rate zone, per the settlement proposal, the balance in Account 1533 will be disposed and the account closed. For the Peterborough rate zone and Hydro One Distribution, the funding is based on forecast costs. Therefore, as part of the next rebasing application Hydro One is expected to file evidence to support the OEB's review for prudence of the actual incurred cost of the in-service assets.[25]

In its next rebasing application, Hydro One Networks Inc. shall seek approval to dispose of the balance in Account 1533 and to close the account for the Haldimand rate zone.[26]

3.1.2 HYDRO ONE ACTIONS

Hydro One has addressed the OEB's directions to dispose of the RGCRP amounts in Exhibit G-01-01, section 6.7, and request discontinuance of Account 1533 - Haldimand rate zone in Exhibit G-01-03.

3.2 EB-2023-0198 DECISION AND ORDER FOR LEAVE TO CONSTRUCT APPLICATION – WAASIGAN PROJECT

3.2.1 OEB DIRECTION

With respect to Hydro One's use of the Early Contractor Involvement (ECI) delivery model, which engages external engineering firms and ECI contractors (ECI-EPC) for the Waasigan project, the OEB made the following finding in its Decision and Order for the Waasigan Leave to Construct Project:[27]

> Hydro One's overhead capitalization methodology is a rates issue and is, therefore, beyond the scope of this leave to construct proceeding. […] Hydro One should proceed with the Project in an economically efficient

[25] EB-2023-0291, Decision and Order, May 7, 2024, p. 6.
[26] Ibid., p. 8.
[27] EB-2023-0198, Decision and Order for Waasigan Leave to Construct Project, April 16, 2024, p. 18 and 19.

manner. Hydro One appropriately advised the OEB of this interim change in cost incurrence for large transmission projects, but explicit OEB approval in this leave to construct proceeding is not required nor is it provided.

The OEB questions whether Hydro One will reassess and reduce its internal overhead functions in adopting this new ECI-EPC model. While $60 million is at issue in this Project, the OEB expects avoided costs will be material if this new contracting model is extended to all transmission projects as indicated by Hydro One. At the appropriate future proceeding, Hydro One should demonstrate how adopting the ECI-EPC model benefited ratepayers and how overhead functions were reassessed to avoid cost duplication.

3.2.2 HYDRO ONE ACTION

Hydro One has addressed the OEB's directions in Exhibit C-08-02.

3.3 EB-2021-0136 LEAVE TO CONSTRUCT APPLICATION – RICHVIEW TO TRAFALGAR RECONDUCTORING AND EB-2020-0265 HAWTHORNE TO MERIVALE RECONDUCTORING PROJECT

3.3.1 OEB DIRECTION

In respect of the Hawthorne to Merivale Reconductoring Project and the Richview to Trafalgar Reconductoring Project, the OEB issued letters to Hydro One, dated February 27, 2023, and June 26, 2024, respectively, advising it that any project costs for which recovery from ratepayers is sought will be subject to review in Hydro One's next cost-based transmission revenue requirement proceeding. The OEB outlined its expectation that Hydro One provide evidence, at a sufficiently granular level, to substantiate the nature and drivers of the cost increases to facilitate a prudence review of the incremental costs.[28]

In the case of the Richview to Trafalgar Reconductoring Project, the OEB further indicated that Hydro One should provide details regarding the steps being taken to improve its cost estimation process for reconductoring projects.[29]

[28] EB-2020-0265, OEB Letter to Hydro One Networks Inc. re Hawthorne to Merivale Reconductoring Project Change Notification, issued February 27, 2023.
[29] EB-2021-0136, OEB Letter to Hydro One Networks Inc. re Richview to Trafalgar Reconductoring Project Change Notification, issued June 26, 2024.

3.3.2 HYDRO ONE ACTION

Hydro One has included detailed evidence in this Application substantiating project cost increases at a granular level for reconductoring projects, including the Richview to Trafalgar (EB-2021-0136) and Hawthorne to Merivale (EB-2020-0265) projects, consistent with information previously provided to the OEB. In addition, Hydro One has outlined the steps taken to support cost estimation practices, including defined thresholds and standardized approaches for explaining material variances, supported by a third-party review of its Capital Project Delivery process. Please see TSP Section 2.3, Attachment 1; TSP Section 2.9, Attachment 2; and TSP Section 2.11 for further details.

3.4 EB-2023-0030/EB-2023-0059, PARTIAL DECISION AND RATE ORDERS FOR 2024 RATES, HYDRO ONE DISTRIBUTION AND ORILLIA AND PETERBOROUGH RATE ZONES

3.4.1 OEB DIRECTION

In the OEB's Partial Decision and Rate Order for Hydro One Distribution and Orillia and Peterborough RZ's 2024 rates, the OEB ordered Hydro One to present a plan with the costs and implications of fully adopting the OEB's Accounting Guidance on a prospective basis by no later than its 2028 Custom IR proceeding.[30]

3.4.2 HYDRO ONE ACTION

Hydro One has addressed the OEB's directions in Exhibit G-01-08.

3.5 EB-2020-0246, DECISION AND ORDER IMPLEMENTING THE ELIMINATION OF THE SEASONAL RATE CLASS

3.5.1 OEB DIRECTION

In the OEB's Decision and Order Implementing the Elimination of the Seasonal Rate Class, the OEB directed Hydro One "to maintain existing billing and meter reading frequencies for seasonal customers until such time that alternative options can be more thoroughly

[30] EB-2023-0030, Partial Decision and Rate Order, Hydro One Networks, December 14, 2023, p. 21; and EB-2023-0059, Partial Decision and Rate Order, Hydro One Networks (Peterborough and Orillia Rate Zones), December 19, 2023, p. 21.

examined with meaningful customer input, including cost and implementation issues of each alternative."[31]

3.5.2 HYDRO ONE ACTION

Hydro One has addressed the OEB's directions in Exhibit L-01-03.

3.6 EB-2018-0218, DECISION AND ORDER FOR ELECTRICITY TRANSMISSION REVENUE REQUIREMENT BEGINNING JANUARY 1, 2019 AND RELATED MATTERS

3.6.1 OEB DIRECTION

In the OEB's Decision and Order for Hydro One Sault Ste. Marie LP's (HOSSM) 2019 Revenue Requirement, the OEB approved HOSSM's scorecard with amendments and directed that it must be filed with the OEB each year, starting in 2020 with 2019 results.[32]

3.6.2 HYDRO ONE ACTION

In preparing this Application, HOSSM identified that the scorecard had not been filed annually. HOSSM has now provided its complete scorecard for the 2019-2025 period at TSP Section 2.10 Attachment 3.

[31] EB-2020-0246 Decision and Order dated November 10, 2021 page 18.
[32] EB-2018-0218, Decision and Order, June 20, 2019, sec. 8 Performance Scorecard, p. 29-30.

1 This page has been left blank intentionally.

EXECUTIVE SUMMARY

1.0 INTRODUCTION

1.1 APPLICATION OVERVIEW

Application Scope and Requested Approvals

This Application seeks approval of Hydro One Networks Inc.'s ("Hydro One" or the "Company") Distribution rates and Transmission revenue requirement under Custom Incentive Rate-setting ("Custom IR") frameworks for the five-year period from January 1, 2028 to December 31, 2032. It also seeks approval of Hydro One Sault Ste. Marie LP's ("HOSSM") transmission revenue requirement on a final basis for 2027, and under a Custom IR framework for the five-year period from January 1, 2028 to December 31, 2032. Together, the approvals requested for Hydro One Transmission, Hydro One Distribution and HOSSM are referred to as the "Application". This is Hydro One's second joint Transmission and Distribution rate application and builds on the structure accepted in the prior proceeding.

This Application presents Hydro One's integrated plan to meet Ontario's evolving electricity needs over the 2028 to 2032 period. Ontario's electricity system is entering a period of sustained growth and structural change, driven by population and housing growth, industrial and commercial development, electrification, new generation, distributed energy resources, and regional and bulk-system requirements. At the same time, Hydro One must renew aging infrastructure, maintain safe and reliable service, strengthen resilience to severe weather, and respond to increasingly complex operational, security and compliance obligations. The Application therefore addresses both the needs of the existing system and the investments required to support Ontario's future economic growth and electricity demand.

The proposed 2028 revenue requirements for Hydro One Transmission and Distribution are established on a cost-of-service basis, with annual revenue requirement adjustments for 2029 to 2032 determined formulaically under the proposed Custom IR frameworks. Hydro One requests recovery of its proposed Transmission and HOSSM revenue

requirements through amendments to the Uniform Transmission Rates, and recovery of its proposed Distribution revenue requirement through approval of the distribution rates and charges set out in the Application.

The principal approvals requested are:

- **Transmission:** a 2028 transmission rates revenue requirement of $2,592.6M;
- **HOSSM:** a total transmission revenue requirement of $46.1M for 2027 on a final basis[1] and a 2028 transmission rates revenue requirement of $49.1M; and
- **Distribution:** a 2028 base revenue requirement of $2,640.7M.

The Application also seeks approval of the associated capital and OM&A plans, cost-of-capital proposals, regulatory accounts, cost allocation and rate design, and the harmonization of the former Peterborough and Orillia distribution rate zones with Hydro One Distribution in 2031. The detailed requests for relief are set out in Exhibit A-02-01.

Proposed Investment Plans

Hydro One's proposed capital and OM&A plans respond to system and operating conditions that are materially different from those experienced during the 2023 to 2027 period. Sustained inflation, supply-chain constraints, severe weather, evolving policy and market conditions, and increasing customer-connection and system-expansion requirements increased both the cost and volume of necessary work. Hydro One managed these pressures through productivity and cost-control initiatives, portfolio reprioritization, scope and delivery adjustments, and the deferral or re-pacing of selected work. Those actions moderated customer impacts and allowed Hydro One to address the most immediate customer, reliability and compliance requirements towards OEB-approved envelopes, but shifted certain system needs and costs into the next rate period.

Hydro One must now deliver a larger and more complex plan to connect new customers and generation; expand and reinforce the transmission and distribution systems; renew

[1] Hydro One is also proposing to return to customers a $3.1M difference from its OEB-approved interim 2027 transmission revenue requirement of $49.2M, as an offset to its 2028 revenue requirement.

aging and deteriorated assets; maintain or improve reliability, resilience and compliance; and provide the technology, facilities, fleet and other shared capabilities needed to deliver and operate the expanded work programs. Hydro One developed the plans through its established asset-management and investment-planning processes, considering customer preferences, asset condition and performance, system studies, regulatory obligations, alternative solutions, and the costs and risks of delaying work. Hydro One also challenged investment scope and timing, bundled work where efficient, and re-paced investments to moderate customer impacts.

Hydro One relied upon customer engagement in developing the Investment Plans in this Application as discussed in SPF Section 1.6. This engagement allowed Hydro One to both shape and refine its investments based on customer input and implement explicit trade-offs between spending levels and outcomes. Overall, feedback collected from more than 100,000 customers shows that there is strong support across all customer types for a level of investment at or above Hydro One's 2028-2032 draft plans. Phase II demonstrated that customers are willing to accept rate increases in exchange for prudent investments in the distribution and transmission systems. This feedback, together with consideration of ongoing IESO Bulk Planning studies, updated system and asset data, and updated cost and execution considerations, helped refine the investment plan for this Application.

The resulting capital, prepaid expenditures related to cloud computing (prepaid) and OM&A expenditures underpinning this Application are provided in Table 1.

Table 1 - Summary of Proposed Investment Plan Investments ($M)

	5-Year Capital (2028-2032)	5-Year Prepaid (2028-2032)	2028 Test Year OM&A
Transmission	16,652.4	309.0	634.5
Distribution[1]	10,863.3	536.0	958.7
	6-Year Capital (2027-2032)	**6-Year Prepaid (2027-2032)**	**2027 / 2028 Test Year OM&A**
HOSSM[2]	192.0	0.0	10.6 / 10.9

[1] Includes the Orillia and Peterborough rate zones beginning in 2031.
[2] 2027-2032 are being rebased as part of this Application, with 2027 and 2028 OM&A being the Test Years.

Rate Framework and Customer Protections

The proposed Custom IR frameworks are complemented by revenue requirement features intended to balance funding needs, financial integrity, affordability, and the allocation of risk between Hydro One and its customers. The frameworks establish the 2028 revenue requirements on a cost-of-service basis, with annual adjustments for 2029 to 2032 determined through a Custom Revenue Cap Index that reflects inflation, productivity, growth, Hydro One-specific input-price pressures, and the capital funding required to support the proposed System Plans. The productivity factors, including a supplemental stretch factor on capital, provide incentives for Hydro One to achieve incremental capital and OM&A efficiencies while sustaining the ongoing productivity savings embedded in its business plans. Hydro One proposes an Earnings Sharing Mechanism under which customers receive 50% of cumulative earnings over the Custom IR term that exceed the OEB-approved regulatory return on equity by more than 100 basis points.

To support the significant investment required over the 2028 to 2032 period, Hydro One proposes a measured increase in deemed equity thickness from 40% to 45% for Transmission and Distribution. The proposal responds to increased business and financial risks and is intended to support credit quality and continued access to capital at a reasonable cost. Hydro One's proposed 45% equity thickness remains at the lower end of the 45% to 50% range supported by its independent expert evidence, thereby moderating near-term revenue requirement and customer bill impacts.

The Application proposes targeted deferral and variance accounts to address material uncertainty that cannot reasonably be forecast or controlled over a five-year rate period. The accounts address defined circumstances including externally driven work, changes in law, evolving cybersecurity obligations, and essential third-party digital and technology operating costs. The Application also proposes to return approximately $295.3M, $4.3M and $224.0M in forecast regulatory account credit balances to Transmission, HOSSM and Distribution customers, respectively. These credits, together with the resetting of load forecasts and the pacing of proposed investments, moderate the rate and bill impacts associated with the Application.

Taken as a whole, the Application provides the investment and funding framework required to serve growth, renew critical infrastructure, sustain safe and reliable service, and strengthen the resilience and operational capabilities of Ontario's electricity system. It combines a substantially larger program of necessary work with customer-informed planning, productivity requirements, earnings sharing, measured financial-integrity proposals, and targeted protections against exceptional uncertainty. Hydro One continues to bear the risks that actual costs, demand, inflation, productivity and execution may differ from forecast, while customers receive protections through the design of the proposed frameworks and continued OEB oversight. Hydro One will be accountable for delivering the proposed plans and associated customer outcomes through its Performance Reporting Governance Framework, updated regulatory scorecards and expanded accomplishment measures. The proposed measures are intended to provide transparent reporting on capital delivery, reliability, customer service, responsiveness to evolving system needs and other outcomes over the Custom IR term.

Customer Bill Impacts

The bill impacts for customers are summarized in Table 2.

Table 2 - Estimated Total Monthly Bill Impacts

	Typical R1 Residential Customer Consuming 750 kWh per month		Typical GSe Customer Consuming 2,000 kWh per month	
	First Year	**Average Annual**	**First Year**	**Average Annual**
Transmission	$0.50	$1.14	$1.12	$2.54
HOSSM	$0.02	$0.02	$0.05	$0.04
Distribution	($3.31)[1]	($0.10)[1]	$34.63	$20.00

[1] *With Distribution Rate Protection (DRP)*

Structure of the Executive Summary

This Executive Summary provides an overview of the following key aspects of the Application:

- Section 1 – Introduction
- Section 2 – Key Drivers and Considerations
- Section 3 – Investment Planning Process
- Section 4 – Capital Plans
- Section 5 – OM&A Plans
- Section 6 – Performance Measurement
- Section 7 – Key Financial Components, including Revenue Requirement, Rate Base, Cost of Capital, and Deferral and Variance Accounts
- Section 8 – Custom IR Proposal
- Section 9 – Load Forecasts
- Section 10 – Cost Allocation and Rate Design
- Section 11 – Bill Impacts
- Section 12 – Conclusion

1.1 HYDRO ONE'S BUSINESS

Hydro One owns and operates electricity transmission and distribution facilities across Ontario under licenses issued by the OEB. The Transmission and Distribution businesses are fundamentally different in their functions, operations, customers, system needs, and

regulatory requirements, although they rely on common employees and shared assets that are critical to the efficient delivery of safe and reliable service.

Hydro One's transmission system is the backbone of Ontario's electricity system, comprising 297 transmission stations and approximately 28,488 circuit-km of transmission lines that deliver electricity from generation sources to local distribution companies, including Hydro One's distribution system, and directly connected industrial customers across the province. The system spans a large and diverse geography and must continue to provide reliable bulk transfer capability while accommodating significant new load, generation, and regional infrastructure needs. The system also supports interjurisdictional power transfers through 26 interconnections with neighbouring provinces and U.S. states.

HOSSM owns and operates transmission assets in Northern Ontario, consisting of 15 transmissions stations and 554 circuit-km of overhead transmission lines. Operationally, HOSSM's transmission system is integrated into Hydro One's transmission system, but remains distinct legally, financially and for rate-setting purposes.

Hydro One's distribution system serves predominantly rural and low-density communities over an exceptionally large service territory. Hydro One's system spans more than 960,000 km^2 and provides service to approximately 1.5 million customers. Hydro One maintains approximately 126,000 circuit-km of distribution line, 104,000 km of rights of way in several remote and rural locations, approximately 1.6 million poles, approximately 1,000 distribution and regulating stations, and 549,000 service transformers. These characteristics increase travel, inspection, vegetation-management, maintenance, and storm-restoration requirements and require investment solutions tailored to local conditions. Consistent with this broad and geographically diverse service territory, the former Peterborough and Orillia rate zones will be integrated into Hydro One's distribution forecast and rate structure in 2031.

2.0 KEY DRIVERS AND CONSIDERATIONS

Ontario's electricity system is entering a period of sustained growth and structural change: Population and housing growth, industrial and commercial development, electrification, new generation, distributed energy resources, and regional and bulk-system requirements are increasing demands on Ontario's electricity system. The Application responds to these needs by addressing both the requirements of the existing system and the infrastructure needed to support Ontario's future electricity needs.

Electricity infrastructure is foundational to Ontario's economic growth and investment ambitions: Timely access to available capacity and reliable electricity is increasingly important to Ontario's prosperity, competitiveness, and growth priorities, including housing, advanced manufacturing, mining, agriculture, data centres, transportation, and community development. As a critical enabler of the communities and businesses it serves, Hydro One must strengthen the grid today to support tomorrow's demands. The Application provides the transmission and distribution investments required to connect customers and generation, implement IESO and regional planning outcomes, and enable economic growth and development where needs arise.

Cost pressures have been managed but underlying system needs remain: During 2023 to 2027, Hydro One absorbed significant inflation, supply-chain, growth, and severe-weather pressures by leveraging its supply chain processes, productivity improvements, and reprioritization that deferred or re-paced select work. Hydro One proactively managed these external pressures, but these measures did not eliminate the underlying system needs. Asset condition, maintenance backlogs, connection requirements, and system risks continue to evolve. The Application addresses work carried forward from the current period and the new investments required to serve growth. Further broad deferral would transfer greater cost and risk to future customers.

The required investment is substantial because connection, system expansion, and renewal needs are occurring at the same time: Hydro One must connect new customers and generation, expand and reinforce system capacity, renew aging and deteriorated assets, maintain compliance, and provide the technology, facilities, fleet, and operating capabilities required to deliver a materially larger work program. At the same time, input costs, supply chain constraints, and execution complexity have also increased, placing additional pressure on the delivery of this necessary work. While Hydro One has implemented productivity initiatives, scope optimization, alternative solutions, and prudent re-pacing where feasible, these measures alone cannot fully offset customer-driven, mandatory, or time-sensitive work, nor can they eliminate the risks associated with aging and deteriorating infrastructure.

The plans strengthen reliability, resilience, security, and the operational foundation on which growth depends: Customers and communities increasingly depend on a resilient electricity system, while aging assets, severe weather, vegetation exposure, technology obsolescence, and evolving cyber and physical threats continue to increase operational risk. To address these challenges, the Application includes prudent, forward-looking investment in targeted asset renewal, preventive maintenance, vegetation management, system hardening, automation, cybersecurity, and grid modernization. It embraces innovation where new technologies and operating approaches can improve system visibility, flexibility, efficiency, and customer outcomes. Together, these investments are intended to improve outage performance and restoration, protect critical infrastructure, maintain mandatory standards, and sustain the existing platform on which new connection and system-expansion capability depends.

The proposed plans are prioritized and paced responses to identified needs, not unconstrained expressions of need: Affordability was a central consideration throughout planning. Hydro One challenged investment scope and timing, distinguished mandatory and time-critical work from work that could be re-paced, considered non-wires and other alternative solutions, bundled work where efficient, and embedded productivity improvements. Following customer engagement and further review, Hydro One also

reduced and re-paced selected Distribution and General Plant investments by approximately $1.5B relative to the draft plans that were supported by customers. The resulting portfolios represent a balanced approach that moderates customer bill impacts without creating long-term costs or operational risks that can result from deferring essential work.

Customers informed the plans and broadly support the direction of investment: Hydro One coordinated customer engagement with investment planning so that customer priorities informed the initial planning assumptions and customers could then assess alternative spending, service, and rate-impact scenarios. In Phase II, majorities across every customer segment supported either the draft plan or higher levels of investment. Hydro One considered this feedback alongside other planning factors and undertook a further re-pacing exercise. As a result, the proposed Distribution plan is below the draft plan presented to customers. This approach reflects both customer preferences for continued investment and Hydro One's responsibility to exercise prudent judgment and moderate bill impacts.

Hydro One has the planning discipline, delivery capability, and accountability framework required to execute the plans: The Application is supported by asset-condition assessments, system studies, benchmarking, independent expert reviews, and established risk-based planning and portfolio challenge processes. Hydro One’s current execution portfolio has grown while cost and schedule performance has improved, and the proposed plans expressly consider resource, supply-chain, outage, permitting, and other delivery constraints. Delivery will depend on coordinated planning, disciplined execution, strong partnerships, and the skilled employees who operate the system, respond to customers and emergencies, and build and maintain critical infrastructure across Ontario. Updated scorecards with new measures and the proposed Custom IR frameworks will provide transparent accountability for cost, delivery, customer, reliability, and public-policy outcomes throughout the 2028 to 2032 period.

3.0 INVESTMENT PLANNING PROCESS

This section summarizes the major drivers and elements of Hydro One's System Plans, the investment planning process, and the proposed capital expenditures over the 2028-2032 period.

3.1 STRATEGY AND CONTEXT

Hydro One's planning process begins with a consideration of Hydro One's Strategic Priorities, the OEB's RRF outcomes, and customer engagement results. These factors establish the focus of the System Plans by identifying areas that are valued by the Company's diverse stakeholders, customers, and regulators. Hydro One's Strategic Priorities are presented in Figure 1 below.

Figure 1: Hydro One's Strategic Priorities

In addition to these Strategic Priorities, Hydro One's System Plans are guided by the four outcomes identified in the OEB's RRF:

- **Customer Focus** – services are provided in a manner that responds to identified needs and customer preferences

- **Operational Effectiveness** – continuous improvement in productivity and cost performance is achieved; and distributors and transmitters deliver on system reliability and quality objectives
- **Public Policy Responsiveness** – distributors and transmitters deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board)
- **Financial Performance** – Financial viability is maintained; and savings from operational effectiveness initiatives are sustainable

In managing assets that are critical to customers and Ontario's economy, Hydro One is committed to meeting the RRF outcomes and has integrated them into its Investment Planning Process.

They inform forecasts and needs assessments, the identification and evaluation of alternatives, risk scoring, project scope and timing, and the enterprise-wide prioritization of investments. This integrated approach helps Hydro One distinguish work that is mandatory or time-critical from work that can be re-paced, while ensuring that short-term affordability decisions do not create disproportionate long-term costs or risks for customers.

3.2 ASSET MANAGEMENT

As detailed in SPF Section 1.7, TSP Section 2.7, DSP Section 3.7 and GSP Section 4.7, Hydro One uses its Asset Management Process to monitor its assets and determine the appropriate timing for asset maintenance and capital investments throughout the asset life cycle. The output of the asset management process is a key component of the investment planning process.

The development of candidate investments is underpinned by a needs assessment which considers: (i) asset-specific investment needs (particularly condition), (ii) customer needs and preferences, and (iii) system needs (including regional planning considerations). Each of these is described below.

3.2.1 ASSET NEEDS ASSESSMENT

Hydro One performs a needs assessment to identify the drivers in the development of candidate investments and collect the data necessary to assess risks and facilitate the subsequent calibration process. The needs assessment process is primarily concerned with the major equipment groups across transmission (e.g., transformers, conductors, breakers, and protection and control systems) and distribution (e.g., station transformers, poles) that directly affect system reliability. Hydro One considers the following principal factors:

- Condition – risk related to the increased probability of failure that assets experience when their condition degrades over time
- Criticality – represents the impact that the failure of a specific asset would have on the transmission or distribution system
- Performance – risk that reflects the historical performance of an asset, typically derived from the frequency and duration of outages
- Utilization – risk that reflects the increased rate of deterioration exhibited by an asset that is highly utilized

Hydro One also considers factors such as load forecasts, equipment ratings, operating restrictions, security incidents, environmental risks and requirements, compliance obligations, equipment defects, obsolescence, and health and safety considerations to help ensure that capital expenditures target the appropriate mix of assets.

Many proposed System Renewal investments are informed by an asset-needs assessment and are driven principally by condition, performance, criticality, utilization, and obsolescence. These are detailed in TSP Section 2.2, DSP Section 3.2, and GSP Section 4.2. Examples include:

Table 3 - Examples of System Renewal Investments

ISD	Investment	Principal driver and supporting evidence
T-SR-04	Wood Pole Structure Replacements	**Condition.** Approximately 7,445 transmission wood poles (~19% of the population) are currently in poor condition, an increase of 7% over the 2023-2027 period. During the 2028-2032 period, 5,560 wood poles are expected to be replaced.
T-SR-13	Transmission Line Renewal	**Condition.** Approximately 3,079 circuit-km are in poor condition, with another 5,296 circuit-km showing deterioration. Together, 8,375 circuit-km or 30% of the fleet is now verified through testing to have, at minimum, commenced irreversible degradation. During the 2028-2032 period, 1,369 circuit-km are expected to be placed in-service.
Multiple ISDs	Transmission Station Renewal	**Condition and Obsolescence.** The proportion of poor condition transmission transformers increased from 16% in 2016 to 29% in 2025, and 44% of transmission breakers are obsolete. During the 2028-2032 period, 75 transformers and 293 breakers are expected to be placed in-service through planned material investments.
D-SR-07	Pole Sustainment Program	**Condition.** There are currently 99,000 poles in poor condition. The number of poles identified as poor condition annually has increased about 50%, from 10,000 in 2021 to approximately 15,000. Without intervention, the total fleet of poor condition poles is projected to increase to more than 200,000 by 2032. The program replaces 54,500 and refurbishes 31,500 poles and incorporates targeted hardening through the installation of approximately 41,000 higher-strength poles in vulnerable areas.
D-SR-04	Distribution Station Refurbishment or Replacement	**Condition.** Approximately 20% of total station transformers,[1] or 242, are in poor condition. The program proposes to replace 86 of the 242 poor condition station transformers.
G-GP-04	Transmission Facilities	**Condition and criticality.** Approximately 33% of high-criticality transmission-station buildings are currently in poor condition; without investment, that proportion is forecast to increase materially.

[1] *Accounting for Hydro One, Peterborough rate zone (PRZ) and Orillia rate zone (ORZ)*

3.2.2 SYSTEM NEEDS

System needs relate to work that is necessary to maintain and operate the transmission and distribution system to reliably and securely deliver power to customers and meet current and forecast requirements resulting from new load customers, generation facilities and other distributed energy resources. System needs include providing adequate capacity to meet forecast load growth and addressing local area reliability performance, implementing mitigation measures to minimize high-impact events in accordance with mandatory industry standards, implementing IESO Bulk System planning needs and regional transmission facility needs identified as part of the Regional Planning process, and protecting critical infrastructure from physical and cyber threats. System-needs assessments, regional planning, and bulk-system planning result in System Access and System Service investments needed to connect customers, expand capacity, maintain or improve reliability, and satisfy mandatory standards. Examples include:

Table 4 - Examples of System Access and System Service Investments

ISD	Investment	Principal driver and supporting evidence
T-SA-11	Customer Connections: Regulated Entities	**Customer connections and capacity.** Constructs new transformer stations, supply lines and station expansions to provide additional capacity requested by LDCs in growing areas, including Markham, Whitby, Oshawa-Clarington, Brant and Middleport.
T-SS-11	Bulk Planning	**Capacity, generation connections, and compliance with reliability requirements.** Modifies existing network assets or constructs new assets for projects identified through the Bulk System Planning Process and related studies.
T-SS-12	Regional Planning	**Capacity and reliability.** Constructs or upgrades transmission stations and circuits to address identified capacity, voltage, restoration and reliability needs, as recommended through Ontario's Regional Planning process.
D-SA-02	New Load Connections, Upgrades and Cancellations	**Customer connections.** Constructs and upgrades service lines, transformers, metering and related facilities to accommodate approximately 93,500 new connections and 38,900 service upgrades while meeting Hydro One's obligation to connect customers.
D-SS-01	System Upgrades Driven by Load Growth	**Capacity expansion.** Delivers 190 material investments to upgrade, expand or reconfigure stations, feeders and secondary systems, maintaining capacity, voltage and reliability. Forecast load growth is expected to push targeted stations from approximately 90% of their planning limits today to more than 140% by 2032, while targeted feeders could exceed 200% without action.
G-GP-11	Cybersecurity and Digital Protection	**Mandatory standards and reliable operation.** Upgrades cybersecurity and digital-protection capabilities to address evolving threats and comply with applicable NERC CIP, IESO and other critical-infrastructure requirements.

3.2.3 CUSTOMER NEEDS AND PREFERENCES

Hydro One conducted extensive customer engagement during the development of the 2028–2032 plans. Over 100,000 customers participated in focus groups, in-depth interviews, telephone surveys, and online surveys. Engagement also included conversations with First Nations Chiefs or their representatives, Métis Nation of Ontario regional representatives, stakeholders and municipalities.

The engagement and investment-planning processes were coordinated in a two-phase approach, engaging customers in advance of the investment planning process, in mid-to-

late 2024, and again after draft investment plans were prepared, in late 2025. This allowed Hydro One to develop and finalize investment plans that are informed by customer input and have been refined based on specific investment trade-offs to achieve outcomes valued by customers.

The engagement results indicate strong support for Hydro One's proposed investment plans. As stated in the IRG Overview Report: "Overall, feedback collected from more than 100,000 customers shows that there is strong support across all customer types for a level of investment at or above Hydro One's 2028-2032 draft plans."[2] Depending on customer type, 68% to 88% of customers support spending at or above the level of investment included in the plans.[3] Similar levels of support were observed for categories of investments in the transmission and distribution systems, as well as shared services.[4] Further information on customer engagement and its integration into investment planning is provided in SPF Sections 1.6 and 1.7, TSP Sections 2.6 and 2.7, DSP Sections 3.6 and 3.7, and GSP Sections 4.6 and 4.7.

3.3 INVESTMENT PLANNING

Based on identified investment needs, Hydro One develops a suite of candidate investments for further screening and prioritization. The information and data collected through the asset management process establish the fact base to assess the probability and consequence of safety, reliability and environmental risks at the scoring stage of the investment planning process.

Hydro One planners determine risk probability (based on asset condition, performance and utilization) and risk consequence (based on asset criticality across three taxonomies of safety, reliability and environmental risks). Planners quantify the risk mitigated by comparing the expected operational risks of not making the investment versus the residual risks that would remain if the investment is made.

[2] SPF Section 1.6 Attachment 1, IRG Overview Report p. 3
[3] SPF Section 1.6 Attachment 1, IRG Overview Report p. 3 and p.14
[4] SPF Section 1.6 Attachment 1, IRG Overview Report p. 14-18

Customer-driven outcomes directly impact this process through the definition of consequence scores and risk taxonomies as well as “flags” that reflect priorities and investment benefits beyond quantified risk mitigation. In alignment with RRF outcomes and corporate priorities, flags are clearly defined to reflect either mandatory obligations (e.g., obligations to regulators, stakeholders or contractual counterparties) or customer preferences and other priorities (e.g., productivity commitments, corrective maintenance/replacements, preventative maintenance/renewal).

Once candidate investments have been scored and flagged, enterprise-wide calibration sessions are held to ensure consistent evaluation across investments and lines of business. Based on the risk scores and estimated investment costs, candidate investments (broken into mandatory versus non-mandatory groups) are ranked according to risk mitigation achieved per dollar. Challenge sessions take place among a broad set of stakeholders to debate the feasibility and merits of investments on the margin and to ensure that valuable investments (from both a risk and non-risk perspective) are included in the plan. As well, Phase II customer engagement results are incorporated into the final plan at this stage. The output is an investment portfolio that is subject to enterprise engagement with portfolio owners and the executing lines of business, so as to create a realistic and up-to-date plan (i.e. reflecting the latest cost estimates, schedules and investment scope) and account for operational and execution considerations (e.g., resourcing, material availability and outage feasibility).

The Investment Planning process is described in greater detail in SPF Section 1.7 (as well as TSP Section 2.7, DSP Section 3.7, and GSP Section 4.7).

4.0 CAPITAL PLANS

Applying the investment planning process described above, Hydro One developed prioritized and paced capital plans that respond to materially evolved system conditions. Electricity demand is growing, customer connection requests are increasing in number and complexity, IESO-led regional and bulk planning is identifying substantial new infrastructure requirements, and important asset classes continue to deteriorate. At the

same time, severe weather, cybersecurity threats, technology obsolescence, and market-driven cost pressures are increasing the scope and cost of maintaining safe and reliable service. Hydro One's capital plans respond to these factors by focusing on mandatory, time-sensitive and high-value work, while moderating customer impacts through scope optimization, alternative solutions, bundling and re-pacing where appropriate.

As noted above, the current period has been impacted by an unprecedented set of market forces that have resulted in sustained inflation, significantly increasing the cost of key electrical equipment and materials as discussed in SPF Section 1.8. Hydro One has updated cost estimates to reflect current market prices for materials and equipment, including power transformers, breakers, conductors, and other critical inputs. These updated costs form the basis of the assumptions underlying the capital plans described below.

4.1 TRANSMISSION CAPITAL EXPENDITURES

Over the 2028-2032 period, Hydro One plans to invest an average of $3,330.5M per year in Transmission capital, for a total of $16,652.4M, to maintain transmission reliability performance, address increasing customer and system needs, respond to government policy and directives related to system expansion, and mitigate asset and operational risks. Hydro One also proposes to invest approximately $309.0M in prepaid expenditures related to cloud computing discussed in the General Plant section below. Table 5 summarizes Hydro One's planned transmission capital expenditures by OEB investment category.

Table 5 - Transmission Forecast Capital Expenditures ($M)[5]

OEB Investment Category	Forecast Period					% of Portfolio
	2028	2029	2030	2031	2032	
System Access	286.4	363.5	560.7	320.1	98.1	9.8%
System Renewal	955.2	1,072.4	1,435.0	1,864.4	1,766.6	42.6%
System Service	1,102.4	1,391.9	1,432.4	1,577.5	1,138.9	39.9%
General Plant (Transmission)	287.9	259.0	275.3	247.2	217.6	7.7%
Total Capital	**2,631.9**	**3,086.7**	**3,703.3**	**4,009.3**	**3,221.2**	**100%**
Prepaid Related to Cloud (Transmission)	70.9	65.4	70.4	58.4	44.0	

**Exhibit Reference: TSP Section 2.1, Table 4*

Hydro One's Transmission capital program is shifting from one driven primarily by system renewal to one increasingly driven by external requirements for customer connections, system expansion and resilience. This shift emerged during the 2023–2027 period and is expected to accelerate over the 2028–2032 period as Hydro One supports Ontario's growing electricity needs and economic development, as illustrated in Figure 2 below.

[5] Figures presented in the tables may not sum to the totals shown due to rounding.

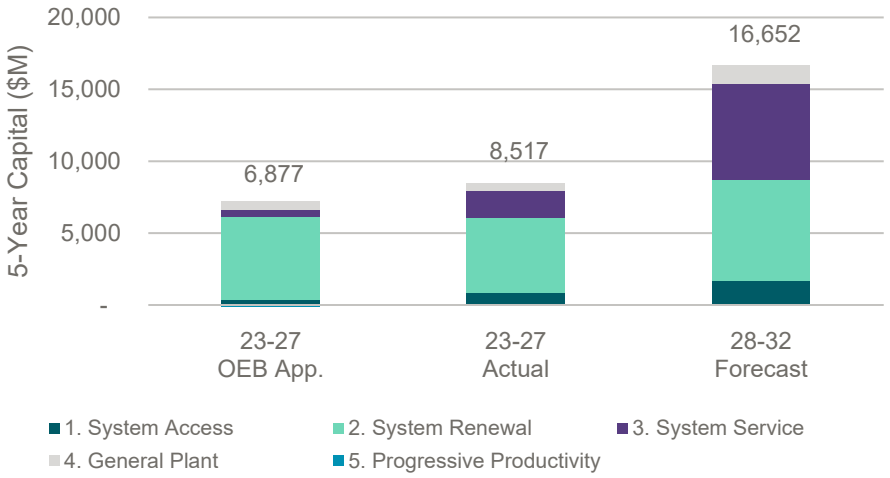


Figure 2: Transmission Capital Portfolio, 2023-2027 period Compared with 2028-2032 period

Relative to the levels of investment approved in Hydro One's prior Application (EB-2021-0110), the actual proportion of System Access investments in 2023-2027 has more than doubled, and the proportion of System Service investments has more than tripled. Together, investments in System Access and System Service are expected to comprise approximately 31.2% of transmission capital investments over the 2023-2027 period, compared to the proportion approved in the prior Application of 11.1%.[6] This trend is expected to continue into the 2028-2032 period, with System Access and System Service expenditures accounting for approximately 49.7% of capital expenditures.

At the same time, Hydro One must continue to invest in System Renewal work, which was reduced in the current period to facilitate the non-discretionary System Access and System Service investments that emerged. Over the 2028-2032 period, Hydro One will invest to renew critical transmission assets that are in poor condition, have inadequate performance, are functionally obsolete or have failed, and to ensure safety, mitigate reliability risk and maintain compliance with regulatory, environmental and reliability standards.

[6] Values relative to OEB-approved capital categories before progressive productivity (EB-2021-0110, Settlement Proposal, Table 22, p. 33).

The increase in proposed capital spending reflects the transmission system Ontario now requires: one that can connect major new loads and generation, implement IESO regional and bulk-planning outcomes, carry out priority projects designated by the Government of Ontario, and continue to renew aging critical infrastructure. This is consistent with Ontario's Integrated Energy Plan (IEP), *Energy for Generations*, which forecasts a 75% increase in electricity demand by 2050 and calls for accelerated transmission development to support electrification, economic growth, and a reliable and resilient electricity system.

System Access

Hydro One proposes $1,628.8M of System Access expenditures over 2028-2032, representing 9.8% of total Transmission capital and an increase of $1,316.5M, or 421.6%, from the 2023-2027 OEB-approved expenditures. System Access investments facilitate new load and generation customer connections and address transmission asset modifications to accommodate third-party requests.

Hydro One is forecasting more than 6,000 MW of connection capacity enablement in 2028-2032, reflecting a material increase in requests for new and expanded load connections from LDCs, industrial customers, and large commercial loads. This is equivalent to more than 5% of Ontario's peak demand. Forecasts are underpinned by emerging load and generation connection requests that have increased by 70% to 250% in the current period. The scale and complexity of this activity represent a fundamental step change from the amounts forecast in the prior Application. Proposed investments are aligned with the IEP and the OEB's statutory objective to support economic growth.

System Renewal

Hydro One proposes $7,093.5M of System Renewal expenditures over 2028-2032, representing 42.6% of total Transmission capital and an increase of $1,286.6M, or 22.2%, from 2023-2027 OEB-approved expenditures. The increase is necessary to address a significant and growing proportion of poor condition transmission assets across major asset classes, including transformers, breakers, protection systems, conductors and wood structures, which increase the risk of equipment failures, misoperations, extended outages

and reduced operational flexibility. Asset condition trends are most pronounced for transformers and wood structures. Between 2016 and 2025, poor condition transformers increased from 16% to 29%, while poor condition wood structures increased from 12% to 19%. In addition, 44% of breakers are obsolete, approximately 27% of protection systems are beyond expected service life, and 11% of conductors remain in poor condition.

Hydro One has prioritized planned System Renewal investments to target the most pressing needs, based on asset condition, criticality, performance, and other factors, at a pace that maintains the population of deteriorated assets at a manageable level or avoids a material negative impact on system operations and reliability. For example, Hydro One will invest $2,059M in connection stations, which directly supply industrial and commercial customers and LDCs. Investments at these stations are critical to the reliability of directly connected LDCs and industrial and commercial customers. The Company will also invest $410.3M to replace individual transmission station assets that are in poor condition.

For transmission lines, Hydro One will invest $1,035M to replace or refurbish 1,369 circuit-km of transmission lines and place them in service, addressing 45% of the known poor condition conductors in the fleet. This renewal work sustains service to a variety of network and radial line connected customers, including large and small municipalities, First Nations communities, and large load facilities such as petrochemical processing facilities, mines, and paper mills. Hydro One also plans to invest $1,467M to replace or refurbish various transmission line components such as wood poles, steel structures, foundations, insulators and shieldwires that have been confirmed to be in poor condition. These components are integral parts of the transmission line system required to support the overhead conductors and enable them to perform their functions.

Hydro One does not propose to replace all deteriorated or obsolete assets during 2028-2032 but has paced its investments to prioritize the highest-risk needs while managing the remaining population over time.

System Service

Hydro One proposes approximately $6,643.1M of System Service expenditures over 2028-2032, representing about 39.9% of total net transmission capital and an increase of $6,157.4M, or 1,268%, from 2023-2027 OEB-approved expenditures. System Service investments are required to maintain inter-area network transfer capability, ensure local area supply adequacy, mitigate system risks related to safety, security and reliability, and address customer power quality concerns. Most of these investments are non-discretionary with the majority identified through regional planning processes or IESO bulk planning studies.

During the 2023-2027 rate period, Hydro One experienced unprecedented and unexpected growth in system expansion needs, which is expected to continue and intensify throughout the 2028-2032 period.

As a result, Hydro One's planned 2028-2032 System Service expenditures are significantly higher, driven largely by an increase in Transmission Regional Planning and Bulk Planning investments that together will significantly increase system transfer capability by at least 10,000 MW and support the integration of more than 2,500 MW of new generation capacity.

The System Service portfolio includes 47 material investments that will result in the construction of 8 new HV transmission stations, 26 HV transmission station expansions, and approximately 387 km of new HV lines. These investments generally result from Ontario's Bulk System and Regional Planning Processes, as well as priority project designations by the Government of Ontario, and are essential to supporting housing and population growth in high-growth regions, as well as industrial developments in the manufacturing, agricultural and technology sectors.

For more information on Hydro One's Transmission System Plan, see TSP Section 2.1.

4.2 HOSSM CAPITAL EXPENDITURES

HOSSM has prepared a comprehensive six-year System Plan covering the 2027-2032 period. HOSSM plans to invest an average of $32.0M per year in transmission capital, for a total of $192.0M, summarized in Table 6 below. This plan represents the level of investment required to maintain a reliable and resilient grid and meet Ontario's growing demand.

Table 6 - HOSSM Forecast Capital Expenditures ($M)

OEB Investment Category	Forecast Period						% of Portfolio
	2027	2028	2029	2030	2031	2032	
System Access	2.2	0.0	0.0	0.0	0.0	0.0	1.1
System Renewal	19.2	35.2	20.7	21.8	22.3	13.4	69.1
System Service	18.3	29.4	9.2	0.3	0.0	0.0	29.8
General Plant	0.0	0.0	0.0	0.0	0.0	0.0	0
Total	**39.6**	**64.6**	**29.9**	**22.1**	**22.3**	**13.4**	**100**

**Exhibit Reference: TSP Section 2.10, Table 3*

System Access investments account for 1% of the 2027-2032 HOSSM capital plan and include minimal expenditures in 2027 to complete an ongoing customer connection investment.

System Renewal investments account for 69% of HOSSM's 2027-2032 capital plan. HOSSM expects to increase annual System Renewal expenditures driven by asset need and work that was reprioritized from prior years.

System Service investments account for 30% of HOSSM's 2027-2032 capital plan. HOSSM has one System Service investment related to the North Shore Link, which was recommended in the IESO's Northeast Bulk Plan and is being developed pursuant to two Orders in Council issued by the Minister of Energy and Mines.

HOSSM does not have any planned General Plant investments. Generally, General Plant expenditures are provided by Hydro One to HOSSM through services Hydro One carries out.

For more information on HOSSM's System Plan, see TSP Section 2.10.

4.3 DISTRIBUTION CAPITAL EXPENDITURES

Hydro One's Distribution System Plan presents an outcomes-driven and customer-focused portfolio of approximately $10,863.3M in Distribution capital expenditures over 2028 to 2032. Of this, $8,835.4M, or approximately 81%, is allocated to System Access, System Renewal, or System Service investments as further described in the DSP. The remaining $2,027.9M is allocated to General Plant investments and is described in the General System Plan section below.

Table 7 below shows the annual and total capital investments planned for the 2028-2032 period, by OEB category. It reflects the integration of the former Peterborough and Orillia rate zones in 2031.

Table 7 - Distribution Capital Expenditure Summary

OEB Investment Category	Forecast Period ($M)					
	2028	**2029**	**2030**	**2031**	**2032**	**% of Total**
System Access	549.6	406.8	416.0	431.4	445.1	20.7%
System Renewal	630.8	711.9	823.4	806.6	852.3	35.2%
System Service	405.2	497.1	708.4	627.3	523.4	25.4%
General Plant	342.1	311.2	342.2	583.3	449.0	18.7%
Total	**1,927.8**	**1,927.0**	**2,290.1**	**2,448.6**	**2,269.9**	**100.0%**

**Exhibit Reference: DSP Section 3.1, Table 8*

Figure 3 below shows the material increase in the scale of Hydro One's Distribution capital plans and the change in their composition for the 2028–2032 period.

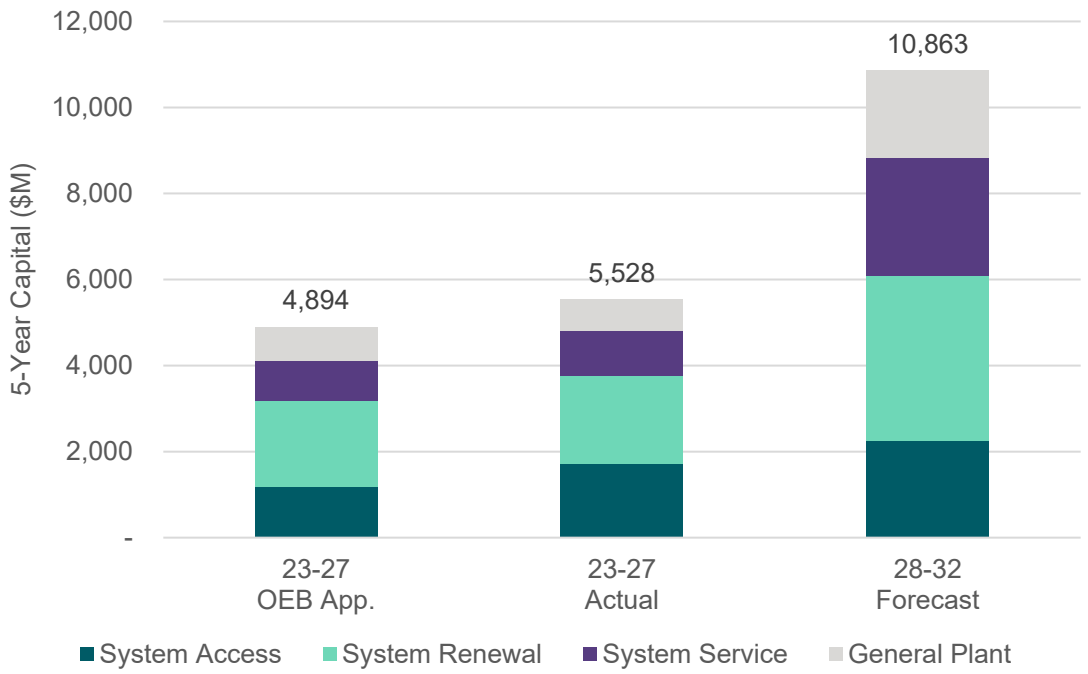


Figure 3: Distribution Capital Portfolio, 2023-2027 period
Compared with 2028-2032 period

During the 2023-2027 period, Hydro One experienced materially higher demand-driven and mandatory work than contemplated in the OEB-approved plan, together with significant storm restoration requirements and higher material and equipment costs. Hydro One responded by reprioritizing available capital and directing resources toward the most immediate customer, safety, reliability, and compliance requirements, and by deferring and re-pacing certain planned condition-based renewal and selected reliability and resiliency work. These measures partially mitigated the expenditure pressures. Following this reprioritization and deferral of planned work, total Distribution capital expenditures for 2023-2027 are forecast at $5,527.6M, compared with the OEB-approved amount of $4,893.8M, or 13% above plan. The reprioritized asset, reliability, and system requirements continue into 2028-2032 and form part of the broader set of needs addressed by the proposed plan.

A material portion of the proposed plan addresses work required by legislative, regulatory and service obligations, leaving Hydro One limited discretion as to whether the work proceeds. Approximately 45% of proposed 2028-2032 Distribution capital expenditures are driven by legislative and regulatory mandates, including requirements associated with customer connections, distributed energy resource connections, third-party access and relocations, metering, broadband and meeting growing customer demand and maintaining service obligations. For certain investments, Hydro One retains some discretion over scope, timing or delivery approach, but the underlying requirements materially constrain whether the work proceeds.

Within this context, Hydro One applied its risk-informed investment planning process to prioritize and pace the remaining requirements. Customer engagement indicated strong support for Hydro One's proposed distribution plan. Across all customer types, a majority selected a level of investment at or above Hydro One's draft investment plan as it related to investments that improve reliability, improve resilience to severe weather, address deteriorating assets and accommodate future growth, while also identifying affordability as an important consideration. Following customer engagement and further review, Hydro One refined and re-paced select Distribution and General Plant investments to balance customer priorities, system needs, execution considerations, and affordability. The resulting DSP is approximately $1,500.0M lower than the draft plan presented during customer engagement and supported by a majority of customers.

The plan responds broadly to three related sets of needs. First, the continued deterioration of the existing asset base is increasing lifecycle intervention requirements. Second, Hydro One must address reliability and resiliency challenges associated with asset performance, long radial supply paths, limited alternate supply, vegetation and severe-weather exposure, and difficult restoration access. Third, customer growth, electrification, economic development and DER adoption are increasing connection, capacity and operational-capability requirements.

These needs must be addressed across Hydro One's large, geographically dispersed and predominantly rural distribution system. Hydro One operates approximately 126,000 circuit-km of distribution line, approximately 91% of which is overhead and directly exposed to vegetation and severe weather. More than 24,000 line-km are located on feeders longer than 100 km, many with limited alternate-supply capability, and approximately 400 feeders contain significant off-road assets. This combination of extensive overhead infrastructure, long radial supply paths, limited alternate supply and difficult access increases exposure to external hazards, the complexity and duration of fault location and restoration, and the customer consequences of individual failures. These characteristics contribute to the need for sustained asset renewal and targeted investments in system hardening, feeder ties and sectionalization, automation, energy storage and relocation of difficult-to-access infrastructure.

Hydro One has organized its response to these needs around three distribution investment priorities:

1. Maintaining the Grid – approximately $3,437.9M: maintains the safe and reliable operation of the existing distribution system by addressing priority asset-condition, lifecycle and system-sustainment requirements
2. Improving Reliability and Resiliency – approximately $1,604.4M: reduces outage exposure and impacts, improves restoration capability and strengthens the system's ability to withstand and recover from equipment failures and severe weather
3. Meeting Ontario's Growing Demand – approximately $3,792.3M: provides customer access, system capacity and operational capability to accommodate growth, electrification, economic development and DER integration, while responding to customer-driven and externally driven infrastructure requirements.

These priorities, and the outcomes they seek to achieve, drive investments in each of the System Access, System Renewal and System Service categories in the DSP.

System Access

Hydro One proposes $2,248.9M of System Access expenditures over 2028-2032, representing 20.7% of total Distribution capital and an increase of $541.5M, or 31.7%, relative to 2023-2027 OEB-approved expenditures. System Access investments are primarily customer and externally driven and support Hydro One's obligations to connect new customers, upgrade existing customer services, accommodate customer-driven DER connections, and undertake system modifications required for municipal, provincial, telecommunications and broadband infrastructure. These investments provide timely access to the distribution system and enable customer growth, electrification, infrastructure development and economic activity.

Over the planning period, Hydro One expects to complete approximately 93,500 new customer connections and 38,900 service upgrades. Relative to 2023-2027, new-connection volumes increase by approximately 6% and service-upgrade volumes by approximately 33%, reflecting customer growth and increasing residential electricity requirements associated in part with EV chargers and heat pumps. Hydro One also forecasts approximately 9,900 customer DER connections. In addition, the portfolio includes municipal and provincial relocations and approximately $150M of legislatively required broadband make-ready work.

System Renewal

Hydro One proposes $3,825.1M of System Renewal expenditures over 2028-2032, representing 35.2% of total Distribution capital and an increase of $1,766.1M, or 85.8%, relative to 2023-2027 OEB-approved expenditures. The increase reflects a materially greater volume and broader scope of planned renewal required to address poor condition, aging, damaged, exposed, obsolete and vulnerable assets. The proposed level of investment is intended to manage continued deterioration of the asset base, reduce exposure to unplanned failures and reactive replacement, maintain safe and reliable service, and improve resiliency and restoration capability where renewal provides an opportunity to address existing system vulnerabilities.

Hydro One's plan increases pole sustainment investment to 54,500 replacements, 31,500 mechanical refurbishments, and 460,000 test-and-treat activities during 2028-2032. Hydro One currently has 99,000 poles identified in poor condition. The investment extends the service life of the pole fleet through a return to the 15-year test-and-treat cycle and targeted refurbishment, while focusing replacement on poles that are currently in poor condition or are expected to deteriorate to poor condition over the planning period. With the proposed investment, Hydro One expects to contain the poor condition pole population at approximately 135,000 by 2032, compared to more than 200,000 without intervention. Where poor condition poles are concentrated in areas vulnerable to severe weather, Hydro One will strengthen selected pole clusters using higher-class poles. Where concentrations of deteriorated pole and line assets occur on difficult-to-access off-road sections, Hydro One will rebuild and, where appropriate, relocate more than 400 km of line to road allowance to improve access for inspection, maintenance and restoration. Where poor condition overhead infrastructure also has significant vegetation, severe-weather, access and customer-consequence risks, Hydro One will selectively underground 120 km of targeted line. Through this coordinated approach, Hydro One addresses the underlying renewal need while improving the resilience, accessibility and restoration performance of the renewed infrastructure.

Station renewal also increases materially, from eight material investments in the current period to 81 planned station renewal investments in 2028-2032. The plan further coordinates renewal with voltage consolidation where appropriate, including conversion of end of life 4.16kV station transformers and associated line to standardized higher voltages, improving load-serving capability, feeder-transfer capability and operational flexibility.

Hydro One operates one of the largest underground cable systems in Ontario by total length. As this cable population ages, the plan establishes a proactive approach to cable renewal. Hydro One proposes to replace 250 km of deteriorated underground cable and rejuvenate 500 km through cable injection, focusing on five areas experiencing poor

reliability associated with aging and deteriorating cable. The submarine-cable program will replace 1,720 cables and refurbish 1,530 cables.

System Service

Hydro One proposes approximately $2,761.3M of System Service expenditures over 2028-2032, representing 25.4% of total Distribution capital and an increase of $1,722.6M, or 165.8%, relative to 2023-2027 OEB-approved expenditures. The increase responds to higher requirements for system capacity, reliability and resiliency, DER integration, system monitoring and operational capability arising from load growth, electrification, increasing DER penetration and the growing complexity of distribution-system operation.

Hydro One's reference distribution peak is forecast to increase by approximately 550 MW, or 8%, from 6,903 MW in 2026 to 7,453 MW in 2032. To address identified and forecast capacity constraints associated with this growth, Hydro One plans approximately 190 material load-growth investments to construct new or upgrade existing stations and feeders, compared with 123 projects during 2023-2027. The investments address identified capacity, thermal, voltage and operational constraints and provide the infrastructure required to reliably serve increasing customer demand.

Hydro One will use non-wires solutions where they provide a cost-effective alternative to conventional capacity investment. The proposed DSP includes non-wires solutions across 16 projects, together with one ongoing project deferral, expected to defer approximately $103M, or 6.9%, of conventional load-growth investments from the 2028-2032 plan.

The portfolio materially expands targeted reliability and restoration capability. Energy Storage Solutions increase from one grid-scale project and approximately 360 residential installations during 2023-2027 to 25 grid-scale projects and 5,400 residential installations, providing localized backup supply and improving reliability for up to 9,400 customers. Distribution Automation and Sectionalization expands from 400 remote-operable devices installed during 2023-2027 to 1,150 devices during 2028-2032, increasing remote

operational capability from 42% to 90% of Hydro One's sub-transmission feeders and enabling faster fault isolation, sectionalization and restoration.

DER Hosting Capacity investments will remove micro-generation constraints on approximately 190 feeders, provide more than 43 MW of additional hosting capacity, and enable an estimated 3,600 to 4,300 additional micro-embedded generation customer connections. Hydro One will also expand system monitoring, visibility and operational-control capabilities through System Monitoring, the Intelligent Grid Platform, and Real-Time Distribution Station and Feeder Monitoring. These investments will improve visibility into asset condition and system loading, enable earlier identification of emerging issues, and provide the information and control capabilities required to operate a more complex, electrified and DER-active distribution system.

Overall, the DSP represents a prioritized and paced response to the system's asset, reliability, resiliency and growth needs, balancing customer outcomes, affordability, regulatory obligations and execution capability. The plan provides the connections and capacity required to support growth, materially increases planned lifecycle intervention on the existing asset base, improves reliability, strengthens resilience to severe weather and enhances restoration capability, and provides the monitoring, automation and operational capabilities required to manage a more electrified and DER-active distribution system.

For more information on Hydro One's Distribution System Plan, see DSP Section 3.1.

4.4 GENERAL PLANT CAPITAL EXPENDITURES

General Plant assets enable Hydro One to deliver the Transmission and Distribution work programs safely, efficiently, and reliably. The GSP comprises four portfolios: (i) Fleet & Aviation, (ii) Facilities & Real Estate (FRE), (iii) Digital & Technology Solutions (DTS), and (iv) System Operations. Over the 2028 to 2032 planning period, Hydro One plans to invest $4,159.9M in General Plant investments, including $3,314.9M in capital expenditures and approximately $845.0M in prepaid expenditures.

Investments in these portfolios are allocated to Transmission and Distribution using the Shared Asset Allocation Study prepared by Atrium Economics and presented in Exhibit E-04-08 Attachment 1. The plan allocates General Plant expenditures to Transmission, Distribution, or shared functions.

Tables 8 and 9 summarize the planned capital investments and prepaid expenditures related to cloud for the 2028-2032 period by General Plant function, respectively.

Table 8 - GSP 2028-2032 Planned Capital Expenditures[7]

Line of Business	Forecast Period (Planned $M)					Total 2028-2032	% of Total GP
	2028	2029	2030	2031	2032		
Fleet & Aviation	285.9	158.0	190.7	136.3	132.9	904.0	27.3%
Facilities & Real Estate	131.1	230.1	231.6	225.8	154.3	972.9	29.3%
Digital & Technology Solutions	152.6	150.9	155.4	144.7	137.4	741.1	22.4%
System Operations	18.4	5.5	7.3	10.4	13.5	55.1	1.7%
Other	41.9	25.7	32.5	313.3	228.4	641.8	19.4%
General Plant Total	**630.0**	**570.2**	**617.5**	**830.5**	**666.6**	**3,314.9**	
General Plant - Transmission Allocation	287.9	259.0	275.3	247.2	217.6	1,287.0	38.8%
General Plant - Distribution Allocation	342.1	311.2	342.2	583.3	449.0	2,027.9	61.2%

**Exhibit Reference: GSP Section 4.1, Table 5*

[7] Figures presented in the tables may not sum to the totals shown due to rounding.

Table 9 - GSP 2028-2032 Planned Prepaid Expenditures

OEB Category	Forecast Period (Planned $M)					Total 2028-2032	% of Total GP
	2028	2029	2030	2031	2032		
Prepaid Related to Cloud	168.8	190.0	189.3	157.9	138.9	845.0	
General Plant Total	**168.8**	**190.0**	**189.3**	**157.9**	**138.9**	**845.0**	
General Plant - Transmission Allocation	70.9	65.4	70.4	58.4	44.0	309.0	36.6%
General Plant - Distribution Allocation	98.0	124.7	118.9	99.5	94.9	536.0	63.4%

**Exhibit Reference: GSP Section 4.1, Table 6*

The plan is organized around four priorities: Workforce Enablement & Safety, Protect and Secure Critical Infrastructure, Reliability & Resiliency of the Grid, and Customer Centricity. Workforce Enablement and Safety investments support the Transmission, Distribution, and corporate support portfolios in achieving their operational and investment objectives. Protect and Secure Critical Infrastructure driven investments strengthen physical and cybersecurity capabilities to ensure the continued delivery of safe and reliable electricity service. Reliability & Resiliency focused investments are aimed at sustaining and improving transmission and distribution system performance. Customer Centricity investments improve the customer experience and service delivery through the modernization of customer service technologies, digital channels, and supporting platforms

Fleet & Aviation investments total $904.0M, or 27.3% of the General Plant capital expenditures. Hydro One manages approximately 8,000 vehicles and miscellaneous units, more than 1,000 small off-road units and 10 helicopters that support field work, line inspections and maintenance, outage restoration and access to remote locations. The plan provides $850.1M for Transport and Work Equipment, including approximately $611.5M for lifecycle replacement and $238.6M for additional equipment required by larger Transmission and Distribution work programs, and $53.8M to renew three aging helicopters. Fleet planning combines age, mileage, engine hours, mechanical condition,

maintenance history, downtime, utilization, safety risk and procurement lead times, informed by Utilimarc lifecycle analysis.

FRE investments total $972.9M, or 29.3% of the General Plant capital expenditures. The investments are needed to sustain and modernize 1,474 buildings across 529 sites. The portfolio includes 1,085 Transmission facilities at 371 sites and 389 operating-centre and administrative buildings at 158 sites. High-criticality components such as foundations, structures, roofs and HVAC systems are, on average, operating 56% beyond expected useful life. Hydro One has identified approximately $362M of facility deficiencies, of which about $210M, or nearly 60%, are high risk. The plan includes $434.3M of Sustainment, $339.7M of Growth and $198.9M of Compliance & Governance investments, including 10 new builds, two major renovations and a land purchase. Investments are prioritized using Building Condition Assessments and a risk framework that considers likelihood and consequence of failure, facility and component criticality, safety, reliability, productivity and customer impacts. With the proposed plan, poor condition high-criticality buildings are projected to decline from 238, or approximately 34%, to at least[8] 130, or approximately 18%; under current investment levels, they would increase to at least 284[9], or approximately 40%.

DTS investments total approximately $1,586M including $741.1M of capital (representing 22.4% of the General Plant capital expenditures) and $845.0M of prepaid expenditures. Hydro One manages more than 600 IT and OT business applications and thousands of supporting hardware assets. The plan renews aging and unsupported platforms and expands the digital capabilities required for grid operations, customer service, cybersecurity, work execution and enterprise decision-making. Key investments include the SAP S/4HANA OneCore Transformation, modernization of customer service and work and asset management platforms, enhancements to cybersecurity and physical security

[8] In light of limitations associated with forecasting building condition data more than five years beyond a BCA, this figure uses the number of buildings projected to be in poor condition in 2030 as its starting point and incorporates the effects of refurbishment work planned through 2032. Accordingly, it does not reflect any additional building deterioration that would occur throughout 2031 and 2032.
[9] *Ibid.*

capabilities, and investments in data, analytics, and AI. Together, these investments strengthen grid reliability and resilience, improve customer outcomes, enhance cybersecurity, and support efficient and effective utility operations.

System Operations investments total $55.1M, or 1.7% of the General Plant capital expenditures, and focus on the Integrated System Operations Centre (ISOC) and Backup Ontario Grid Control Centre (BU-OGCC). The approximately 120,000-square-foot ISOC, opened in 2021, is Hydro One's primary 24/7 control centre; the BU-OGCC has operated since 2003 and provides continuity if the ISOC or its systems are unavailable. Planned work addresses end of life or poor condition generators, breakers, roofs, elevators, HVAC systems and uninterruptible power-supply batteries, while adding control-room desks and data-hall cooling capacity to support growing operational needs.

Together, these Transmission and Distribution General Plant plans deliver the investments needed to manage lifecycle and operational risks, maintain regulatory compliance, and deliver reliable service and customer value over 2028–2032.

For more information on Hydro One's General Plant System Plan, see GSP Section 4.1.

5.0 OM&A PLANS

Hydro One's proposed OM&A expenditures establish the baseline required to safely and reliably operate and maintain the Transmission and Distribution systems, serve customers, respond to emergencies, comply with regulatory requirements, and enable the delivery of larger capital programs. The proposed 2028 levels represent a step change from the current period, driven by Hydro One's return to a sustainable operating model following the temporary reprioritization and deferral measures adopted during 2023-2027. The proposal responds to higher input costs, increasing system complexity, growing vegetation management needs, evolving cyber and physical security risks, and increasing operational and investment demands across the business.

5.1 TRANSMISSION OM&A EXPENDITURES

Hydro One Transmission is proposing $634.5M of OM&A expenditures for the 2028 Test Year, representing an increase of $200.8M over the 2023 OEB-approved amount of $433.7M. Of the increase, $82.0M is attributable to inflation based on applicable I-X factors.[10] The remaining $118.8M, which is 23.0% above the inflation-adjusted benchmark, reflects the funding required to restore sustainable maintenance levels and respond to increasing system needs. Table 10 sets out Hydro One Transmission's OM&A for the Historical, Bridge, and Test Years. Further details are provided in Exhibit E-02-01.

Table 10 - Transmission OM&A Summary ($M)

Transmission		Historical				Bridge Year	Test Year
	2023	2023	2024	2025	2026	2027	2028
	OEB Approved	Actual	Actual	Actual	Forecast	Forecast	Forecast
Sustainment	N/A	241.1	237.1	224.5	231.4	229.7	305.9
Development		12.7	12.0	8.2	11.7	11.3	13.0
Customer Care		6.3	6.6	6.8	5.0	4.9	6.8
Common and Other OM&A[1]		175.1	162.4	148.7	178.7	187.3	219.1
Property Taxes and Rights Payments		72.4	68.8	73.5	77.8	79.2	89.7
Total	**433.7**	**507.7**	**487.0**	**461.7**	**504.6**	**512.5**	**634.5**

**Exhibit Reference: E-02-01, Table 1*

[1] This includes Common Corporate Functions & Services (CCF&S), Asset Management (Planning) costs, Digital & Technology Solutions (DTS), Operations, and Cost of Sales for external work and Other OM&A.

During the 2023-2027 period, Hydro One Transmission faced increased funding requirements driven by demand-driven work and mandatory compliance, security, and telecommunications requirements. Where critical work could not prudently be deferred or

[10] Inflationary impacts were calculated by applying the applicable OEB I-X factors to the 2023 OEB-approved OM&A amount to derive an inflation-adjusted benchmark for comparison to the 2028 Test Year OM&A requirement. Where 'I' is the applicable annual OEB Inflation Factor, and 'X' is the 0.15% productivity factor approved in EB-2021-0110.

reprioritized, Hydro One proceeded with the work, resulting in approximately $119.9M of expenditures above amounts funded in rates over the 2023-2027 period.[11]

Hydro One took active steps to moderate these pressures through productivity and cost-control initiatives, while reducing, deferring, or re-pacing selected work where doing so would not create unacceptable near-term safety, reliability, compliance or operational risk. These measures helped manage cumulative spending, but required temporary reductions in preventive maintenance, condition assessments, patrols, vegetation work and transformer refurbishments. These activities must now be restored because they provide critical asset condition information used to identify deficiencies, prioritize corrective work, and inform replacement decisions.

Deferrals can no longer continue without increasing longer-term risk and cost. Hydro One must transition from short-term reprioritization to sustainable maintenance levels that restore maintenance cycles and address accumulated deferred work. The principal increase is in Sustainment OM&A, which rises from $229.7M in 2027 to $305.9M in 2028. The largest drivers of the 2028 Sustainment OM&A forecast are Vegetation Management, Power Equipment Maintenance, and Protection, Automation and Telecom Maintenance.

The 2028 Vegetation Management forecast is $68.4M, which is $30.0M above the 2023-2027 annual average.[12] During the current period, Hydro One prioritized brush control activities on NERC-applicable transmission circuits while deferring work on portions of the 115 kV network. Recent vegetation patrols and LiDAR assessments have increased visibility into vegetation risk and confirmed the consequences of deferred maintenance. The deferred work consistently ranked among the rights-of-way with the highest concentrations of urgent vegetation defects. Approximately 28% of urgent vegetation defects are associated with rights-of-way already one year beyond their target

[11] Calculated as cumulative 2023–2027 actual and forecast expenditures of $2,473.4M less cumulative funding available in rates of $2,353.5M, including applicable annual I-X adjustments, resulting in a variance of $119.9M, rounded to $120M.
[12] Refer to Exhibit E-02-01, Section 3.3.

maintenance cycle, and a further 26% are associated with rights-of-way where maintenance is currently due.

The 2028 Power Equipment Maintenance forecast is $66.1M, which is $16.7M above the 2023-2027 annual average.[13] It addresses maintenance activities deferred during the 2023-2027 period, including preventive maintenance on transformers, circuit breakers, and switches. This work is required to restore planned maintenance cycles and generate the condition information needed to identify deficiencies, prioritize corrective work, and inform capital replacement decisions. Hydro One's transmission system includes 722 transformers and 4,691 circuit breakers across 297 transmission stations.

The 2028 Protection, Automation and Telecom Maintenance forecast is $63.6M, which is $12.7M above the 2023-2027 annual average.[14] It reflects higher Protection and Automation expenditures required to complete the final 2028 implementation milestone under NERC PRC-005-6 and clear deferred non-Bulk Electric System preventive maintenance activities. It also reflects higher Power System Telecom expenditures associated with increased preventive and corrective maintenance expenditures.

Beyond Sustainment OM&A, the other material contributor to the increase in Transmission OM&A is Common and Other OM&A, with $219.1M allocated to Transmission. The increase over recent spending primarily reflects higher Digital & Technology Solutions costs to sustain vendor-supported systems, cloud services and cybersecurity capabilities; additional corporate services, planning and system-operations resources required to support a substantially larger and more complex transmission work program; and evolving regulatory, reliability and security obligations. These increases are partly offset by higher overhead capitalization associated with the expanded capital program. Further details are provided in Exhibit E-04-01.

[13] *Ibid.*
[14] *Ibid.*

Hydro One's proposed Transmission OM&A expenditures are reasonable and reflect the funding required to establish a sustainable operating baseline for 2028. They are the product of an integrated planning process informed by customer and system needs and are paced to balance operational requirements against customer rate impacts. Having managed expenditures during the 2023-2027 period as closely as possible to the rate-period envelope, Hydro One now requires funding to restore deferred work where needed, support a substantially larger capital program, maintain reliable and resilient service, and build the capabilities required for Ontario's electricity transition.

5.2 HOSSM OM&A EXPENDITURES

HOSSM is proposing OM&A expenditures of $10.6M and $10.9M for the 2027 and 2028 Test Years, respectively. Both amounts are lower than HOSSM's last OEB-approved OM&A amount for 2016, reflecting efficiencies and synergies achieved, notwithstanding accumulated inflation over the 10-year deferred rebasing period.

Since October 1, 2018, HOSSM's operational integration with Hydro One has provided access to specialized resources and expertise, and has standardized business processes. These efficiencies reduce duplication and enable HOSSM to address asset and system needs cost-effectively.

HOSSM's proposed 2027 and 2028 Test Year OM&A expenditures are required mainly to: (i) perform preventive and corrective maintenance on station equipment, assess asset condition, and maintain safety and reliability; (ii) maintain protection, automation, and telecom systems required to protect, monitor, control, and operate the transmission system; (iii) maintain aging facilities and site infrastructure in a safe and functional condition; (iv) undertake vegetation management to maintain required clearances, support reliability, and comply with NERC requirements; (v) inspect and maintain overhead lines and address defects; and (vi) fund HOSSM's share of Common Corporate Functions & Services.

Table 11 sets out HOSSM's OM&A for the Historical, Bridge, and Test Years. Further details are included in Exhibit E-02-06.

Table 11 - HOSSM Summary of OM&A ($M)

Description	Historical											Bridge	Test Years	
	2016	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
	OEB Approved	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Forecast	Forecast	Forecast
Sustainment					7.2	7.9	8.0	8.0	7.1	7.2	7.0	8.4	8.5	9.1
Common and Other*					3.7	2.1	1.7	1.3	1.9	2.2	2.2	2.4	2.1	1.8
Total	**11.4[1]**	**11.1**	**9.4**	**9.1**	**10.9**	**10.1**	**9.7**	**9.3**	**9.1**	**9.4**	**9.2**	**10.8**	**10.6**	**10.9**

**Exhibit Reference: E-02-06, Table 1*

**This includes Common Corporate Functions & Services (CCF&S), Asset Management (Planning), Digital & Technology Solutions (DTS), Operations, and Other OM&A*

[1] EB-2014-0238, Decision, December 18, 2014, Great Lakes Power Transmission Rate Application for 2015 and 2016 rates, Appendix A-1, p.19. The approved amount comprises $11.1M, and $0.2M for Property Taxes, with rounding equals $11.4M.

5.3 DISTRIBUTION OM&A EXPENDITURES

Hydro One Distribution is proposing $958.7M of OM&A expenditures for the 2028 Test Year, representing an increase of $342.4M over the 2023 OEB-approved amount of $616.3M. Of the increase, $104.0M is attributable to inflation based on the applicable I-X factors.[15] The remaining $238.4M, which is 33.1% above the inflation-adjusted benchmark, reflects the funding required to restore sustainable maintenance levels, address accumulated work requirements, support a materially larger capital program and respond to a more complex operating environment. Table 12 sets out Hydro One Distribution's OM&A for the Historical, Bridge, and Test Years. Further details are provided in Exhibit E-03-01.

Table 12 - Distribution OM&A Summary ($M)

Distribution	Historical					Bridge	Test
	2023	2023	2024	2025	2026	2027	2028
	OEB-Approved	Actual	Actual	Actual	Forecast	Forecast	Forecast
Sustainment	N/A	366.2	365.9	319.3	359.4	358.2	523.0
Development		9.5	10.0	10.6	12.4	12.4	17.6
Customer Care		94.8	106.7	102.1	115.9	120.0	139.6
Common and Other OM&A[1]		200.1	220.7	193.9	181.4	186.3	271.1
Property Taxes		6.2	5.8	6.4	6.7	7.0	7.5
Cost Containment Efforts					-17.0	-37.0	
Total	**616.3**	**676.8**	**709.1**	**632.4**	**658.9**	**646.9**	**958.7**

**Exhibit Reference E-03-01, Table 1*
[1] This includes Common Corporate Functions & Services (CCF&S), Asset Management (Planning) costs, Digital & Technology Solutions (DTS), Operations, and Cost of Sales for external work and Other OM&A

During the 2023-2027 period, Hydro One experienced higher volumes of demand-driven work and market cost pressures. In 2023, actual Distribution OM&A expenditures were $676.8M, $60.5M above the OEB-approved envelope, primarily due to incremental demand-driven Sustainment work and sector-wide market-based cost pressures following

[15] Inflationary impacts were calculated by applying the applicable OEB I-X factors to the 2023 OEB-approved OM&A amount to derive an inflation-adjusted benchmark for comparison to the 2028 Test Year OM&A requirement. Where 'I' is the applicable annual OEB Inflation Factor, and 'X' is the 0.45% productivity factor approved in EB-2021-0110.

the COVID-19 pandemic. These pressures continued throughout the current rate period: annual average expenditures during 2023-2027 for Trouble Calls, Cable Locates and Disconnects/Reconnects were 41%, 115% and 105%, respectively, above planned levels.

Hydro One responded by prioritizing mandatory, safety-critical, customer service and compliance activities while reducing, deferring or re-pacing work where near-term risks could be managed. Hydro One also implemented substantial productivity and cost-control measures. Distribution OM&A programs achieved $125.2M in productivity savings from 2023 to 2025, while the Enterprise Cost Optimization Program contributed a further $17.0M in 2025. Additional cost containment targets of $17.0M and $37.0M are reflected in the 2026 and 2027 forecasts. As a result of these efforts, Hydro One expects cumulative expenditures from 2023 to 2027 to exceed total available funding by only $13.9M.

These measures are not sustainable over the longer term. Vegetation continues to grow, asset defects and maintenance backlogs accumulate, demand-driven work remains elevated, and Hydro One's OM&A programs must scale to support growing work volumes, electrification, DER adoption and increasing exposure to severe weather.

The 2028 plan marks the transition from short-term reprioritization to a sustainable operating model, requiring a $293.9M increase in Distribution OM&A expenditures from the 2023-2027 annual average to the 2028 Test Year. The increase is driven primarily by Sustainment OM&A and Common and Other OM&A, with Customer Care OM&A and Development OM&A also contributing.

Sustainment OM&A is forecast at $523.0M in 2028, which is $169.1M, or 47%, above the 2023-2027 annual average. Vegetation Management is the largest driver of this increase. Hydro One's 104,000 km overhead network traverses heavily forested terrain, and vegetation remains a leading cause of outages. Reduced work volumes during the current rate period extended the average vegetation-management cycle to approximately 8.3 years, compared with the five-year cycle targeted through Hydro One's Optimal Cycle Protocol. Key indicators of system risk and program performance also deteriorated:

density defects increased from 26 defects per km in 2022 to 60 defects per km by year-end 2025, driving higher unit costs. Hydro One is proposing $230.9M for Vegetation Management in 2028, $123.7M above the 2023-2027 annual average, to reduce the cycle to 6.6 years, eliminate the accumulated brush backlog across the province, and move the program toward a sustainable and cost-efficient trajectory.

Within Sustainment OM&A, Hydro One is also proposing $218.8M for Lines and Other Maintenance, $22.9M above the 2023-2027 annual average. These expenditures will address additional defect corrections to mitigate a growing backlog of more than 400,000 system deficiencies, reintroduce insulator washing, patrol overhead lines to maintain compliance with the Distribution System Code, and establish a new underground cable diagnostics program to support the capital program and mitigate growing reliability risks in targeted parts of Hydro One's aging underground system.

Meters, Telecom and Smart Grid is forecast at $46.4M in 2028, $19.1M above the 2023-2027 annual average. These expenditures will sustain the digital and communications platforms required for Distribution Intelligence and Automation, AMI 2.0, ADMS, DERMS, non-wires solutions and battery energy storage systems.

Beyond Sustainment OM&A, the other material contributor to the increase in Distribution OM&A is Common and Other OM&A, with $271.1M allocated to Distribution, representing a $74.6M increase relative to the 2023-2027 annual average. The increase is primarily driven by Digital & Technology Solutions costs associated with cloud subscriptions, licensing, application sustainment and cybersecurity, together with additional system-operations and planning capabilities needed to support grid modernization, DER integration, growing work volumes and increasingly complex outage and system-management requirements. These increases are partly offset by higher overhead capitalization and lower external-work costs. Further details are provided in Exhibit E-04-01.

Customer Care OM&A is forecast at $139.6M in 2028, which is $31.6M above the 2023-2027 annual average. The increase supports Hydro One's 1.5 million customers as interaction volumes and complexity increase, while maintaining billing, collections, meter-to-cash operations, affordability programs and customer participation in emerging energy initiatives.

Development OM&A is forecast at $17.6M in 2028, which is $6.6M above the 2023-2027 annual average. The increase supports higher DER connection volumes, hosting-capacity requirements, engineering studies, technical standards and power-quality monitoring.

The proposed 2028 Distribution OM&A expenditures were developed through a bottom-up planning process grounded in asset condition, customer needs, operational requirements and coordination with the DSP. They establish the sustainable operating baseline required to preserve asset health, support capital delivery and continue providing safe, reliable, resilient, secure, and customer-focused distribution services.

5.4 COMPENSATION AND WORKFORCE PLANNING

Hydro One has taken steps to manage compensation costs and limit workforce growth relative to its growing capital and operational work programs for both Transmission and Distribution. Hydro One has reduced compensation program costs through amendments to pension rules and mutually beneficial collective bargaining outcomes related to wage increases, pension contribution rates, lump-sum payments, and equity grants. Hydro One's workforce planning also reflects disciplined FTE[16] growth relative to the growth in its investment plan. Over the 2028-2032 period, FTEs are forecast to increase by approximately 15%, compared with approximately 60% growth in the investment plan. Most of the workforce growth is expected to come from casual employees, who have lower compensation costs than regular employees.

[16] A Full-time Equivalent or 'FTE' represents the average monthly headcount over a 12-month period. A regular status employee who is budgeted for one year of work, represents one FTE. For casual employees, one FTE equates to 12 person months of work. For example, if one casual employee worked for six months they would account for 0.5 FTEs.

Hydro One engaged Mercer to conduct an updated compensation benchmarking study. The study shows that Hydro One's overall compensation position improved from 9% above the P50 market median and 4% above the market competitive range in 2020 to 6% above the P50 market median and 1% above the market competitive range in 2026. A position within ±5% of the P50 market median is considered "at market". Further details regarding the steps taken by Hydro One to manage its overall compensation costs and the updated Mercer benchmarking study are provided in Exhibit E-06-01. Hydro One's approach to workforce planning and forecast FTE levels for the 2028-2032 period are discussed in Exhibit E-06-02.

Hydro One's Transmission and Distribution allocated compensation costs for 2027 and 2028 are summarized in the tables below.[17]

Table 13 - Summary of Total Transmission-Allocated Compensation Costs

($M)	2027 Bridge	2028 Test	Change
Capital – Transmission Compensation	729.9	861.8	131.9
OM&A – Transmission Compensation	155.0	183.0	28.0
Total Transmission Compensation	**885.0**	**1,044.9**	**159.9**

**Exhibit reference: E-06-01-01A*

Table 14 - Summary of Total Distribution-Allocated Compensation Costs

($M)	2027 Bridge	2028 Test	Change
Capital – Distribution Compensation	754.4	831.3	76.9
OM&A – Distribution Compensation	304.6	335.6	31.2
Total Distribution Compensation	**1,059.0**	**1,166.9**	**107.9**

**Exhibit reference: E-06-01-01A*

[17] In EB-2021-0110, the OEB approved a settlement proposal filed by the parties on October 24, 2022, as updated November 16, 2022. The settlement included approved OM&A envelopes for Distribution and Transmission. The OEB did not approve specific Distribution nor Transmission compensation amounts.

5.5 SERVICE LEVEL AGREEMENT (SLA) FEE ALLOCATION STRUCTURE AND SUMMARY

All Affiliate Services are provided or received by Hydro One Networks pursuant to affiliate service level agreements (Affiliate SLAs). The Affiliate Services are directly charged by the applicable service provider to the applicable service recipient. A portion of the revenues received by Hydro One Networks from providing Affiliate Services are accounted for as Other External Revenues. Exhibit D-02-03 provides a summary of the shared and directly charged Affiliate Services that Hydro One Networks provides to, and receives from, its affiliates under Affiliate SLAs. Details on the SLA Fee Allocation Structure are included in Exhibit E-04-01, Attachment 1.

6.0 PERFORMANCE MEASUREMENT

Hydro One maintains four regulatory scorecards to assess performance relative to the OEB's RRF outcomes: the Transmission Scorecard, the HOSSM Scorecard, the Hydro One Distribution OEB Scorecard, and the OEB Electricity Distributor Scorecard. Collectively, these scorecards comprise more than 60 measures that align with the RRF outcomes of Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance. Together, the scorecards provide a comprehensive framework for monitoring operational performance, service quality, regulatory outcomes, and the delivery of Hydro One's capital and OM&A investment plans, with performance targets established based on the proposed investments for the 2028-2032 period.

Hydro One's proposed scorecards build on the scorecards approved in prior rate applications. In addition to the previously approved metrics, Hydro One is introducing or expanding four measures for the Transmission Scorecard and introducing five new measures for the Hydro One Distribution OEB scorecard. These new and expanded measures increase transparency regarding the delivery of the proposed capital plan and provide greater visibility into areas of growing importance, including reliability, system capacity, customer participation, and regional planning.

For Transmission, Hydro One is proposing three new measures to strengthen tracking of resource enablement, stakeholder engagement, and responsiveness within the regional planning process. Hydro One is also proposing to expand its Transmission Capital Accomplishment Index measure to provide greater coverage of the capital plan and strengthen transparency regarding the delivery of planned investments.

HOSSM's scorecard remains consistent with its existing measures and planned investments. Since the integration of HOSSM, several scorecard measures are consolidated into Hydro One's Transmission Scorecard and are now reported on a combined basis, including the three new measures introduced in this Application.

Table 15 - Additional Transmission Scorecard Measures Proposed for 2028-2032

Measure	Alignment with Capital Plan
Transmission Capital Accomplishment Index (TCAI)	Expands the TCAI measure to include all planned major unit accomplishments, providing broader coverage of the transmission capital portfolio. The revised metric places greater emphasis on larger, higher-value investments, strengthening transparency and accountability for delivery of the proposed transmission capital plan.
Resource Enablement (Connections & MW Enabled)	Aligns with planned investments to connect new generation resources and support Ontario's evolving electricity needs. The metric provides visibility into Hydro One's delivery of generation connection projects and its ability to enable the capacity additions contemplated in the capital plan.
Email communication sent to municipalities with a request for electricity planning input prior to the start of Regional Planning	Supports effective identification and prioritization of future transmission investments by ensuring municipal growth plans and local electricity needs are incorporated into regional planning. This strengthens alignment between capital investment decisions and anticipated customer, community, and system requirements.
Regional Planning Responsiveness	Supports proactive identification and prioritization of future transmission investments by accelerating regional planning in response to unforeseen growth, LDC requests, and government directives. This strengthens alignment between capital investment decisions and emerging customer, community, and system needs while enabling timely planning to support future electricity demand.

For Distribution, Hydro One is proposing five new measures that complement the existing scorecard by providing a more comprehensive view of capital plan execution, asset risk mitigation, grid modernization, capacity planning, and customer-focused energy initiatives. Collectively, these measures strengthen the linkage between planned investments and expected customer, reliability, and system-capacity outcomes, while enhancing transparency regarding Hydro One's progress in delivering the proposed distribution capital program and supporting Ontario's evolving electricity needs.

Table 16 - Additional Distribution Scorecard Measures Proposed for 2028-2032

Measure	Alignment with Capital Plan
Kilometres of Forestry Managed	Supports delivery of Hydro One's vegetation management investments by providing visibility into the assessment and mitigation of vegetation-related reliability risks. The measure helps ensure forestry resources are prioritized to the highest-risk areas, maximizing the reliability benefits of planned forestry investments.
Distribution Capital Program Work Composite Index (DCAI)	Provides a portfolio-level measure of Hydro One's delivery of planned distribution capital investments by comparing actual accomplishments against the approved capital plan. The metric enhances transparency and accountability for the execution of System Access and System Renewal investments across the distribution network.
Flexibility & Local Energy Efficiency Programs	Supports Hydro One's investment strategy by tracking participation in programs that help manage demand growth, improve system utilization, and enable non-wires alternatives. The measure provides visibility into initiatives that can complement traditional infrastructure investments while supporting the energy transition.
Enabling Remote Operable Capabilities	Aligns with grid modernization investments by tracking progress in expanding remote operational capabilities across the distribution network. The measure provides visibility into investments that improve system resiliency, operational flexibility, outage response, and overall reliability.
Load Capacity Constrained Distribution Stations	Supports Hydro One's capacity expansion investments by measuring progress in addressing distribution station constraints. The metric provides visibility into the effectiveness of capital investments intended to meet growing electricity demand and maintain reliable service for customers.

For more information on Hydro One's Performance Reporting Governance Framework, see SPF Section 1.5. Hydro One's Transmission Scorecard is found at TSP Section 2.5; the Hydro One Distribution OEB Scorecard and OEB Electricity Distributor Scorecard are addressed in DSP Section 3.5; and HOSSM's Transmission Scorecard is found at TSP Section 2.10, Attachment 3.

7.0 KEY FINANCIAL COMPONENTS

Hydro One's proposed revenue requirements, rate bases, and cost of capital will provide the funding required to operate the Transmission and Distribution systems and deliver the proposed capital plans. The financial components of the Application reflect the increase in investment needs during the 2028–2032 period to renew deteriorating assets and meet growing customer demand, higher costs for materials and equipment, the timing of assets going into service, and the continuing need to maintain Hydro One's financial integrity and access to capital at a reasonable cost.

7.1 REVENUE REQUIREMENT

Hydro One calculated the Transmission and Distribution revenue requirements, as well as the HOSSM revenue requirements, using established cost-of-service methodologies for the 2028 Test Year (and the 2027 Test Year in respect of HOSSM). The revenue requirements include OM&A, depreciation and amortization, income taxes, return on capital, and the amortization associated with prepaid cloud-computing arrangements. For Hydro One Transmission and Distribution, the amortization of prepaid cloud costs for the 2028-2032 term is proposed to be included in the revenue requirement calculation and aligns with the period over which customers receive the associated services. See Exhibits D-01-01 and D-01-01A for details on the revenue requirement and Exhibit E-08-01 for treatment of prepaid cloud costs in the revenue requirement.

7.1.1 TRANSMISSION REVENUE REQUIREMENT

Hydro One's proposed 2028 Transmission revenue requirement is $2,726.6M, an increase of $774.1M, or 39.6%, relative to the 2023 OEB-approved rebasing year. In comparison

to the latest approved revenue requirement in 2026, the 2028 revenue requirement is $444.1M, or 19.5% higher.

Table 17 - Transmission Revenue Requirement ($M) [18]

Components	2023 OEB-Approved[1]	2024[2]	2025[3]	2026[4]	2027[5]	2028 Test Year	Reference
OM&A	433.7	-	-	-	-	634.5	Exhibit E-02-01
Depreciation and Amortization	531.3	-	-	-	-	738.4	Exhibit E-08-01
Income Taxes	65.2	-	-	-	-	103.7	Exhibit E-09-02 Attachment 1
Return on Capital	922.2	-	-	-	-	1,250.1	Exhibit F-01-03
Total Revenue Requirement	**1,952.5**	**2,079.8**	**2,174.5**	**2,282.5**	**2,363.3**	**2,726.6**	

**Exhibit Reference: D-01-01, Table 1*
[1] Represents OEB-approved 2023 revenue requirement in EB-2021-0110
[2] Represents OEB-approved 2024 revenue requirement in 2024 Annual Update in EB-2023-0127
[3] Represents OEB-approved 2025 revenue requirement in 2025 Annual Update in EB-2024-0217
[4] Represents OEB-approved 2026 revenue requirement in 2026 Annual Update in EB-2025-0159
*[5] 2027 revenue requirement = $2,282.5M (2026 Revenue Requirement) * (1 + (2.90% inflation factor – 0.15% stretch factor + 0.79% capital factor)) = $2,363.3M. 2027 OEB approved revenue requirement to be established as part of the 2027 Annual Update in EB-2026-0169.*

Compared with the 2023 rebasing year, the principal drivers of the increase are approximately $475.4M from rate-base growth, $200.7M from higher OM&A, $44.1M from the proposed capital-structure change, $24.1M from cloud-computing amortization and return, and $29.8M from increased taxes and other changes. These increases reflect the cost of operating a larger and more complex system and placing into service the assets required to connect customers, support growing demand across Ontario, reinforce the grid, and renew aging infrastructure.

[18] Figures presented in the tables may not sum to the totals shown due to rounding

7.1.2 HOSSM REVENUE REQUIREMENT

HOSSM's proposed revenue requirements for 2027 ($46.1M) and 2028 ($50.0M) represent increases of 16% and 25%, respectively, compared to the OEB-approved 2016 amounts of $39.9M. These increases are predominantly driven by rate base growth. In comparison to the 2027 interim approved revenue requirement of $49.2M, the proposed 2027 and 2028 revenue requirements are $3.1M, or 6% lower and $0.8M or 2% higher, respectively.

Table 18 - HOSSM Revenue Requirement ($M)[19]

Components	2016 OEB Approved[1]	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027 Test Year	2028 Test Year	Reference
OM&A	11.4	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	10.6	10.9	E-02-06
Depreciation and Amortization	9.8	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	13.0	14.3	E-08-02
Income Taxes	2.1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.1	0.4	E-09-04
Return on Capital	16.6	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	22.4	24.3	F-02-03
Total Revenue Requirement	**39.9**	**39.9**	**39.9**	**40.3**	**40.9**	**41.6**	**42.5**	**44.0**	**46.2**	**47.8**	**49.4**	**46.1**	**50.0**	

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

[1] Excludes "Other Revenue" that is not part of the Service Revenue Requirement in 2016 GLPT application, escalated every year for Revenue Cap Index (RCI) based on OEB-approved inflation factor.

7.1.3 DISTRIBUTION REVENUE REQUIREMENT

Hydro One's proposed 2028 Distribution revenue requirement is $2,694.8M, an increase of $967.6M, or approximately 56.0%, relative to the 2023 OEB-approved rebasing year. In comparison to the latest approved revenue requirement in 2026, the 2028 revenue requirement is $703.6M, or 35.3% higher.

[19] Figures presented in the tables may not sum to the totals shown due to rounding

Table 19 - Distribution Revenue Requirement ($M)[20]

Components	2023 OEB Approved[1]	2024[2]	2025[3]	2026[4]	2027[5]	2028 Test Year	Reference
OM&A	616.3	-	-	-	-	958.7	Exhibit E-03-01
Depreciation and Amortization	461.4	-	-	-	-	753.7	Exhibit E-08-01
Income Taxes	53.7	-	-	-	-	42.7	Exhibit E-09-02 Attachment 1
Return on Capital	595.8	-	-	-	-	939.8	Exhibit F-01-03
Total Revenue Requirement	**1,727.2**	**1,819.8**	**1,892.6**	**1,991.2**	**2,073.4**	**2,694.8**	

**Exhibit Reference: D-01-01, Table 7*
[1] Represents OEB-approved 2023 revenue requirement in EB-2021-0110
[2] Represents OEB-approved 2024 revenue requirement in 2024 Annual Update in EB-2023-0030
[3] Represents OEB-approved 2025 revenue requirement in 2025 Annual Update in EB-2024-0032
[4] Represents OEB-approved 2026 revenue requirement in 2026 Annual Update in EB-2025-0030
*[5] 2027 revenue requirement = $1,991.2M (2026 Revenue Requirement) * (1 + (3.00% inflation factor – 0.45% stretch factor + 1.58% capital factor)) = $2,073.4M. 2027 OEB-approved revenue requirement to be established as part of the 2027 Annual Update in EB-2026-0049.*

Compared with the 2023 rebasing year, the principal drivers are approximately $558.7M from rate-base growth, $342.4M from higher OM&A, $46.0M from cloud-computing amortization, and $33.2M from the proposed capital-structure change, partially offset by approximately $12.6M from decreased taxes and other changes.

The proposed increase supports the work required to sustain the grid, connect customers, accommodate growth, improve reliability and resilience, and operate a system with increasing technology and cybersecurity requirements. Hydro One has moderated the proposed increase through Enterprise Cost Optimization and productivity (see Exhibit SPF Section 1.4), investment re-pacing (see DSP Section 3.7, GSP Section 4.7), and use of non-wires alternatives (see DSP Section 3.11, D-SS-01).

7.2 RATE BASE

Rate base represents the net investment in utility assets used to provide service to customers, together with the applicable working-capital allowance. Hydro One's Transmission and Distribution rate bases, as well as HOSSM's rate base, increase during

[20] Figures presented in the tables may not sum to the totals shown due to rounding.

the 2028–2032 period as capital investments are completed and placed in service. The higher 2028 rate base, relative to the current rate period, is attributable to the significant increase in planned capital investments. The timing of rate-base growth reflects the construction and in-service profiles of the Transmission, Distribution, and General Plant portfolios.

- Hydro One's proposed 2028 Transmission rate base is $19,199.2M, an increase of $895.6M or 4.9% relative to the 2027 OEB-approved rate base.
- Hydro One's proposed 2028 Distribution rate base is $14,434.6M, an increase of $1,389.1M or 10.6% relative to the 2027 OEB-approved rate base.
- HOSSM's proposed 2027 and 2028 rate bases are $345.6M and $376.1M, an increase of $127.0M or 58% and an increase of $157.4M or 72.0%, relative to the 2016 OEB-approved rate base.

Table 20 - Transmission, HOSSM and Distribution Rate Base ($M)

Description	2027	2028	2029	2030	2031	2032
Transmission Rate Base	18,303.6	19,199.2	20,660.8	22,267.9	24,204.8	28,469.6
Distribution Rate Base	13,045.5	14,434.6	15,795.3	17,135.8	18,957.7	20,712.4
HOSSM Rate Base	345.6	376.1	425.3	456.4	463.0	474.7

**Exhibit reference: C-01-01, Table 4B (Transmission), Table 10B (Distribution) and C-1-2, Table 4B*

Rate base growth reflects capital assets placed in service, rather than capital expenditures alone. The increase supports customer and generation connections, regional and bulk-system reinforcements, additional distribution capacity, renewal of deteriorating assets, grid modernization, and improved reliability and resilience. It also reflects the General Plant assets required to deliver and operate these expanded work programs.

Further information may be found at Exhibits C-01-01 and C-02-01.

7.3 COST OF CAPITAL

This section provides an overview of Hydro One's proposed cost of capital (CoC) including capital structure, cost of debt and return on equity. Together, these make up the return on capital in the Transmission and Distribution revenue requirements, as well as the HOSSM revenue requirement, for each year of this Application. Hydro One proposes the same approach for Transmission and Distribution, which is a change from EB-2021-0110. Hydro One proposes, for both Transmission and Distribution, a deemed capital structure of 45% common equity and 55% debt, with the debt portion being 51% long-term debt and 4% short-term debt. In addition, Hydro One proposes that the long-term debt rate calculated for each year of this Application, as summarized in Exhibit F-01-03 and calculated in F-01-04, be applied to the return on debt for each specific year. This differs from EB-2021-0110, where the long-term debt rate established for the first test year was applied consistently across the remaining test years. No change to the cost of capital parameters is requested for HOSSM.

Hydro One applies the OEB's established methodology to the remaining components of the cost of capital. As a placeholder, Hydro One has used the OEB's 2026 ROE and the deemed short-term debt rate. It will update its ROE, short-term debt cost and long-term debt cost when the OEB releases its 2028 cost of capital parameters. Hydro One's proposal maintains all elements of the OEB's established framework except for capital structure. The proposed change responds to the increasing business and financial risks facing the Company during the next rate period, including elevated competition for investment capital in North American and international markets.

Capital Structure

Hydro One proposes an increase in its deemed equity ratio from the OEB's default 40% to 45% starting in 2028, for both Transmission and Distribution. The current 60% debt and 40% equity capital structure was approved for Hydro One in EB-2021-0110 and reaffirmed as the default structure in EB-2024-0063[21] (the "OEB Generic CoC Decision"). In that proceeding, the OEB noted that departures from its deemed capital structure may be

[21] Decision and Order, March 27, 2025

appropriate where a utility demonstrates an increase in business or financial risk. The evidence in this Application demonstrates such an increase and supports the proposed capital structure as the appropriate mechanism for reflecting those risks.

In its Cost of Capital Report provided in Exhibit F-01-01, Appendix 1 (the "Concentric Report"), Concentric found that a reasonable range for Hydro One's equity ratio is 45% to 50%, and within this range recommended 47.5%. Hydro One has proposed an equity ratio at the lower end of the range supported by the evidence, reflecting an appropriate balance between maintaining credit quality and recognizing affordability considerations. Accordingly, Hydro One is not seeking the full increase in equity thickness that is supported by its expert evidence.

Table 21 - Transmission 2028 Cost of Capital Parameters

Particulars	Amount ($M)	Capital Structure	Cost Rate	Return ($M)
Long-term debt	13,168.4	68.6%	4.52%	594.6
Short-term debt	768.0	4.0%	2.72%	20.9
Deemed long-term debt (Notional)	(3,376.8)	(17.6%)	4.52%	(152.5)
Total debt	10,559.5	55.0%	4.38%	463.0
Common equity	8,639.6	45.0%	9.11%	787.1
Total rate base	19,199.2	100.0%	6.51%	1,250.1

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

Table 22 - Distribution 2028 Cost of Capital Parameters

Particulars	Amount ($M)	Capital Structure	Cost Rate	Return ($M)
Long-term debt	8,419.4	58.3%	4.51%	380.1
Short-term debt	577.4	4.0%	2.72%	15.7
Deemed long-term debt (Notional)	(1,057.73)	(7.3%)	4.51%	(47.7)
Total debt	7,939.0	55.0%	4.38%	348.0
Common equity	6,495.6	45.0%	9.11%	591.7
Total rate base	14,434.6	100.00%	6.51%	939.8

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

Hydro One's Risk Profile Has Changed

The most significant change in Hydro One's risk since EB-2021-0110 is the scale of its capital investments for Transmission and Distribution. Those investments bring related execution, financing and cost-recovery risks. The IESO forecasts that Ontario electricity demand will grow by about 65% between 2026 and 2050. The Province has advanced new priority transmission projects in addition to the transmission lines already scheduled for completion by 2032. As a result, Construction Work in Progress (CWIP) balances that include Affiliate Transmission Partnership (ATP) projects will reach unprecedented levels. Hydro One develops and finances ATP projects on its own balance sheet until the applicable assets are transferred to partnerships with First Nations. In addition, capital work was deferred from the 2023–2027 period because of limits in the approved capital envelope, which adds further pressure going forward.

Concentric's conclusion is based on the combined effect of business and financial risk. In particular, Concentric considers the financial risk associated with supporting a significant capital investment plan under a capital structure that places pressure on the Company's credit quality and credit metrics.

The Importance of Financial Integrity and Credit Quality

Credit quality is a key determinant of the cost of capital borne by customers. The Credit-Focused Capital Markets Analysis Report, provided in Exhibit F-01-01, Appendix 2 (the "Capital Markets Report") explains that credit ratings directly influence debt costs and are an important indicator of risk for investors. Rating agencies see authorized return on equity and capital structure as the two most important parts of the revenue requirement. They view the two together as a signal of the regulator's attitude toward capital providers.

While Hydro One currently maintains strong credit quality, its credit metrics provide limited buffer relative to downgrade thresholds. The Capital Markets Report explains that Hydro One's financial metrics rank near the bottom of S&P's comparable A-rated utilities and its current ratings rely, in part, on rating agency adjustments and assumptions regarding

provincial support. Moody's has also identified Hydro One's relatively low authorized equity ratio as a key factor contributing to its weaker financial metrics.

Ratings are forward-looking. Agencies do not wait for deterioration to occur before downgrading, and ratings are easier to lose than to regain. The Capital Markets Report concludes that adopting the proposed capital structure would help Hydro One and its customers withstand growing risks. It concludes that, without the proposed capital structure, Hydro One would be susceptible to a downgrade.

The Concentric Report confirms that, under the existing 40% equity ratio, key credit metrics remain below rating agency downgrade thresholds throughout the rate period. The proposed 45% equity ratio would meaningfully strengthen these metrics and improve Hydro One's ability to maintain credit quality. While Concentric identifies higher equity ratios as further reducing financial risk, Hydro One has proposed the lower end of the recommended range to balance financial integrity with customer affordability. Accordingly, the proposal represents a measured and necessary step to support Hydro One's financial profile and access to capital.

Comparability With Peer Group

Hydro One's current 40% equity ratio no longer satisfies the Fair Return Standard, particularly the requirement that returns be comparable to those available for investments of similar risk. Concentric's analysis shows that authorized and actual equity ratios among comparable North American utilities are significantly higher than Hydro One's, with median equity ratios generally ranging from approximately 50% to 53%. Concentric found no basis for a material risk discount relative to these peers.

Hydro One competes for capital in an integrated North American market and comparable utility capital structures are an important indicator of investor expectations. While Ontario is recognized by credit ratings agencies as a highly credit-supportive jurisdiction, Concentric concludes that regulatory support alone does not fully offset the increased business and financial risks facing utilities.

Taken together, the evidence from the Concentric Report and the Capital Markets Report demonstrates that Hydro One's current capital structure provides limited support for maintaining strong credit quality and efficient access to capital. The proposed 45% equity ratio represents a measured response that strengthens financial integrity, supports continued access to capital on reasonable terms, and enables Hydro One to finance the significant investments required to support Ontario's electricity infrastructure needs for the benefit of customers and the province.

Long-Term Debt

In line with the proposed capital structure, Hydro One proposes a deemed long-term debt component of 51% of rate base. For each test year, Transmission and Distribution long-term debt rates will be calculated as the weighted average rate on embedded, new and forecast debt. The rates differ between the two businesses because their annual borrowing needs differ. Hydro One will update these rates after the OEB issues its 2028 cost of capital parameters. The update will reflect actual 2026 and 2027 issuances and forecast coupons for 2028 to 2032 based on the Consensus Economics forecast, the same method used in prior applications. However, as mentioned above, Hydro One is seeking approval to update the long-term debt rates for Transmission and Distribution for each of the 2028 to 2032 test years due to the large volume of debt forecast to be issued in the rate application period in support of the significant capital buildout required in the Province over this period.

Consistent with past practice in EB-2021-0110, the weighted average long-term debt rate also applies to any notional debt. Hydro One will continue to access the Canadian bond market and expects to access the US bond market on a consistent basis in the future, given the large scale of debt financing requirements expected during the 2028 to 2032 period.

HOSSM

HOSSM proposes to use the OEB's deemed capital structure of 40% equity and 60% debt, consisting of 4% short-term debt and 56% long-term debt. HOSSM also proposes to use

OEB's 2026 ROE and the OEB's deemed short-term debt rate as a placeholder, both of which will be updated with the 2028 OEB cost of capital parameters.

HOSSM will update the long-term debt rate for each year of this Application based on actual issuances of debt, which are planned in 2027 and are discussed in Exhibit F-02-02 Section 1.0.

Table 23 - HOSSM 2028 Cost of Capital Parameters

Particulars	Amount ($M)	Capital Structure	Cost Rate	Return ($M)
Long-term debt	193.5	51.5%	4.86%	9.4
Short-term debt	15.0	4.0%	2.72%	0.4
Deemed long-term debt (Notional)	17.1	4.5%	4.86%	0.8
Total debt	225.7	60.0%	4.71%	10.6
Common equity	150.4	40.0%	9.11%	13.7
Total Rate Base	376.1	100.00%	6.47%	24.3

**Exhibit reference: F-02-03 (page 2b)*

7.4 DEFERRAL AND VARIANCE ACCOUNTS

Hydro One requests approval to dispose of specified regulatory account balances based on audited balances as at December 31, 2025, adjusted for prior OEB-approved dispositions and forecast carrying charges through December 31, 2027. Hydro One intends to update the balances during the proceeding to reflect 2026 audited actuals. Please see Table 24 below and Exhibit G-01-01 for details.

Table 24 - Summary of Regulatory Account Disposition

	Forecast Balance at December 31, 2027 ($M)	Proposed Disposition Period	Treatment
Hydro One Transmission	295.3	5 years	Credit
HOSSM	4.3	5 years	Credit
Hydro One Distribution – Group 1	209.8	1 year	Credit
Hydro One Distribution – Group 2	14.2	5 years	Credit

7.4.1 REGULATORY ACCOUNTS – TRANSMISSION

Hydro One Transmission requests final disposition to customers of a $295.3M credit balance, comprised of a $274.5M credit principal balance and $20.8M of net credit carrying charges through to December 31, 2027. The credit will be returned to customers over five years, from 2028 to 2032, at approximately $59.1M annually, before interest improvement during the disposition period. The proposed five-year disposition period aligns with the Custom IR term and helps moderate customer rate impacts.

As set out in Exhibit G-01-03, Hydro One Transmission also seeks approval to continue 13 and discontinue five existing accounts, as well as to modify six existing accounts and establish three targeted new accounts for the 2028 to 2032 rate period. The proposed new accounts and the proposed modifications to existing accounts address defined risks that cannot reasonably be forecast or managed through the revenue requirement:

Cyber Security Variance Account (New): To record revenue requirement impacts associated with material incremental capital and prepaid investments required by new or amended cybersecurity compliance obligations that were not known or reasonably foreseeable when the Application was prepared.

Change of Laws Deferral Account (New): To record material cost and revenue impacts resulting from changes in legal or regulatory requirements that are not reflected in the approved revenue requirement and are not captured by another regulatory account.

Digital and Technology Services Operations Variance Account (New): To record the difference between actual third-party technology contract costs and the funding provided through the Custom IR framework. Eligible costs would include software licences, cloud services, telecommunications, cybersecurity tools and other vendor-supported technologies required to sustain digital operations.

Externally Driven Transmission Projects Variance Account (Modified): To clarify the inclusion criteria for qualifying externally driven work and to expand it to include

development work and projects arising from legislation, regulations, codes, licences, government or planning-authority directions, and IESO regional and bulk-system planning.

External Secondary Land Use Revenue Variance Account (Modified): To modify the account to record secondary land-use revenue variances on a net basis by including the incremental cost of sales required to generate and administer the applicable revenues.

Transmission Sale of Properties Deferral Account (Modified): To modify the account to record revenue requirement impacts and after-tax gains or losses related to land and buildings that are sold during the 2028-2032 period, but only where in connection with the purchase of new land and the purchase or construction of new buildings for purposes of consolidating or replacing the land and buildings that are sold.

Long-Term Transmission Studies Deferral Account (Modified): To expand the scope of the account beyond the cost of undertaking transmission planning and studies associated with preliminary consideration of corridor routing for new transmission infrastructure, to also include the costs of undertaking transmission planning and studies related to transmission stations at the request of governmental authorities, to inform studies, reports, plans and other evaluations including but not limited to informing bulk system planning and regional system planning.

Earnings Sharing Mechanism (ESM) Deferral Account (Modified): To modify the account so that amounts for earnings sharing are calculated cumulatively over the five-year Custom IR term using actual rate base, whereby 50% of any cumulative earnings in excess of the approved ROE by more than 100 basis points would be recorded in the account for the benefit of customers.

Depreciation Expense, Asset Removal Costs Variance Account (Modified): To modify the account to operate as a symmetrical cumulative variance account so that both overspending and underspending of actual asset removal costs relative to the approved forecasts are recorded for future disposition.

7.4.2 REGULATORY ACCOUNTS – HOSSM

HOSSM requests final disposition of a $4.3M credit balance, comprised of a $3.9M credit principal balance and $0.4M of credit carrying charges through to December 31, 2027. The balance will be returned to customers over five years, from 2028 to 2032, at $0.86M annually during the disposition period.

As set out in Exhibit G-01-04, HOSSM is also seeking to continue three accounts, discontinue two accounts, and modify and establish the following accounts to be effective in 2027, and to continue in 2028 and for the duration of the Custom IR term. The proposed new account and modification are as follows:

Externally Driven Transmission Projects Variance Account (New): To establish an account similar to Hydro One Transmission's Externally Driven Transmission Projects Variance Account, which will be used to record development work and projects arising from legislation, regulations, codes, licences, government or planning-authority directions, and IESO regional and bulk-system planning. HOSSM has limited ability to absorb these costs through reasonable reprioritization without materially deferring other planned investments.

ESM Deferral Account (Modified): To modify the account to calculate earnings sharing cumulatively over the 2027 to 2032 term using actual rate base, whereby 50% of any cumulative earnings in excess of the approved ROE by more than 100 basis points would be returned to customers.

7.4.3 REGULATORY ACCOUNTS – DISTRIBUTION

Hydro One Distribution requests final disposition to customers of a $224.0M credit balance, comprising a $209.8M credit balance from Group 1 accounts and a $14.2M credit balance from Group 2 accounts, subject to different disposition periods as follows.

As set out in Exhibit G-01-05, Hydro One Distribution's Group 1 balance is comprised of a credit balance of $199.3M in principal and $10.5M in carrying charges, which will be

returned to customers over a one-year period beginning January 1, 2028. The Group 2 balance is comprised of a $1.4M debit principal balance, which is more than offset by a $15.6M credit balance from carrying charges, resulting in a net credit balance of $14.2M. This balance will be returned to customers over a five-year period from 2028 to 2032, at $2.8M annually during the disposition period.

As detailed in Exhibit G-01-01, Hydro One Distribution's Group 2 accounts include the disposition of three legacy Chapleau Group 2 balances and the proposed closure of the remaining legacy Chapleau[22] accounts effective January 1, 2028. Hydro One is not requesting disposition of the Orillia and Peterborough Rate Zones Group 2 balances in this Application. Those balances are expected to be brought forward for disposition in the 2030 IRM application before those rate zones are harmonized with Hydro One Distribution in 2031.

As set out in Exhibit G-01-03, Hydro One Distribution requests approval to continue 22 and discontinue 25 existing accounts, as well as to modify four existing accounts and establish four targeted new accounts for the 2028 to 2032 rate period. Like Hydro One Transmission, Hydro One Distribution is requesting new regulatory accounts to manage and address potential risks arising from incremental costs incurred for Cybersecurity, Change of Laws, and Digital and Technology Services Operations that cannot reasonably be forecast or managed through the revenue requirement. Hydro One Distribution is also seeking to modify the Distribution Sale of Properties and ESM accounts consistent with the modifications proposed by Hydro One Transmission to its equivalent accounts. The other new and modified accounts proposed by Hydro One Distribution are:

Non-Wires Solutions (NWS) Implementation Cost Variance Account (New): To address capital and OM&A variances arising when NWS replace planned wires investments, when a planned NWS must revert to a traditional investment, or when new

[22] The OEB approved the sale of CPUC's distribution system assets to Hydro One in EB-2023-0328 with the transaction closing on August 1, 2024. Chapleau integrated into Hydro One Distribution rates in 2025.

non-wires opportunities emerge. The account would also record incremental OM&A expenditures incurred to implement and operate NWS to offset capital projects, and any Margin on Payments incentives associated with qualifying third-party distributed energy resources.

Externally Driven Distribution Projects Variance Account (Modified): To expand the account scope to include additional externally driven load and DER connections, distribution work required by externally driven Transmission projects, and their associated asset-removal costs. The account would remain symmetrical against the approved capital, in-service addition and asset removal baselines.

Designated Broadband Project Impacts Variance Account (Modified): To convert the existing deferral account to a variance account to record differences between approved forecasts and actual project impacts over the extended provincial broadband implementation period.

8.0 CUSTOM IR PROPOSAL

Hydro One's proposed rates framework is an evolved Custom Incentive Rate-setting (Custom IR) framework for determining annual revenue requirement adjustments after the 2028 rebasing year, together with broader revenue requirement features addressing cost of capital, earnings sharing, uncertainty and the allocation of risk between Hydro One and its customers. The proposed framework is designed to provide the funding required to deliver safe and reliable service and undertake the investments needed to support electrification, customer connections, economic growth, and system reliability and resilience. The framework also incorporates meaningful productivity incentives, affordability considerations, and customer protections. The development of the framework involved balancing various priorities.

There is strong need for a Custom IR framework, including taking into account Hydro One's experience during the rate period and forecast business conditions, and that a

standard I-X revenue cap index approach would significantly underfund Hydro One's Transmission and Distribution businesses in the 2029-2032 period (by billions of dollars).

Under the proposal, revenue requirement for 2028 would be established on a cost-of-service basis, with revenue requirements for 2029 to 2032 determined through a Custom Revenue Cap Index (RCI). The proposed methodology is an evolved and updated framework that contains elements of and builds upon the approved framework in Hydro One's prior rate Application (EB-2021-0110). The Custom RCI is expressed as follows:

$$\mathbf{RCI = I - X + G + IPD_{OM\&A} + C}$$

Where:

- **I** is the Inflation Factor, based on the OEB's two factor input-price index;
- **X** is the Productivity Factor, equal to the sum of Hydro One's base productivity factor informed by Clearspring's Industry Total Factor Productivity study, and Hydro One's Custom Productivity Stretch Factor informed by Clearspring's total cost benchmarking study, but without allowing the X-factor to become negative;
- **G** is the Growth Factor, based on increasing real (non-inflated) costs driven by growth in the measured outputs applicable to each business - transmission line length and transmission peak demand for Transmission, and increasing customer count and increasing system peak demand for Distribution;
- $\mathbf{IPD_{OM\&A}}$ is an Input Price Differential capturing the difference between OEB-established Inflation Factors and inflation factors more specific to Hydro One, scaled to reflect the OM&A portion of revenue requirement; and
- **C** is the Custom Capital Factor, designed to recover incremental revenue each year necessary to support Hydro One's proposed system plans, beyond the amount of revenue recovered through the I – X adjustment, but reduced by a supplemental stretch factor on capital of 0.15%.

The Tables below summarize the Custom RCI by component that Hydro One Transmission, HOSSM and Hydro One Distribution propose to determine the total revenue requirement for rate-making purposes for 2029 to 2032.

Table 25 - Transmission Custom Revenue Cap Index (%)

Component	2029	2030	2031	2032
Inflation Factor	1.84%	1.84%	1.84%	1.84%
Productivity Factor	0.00%	0.00%	0.00%	0.00%
Growth Factor	0.99%	0.99%	0.99%	0.99%
Input Price Differential scaled to OM&A	0.06%	0.06%	0.06%	0.05%
Capital Factor	4.61%	5.78%	2.75%	5.60%
Custom Revenue Cap Index	**7.50%**	**8.67%**	**5.64%**	**8.48%**

**Exhibit Reference: A-04-02, Table 2*

Table 26 - HOSSM Custom Revenue Cap Index (%)

Component	2029	2030	2031	2032
Inflation Factor	1.84%	1.84%	1.84%	1.84%
Productivity Factor	0.00%	0.00%	0.00%	0.00%
Growth Factor	0.89%	0.89%	0.89%	0.89%
Input Price Differential scaled to OM&A	0.05%	0.05%	0.05%	0.05%
Capital Factor	1.88%	9.05%	-1.23%	1.44%
Custom Revenue Cap Index	4.66%	11.83%	1.55%	4.22%

**Exhibit Reference: A-04-02, Table 6*

Table 27 - Distribution Custom Revenue Cap Index (%)

Component	2029	2030	2031	2032
Inflation Factor	1.96%	1.96%	1.96%	1.96%
Productivity Factor	0.29%	0.29%	0.29%	0.29%
Growth Factor	1.17%	1.17%	1.17%	1.17%
Input Price Differential scaled to OM&A	0.09%	0.08%	0.08%	0.07%
Capital Factor	8.33%	5.32%	1.56%	1.18%
Custom Revenue Cap Index	**11.26%**	**8.24%**	**4.48%**	**4.10%**

**Exhibit Reference: A-04-03, Table 2*

The Distribution framework includes a one-time adjustment in 2031 to incorporate the OM&A costs of the former Peterborough and Orillia rate zones when they are integrated for rate-making purposes. Thereafter, the combined amount is escalated through the Custom RCI. Orillia and Peterborough rate zones' capital related revenue requirement will be based on the Distribution rate base which includes the Orillia and Peterborough rate base in 2031 and 2032.

In respect of productivity incentives, the proposed X-factors and supplemental stretch factor on capital for Hydro One and HOSSM, as described in Exhibit A-04-01, provide an incentive to achieve incremental productivity improvements, in addition to sustained and ongoing productivity savings already embedded in the investment plans as described in SPF Section 1.4. Hydro One and HOSSM bear the risk of achieving these productivity requirements.

Hydro One and HOSSM also propose additional revenue requirement features to align its interests with those of customers and to provide additional elements of protection for them. These include: an Earnings Sharing Mechanism under which customers receive 50% of cumulative earnings above the approved return on equity plus 100 basis points, while Hydro One and HOSSM bear all downside earnings risk; an equity thickness proposal for Hydro One that is at the lower end of the range recommended by an independent expert (Concentric); and certain deferral and variance accounts to manage material uncertainty that cannot be reasonably forecast or controlled over a five-year rate period.

The proposed framework evolves the prior approach to reflect the scale, cost, growth, and uncertainty of the 2028 to 2032 period while retaining strong incentives for cost control and continuous improvement.

9.0 LOAD FORECASTS

Hydro One's load and customer forecast methodology uses established industry practices and methods, such as econometric and end-use approaches, Conservation and Demand Management (CDM) inputs from the IESO, and weather normalization based on a 31-year average of relevant weather data. The forecast methodology has been used and approved by the OEB in Hydro One's Transmission and Distribution rate applications since 2006. Together with a refined end-use analysis that has been incorporated to account for current and available information, the methodology remains appropriate.

The load forecasts use the base year (2025) as the starting point, and include consensus information available as of April 2026 for provincial/commercial/industrial GDP, population,

housing starts, and disposable income forecasts over the Application period. The load forecasts also account for changes in electricity usage trends as well as the load impacts of electrification.

Detailed descriptions of the methodologies, assumptions and all of the inputs to the econometric and end-use approaches used for load forecasting are provided in Exhibits D-03-01 (Key Economic and Demographic Assumptions), D-04-01 (Transmission Load Forecast and Methodology) and D-05-01 (Distribution Load Forecast and Methodology).

9.1 TRANSMISSION LOAD FORECAST

The monthly average transmission peak load is projected to grow at an average annual rate of 1.2% over the 2028-2032 period, largely driven by economic and population growth, and electrification, as presented in Table 28 below.

Table 28 – 2027-2032 Weather-Normal Transmission Load Forecast (Net of CDM and Embedded Generation)

Measure	2027	2028	2029	2030	2031	2032
Average Monthly Peak (MW) - OEB Approved	19,392					
Average Monthly Peak (MW) - Forecast	20,658	20,800	20,970	21,251	21,586	21,949
% change over prior year - Forecast		+0.7%	+0.8%	+1.3%	+1.6%	+1.7%

**Exhibit reference: D-04-01 (Table 3a and Section 5.0)*

For Hydro One Transmission, the transmission load forecast was last approved by the OEB in 2022 for the 2023 to 2027 period. Resetting of the current OEB-approved 2027 forecast as proposed in this Application is estimated to contribute to a 9.5% decrease in transmission rates in 2028, while increasing peak demand over the remaining four years of the Application period (2029 to 2032) is expected to result in an average decrease in transmission rates of 1.3% per year, as shown in Section 11.1 (Transmission Bill Impacts) below.

For HOSSM, resetting of the current OEB-approved forecast as proposed in this Application is estimated to contribute to a 7.5% increase in HOSSM's transmission rates in 2028, while increasing peak demand over the remaining four years of the Application period (2029 to 2032) is expected to result in an average decrease in HOSSM's

transmission rates of 1.3% per year, as shown in Section 11.1 (Transmission Bill Impacts) below.

This transmission load forecast is used to derive the charge determinants for the Network, Line Connection and Transformation Connection rate pools for Hydro One Transmission and HOSSM, which are provided in Exhibit H-07-01 (Tables 1 and 2).

9.2 DISTRIBUTION LOAD AND CUSTOMER FORECAST

Distribution sales are projected to grow at an average annual rate of 1.7% over the 2028-2032 period, including a 2.8% increase in 2031 that reflects underlying growth as well as the integration of the Orillia and Peterborough rate zones into Hydro One's forecast. The number of customers is expected to grow at an average rate of 1.4% over the 2028-2032 period, including a 4.4% increase in 2031 that likewise reflects underlying growth as well as the integration of the Orillia and Peterborough rate zones. Aside from growth driven by including the Orillia and Peterborough rate zones in Hydro One's load forecast, the expected load growth over the Application period is driven by economic and population growth, and electrification.

Table 29 - 2027-2032 Weather-Normal Distribution Load and Customer Forecast (Net of CDM and Embedded Generation)

Measure	2027	2028	2029	2030	2031	2032
Sales (GWh) – OEB Approved	33,672					
Sales (GWh) – Forecast	38,723	39,053	39,673	40,279	41,415	42,023
% change over prior year		+0.9%	+1.6%	+1.5%	+2.8%	+1.5%
Customer # (M) – OEB Approved	1.453					
Customer # (M) – Forecast	1.480	1.490	1.501	1.512	1.578	1.589
% change over prior year		+0.7%	+0.7%	+0.7%	+4.4%	+0.7%

**Exhibit reference: D-05-01 (Tables E.6 and E.3)*

Hydro One's distribution load forecast was last approved by the OEB in EB-2021-0110 for the 2023 to 2027 period. The number of customers, sales and peak demand are forecast to increase relative to the OEB-approved 2027 forecast, which contributes to lower rates when the distribution forecast is reset in this Application. The impact of the load forecast

on individual rate classes depends on the forecast customer count, sales and, for demand-billed rate classes, peak demand for each rate class. The total bill impacts by rate class, including the effects of the load forecast, are shown in Section 11.2 (Distribution Bill Impacts) below.

10.0 COST ALLOCATION AND RATE DESIGN

Hydro One has applied established cost allocation and rate design methodologies, previously approved by the OEB, to translate the proposed Transmission, HOSSM and Distribution rates revenue requirements into rates. The proposals are intended to recover costs from the rate pools or rate classes (as applicable) that cause them, maintain continuity with approved approaches, and implement the integration of the Orillia and Peterborough rate zones into Hydro One's rate structure in 2031 in a fair and transparent manner.

10.1 TRANSMISSION COST ALLOCATION

Hydro One Transmission's rates revenue requirement is allocated among the Network, Line Connection, and Transformation Connection rate pools using the methodology approved by the OEB since 2006 and as described in Exhibits H-01-02 and H-01-03. HOSSM's rates revenue requirement is allocated to the rate pools based on Hydro One Transmission's rates revenue requirement percentages, as previously approved by the OEB. The resulting rates revenue requirements by rate pool, as shown in Exhibit H-05-01, are inputs to the calculation of Uniform Transmission Rates in Exhibit H-06-01. This approach preserves cost causality and consistency across Ontario's transmitters and transmission customers. The rates revenue requirements reflect offsets for external revenues, Export Transmission Service (ETS) revenue, disposition of regulatory accounts and low voltage switchgear credit amounts, as applicable, as detailed in Exhibit H-01-01. As directed by the OEB in EB-2021-0243, Hydro One has also prepared an updated cost allocation study for the ETS rate, as described in Exhibit H-08-01.

10.2 DISTRIBUTION COST ALLOCATION

Hydro One prepared its Distribution cost allocation evidence in accordance with the OEB's filing requirements and the OEB's 2027 cost allocation model. Hydro One has populated two cost allocation models, for the 2028 and 2031 test years. Costs are allocated among rate classes using the approved methodology, with updates for, among other items, forecast customers, loads, costs, and the proposed integration of the former Orillia Power Distribution Corporation (OPDC) and Peterborough Distribution Inc. (PDI) in 2031, as detailed in Exhibits L-01-02 and L-01-03. Where required, Hydro One's proposal seeks to move revenue-to-cost ratios toward the OEB-prescribed ranges while considering bill impacts and avoiding unnecessary rate instability.

10.2.1 HARMONIZATION OF FORMER OPDC AND PDI CUSTOMERS

The customers of the former OPDC and PDI will be harmonized into Hydro One's rate structure effective January 1, 2031. The proposed harmonization plan places these customers in the appropriate Hydro One rate classes and allocates the costs of serving them using the same cost allocation principles applied to legacy Hydro One customers. Exhibits L-01-02, L-01-03 and L-03-01 describe the customer classifications, cost allocation, and resulting benefits for acquired and legacy Hydro One customers.

Former OPDC and PDI residential and general service customers will move to Hydro One's Acquired Urban Residential, Acquired Urban General Service Energy and Acquired Urban General Service Demand rate classes; eligible large use customers will move to the Sub-Transmission (ST) rate class; and Street Lights, Sentinel Lights and Unmetered Scattered Load customers will move to the corresponding Hydro One rate classes. Former OPDC's Standby Power classification will be eliminated.

As detailed in Exhibit L-03-01, the integration will produce total annual benefits of approximately $12.6M in 2031, such that acquired customers would pay approximately $6.1M less than under the status quo, while legacy Hydro One customers would benefit by approximately $6.5M. This is because the $41.0M in revenues collected from acquired customers is (i) below the status quo revenue requirement of $47.1M for the former OPDC

and PDI, and (ii) greater than Hydro One's estimated $34.5M incremental cost to serve them. To moderate customer impacts, Hydro One proposes to phase in the revenue-to-cost ratio adjustment for the Acquired Urban Residential rate class over 2031 and 2032, limiting the estimated 2031 total bill increase for former PDI residential customers to no more than 10%.

10.3 DISTRIBUTION RATE DESIGN

Hydro One's proposed Distribution rate design in Exhibit L-02-01 implements the cost allocation results and recovers the revenue requirement allocated to each rate class through fixed and variable charges. The proposal maintains established rate design principles, reflects forecast billing determinants, and considers customer bill impacts.

Hydro One has sought to avoid abrupt or unwarranted changes in rates. Where required, transition or mitigation measures are proposed to manage significant impacts while continuing to move revenue-to-cost ratios toward the OEB-prescribed ranges.

Residential distribution rates are all-fixed, except for the Low Density Residential (R2) rate class, which will continue to have a small volumetric charge until 2032, consistent with the previously approved bill impact mitigation for former Seasonal customers.

10.3.1 SPECIFIC SERVICE CHARGES

In this Application, Hydro One is not requesting any new Specific Service Charges (SSCs) and proposes to maintain SSCs at their current amounts with the exception of pole rental charges for generators and LDCs where Hydro One proposes to update the charges based on the 2025 OEB-approved inflationary adjustment applied to the telecom pole rental rate.

11.0 BILL IMPACTS

Customer bill impacts reflect the combined effect of, among other items, the proposed revenue requirements, load and customer forecasts, cost allocation and rate design, and disposition of regulatory account balances.

Exhibits H-09-01 and L-06-01 provide the detailed Transmission (including HOSSM) and Distribution bill impacts resulting from approval of the Application, respectively.

11.1 TRANSMISSION BILL IMPACTS

Tables 30 and 31 show the estimated average bill impacts of the proposed changes in Hydro One Transmission's rates revenue requirement and load forecast on transmission- and distribution-connected customers over the Application period. Tables 32 and 33 show this view for HOSSM.

Table 30 - Average Rate and Bill Impacts on Transmission Connected Customers

Hydro One Transmission

Hydro One Transmission	2027[1]	2028	2029	2030	2031	2032
Revenue Requirement ($M)	2,363.3	2,726.6	2,931.0	3,185.2	3,364.8	3,650.2
Revenue Requirement Offsets ($M)[2]	-57.5	-134.0	-131.5	-128.4	-127.1	-124.8
Rates Revenue Requirement ($M)	2,305.8	2,592.6	2,799.5	3,056.8	3,237.8	3,525.5
% Increase in Rates Revenue Requirement over prior year		12.4%	8.0%	9.2%	5.9%	8.9%
% Impact of load forecast change		-9.5%	-0.8%	-1.3%	-1.5%	-1.6%
Net Impact on Average Transmission Rates[3]		**2.6%**	**6.5%**	**7.1%**	**4.0%**	**6.6%**
Transmission as a % of Tx-Connected Customer's Total Bill		12.8%	12.8%	12.8%	12.8%	12.8%
Estimated Average Bill Impact		**0.3%**	**0.8%**	**0.9%**	**0.5%**	**0.8%**

[1] The 2027 OEB-approved rates revenue requirement will be established as part of the 2027 Annual Update (EB-2026-0169).
[2] Adjustments include non-rate revenues, export revenues, disposition of regulatory accounts and funding for the low voltage switchgear credit.
[3] The calculation of net impact on transmission rates accounts for Hydro One's revenue disbursement allocation factor of 90.4% as approved for 2026 UTR Revenue Requirement (EB-2025-0232 issued on January 15, 2026).

Table 31 - Average Rate and Bill Impacts on Typical Distribution Connected Customers Hydro One Transmission

Total Monthly Bill Impact from Transmission Rates	Impacts	2028	2029	2030	2031	2032	5-year Average
R1 Residential (750 kWh)	$	$0.50	$1.28	$1.49	$0.89	$1.53	$1.14
	%	0.3%	0.9%	1.0%	0.6%	1.0%	0.8%
GSe (2,000 kWh)	$	$1.12	$2.84	$3.32	$1.98	$3.41	$2.54
	%	0.2%	0.6%	0.7%	0.4%	0.7%	0.5%

**Exhibit reference (Tables 30, 31): H-09-01, (Tables 2, 4 and 6)*

The impact on transmission rates of Hydro One's proposals in this Application is estimated to be an increase of 2.6% in 2028, resulting in an average annual increase of 5.4% over the Application period. This translates into average bill impacts on transmission-connected customers of 0.3% in 2028 and 0.7% on average over the Application period. For distribution-connected customers, the monthly bill impact in 2028 is estimated at 0.3% or $0.50 for a typical R1 residential customer consuming 750 kWh and 0.2% or $1.12 for a typical GSe customer consuming 2,000 kWh, with average annual impacts of 0.8% and 0.5%, respectively, over the Application period.

Table 32 - Average Rate and Bill Impacts on Transmission Connected Customers HOSSM

HOSSM	2027[1]	2028	2029	2030	2031	2032
Revenue Requirement ($M)	49.2	50.0	52.3	58.5	59.4	61.9
Revenue Requirement Offsets ($M)[2]	0.0	-0.9	-0.9	-0.9	-0.9	-0.9
Rates Revenue Requirement ($M)	49.2	49.1	51.4	57.6	58.5	61.0
% Increase in Rates Revenue Requirement over prior year		-0.3%	4.7%	12.0%	1.6%	4.3%
% Impact of load forecast change		7.5%	-0.8%	-1.3%	-1.5%	-1.6%
Net Impact on Average Transmission Rates[3]		**0.1%**	**0.1%**	**0.2%**	**0.0%**	**0.0%**
Transmission as a % of Tx-Connected Customer's Total Bill		12.8%	12.8%	12.8%	12.8%	12.8%
Estimated Average Bill Impact		**0.02%**	**0.01%**	**0.03%**	**0.00%**	**0.01%**

[1] OEB approved the use of 2026 base revenue requirement for 2027 on an interim basis (EB-2026-170).
[2] Adjustments include disposition of regulatory accounts.
[3] The calculation of net impact on transmission rates accounts for HOSSM's revenue disbursement allocation factor of 1.9% as approved for 2026 UTR Revenue Requirement (EB-2025-0232 issued on January 15, 2026).

Table 33 - Average Rate and Bill Impacts on Typical Distribution Connected Customers HOSSM

Total Monthly Bill Impact from HOSSM Rates	Impacts	2028	2029	2030	2031	2032	5-year Average
R1 Residential (750 kWh)	$	$0.02	$0.01	$0.04	$0.00	$0.01	$0.02
	%	0.02%	0.01%	0.02%	0.00%	0.01%	0.01%
GSe (2,000 kWh)	$	$0.05	$0.03	$0.08	$0.00	$0.02	$0.04
	%	0.01%	0.01%	0.02%	0.00%	0.00%	0.01%

**Exhibit reference (Tables 32, 33): H-09-01, (Tables 3, 5 and 7)*

The impact on transmission rates of HOSSM's proposals in this Application is estimated to be an increase of 0.1% in 2028 and 0.1% on average over the Application period. This translates into average bill impacts on transmission-connected customers of 0.02% in 2028 and 0.01% on average over the Application period. For distribution-connected customers, the monthly bill impact in 2028 is estimated at 0.02% or $0.02 for a typical R1 residential customer consuming 750 kWh and 0.01% or $0.05 for a typical GSe customer consuming 2,000 kWh, with average annual impacts of 0.01% for each over the Application period.

11.2 DISTRIBUTION BILL IMPACTS

Distribution bill impacts vary by rate class because they reflect each rate class's allocated costs, rate design, forecast consumption or demand, and any applicable rate riders and bill impact mitigation. Table 34 summarizes the 2028 to 2032 total bill impacts for customers at typical or average consumption levels in all rate classes resulting from Hydro One's Distribution-related proposals in this Application. Bill impacts across a range of consumption levels are provided in Exhibit L-06-01, Attachments 1 to 5.

For a typical R1 residential customer consuming 750 kWh per month, the estimated total monthly bill impact in 2028 is a decrease of 2.1% or $3.31 with DRP, with an average annual decrease of 0.1% or $0.10 over the Application period. For a typical GSe customer consuming 2,000 kWh per month, the estimated total monthly bill impact in 2028 is an

increase of 7.2% or $34.63, with an average annual increase of 3.9% or $20.00 over the Application period.

1

Table 34 - 2028-2032 Total Bill Impacts for Distribution Customers

Rate Class	2028		2029		2030		2031		2032		Average	
	$	%	$	%	$	%	$	%	$	%	$	%
UR	$6.68	4.4%	$8.48	5.3%	$4.13	2.5%	$1.66	1.0%	$2.03	1.2%	$4.60	2.9%
R1 (with DRP)[1]	($3.31)	-2.1%	$3.22	2.1%	$0.00	0.0%	($0.43)	-0.3%	$0.00	0.0%	($0.10)	-0.1%
R2 (with DRP)[1]	($3.48)	-2.2%	$3.22	2.1%	$0.00	0.0%	($0.37)	-0.2%	$0.00	0.0%	($0.13)	-0.1%
Seasonal-R2[2]	$15.51	9.9%	$23.11	13.4%	$25.89	13.3%	$28.62	13.0%	$35.77	14.3%	$25.78	12.8%
GSe	$34.63	7.2%	$32.17	6.2%	$18.26	3.3%	$6.97	1.2%	$7.96	1.4%	$20.00	3.9%
UGe	$13.72	3.5%	$21.32	5.3%	$9.95	2.3%	$3.93	0.9%	$4.73	1.1%	$10.73	2.6%
GSd	$252.77	2.8%	$842.06	9.2%	$280.01	2.8%	$61.95	0.6%	$83.81	0.8%	$304.12	3.3%
UGd	($98.01)	-0.9%	$965.50	8.9%	$191.32	1.6%	$88.32	0.7%	$94.00	0.8%	$248.23	2.2%
St Lgt	$25.49	9.4%	$20.69	7.0%	$12.78	4.0%	$6.94	2.1%	$6.33	1.9%	$14.45	4.9%
Sen Lgt[2]	$2.51	14.5%	$1.64	8.3%	$1.15	5.4%	$0.14	0.6%	$0.55	2.4%	$1.20	6.2%
USL	$4.18	3.5%	$8.32	6.7%	$4.87	3.7%	($2.26)	-1.6%	$1.83	1.4%	$3.39	2.7%
DGen[2]	$73.24	10.6%	$73.81	9.7%	$40.78	4.9%	$15.69	1.8%	$20.04	2.2%	$44.71	5.8%
ST	($12,693.39)	-6.0%	$16,900.84	8.5%	$8,205.21	3.9%	$164.83	0.1%	$339.24	0.2%	$2,583.34	1.3%
AUR	$4.83	3.3%	$7.64	5.1%	$3.42	2.2%	($16.51)	-10.2%	$6.68	4.6%	$1.21	1.0%
AUGe	$11.72	3.4%	$16.66	4.7%	$6.09	1.6%	($18.91)	-4.9%	$2.46	0.7%	$3.60	1.1%
AUGd	($485.24)	-5.2%	$781.91	8.9%	$65.13	0.7%	$203.66	2.1%	$35.41	0.4%	$120.17	1.4%
AR	$6.63	4.3%	$8.50	5.3%	$4.14	2.5%	$1.88	1.1%	$2.03	1.2%	$4.64	2.9%
AGSe	$8.72	2.3%	$18.44	4.8%	$7.70	1.9%	$3.58	0.9%	$3.76	0.9%	$8.44	2.2%
AGSd	($190.05)	-1.7%	$1,006.56	8.9%	$110.34	0.9%	$105.68	0.8%	$56.41	0.4%	$217.79	1.9%

2

Rate Class	2028		2029		2030		2031		2032		Average	
	$	%	$	%	$	%	$	%	$	%	$	%
Former OPDC Customers to Hydro One Rate Classes[3]												
AUR-OPDC	-	-	-	-	-	-	$8.17	6.0%	$6.68	4.6%	$7.42	5.3%
AUGe-OPDC	-	-	-	-	-	-	$7.21	2.0%	$2.46	0.7%	$4.84	1.3%
AUGd-OPDC	-	-	-	-	-	-	($32.72)	-0.3%	$37.03	0.3%	$2.15	0.0%
St Lgt-OPDC	-	-	-	-	-	-	($22,487.78)	-69.4%	$176.76	1.8%	($11,155.51)	-33.8%
USL-OPDC[2]	-	-	-	-	-	-	$52.45	70.1%	$1.79	1.4%	$27.12	35.8%
Former PDI Customers to Hydro One Rate Classes[3]												
AUR-PDI	-	-	-	-	-	-	$12.73	9.6%	$6.68	4.6%	$9.71	7.1%
AUGe-PDI	-	-	-	-	-	-	$26.23	7.8%	$2.46	0.7%	$14.34	4.2%
AUGd-PDI	-	-	-	-	-	-	($54.70)	-0.6%	$32.71	0.3%	($11.00)	-0.1%
St Lgt-PDI	-	-	-	-	-	-	$4,411.76	5.0%	$1,641.95	1.8%	$3,026.86	3.4%
Sen Lgt-PDI[2]	-	-	-	-	-	-	$35.10	95.5%	$1.64	2.3%	$18.37	48.9%
USL-PDI[2]	-	-	-	-	-	-	$54.77	57.4%	$1.90	1.3%	$28.34	29.3%

**Exhibit reference: L-06-01, (Tables 1 to 5)*

[1] R1 (with DRP) and R2 (with DRP) impacts assume the Distribution Rate Protection (DRP) cap remains at its estimated July 1, 2027 level over the 2028 to 2032 period.

[2] Rate classes with total bill impacts above 10% at typical or average consumption levels, and Hydro One's proposed approach to mitigation, are discussed in Exhibit L-06-01, Section 2.

[3] Former OPDC and PDI customers are harmonized into Hydro One's rate structure effective January 1, 2031; their 2028 to 2030 rates are set under the deferred rebasing period and are not part of this Application.

12.0 CONCLUSION

The Application presents a balanced and evidence-based plan to address Ontario's evolving electricity needs by enabling growth, supporting electrification, renewing aging infrastructure, and maintaining reliability and resilience. The proposed investments reflect deliberate choices regarding scope, timing, productivity, and affordability, informed by extensive planning, independent analysis, benchmarking, and customer engagement. Approval of the Application would provide the funding framework needed to meet future demand, manage growing asset and system risks, and deliver long-term value for customers.

2028-2032 Joint Rate Application

Elise Andrey, Kathleen Burke, Charles Keizer

September 16, 2026

Updated October 6 with final bill impacts

Agenda

1. Process, timelines and recent trends
2. Overview of the application process & bill impacts
3. Application summary
   a) Transmission Segment
   b) Distribution Segment
   c) General Plant Segment
   d) Workforce
   e) Regulatory

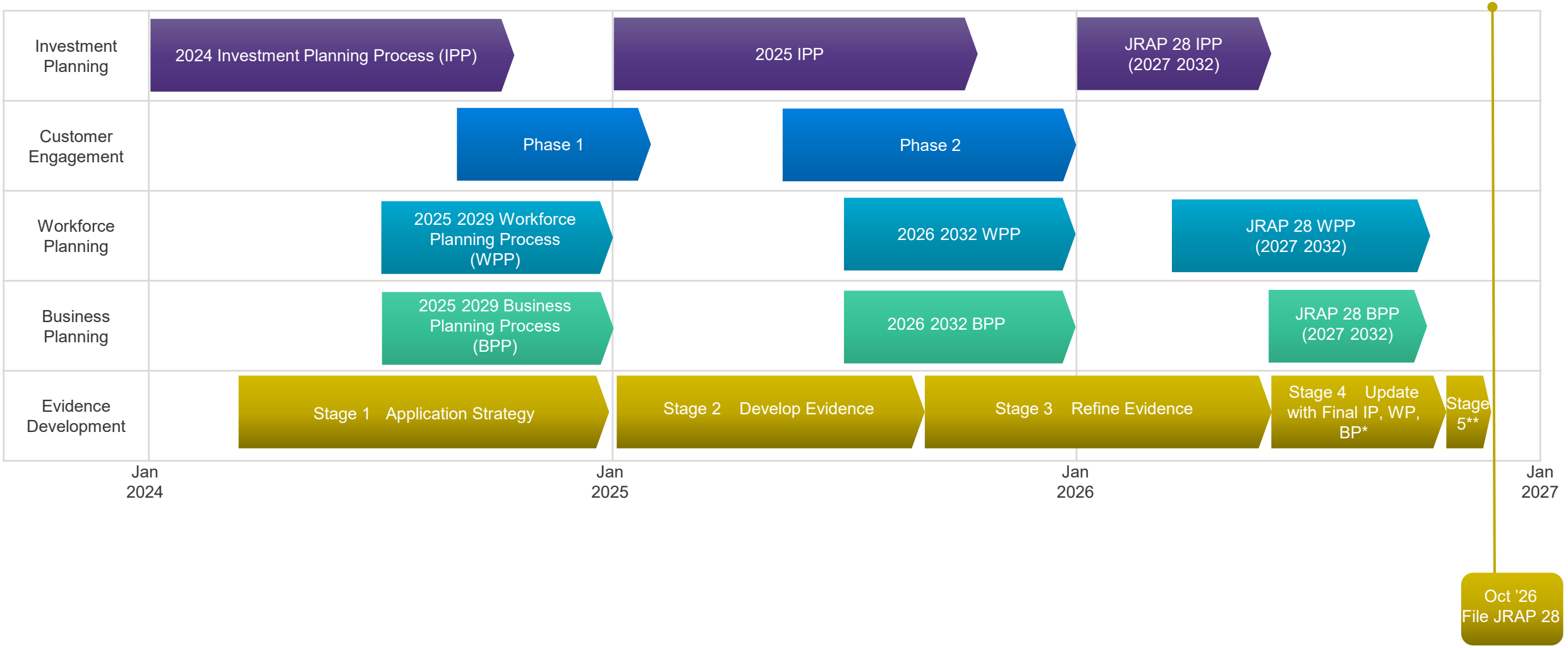
Process, timelines and recent trends

The 2028-2032 Joint Rate Application (JRAP28) is the public litigation process through which Hydro One Network Inc.'s Transmission and Distribution 2028-2032 revenue requirement and rates, respectively, are set by the OEB.

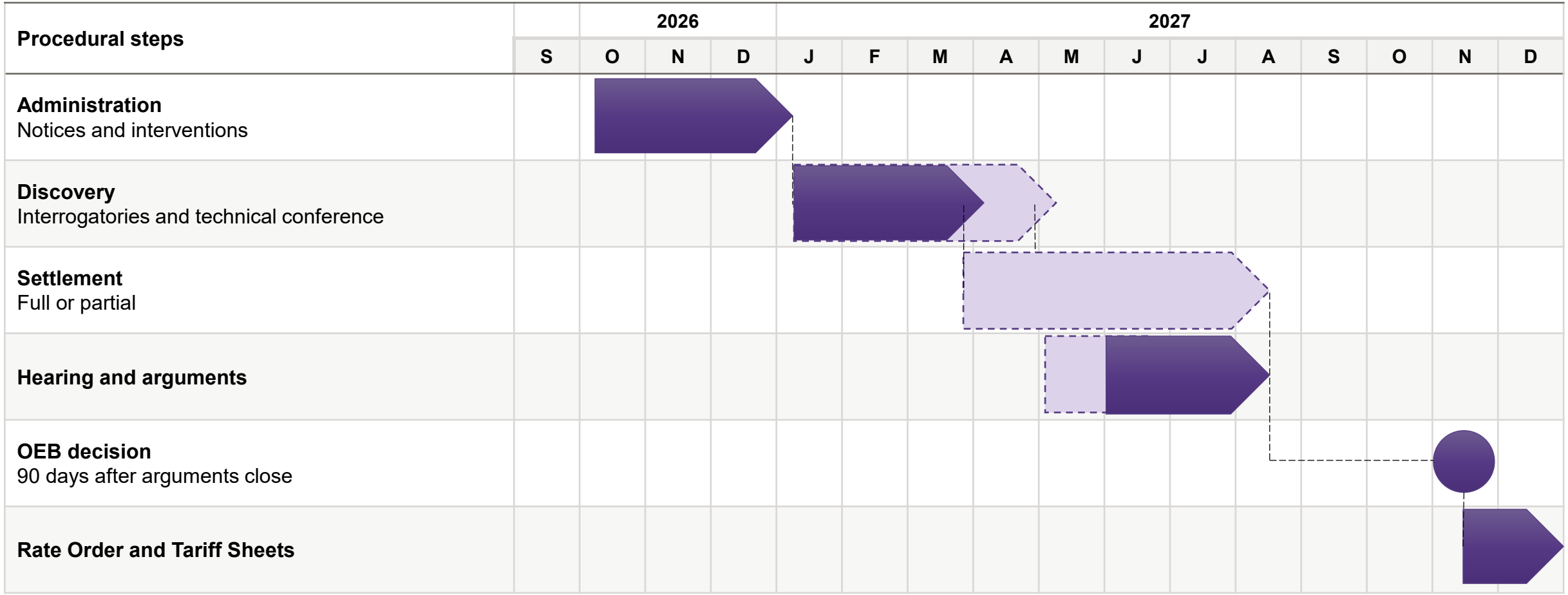
This section reviews the path taken to develop JRAP28 and outlines the application litigation steps.

Recap of process timelines

The rate application development process combines a series of complex, interrelated processes that work together to produce an application that appropriately balances system needs, customer needs, and bill impacts.



OEB litigation timelines



Overview

- Plan objectives
- Plan updates
- Customer Engagement Phase 2
- Draft bill impacts

Plan objectives

This plan is built for Ontario

It responds to what over 100,000 customers told us they need, what communities expect, and what Ontario's future demands.

Sustaining the electricity system

Equipment condition remains a key driver of outages outside of major storms.

Risk-based maintenance and renewal prioritize poor-condition assets while balancing reliability, affordability and long-term system health.

Growth

Demand could increase as much as 65% by 2050* driven by new homes, expanding communities and industry.

Investments in poles, wires, stations, and modern equipment enable customer connections, electrification, grid modernization and province-wide economic development.

Reliability and resiliency

Threats are becoming more sophisticated, severe storms and aging infrastructure are putting pressure on the electricity system. It's increasingly important to strengthen the resilience and security of the electricity system.

Targeted investments in system hardening, vegetation management and automation improve reliability and restoration.

The plan balances system needs with a continued focus on efficiency to help mitigate customer bill impacts.

**Source: IESO, 2026 Annual Planning Outlook (APO) demand forecast. Ontario electricity demand is projected to increase by approximately 65% by 2050*

Customer engagement phase two

Consistent with OEB expectations, Hydro One undertook extensive customer engagement to ensure its proposed plan reflects customer preferences. In phase two, more than 100,000 customers completed a survey exploring seven trade-off questions across transmission, distribution, and general plant. A majority supported either the draft plan or the "spend more" option, demonstrating broad support for the proposed investments

Areas of inquiry

Dx Investment Priorities	Key Investment Areas	Tx Investment Priorities	Key Investment Areas	General Plant Priorities	Key Investment Areas
Overall System Reliability	Poor condition distribution poles, lines and stations replacement	Keeping pace with transmission renewal	Poor-condition transmission stations and lines asset replacement	Maintaining buildings and facilities	Asset replacement, renovations, new builds, climate adaption, equity needs
Targeted Reliability Improvements	Battery storage program for communities with below-average reliability	Stewardship of the transmission system	Asset maintenance, lines and stations monitoring technology	Keeping up with customer needs and information technology	Investments to maintain operations, meet cyber requirements, enhance customer experience
Managing Reliability and Severe Weather Impacts	Veg mngmt, lines and poles replacement, modernization of worst performing feeders				

Survey Results

	Distribution & Transmission Customers					Transmission-Only Customers		
	Residential	First Nations On-Reserve Residential	Small Business	Commercial & Industrial	Large Dx Accounts	Other LDC* Residential	Other LDC* Small Business	Large Tx Accounts
Spend More	25%	28%	21%	16%	23%	37%	35%	33%
Draft Plan	50%	49%	49%	52%	47%	45%	44%	55%
Spend Less	16%	11%	21%	22%	26%	12%	15%	8%
Other	3%	2%	4%	5%	2%	1%	1%	3%
Draft Plan + Spend More	**75%**	**77%**	**70%**	**68%**	**70%**	**82%**	**80%**	**88%**

Plan updates

Planning information has been refined relative to the December 2025 Business Plan to incorporate the following:

Update	Description
Customer engagement Phase 2	Incorporated customer engagement results into the Investment Plan, with further adjustments made as described below
Distribution re-pacing exercise	Distribution capital plan reduced by ~$1.5B relative to the plan customers supported by re-pacing reliability and resilience investments, Digital and Technology enhancements, and Facilities and Real Estate investments
Transmission IESO bulk and regional plans	Transmission capital plan updated in June 2026 to reflect $1.7B in additional investments in the IESO's South & Central Ontario and North of Sudbury bulk plans, to demonstrate a complete plan
Third party studies	Incorporated the results of third-party studies including Common Corporate Allocation & Capitalization, Depreciation, Cost of Capital, Econometric Benchmarking and other work program assessments
Updated planning information	Customer & growth outlook, investment maturity, workforce enablement and the impacts of competitive transmission

Final bill impacts

This slide shows bill impacts for a typical R1 residential distribution customer with and without Distribution Rate Protection (DRP). Note, only rural year-round residential customers receive DRP.

With DRP, distribution rates for rural residential customers decrease in 2028 relative to 2027 as Hydro One refunds a large credit balance from its deferral and variance accounts. In Year 2, when that credit rider expires, they will see a corresponding increase.[1]

The OEB will not consider the impact of DRP when assessing the reasonableness and prudence of Hydro One's proposed capital and OM&A.

Bill Impacts for Typical Residential Customers[2] (% and $)

Utility	5-Year Total Increase	First Year Increase	Avg. Annual Increase (Over 5-Years)
Hydro One Transmission *Includes HOSSM*	*27% (4% Total Bill)* $5.79	3% (0.4% Total Bill) $0.53	5% (0.8% Total Bill) $1.16
Hydro One Distribution (Without DRP)	44% (20% Total Bill) $39.20	18% (7% Total Bill) $13.56	9% (4% Total Bill) $7.84
Hydro One Distribution (With DRP)[3]	Year 1: ($3.31), -7% (-2% Total Bill) Year 2: $3.22, 7% (2% Total Bill)		

[1] These numbers are contingent on the outcome of Hydro One's 2027 annual update, which may require earlier disposition of some account balances which would increase Year 1 bill impacts
[2] Bill impacts are based on a typical R1 customer consuming 750 kWh/month.
[3] Distribution Rate Protection (DRP) limits the increases in base distribution charges to inflation as established annually by the OEB.

JRAP28 Summary

- Transmission
- Distribution
- General Plant
- Workforce
- Regulatory

Transmission Segment

Transmission capital investment priorities

hydro One

1

System Access

- System Access enables new and expanded customer connections
- Since 2023, customer connection requests have increased from 100/yr to 200/yr
- The plan includes **triple** the number of System Access investments representing more than 6,000MW of capacity enablement
- Increases are driven by growth in LDCs, industrial, commercial, and data centre connections
- Connection requests involve greater complexity and more new station builds

2

System Service

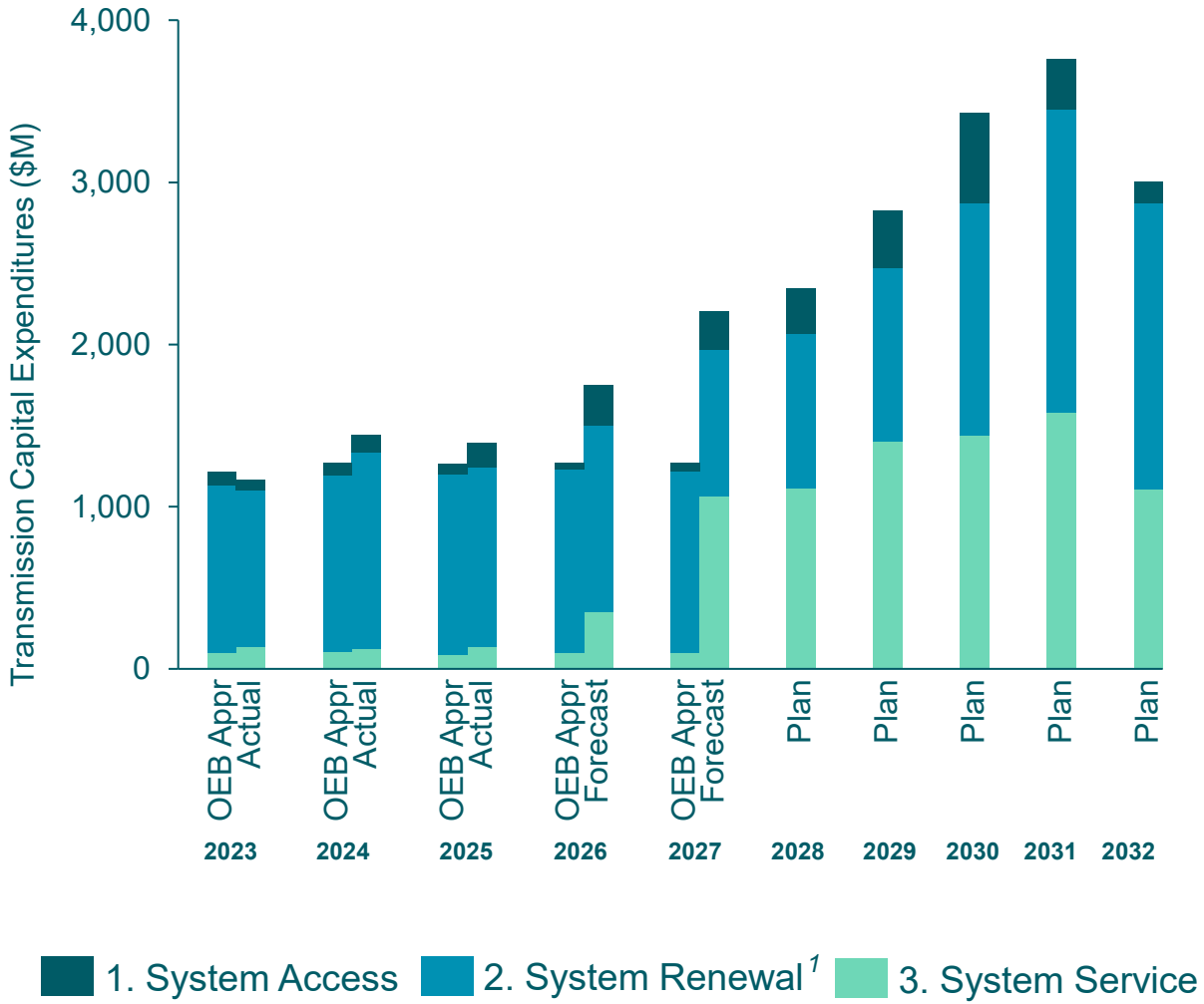
- System Service investments respond to mandatory IESO regional and bulk planning
- Over the 2028-2032 period, Hydro One is forecasting an **eightfold** increase in the number of System Service investments
- Investments will increase system transfer capability by more than 10,000 MW and enable more than 2,500 MW of new generation capacity across the province
- The IESO will publish at least 5 Bulk Studies and 12 Regional Plans in 2026 and 2027 that will identify further mandatory investments, and more in 2028 and beyond

3

System Renewal

- System Renewal investments address deteriorating asset condition and obsolescence
- In 2023 to 2027, significant System Renewal funding was redirected to System Access and System Service
- In 2028-2032, Hydro One is forecasting a **33% increase** in System Renewal to address poor condition assets including deferred work
- The asset condition evidence is compelling: poor-condition transformers increased from 16% in 2016 to 29% in 2025, poor-condition wood structures increased from 12% to 19%

Transmission capital expenditures



[1] *OEB-approved productivity amounts are reflected within System Renewal*

HIGHLIGHTS

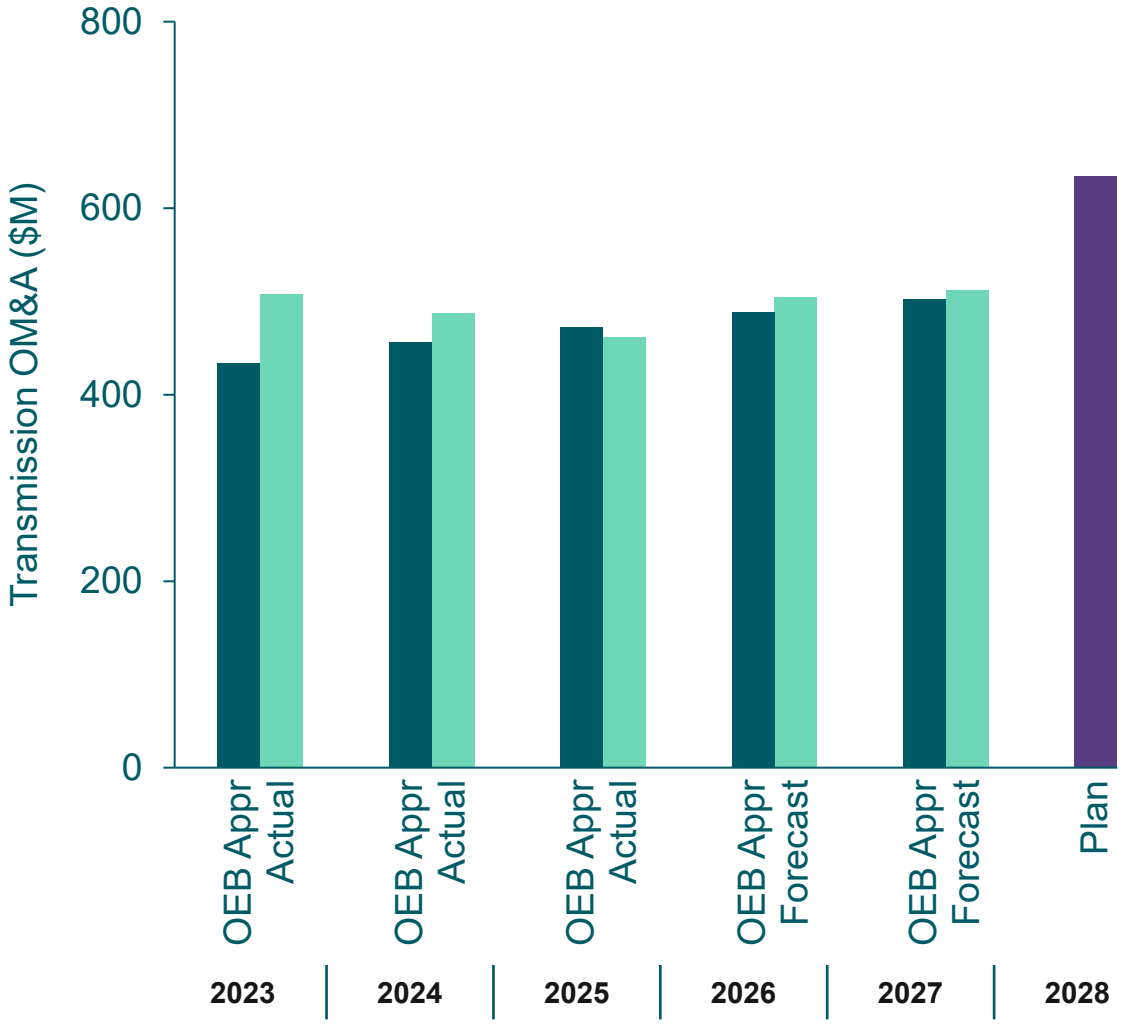
System Access and System Service

- *Electrification, Growth, and Economic Development*: Continue to play a critical role in enabling Ontario's priorities of economic development, including supporting new and expanded industry and preparing for higher growth through system expansions

System Renewal

- *Maintain the Grid*: Maintain first quartile reliability by delivering responsible investments to renew the grid, address aging and poor condition infrastructure and improve climate readiness
- *Reliability, Resiliency and Environment*: Maintain first quartile reliability by targeting investments to improve the resiliency of the transmission grid including climate readiness

Transmission OM&A



HIGHLIGHTS

Maintenance

- *Maintain the Grid:* Carryout critical inspections, testing and patrols, e.g. conductor condition assessments, dissolved gas analysis, annual station inspections, right of way patrols, etc.
- *Reliability, Resiliency and Environment*: Harden cyber security, maintain lines and stations assets and manage vegetation along corridors
- *Reduce greenhouse gas emission*: Carryout targeted SF6 leak reductions and address leaking transformers

Common Support and Enablement

- *Growth and Innovation*: Focus on growing our digital capabilities, enabling the business through technological modernization, harnessing of data, and strengthening our foundation

Distribution Segment

Distribution investment priorities

hydro One

1

Sustaining the grid

- Equipment failure is responsible for about a third of outage hours
- Many assets are approaching or are beyond their expected service life (ESL)
  - 45% of station transformers are beyond their ESL
  - 19% of transformers are in poor condition
  - 34% of underground cable will be beyond ESL by 2028
- While work was deferred in 2023 to 2027 to offset higher costs and growth, deferrals cannot be sustained and system needs must be addressed in 2028 to 2032

2

Supporting growth

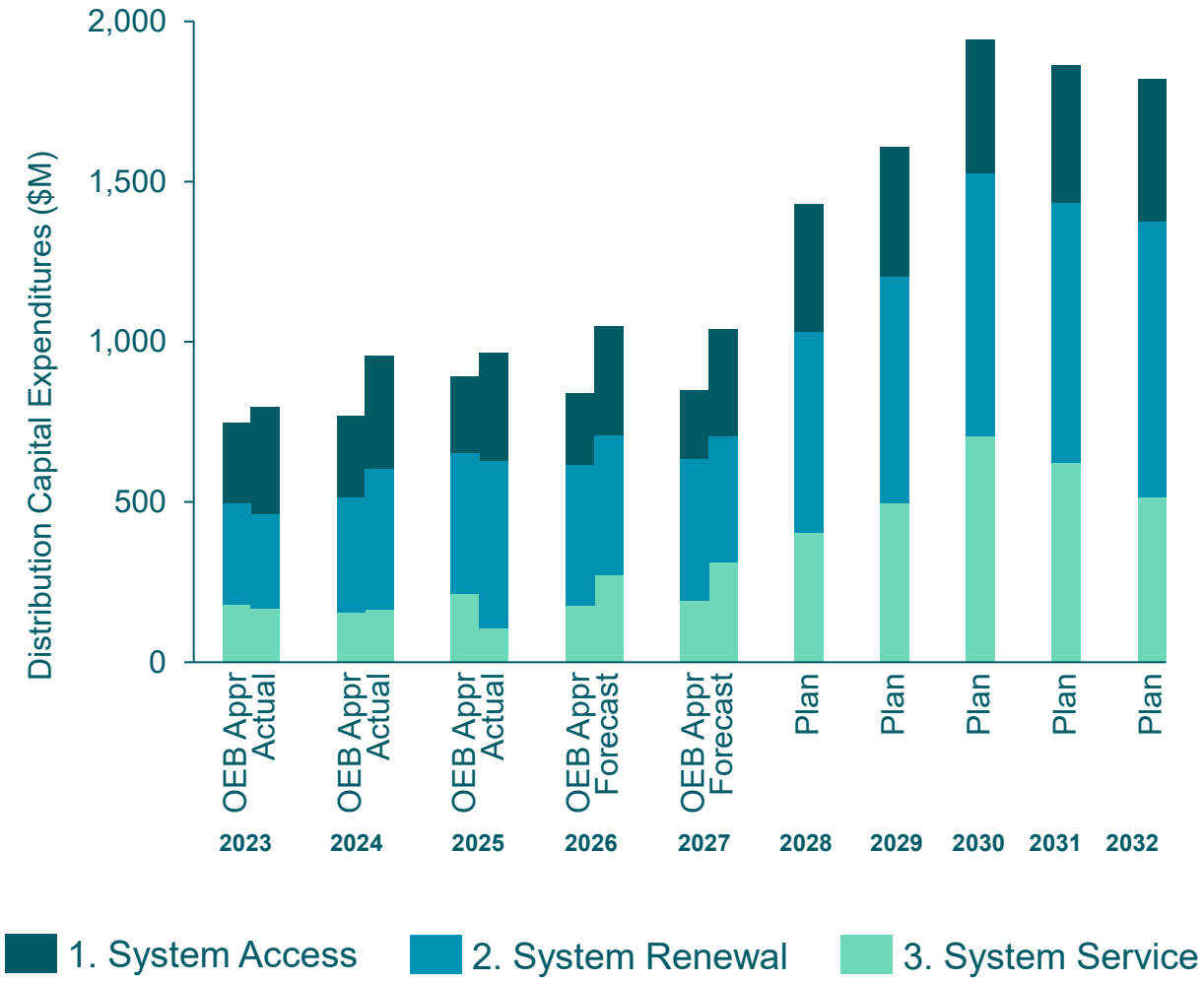
- System is reaching or surpassing operational limits. Transformers and feeders will be replaced where utilization is at or beyond maximum limits
- Over 8,000 residential DERs are forecasted to be connected in 2028 – 32
- Grid modernization investments will improve Hydro One's ability to identify system constraints, monitor loading, enable DER connections, and use non-wires solutions where cost-effective

3

Improving reliability and resiliency

- Hydro One's system is unique: it includes a broader mix of geography, terrain, density, forest profiles, weather exposure, growth profiles, voltage levels and asset configurations which directly affect the investment plan and impact reliability and unit costs
- As assets require replacement, Hydro One is selecting a mix of traditional and new approaches to address worsening reliability and more frequent and severe weather
- Grid modernization investments will help shorten restoration times and reduce outage frequency

Distribution capital expenditures



HIGHLIGHTS

System Access and System Service

- *Connecting new load and generation customers*, supporting a growing provincial population and increasing electricity requirements
- *Enhancing the distribution system to accommodate increased growth*, including the development of new distribution stations and feeders to meet growing demand
- *Modernizing the distribution system* to optimize delivery and connection capability and improve reliability

System Renewal

- *Maintaining the Grid*: Delivering responsible grid investment to address aging and poor condition infrastructure
- *Reliability, Resiliency and Environment*: Improving the resiliency of the grid to handle modern customer and climate demands

Distribution OM&A

HIGHLIGHTS

Maintenance

- *Maintain the Grid:* Address system defects and conduct necessary testing and inspections
- *Reliability, Resiliency and Environment*: Harden cyber security, maintain lines and stations assets and manage vegetation along corridors
- *Using modern technology* such as LiDAR to survey our territory to manage trees and brush which are the leading cause of weather-related outages

Other

- *Customer Choice, Electrification and Growth*: Implementing non-wires solutions, such demand response, to meet grid needs and defer capital investments

Common Support and Enablement

- *Growth and Innovation*: Grow our digital capabilities, enabling the business through technological modernization, harnessing of data, and strengthening our foundation

General Plant Segment

General Plant investment priorities

hydro One

1

Maintaining deteriorated and end-of-life assets

- Prioritizing the safety of Hydro One personnel and contractors by maintaining and replacing assets based on condition and lifecycle requirements, ensuring reliable tools, equipment, and resources are available to support safe and efficient operations.

2

Enabling work-program growth

- Facilitating the execution of expanded work programs and adapting general plant assets and capabilities to support a larger workforce to address growing system, asset, and customer requirements.

3

Responding to evolving requirements

- Addressing evolving customer needs, policy or legislative directives, with an emphasis on improving reliability and resilience, and safeguarding critical physical and digital grid infrastructure.

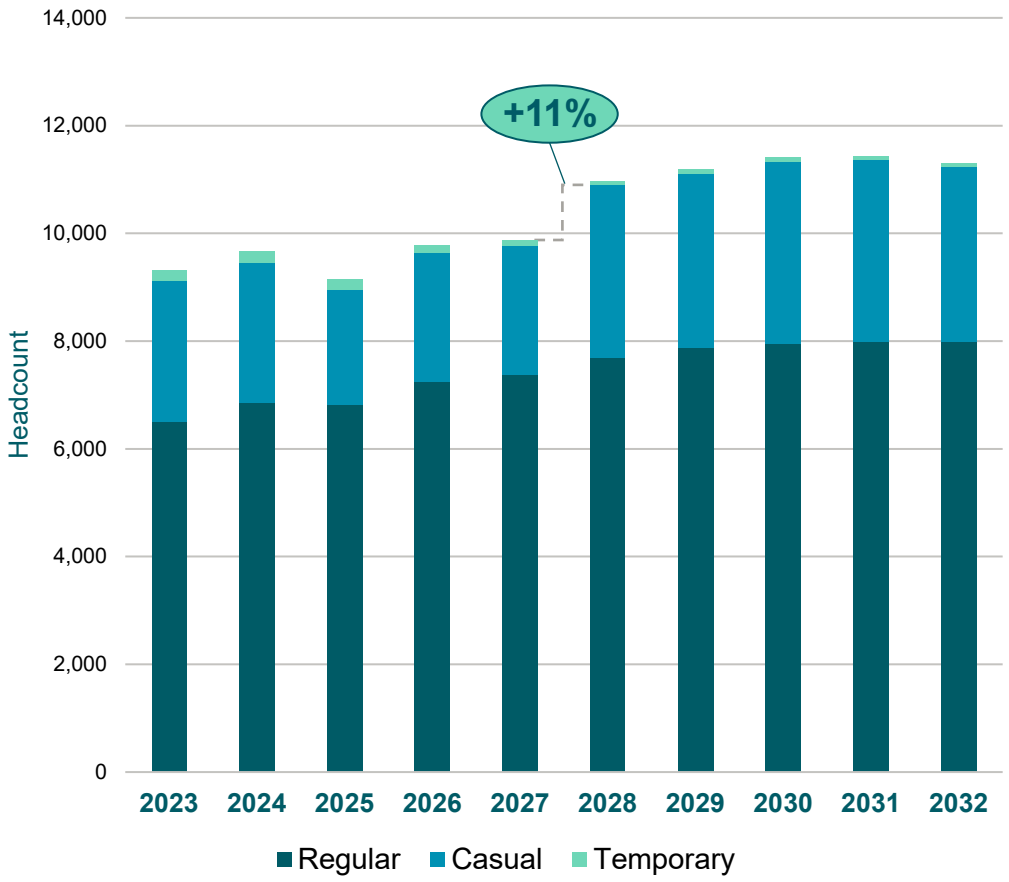
General Plant capital expenditures

HIGHLIGHTS

- *Maintaining assets*: Asset renewal and replacement investments to address aging support infrastructure.
- *Enabling work-program growth*: Enabling investments to support expanded transmission and distribution work programs, including fleet, facilities, operational systems, and related equipment.
- *Responding to evolving requirements:* Technology, security, and resilience investments to renew unsupported systems and enhance data, analytics, cybersecurity, compliance, and storm response capabilities.
- *Prepaid expenditures:* JRAP28 includes cloud computing implementation costs for technology hosting arrangements which are recorded as a non-current asset and amortized over the service life of the arrangement in accordance with U.S. GAAP.

Workforce

JRAP28 workforce planning



The 2028–2032 workforce plan aligns resource requirements with the Investment Plan and operational needs.

Compensation costs are closer to the benchmark median

- Total compensation cost for the 2028-2032 period is 6% above P50 (Mercer benchmarking report), consistent with commitment in JRAP23

Workforce growth will support Hydro One's expanded investment plan

- An 11% increase in 2028 supports a needed and necessary increase in grid investment in 2028 but is not increasing at the same pace as units of accomplishment, demonstrating a reasonable, prudent approach
- Workforce growth moderates thereafter with a ~3**%** increase from 2028-2032, demonstrating efficiency as investment levels continue to increase

JRAP23 variances

2023 and 2024 headcount was ~7% above forecast, with variances resolved in 2025. The variance were driven by:

- 60% due to incremental non-discretionary work (externally driven work, joint use, cable locates, Broadband)
- 30% due to hiring commitments under Letters of Understanding (LOUs)
- 10% due to other (hiring regular staff in addition to those hired for incremental work and LOU commitments)

Regulatory

Key points

Demonstrated Cost Discipline & Stewardship	• Despite rising electricity demand, escalating external cost pressures, and more frequent severe weather, Hydro One has taken best-efforts to manage within OEB-approved budgets through prudent deferral of non-critical work, efficiency-driven cost savings, and proactive cost management, without compromising safety or reliability. • Where safety or reliability could be compromised, Hdyro One made deliberate decisions to spend above OEB-approved envelopes
System Readiness for a Changing Energy Landscape	The proposed investments prepare the system to: • Serve higher and more volatile demand • Enable timely, affordable connections for large and strategic customers • Address aging infrastructure and system renewal • Operate reliably in an increasingly complex and climate-impacted environment • Enhance resilience to extreme weather events
Well-Paced Affordable Approach	Investments are properly paced to balance customer affordability with near and long-term service quality and reliability outcomes. The plan mitigates higher future costs from deferred renewal or capacity constraints. A distribution re-pacing exercise in 2026 better balanced the goals of system readiness and affordability
Evidence-Based, Customer-Supported Plan	The application is grounded in robust expert evidence, pragmatic internal analysis, and meaningful customer engagement, demonstrating both technical rigor and social permission
Alignment with Government & Public Policy Objectives	The proposal supports government priorities by enabling economic growth and electrification, supporting housing, industrial development, and decarbonization, and ensuring infrastructure keeps pace with provincial needs
Risk Management & Regulatory Flexibility	Proposed deferral and variance accounts provide necessary flexibility to respond to uncertainty, allowing spending within the rate period when certain criteria are met

Inputs: Expert Reports

hydro One

JRAP28 Expert Reports

Customer Engagement

Benchmarking

Process Assessment

Position Support

Hydro One's evidence is supported by about two dozen expert reports. Some expert reports are required by the OEB, others are filed to support specific positions taken by the company.

Customer Engagement

- The OEB requires utilities to survey customers on their investment plans. For JRAP28, Hydro One retained Innovative Research Group, an independent expert that conducted a survey of over 100,000 customers. In general, a majority of customers supported the draft plan or higher

Benchmarking

- The OEB requires utilities to perform benchmarking exercises to assess whether the company is operating productively relative to peers

Process Assessment

- Expert reports to assess business or operational processes

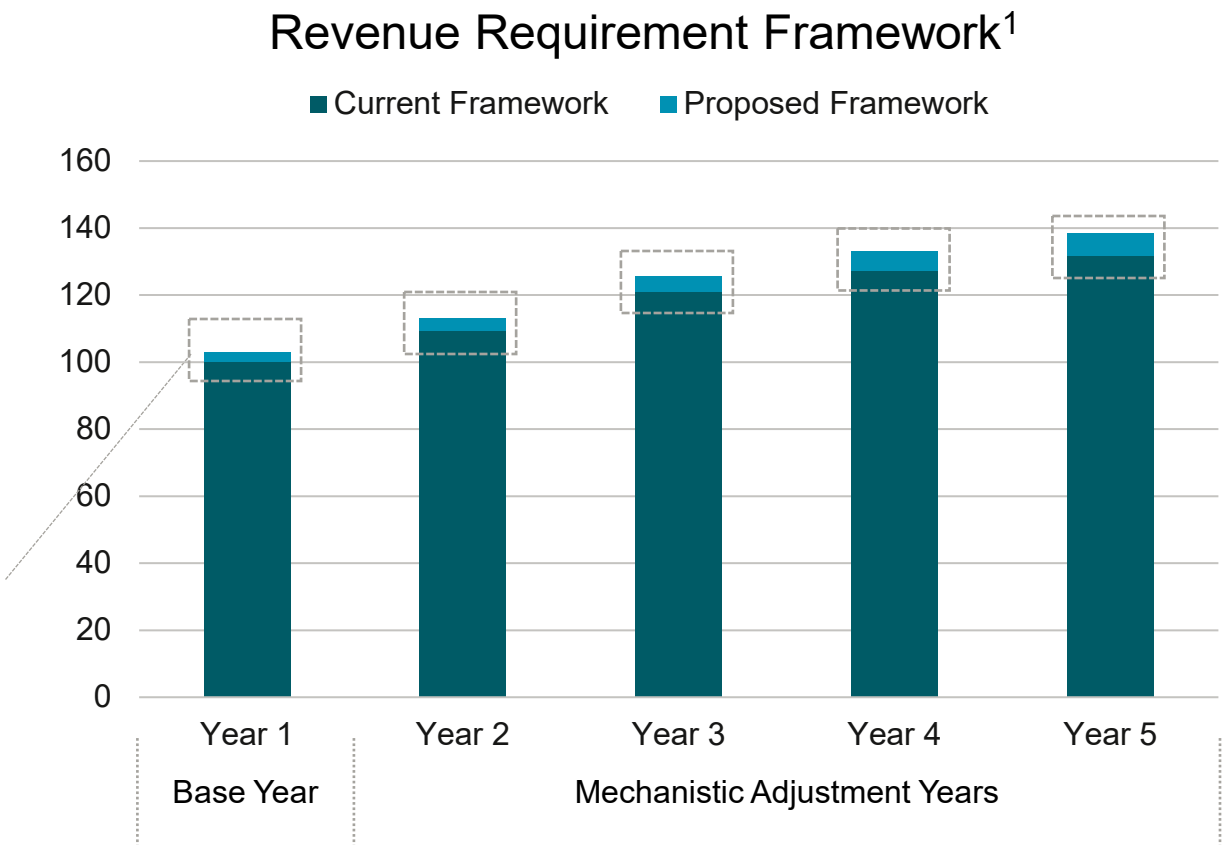
Position Support

- Expert reports to support certain positions including a report by Concentric Energy Advisors recommending a higher equity thickness for Hydro One

Revenue Requirement Framework

In recent rate applications, Hydro One has set revenue requirement using a Custom Incentive Rate-setting (Custom IR) framework.
Hydro One proposes to use an updated Custom IR framework for JRAP28 to better address uncertainty

- The OEB uses "Incentive Rate-Setting" to set utilities' revenue requirement over a five-year term. Hydro One uses a Custom IR framework to allow recovery of its variable capital expenditures
- **Year 1** is a bottom-up build of forecast costs
- **Years 2 – 5** are determined mechanistically, escalated by **Inflation (I)** and partially reduced by an "incentive" **Productivity (X)** factor to drive continuous cost improvement. **Capital (C)** is based on the capital forecast and is also reduced by the X-factor (on a cumulative basis).
- For JRAP28, **new factors** are proposed to address rate period uncertainty:
  - **Growth (G)** for OM&A to address higher OM&A related to a growing system
  - **Input Price Differential (IPD)** for OM&A to address higher input costs
  - Higher **Cost of Capital** parameters
  - Expanded regulatory accounts to respond to uncertainty and Regulatory/Government policy



[1] Illustrative Revenue Requirement, normalized to 100

Deferral and variance accounts

Hydro One is proposing certain variance accounts over the 2028 to 2032 period. Below, the key proposed accounts are described

Account	Description
Transmission Externally Driven Work	Captures variances for mandatory, externally driven transmission work, with an expanded scope to include connection investments arising from regional planning
Distribution Externally Driven Work	Captures variances in customer connection work driven by electrification demand and housing development, supporting timely growth investments without displacing planned system work
Non-wires solutions (NWS) incentives	Captures revenue requirement impacts of NWS identified within rate period and seeks incentives for replacing capital investments with OM&A solutions
Change of Law	Captures incremental costs from unforeseen legislative or regulatory changes potentially including new data centre connection and rate requirements, and Canadian procurement obligations intended to strengthen domestic supply chains and protect the energy sector from economic threats
Cyber-Security	Captures material, unforecasted cybersecurity investments arising from evolving NERC CIP standards and other mandatory requirements
Digital Technology Operations	Addresses unforeseen escalation in essential software, cloud, telecommunications and vendor-support costs beyond inflation-based funding
Changes in Transmission Cost Responsibility	Protects against future regulatory decisions that reallocate responsibility for major transmission project costs

Funding and debt cost considerations

Background: To deliver the scale of investment needed to modernize and expand the grid, Hydro One will require additional equity to strengthen its financial capacity and support sustainable growth. This will:

- Preserve credit quality as investment levels increase, supporting efficient access to capital and helping minimize upward pressure on customer rates
- Enhance Hydro One's ability to manage development risks, economic volatility, and emerging opportunities associated with electrification and the energy transition

Considerations

- Request an increase in equity thickness following Concentric's recommendation of an equity thickness range of 45% to 50%
- Request a cash return on Construction Work in Progress (CWIP)
- Request higher return on equity (ROE)

Path Forward

- Considering the current affordability context, keeping financing costs as low for customers in the future, Hydro One will:
    - Request 45% equity thickness, the lower end of the Concentric recommendation. This will support Hydro One's ability to attract capital, maintain financial integrity, and compete with its North American peers
    - Not pursue a cash return on CWIP or a higher ROE at this time

CUSTOM IR APPLICATION SUMMARY

1.0 INTRODUCTION

This Exhibit describes Hydro One's and Hydro One Sault Ste. Marie LP's (HOSSM, together, Hydro One) proposed rates framework for the 2028 to 2032 rate period. The proposal includes an evolved Custom Incentive Rate-setting (Custom IR) framework for determining annual revenue requirement adjustments after the 2028 rebasing year, together with broader revenue requirement features addressing cost of capital, earnings sharing, uncertainty and the allocation of risk between Hydro One and its customers.

The proposed framework is designed to provide the funding required to deliver safe and reliable service and undertake the investments needed to support electrification, customer connections, economic growth, and system reliability and resilience. At the same time, the framework incorporates meaningful productivity incentives, affordability considerations, and customer protections. In developing the framework, Hydro One sought to balance the following priorities:

- Providing safe and reliable service in compliance with Hydro One's obligations, and meeting generational investment requirements associated with electrification, customer connections and Ontario's economic growth;
- Maintaining access to low-cost funding to support work to deliver that service;
- Relying on sound economic principles, independent econometric benchmarking and well-supported utility forecasts;
- Providing customers with value for money through achievable productivity requirements and the opportunity to share in earnings above an approved threshold;
- Moderating customer bill impacts; and
- Managing risk as reasonably as possible in light of increased uncertainty.

Consistent with the principles of the Renewed Regulatory Framework (RRF) and the *Handbook for Utility Rate Applications* (the Handbook), Hydro One proposes a five-year custom revenue cap framework. Rates for 2028 would be established on a cost-of-service

basis, with annual revenue requirement adjustments for 2029 to 2032 determined through a Custom Revenue Cap Index (RCI). The Custom IR framework retains established components, including the Inflation Factor and X-factor, proposes modifications to the inflation adjustment of the C-factor, and introduces a Growth Factor and an OM&A Input Price Differential to better reflect operating circumstances. It also maintains customer protections through the cumulative application of productivity requirements, a supplemental capital stretch factor, and an Earnings Sharing Mechanism.

This Exhibit also addresses broader revenue requirement features, including proposed equity thickness, deferral and variance accounts, and the continued availability of a Z-factor mechanism. While the Custom IR formula establishes the principal funding methodology, the broader revenue requirement features address financial integrity and circumstances that cannot reasonably be managed through ordinary productivity or forecasting.

This Exhibit is organized as follows:

- **Section 2** explains the continued need for a Custom IR framework, including considering Hydro One's experience during the current rate period and the forecast business environment for 2028 to 2032, and why an I-X revenue cap would not provide sufficient funding.
- **Section 3** describes the proposed Custom IR framework components, including the Inflation Factor, X-factor, Growth Factor, OM&A Input Price Differential and Custom Capital Factor.
- **Section 4** describes the broader features that complement the Custom IR framework, including the Earnings Sharing Mechanism, cost of capital proposal, flexibility mechanisms, and Z-factor.
- **Section 5** describes alternatives Hydro One considered in developing the Custom IR framework and its broader revenue requirement proposal.
- **Section 6** explains how the proposed framework, considered as a whole, balances funding needs, customer affordability, productivity incentives, financial integrity, and allocation of risk.

Supporting calculations and parameters for the Transmission and Distribution Custom IR formulae are provided in Exhibit A-04-02 and Exhibit A-04-03, respectively. The independent econometric benchmarking study results supporting the Custom IR parameters are provided in Exhibit A-04-01 Attachment 1: the Clearspring Energy Advisors Report. Further evidence concerning cost of capital and the proposed deferral and variance accounts is provided in Exhibit F-01-01 and Exhibit G-01-03, respectively.

2.0 THE NEED FOR A CUSTOM IR FRAMEWORK

2.1 CURRENT RATE PERIOD EXPERIENCE AND FORECAST BUSINESS CONDITIONS

Hydro One's experience during the current rate period highlights challenges associated with a framework that does not fully respond when costs and demand unexpectedly and materially depart from forecast. Hydro One has experienced sustained inflation, supply-chain constraints, evolving energy policy, international trade and tariff uncertainty and increasing requests to connect customers and expand and reinforce the electricity system. This increased the cost and volume of some demand work at a time when Hydro One remained subject to funding envelopes established using earlier assumptions.

Hydro One had to reprioritize certain work and defer planned expenditures, to address the most immediate needs while staying approximately within fixed funding envelopes. However, this shifted various work and costs into future periods.

In the 2028 to 2032 rate period, Hydro One must deliver a substantially larger and more complex program that will serve significant demand growth, connect new customers and generation, expand and reinforce the grid, replace aging assets, meet reliability and compliance obligations, improve resilience, and provide the technology, facilities, fleet and other shared capabilities required to support its operations. It will undertake this work in a period of heightened overall business and financial risk.[1]

[1] Concentric Report, Exhibit F-01-01, Attachment 1, pp. 10–12, 19–37.

These circumstances expose Hydro One to greater potential forecasting, inflation, supply-chain, and financing risk. The proposed capital and OM&A investments require specialized equipment, use of external contractors, and increase Hydro One's reliance on timely permitting, approvals and material deliveries. Actual load demand may differ somewhat from forecast. Severe weather, cybersecurity threats, evolving compliance obligations and economic or trade developments may also create additional pressures or requirements.

2.2 A STANDARD I – X APPROACH IS INSUFFICIENT

The OEB-approved settlement in Hydro One's last rebasing application, EB-2021-0110, included a commitment to consider potential alternatives to establishing revenue requirement and rates:

> Hydro One will consider potential alternative approach(es) for establishing the revenue requirement and/or rates for the years following the base year, while meeting OEB Renewed Regulatory Framework ("RRF") objectives and striking an appropriate balance of risk between customers and the utility. If Hydro One applies for another Custom IR in its next cost-based rate application, it will provide evidence regarding potential alternative approach(es) that were considered and why they were rejected.

After considering potential alternatives, Hydro One is proposing to continue certain rate-setting elements and is introducing new or revised components. First, Hydro One considered whether a Revenue Cap Index, in which 2028 rates would be escalated thereafter by Inflation (I) minus a stretch and productivity factor (X), could provide the funding required by the Transmission or Distribution businesses. In both cases, an I-X Revenue Cap Index does not provide the funding necessary for Hydro One's investment needs.

Figure 1 below depicts Hydro One's Transmission revenue requirement forecast over the 2028 to 2032 period as compared to funding provided by a Revenue Cap Index. Figure 2 shows the annual variance in funding between them.

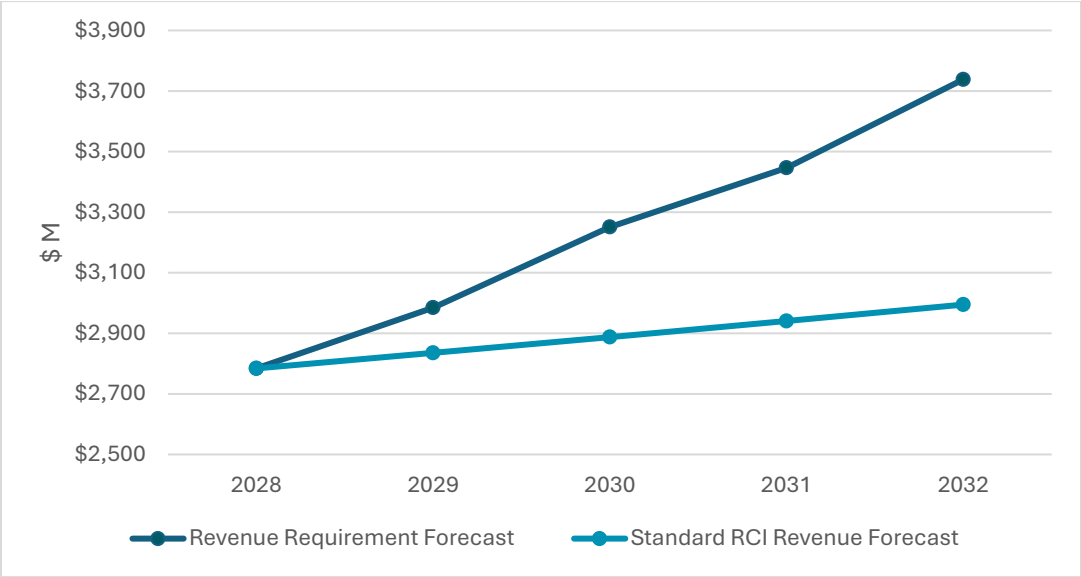


Figure 1: Transmission Revenue Requirement Forecast v. Standard RCI Revenues

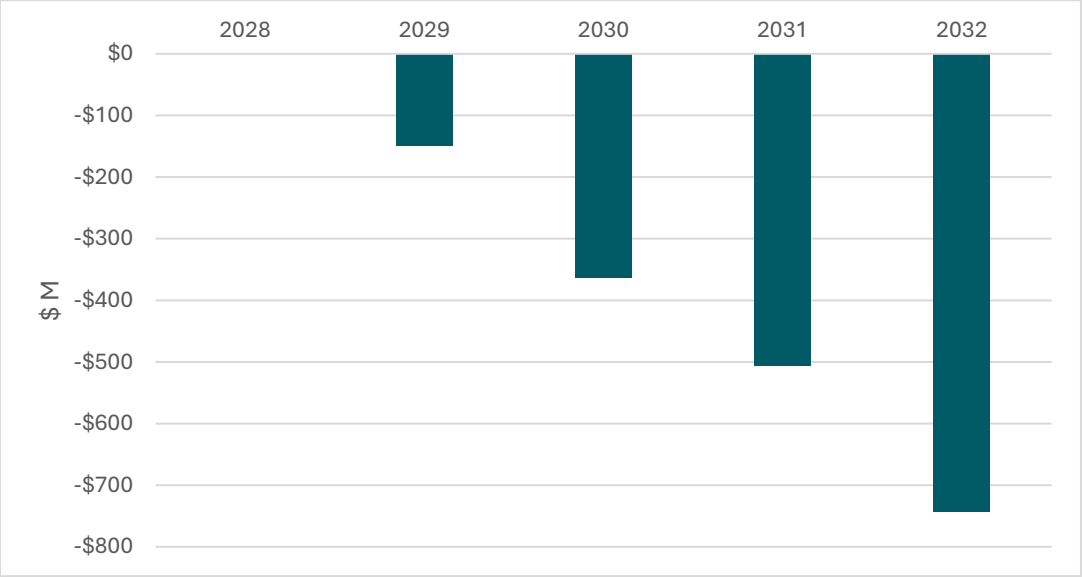


Figure 2: Transmission Variance - Revenue Requirement to Revenue Cap Index

A Revenue Cap Index could underfund Hydro One's Transmission business over the 2029 to 2032 period by $1.76B. In 2032, underfunding would amount to 20% of Hydro One Transmission's needs in that year alone. It assumes a smooth revenue trajectory and does not reflect the variable funding requirements of Hydro One's large and complex

transmission capital program. The timing of capital-related revenue requirement depends on when major projects commence, the progression of expenditures through the project lifecycle and when assets are placed in service. It is impractical to attempt to fit the variable funding needs of this critical work within the comparatively uniform funding produced by an I-X Revenue Cap Index.

An I-X Revenue Cap Index would also not adequately reflect the cost of renewing Hydro One's aging transmission asset base. As discussed in the Clearspring Report,[2] the current revenue requirement reflects, in part, the historical cost of assets placed in service decades ago, while replacement investments must be undertaken at current costs that incorporate the cumulative effect of inflation over the intervening period. As a result, indexing the existing revenue requirement would not provide sufficient funding to support the required level of asset renewal.

A Revenue Cap Index would require significant spending reductions to projects and programs that deliver safe and reliable transmission service, mandatory transmission customer services like new connections, compliance obligations including NERC requirements, and the Provincial government's policy direction in the Integrated Energy Plan (IEP), *Energy for Generations*. It would also impede Hydro One's ability to earn a fair return. It is not a reasonable or feasible option in the circumstances.

Figure 3 below depicts Hydro One's Distribution revenue requirement forecast over the 2028 to 2032 period as compared to funding provided by a Revenue Cap Index. Figure 4 shows the annual variance in funding.

[2] Clearspring Report, Exhibit A-04-01, Attachment 1, p. 15, section 2.5.1 and footnote 12

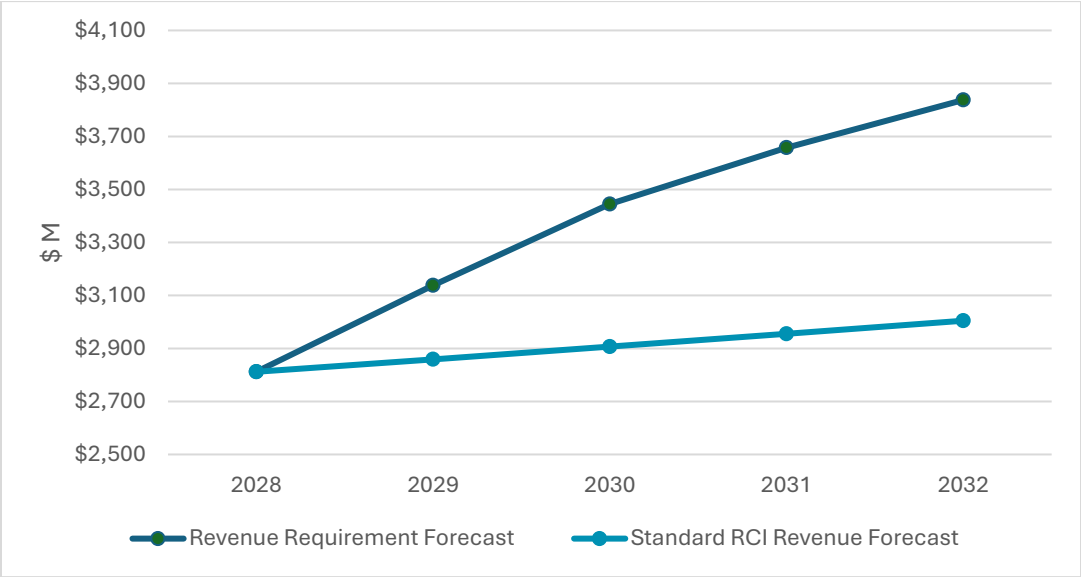


Figure 3: Distribution Revenue Requirement Forecast v. Standard RCI Revenues

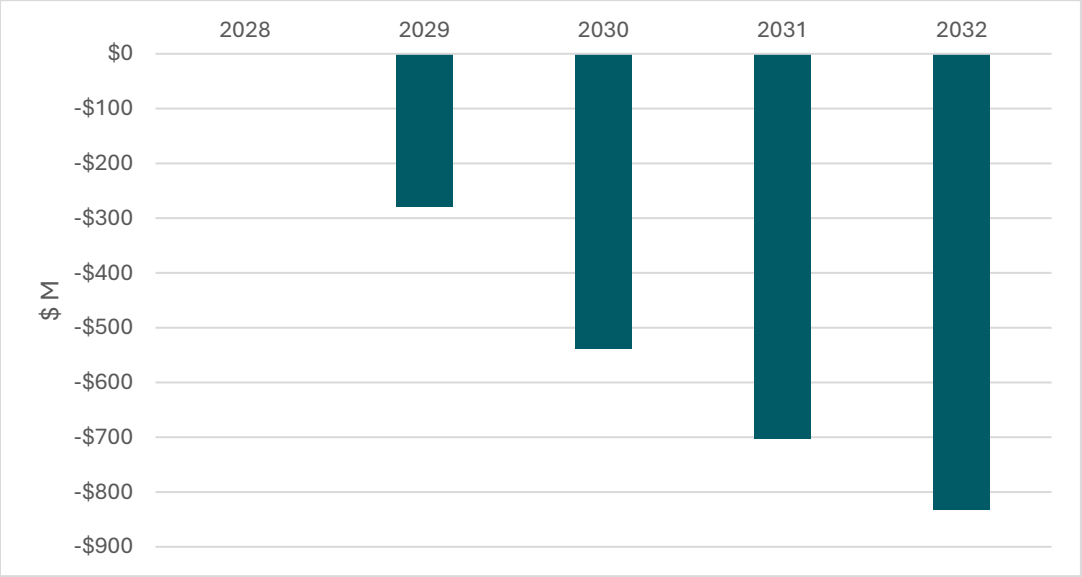


Figure 4: Distribution Variance - Revenue Requirement to Revenue Cap Index

Similar to Transmission, a Revenue Cap Index could underfund Hydro One's Distribution business over the 2029 to 2032 period by $2.35B. In 2032, underfunding would amount to 22% of Hydro One Distribution's needs in that year alone. A Revenue Cap Index would require significant spending reductions to projects and programs that deliver safe and

reliable distribution service, including the vegetation management program, mandatory distribution customer services like new connections, stations and lines maintenance, compliance obligations, and the Provincial government's policy direction in the Integrated Energy Plan (IEP), *Energy for Generations* associated with grid modernization, resiliency and Distributed Energy Resources. It would also impede Hydro One's ability to earn a fair return. It is not a reasonable or feasible option in the circumstances.

Hydro One's objective is to propose a rate-setting framework that facilitates the funding of the proposed capital and OM&A plans, and appropriately balances risk between customers and Hydro One, including offering customers a material amount of productivity savings. Hydro One has thus updated and evolved its proposed Custom IR framework for the 2028-2032 period in several respects, compared to its previous framework. Section 3.0 below summarizes the updates and evolutions.

3.0 PROPOSED CUSTOM IR FRAMEWORK COMPONENTS

This proposed framework is a Custom IR approach for a 5-year period. The methodology is a Revenue Cap IR in which the initial 2028 Test Year is established on the basis of Cost of Service, and funding from 2029 through 2032 is established on the basis of an RCI. Revenue for the year t+1 is equal to the revenue requirement in year t inflated by the RCI. This approach is applied separately to the Transmission and Distribution businesses, however the methodology and elements of the RCI are the same for both. This Exhibit describes the elements of this methodology. Details regarding the specific parameters for the Transmission and Distribution businesses are provided in Exhibits A-04-02 and A-04-03, respectively.

The Custom RCI is expressed as follows:

$$RCI = I - X + G + IPD_{OM\&A} + C$$

Where:

- "I" is the Inflation Factor, based on the OEB's two factor input-price index;
- "X" is the Productivity Factor, equal to the sum of Hydro One's base productivity factor informed by Clearspring's Industry Total Factor Productivity study, and Hydro One's Custom Productivity Stretch Factor informed by Clearspring's total cost benchmarking study, but without allowing the X-factor to become negative;
- "G" is the Growth Factor, based on increasing real (non-inflated) costs driven by growth in the measured outputs applicable to each business - transmission line length and transmission peak demand for Transmission, and increasing customer count and increasing system peak demand for Distribution;
- "$IPD_{OM\&A}$" is the Input Price Differential capturing the difference between OEB-established Inflation Factors and inflation factors more specific to Hydro One, scaled to reflect the OM&A portion of revenue requirement;
- "C" is Hydro One's Custom Capital Factor, designed to recover incremental revenue each year necessary to support Hydro One's proposed system plans, beyond the amount of revenue recovered through the I – X adjustment, but reduced by a supplemental stretch factor on capital of 0.15%.

The revenue requirement in the first year of the 5-year period (2028) is determined using a cost of service, forward test year approach, consistent with the OEB's RRF and the Handbook. The revenue requirement in each of the following years, 2029-2032, is determined using the RCI. The proposed methodology is an evolved and updated framework that contains elements of and builds upon the prior approved framework in Hydro One's prior rate Application (EB-2021-0110).

3.1 UPDATES TO THE FRAMEWORK

As stated, Hydro One's framework retains certain substantive elements consistent with the Custom RCIs approved by the OEB for Hydro One Transmission and Distribution businesses in EB-2021-0110, including the following:

- Supplemental stretch factors applicable to Transmission and Distribution capital related revenue requirement are proposed as pro-active reductions to Hydro One's forecast costs, to the benefit of ratepayers;

- Combined productivity and stretch factors (collectively, "X-factors") continue to be applied on a cumulative basis to capital related revenue requirement, comparable to the accumulation of X-factor revenue reductions to OM&A funding;
- OM&A funding continues to be established for years 2 through 5 of the Custom IR term based on an index reliant upon independent expert econometric benchmarking and analyses;
- Capital related revenue requirement funding continues to be established on the basis of a C-factor which is designed to recover incremental revenue each year necessary to support Hydro One's proposed system plans, beyond the amount of revenue recovered through the I – X + G adjustment, but reduced by a supplemental stretch factor on capital, in this case of 0.15%; and
- The C-factor values for the years 2029 through 2032 will continue to be updated in Hydro One's Annual Update Applications to reflect the most current OEB Inflation Factors applicable to those years.

With respect to updates and evolutions to the prior Custom IR framework, Hydro One is proposing the following:

- The addition of a Growth Factor in the proposed RCI to capture the incremental year-over-year real (non-inflated) costs driven by growth in the applicable Transmission and Distribution outputs. This is further discussed in Section 3.2.3 below, as well as Exhibit A-04-01 Attachment 1
- The addition of an Input Price Differential (IPD) factor applicable to the indexing of OM&A costs, to capture the variance between the OEB's Inflation Factors established on the basis of generic inflation index weightings, and inflation factors established on the basis of Hydro One-specific inflation index weightings. This is further discussed in Section 3.2.4 below, as well as Exhibit A-04-01 Attachment 1;
- A one-time adjustment to Distribution OM&A funding in 2031 to capture the integration of Peterborough and Orillia rate zone costs into Hydro One's broader Distribution funding envelope; and
- The addition of Prepaid Cloud Computing Amortization recovery in the capital related revenue requirement used to derive the C-factor to align rate-setting with

Hydro One's USGAAP-compliant accounting practices. This is further discussed in Section 3.2.5 below, as well as Exhibit E-08-01.

3.2 COMPONENTS OF THE CUSTOM RCI

The individual components of the proposed Custom RCI are further described below.

3.2.1 INFLATION FACTOR

The proposed Inflation Factor (I) is based on the weighted average of the annual percent change of two labour and non-labour indices, namely:

- Canada's GDP-IPI (FDD) as reported by Statistics Canada; and
- Average Weekly Earnings for workers in Ontario, as reported by Statistics Canada.

The industry-specific weightings and pro-forma Inflation Factors for the Transmission and Distribution businesses are set out in Exhibit A-04-02 and Exhibit A-04-03, respectively. The Inflation Factor will be updated annually to reflect the latest values issued by the OEB.

3.2.2 X-FACTOR

The X-factor is the sum of two productivity factors: a base productivity factor and a stretch factor. The base productivity factor is reflective of long-term industry productivity trends which are not specific to any one utility but are representative of broad directional changes in costs relative to unit outputs. As directed in EB-2021-0110, Hydro One engaged its third-party expert Clearspring to conduct Total Factor Productivity studies applicable to both Transmission and Distribution. The results of those studies are at Exhibit A-04-01 Attachment 1. The resulting industry-specific productivity factors have been incorporated into the combined X-factors applicable to Transmission and Distribution, as outlined in Exhibit A-04-02 and Exhibit A-04-03, respectively.

The stretch factors included in the Transmission and Distribution X-factors have been determined on the basis of total cost benchmarking studies completed by Clearspring and provided in Exhibit A-04-01 Attachment 1.

The X-factors for each of Transmission and Distribution, made up of their respective base productivity and stretch factor components, are applied to the revenue requirement in years 2 through 5 (2029 through 2032) of the Custom IR term.

3.2.3 GROWTH FACTOR

Hydro One's Growth Factor (G-factor) is designed to reflect the reality of and account for increased costs associated with forecast growth in the measured outputs applicable to each business. For Transmission, those outputs are transmission line length and transmission peak demand. For Distribution, they are customer count and system peak demand. Derivation of the appropriate G-factors applicable to Transmission and Distribution have been completed by Clearspring. The Clearspring Report assesses the effect of growth in the applicable Transmission and Distribution outputs on non-inflated utility costs.

The inclusion of a G-factor in the framework rectifies a historical gap in prior Custom IR frameworks implemented by Hydro One. Specifically, and as highlighted by Clearspring, there is a clear and logical link between growth in the applicable Transmission and Distribution outputs and resulting growth in cost.[3]

Under the OEB's Price Cap IR – the rate setting framework most often proposed by other Ontario utilities – it is understood that incremental growth-related Distribution costs can be funded in part by incremental revenues resulting from growth in billing determinants (i.e. customers, consumption, and demand). Under a Revenue Cap structure, rates are designed annually based on forecast billing determinants which include forecasted growth. As a result, where Price Cap IR utilities retain the incremental revenues derived from billing determinant growth, Revenue Cap utilities do not retain these revenues. This creates a gap wherein absent a Growth Factor, Revenue Cap utilities are funded only for inflationary cost increases (i.e. higher costs for the same number of units), without being compensated for growth-based cost increases (i.e. more units). For Transmission, the same underlying

[3] Clearspring Report, Exhibit A-04-01, Attachment 1, p.10, section 2.2

principle applies, although the relevant outputs reflect the expected cost consequences of growth in the applicable Transmission outputs.

In the past, the lack of a growth-specific funding component has not negatively impacted Hydro One's capital related revenue requirement, as the incorporation of capital forecasts in the derivation of the C-factor allowed Hydro One to include and fund the forecasted cost of growth (subject to the supplemental stretch on capital). No such relief existed, however, for Hydro One's operating expenditures. Hydro One has historically been provided funding for OM&A on the basis of first-year OM&A, escalated in years 2 through 5 of the rate term solely by inflation less an X-factor. This approach mathematically implies that growth in the applicable Transmission and Distribution outputs places no upward pressure on operating expenditures. The result has been an implicit additional stretch on Hydro One's OM&A, requiring the Company to either fund through revenues or productivity the additional OM&A needed to operate and maintain growing Transmission and Distribution systems or reprioritize work to manage within the OEB-approved OM&A.

This historical gap should be addressed moving forward. Hydro One's proposed G-factor addresses the above historical gap in a manner that is consistent in principle with standard Price Cap IR under the RRF, and consistent in practice with some recently approved Custom IR applications.[4]

Hydro One proposes a single average-based G-factor value in each of its Transmission and Distribution businesses, which will apply evenly through the 2029 to 2032 period. The value for the G-factor is not proposed to be updated in Annual Update applications.

[4] E.g. EB-2023-0195, EB-2024-0115

3.2.4 INPUT PRICE DIFFERENTIAL

Hydro One's proposed $IPD_{OM\&A}$ factor refines the inflation component of the Custom RCI and improves the accuracy of the index by aligning the labour and non-labour weights with Hydro One's actual cost structure. This better reflects Hydro One's operating circumstances and funding requirements. The detailed rationale for the proposed $IPD_{OM\&A}$ factor and the calculation of it are included in the Clearspring Report at sections 2.3 and 10 (Exhibit A-04-01 Attachment 1).

As outlined in the Clearspring Report, the OEB's annually published Inflation Factors for transmitters and distributors rely upon assumed weightings of labour (represented by the Average Weekly Earnings in Ontario) and non-labour (represented by Canada's GDP-IPI-FDD). For Transmission it assumes a generic 14% labour and 86% non-labour weighting and for Distribution it assumes a generic 30% labour and 70% non-labour weighting. These assumptions are different than Hydro One's actual labour and non-labour weightings for its OM&A expenditures. An inflation index used to escalate OM&A should reflect the relative weightings of labour and non-labour inputs actually used to provide OM&A programs.

The $IPD_{OM\&A}$ adjustment is derived based on the weighting of Hydro One's 2025 labour and non-labour OM&A costs. In support of regulatory efficiency, Hydro One has not proposed a Hydro One-specific inflation factor in lieu of the OEB's annually published Inflation Factor. Rather, Hydro One has proposed continued reliance on the OEB's Inflation Factors, augmented by the $IPD_{OM\&A}$ factor.

Given that the IPD calculated by Clearspring is specific to OM&A, and in light of Hydro One's proposed approach to capital funding via the C-Factor, the IPD value determined must be scaled to provide only incremental funding for Hydro One's OM&A, as opposed to its entire revenue requirement. This is accomplished by pro-rating the IPD value to the scale of Hydro One's OM&A relative to its total revenue requirement, converting the IPD value into the proposed $IPD_{OM\&A}$ factor. This factor is proposed to be applied as a single average-based value for each year, 2029 through 2032, for each of Transmission and

Distribution, respectively. The value for $IPD_{OM\&A}$ is not proposed to be updated in Annual Update applications. The values for the IPD, OM&A scaling and annual $IPD_{OM\&A}$ are described in Exhibit A-04-02 for Transmission and Exhibit A-04-03 for Distribution.

3.2.5 CUSTOM CAPITAL FACTOR

The C-factor is designed to provide the incremental revenue requirement associated with Hydro One's forecast rate base and prepaid cloud computing implementation costs (as further described below) that are not otherwise recovered through the I – X + G adjustment. It supports the necessary capital investments in the Transmission System Plan, Distribution System Plan and General Plant System Plan, while ensuring that appropriate incentives are in place with up front benefits to ratepayers through the X-Factor and supplemental stretch factor.

The C-factor is derived based on the percentage change in the total revenue requirement attributable to new rate base that is not otherwise recovered through the I – X + G adjustment. It includes depreciation, return on equity, interest and taxes attributable to rate base additions each year of the Custom IR term. The working capital allowance is not included in the derivation of the C-factor, consistent with the treatment of this element in Hydro One's prior Application and prior OEB Decisions. New in this Application relative to the prior Application is the inclusion of Prepaid Cloud Computing Amortization in the capital-related revenue requirement used to derive the C-factor. As detailed in Exhibit E-08-01, cloud computing arrangements that are service contracts are accounted for under U.S. GAAP by recording eligible implementation costs as prepaid assets.

Inclusion of Prepaid Cloud Computing Amortization in the C-factor is appropriate for two primary reasons. First, while cloud computing implementation costs are not being capitalized, prepaid assets are being amortized over the length of the cloud service arrangement. This is comparable to the depreciation of capital assets over their useful lives. Given the similar financial treatment of capitalized asset amortization and Prepaid Cloud Computing Amortization, it is reasonable to provide similar rate-making treatment. Second, as shown in Exhibit E-08-01, increases to the cost of Prepaid Cloud Computing

Amortization cannot be funded under a traditional OM&A index and require a more explicit funding approach. Taking Hydro One Transmission as an example, escalating 2028 Prepaid Cloud Computing Amortization by the proposed OM&A index of I – X + G + IPD would underfund cloud computing by $117M, or 52% relative to Hydro One's needs.

Hydro One is proposing a Supplemental Stretch factor on capital of 0.15% in respect of both the Transmission and Distribution businesses. The Supplemental Stretch is an additional benefit beyond the productivity and stretch factors informed and supported by the Clearspring econometric analysis. The inclusion of a supplemental stretch factor is consistent with the prior Application and prior OEB Decisions, and reflects Hydro One's continued commitment to productivity and affordability. Hydro One will use its productivity framework, described in SPF Section 1.4, to achieve this Supplemental Stretch (along with the X-factor), and to ensure Hydro One is meeting its planned deliverables and outcomes at a lower cost.

As described in SPF Section 1.4, Hydro One's productivity framework has previously been independently reviewed and validated by Concentric Energy Advisors (Concentric). As was noted by Concentric, early in a productivity program, readily identifiable opportunities can be captured more easily, and over successive rate periods, new productivity initiatives and cost savings (that meet the rigorous standards of the program) become progressively more difficult to identify and achieve, particularly since Hydro One has already achieved significant savings under the program. If capital and OM&A productivity requirements in the rate framework exceed reasonably achievable levels, utilities may in turn need to defer work that supports reliability, growth and customer benefits. This is not a desirable outcome, particularly during a period of system expansion and electrification. Therefore, and as reflected in the proposed capital and OM&A productivity and supplemental stretch factors, Hydro One's goal is to offer customers a commensurate level of productivity savings as was offered in the prior Application as a target that can realistically be achieved. The rate-setting framework should continue to incent achievable productivity; not embed productivity assumptions at levels that effectively require necessary work to be reduced. Doing so would undermine, rather than advance, the objectives of incentive regulation by

effectively converting an expectation of efficiency into an implicit reduction in system outputs and customer benefits.

The Supplemental Stretch factor, along with the X-factor, will be applied in a cumulative manner in each year of the test period, and will be incorporated directly into the derivation of the C-factor. This results in a significant upfront revenue requirement reduction for customers. Details on the calculation of the C-factor are provided for Transmission and Distribution in Exhibit A-04-02 and Exhibit A-04-03, respectively. These calculations will be finalized through the Draft Rate Order process using the OEB-approved values.

4.0 ADDITIONAL REVENUE REQUIREMENT FEATURES

Hydro One is proposing the following revenue requirement features to align its interests with those of customers and to provide additional elements of protection for customers.

4.1 EARNINGS SHARING MECHANISM (ESM)

Hydro One proposes sharing with customers 50% of any cumulative earnings over the entire five-year Custom IR term that exceed the OEB-approved regulatory ROE by more than 100 basis points for each of Hydro One Transmission, Hydro One Distribution and HOSSM. The customer share of the earnings will be grossed-up for the associated tax impact and will be credited to a deferral account for clearance at the time of Hydro One's next rebasing. The calculation of the actual ROE will use the actual rate base consistent with the RRR filing guideline. Further details on Hydro One's ESM are provided in Exhibit G-01-03 and on HOSSM's ESM in Exhibit G-01-04.

4.2 COST OF CAPITAL PROPOSAL

As described in Exhibit F-01-01, Hydro One proposes to increase its deemed equity thickness from 40% to 45% for both its Transmission and Distribution businesses, beginning in 2028. The increase is required to reflect the material change in Hydro One's business and financial risk as it undertakes a substantially larger infrastructure program to support system growth, electrification, reliability and resilience. The financial risk environment has intensified, with global capital markets expected to be significantly more

volatile and uncertain than they have been over the past two decades. Concurrently, utilities worldwide are competing for investment capital against governments and technology firms raising unprecedented amounts of funding, increasing the difficulty of obtaining the capital necessary to finance utility investments on terms comparable to those available in the past. The associated financing requirements will place significant pressure on Hydro One's balance sheet and credit metrics. Without additional equity support, key credit metrics are forecast to deteriorate below thresholds associated with Hydro One's current credit ratings, increasing the risk of downgrades in the near term and higher debt financing costs that would ultimately be borne by customers.

Concentric's independent analysis concludes that Hydro One's current 40% deemed equity ratio is insufficient to satisfy the Fair Return Standard when considered together with Hydro One's risk profile, projected capital requirements and the returns available from comparable North American utility investments. Concentric identifies an appropriate equity thickness range of 45% to 50% and recommends the midpoint of 47.5%. The range is supported by peer capital structures, North American transmission and distribution utility benchmarks and Hydro One's projected credit metrics. Concentric also concludes that a higher equity ratio is needed to maintain financial integrity, attract the substantial incremental capital required over the 2028 to 2032 period on reasonable terms, and remain competitive with utilities of comparable risk.

Hydro One's proposed 45% equity thickness is at the lower end of Concentric's recommended range. Rather than seeking the 47.5% midpoint, Hydro One selected 45% to balance the need for a stronger, more resilient capital structure against customer affordability. The proposal provides reasonable support for credit quality and access to capital while moderating the near-term revenue requirement and bill impact. It therefore represents a measured and balanced response to Hydro One's increased financing needs and risk profile, rather than the full adjustment supported by the expert evidence. See Exhibit F-01-01 for further details.

4.3 REGULATORY MECHANISMS

Hydro One proposes deferral and variance accounts to manage material uncertainty that cannot be reasonably forecast or controlled over a five-year rate period. Collectively, the accounts preserve Hydro One's ability to respond to mandatory or externally driven requirements without displacing approved reliability, renewal and compliance work, while protecting customers from paying for costs that may not arise. Further details are provided in Exhibit G-01-03.

- **Transmission Externally Driven Work.** The existing account approved in Hydro One's prior Application (EB-2021-0110) was limited to variances in mandatory transmission construction, expansion, reinforcement, modification and relocation work required through governmental authorities, agencies, Crown corporations, regulation, policy changes or official directives. Hydro One proposes to clarify and broaden the scope to include mandatory work arising from IESO bulk and regional planning recommendations and similar instruments where Hydro One is expected or directed to undertake the work, including by virtue of its existing facilities or role as the lead or default transmitter. This modification is necessary because the timing, scope and cost of externally directed projects may change materially after rates are set, as projects may be introduced, advanced, delayed or cancelled by parties outside Hydro One's control. A symmetrical account allows Hydro One to deliver required work without redirecting funding from System Renewal while ensuring customers receive the benefit where actual in-service additions are below the approved baseline.

- **Distribution Externally Driven Work.** The existing account approved in Hydro One's prior Application (EB-2021-0110) was narrower in scope and did not fully address the scale or variability of distribution work now being driven by electrification, housing development and customer connection demand. Hydro One proposes to modify the account to capture qualifying variances in externally driven distribution investments, including customer connection and related system work that may arise or materially change during the rate period. The account is

necessary because the location, timing, scale and technical requirements of these projects depend on customer and government-led developments that cannot be forecast with precision when rates are set. It benefits customers by supporting timely connections and economic growth without displacing planned investments in safety, reliability and asset renewal, while ensuring any applicable underspending is returned to customers.

- **Change of Laws.** The proposed Transmission and Distribution Change of Laws Deferral Accounts would capture material incremental cost or revenue requirement impacts arising from new or amended legal and regulatory requirements during the rate period that were not known or reasonably foreseeable when the Application was prepared. The accounts would exclude general inflation, ordinary supply-chain escalation, routine project-cost increases and costs already reflected in the Application or another approved account. Hydro One is identifying potential changes of law prospectively while limiting eligibility to unforeseen and material changes. This allows Hydro One to comply promptly with mandatory requirements without undermining its approved work plan.

- **Cyber Security.** The proposed symmetrical Cyber Security Variance Accounts would capture the revenue requirement impacts of material, incremental capital and prepaid investments required to address new, amended or accelerated cybersecurity compliance obligations that are not reflected in the approved plan. These requirements may arise from evolving NERC Critical Infrastructure Protection standards, legislation, regulatory directives, incident-reporting obligations or other mandatory critical-infrastructure requirements whose scope and timing cannot be reliably forecast. The accounts are necessary because delaying compliance could expose the electricity system and customers to security, reliability and enforcement risks, while absorbing unplanned costs within existing envelopes could displace approved renewal and reliability work. Customers benefit from timely protection of critical infrastructure, recovery limited

to prudently incurred compliance costs, and symmetrical treatment under which underspending relative to the approved baseline is returned to customers.

- **Digital and Technology Services Operations.** The proposed DTS Operations Variance Accounts would record the difference between actual third-party technology operating costs and the funding provided through the Custom IR framework. Eligible costs would include essential software licences, maintenance and subscriptions, cloud services, telecommunications, cybersecurity tools, hardware maintenance and other vendor-supported technologies used to operate the system safely and reliably, support field and outage operations, protect critical infrastructure and provide customer services. The accounts are necessary because Hydro One's expanding digital footprint, changing vendor pricing models, security requirements and increasing data and telecommunications needs may cause essential third-party costs to rise materially faster than the I-X+G funding adjustment. The accounts benefit customers by maintaining reliable and secure technology services without building uncertain future escalation into base rates in advance. Any recovery would remain subject to Hydro One demonstrating that the costs were prudently incurred, incremental and cost-effective, with continued expectations for mitigation and vendor-cost management.

4.4 Z-FACTOR

Consistent with the Handbook, Hydro One is proposing that the OEB's Z-factor mechanism be available during this Custom IR term. The criteria that Hydro One proposes to apply to the use of the Z-factor mechanism are those approved by the OEB in EB-2021-0110.[5] Specifically, Z-factor claims must be outside the control of Hydro One to manage, exceed a $4M materiality threshold on a revenue requirement basis for Hydro One, and for HOSSM calculated as 0.65% of its approved revenue requirement, and meet all of the following criteria on an individual event basis:

[5] See also EB-2017-0047 Decision and Order p 42; EB-2019-0082 Decision and Order, p 41

Criteria	Description
Causation	Amounts should be directly related to the Z-factor event. The amount must be clearly outside of the base upon which rates were derived.
Materiality	The amounts must exceed the relevant materiality threshold on a revenue requirement basis and have a significant influence on the operation of the utility; otherwise they should be expensed in the normal course and addressed through organizational productivity improvements.
Prudence	The amount must have been prudently incurred. This means that the utility's decision to incur the amount must represent the most cost-effective option (not necessarily least initial cost) for ratepayers.

5.0 OTHER ALTERNATIVES CONSIDERED

Hydro One considered other alternatives, in respect of both the design of components of its Custom IR framework and its broader revenue requirement proposal. It did not pursue the alternatives below because they would increase complexity or rate volatility, shift additional risk to customers, and/or produce outcomes inconsistent with affordability and reliable service.

5.1 CUSTOM IR FRAMEWORK ALTERNATIVES

- **Revenue Growth Factor or Forecast Annual OM&A.** Hydro One considered approaches that blend forecast OM&A and capital requirements through a Revenue Growth Factor or establish OM&A funding separately for each year. These approaches were rejected because they would weaken the link between the C-factor and forecast capital in-service additions and reduce the incentive properties of indexed OM&A. Accordingly, Hydro One retains the risk that actual OM&A exceeds funding provided through I-X, the Growth Factor and the $IPD_{OM\&A}$.

- **Capital Input Price Differential or Actual Inflation True-up**. Hydro One considered a capital IPD and an actual-cost inflation true-up. Hydro One instead proposes the C-factor treatment described in section 3.2.5.

- **Negative Transmission X-factor**. Hydro One considered applying the negative Transmission productivity factor that is supported and warranted by the econometric analysis (as discussed in the Clearspring Report). This approach was rejected, however, because it would increase OM&A. Hydro One instead capped the X-factor at zero and retains the risk that actual OM&A exceeds funding provided through inflation, growth and the $IPD_{OM\&A}$.

- **No supplemental capital stretch**. Hydro One considered only proposing the productivity and stretch factors supported by Clearspring's econometric studies. This approach was rejected so that Hydro One could provide customers with an additional upfront benefit and productivity savings broadly commensurate with Hydro One's prior Application (EB-2021-0110) (and, as noted further above, the inclusion of supplemental stretch factor is consistent with prior approved rate frameworks). Hydro One bears the risk of achieving the proposed 0.15% supplemental stretch for both Transmission and Distribution.

- **Application of the Capital Stretch Factor.** Hydro One considered applying the capital productivity factor only to capital placed in service during the rate period, because applying it to the entire rate base raises a methodological issue regarding the productivity achievable from assets already in service. However, Hydro One is not proposing this methodological change at this point and therefore bears the higher implied productivity requirement produced by applying the factor to total capital-related revenue requirement.

- **Continuation of the EB-2021-0110 inflation-neutral C-factor**. Hydro One considered reverting to a fixed C-factor (i.e., a C-factor not recalculated annually to account for the OEB inflation factor) as approved in EB-2017-0049. That approach was rejected. Under the proposed treatment, Hydro One retains the risk of not receiving a higher capital-related revenue requirement if the OEB inflation factor is higher than the inflation factor used in this application.

5.2 BROADER ALTERNATIVES AND CONSIDERATIONS

- **Performance Incentive Mechanisms**. Hydro One considered a PIM that would allow it to earn back part of its stretch factor if specified targets were achieved. It rejected a PIM because the issue is expected to be addressed in the OEB's Next Generation Rates Framework consultation and the mechanism could add complexity during significant system expansion. Hydro One retains the existing performance and productivity obligations without an earn back opportunity.

- **Higher ESM deadband.** Hydro One considered increasing the ESM deadband from 100 to 150 basis points to reflect the cumulative productivity obligations associated with multiple incentive regulation terms, including the application of productivity and stretch factors to the overall capital-related revenue requirement rather than solely to incremental capital additions. It rejected the change because it would reduce the potential earnings shared with customers. Hydro One retains the 100-basis-point deadband, shares 50% of upside earnings above that threshold and bears all downside earnings risk.

- **Broader variance accounts**. Hydro One considered accounts for distribution system upgrades driven by load growth, transmission connections and storm damage. It rejected these broader protections to limit risk transfer and reliance on variance mechanisms. Hydro One retains the associated forecast and execution risk, subject to managing within approved funding, spending above the approved envelope or seeking Z-factor treatment where the criteria are met.

- **Higher capital inflation assumptions**. Hydro One considered escalators of 3.81% for Transmission and 5.69% for Distribution based on historical power-equipment inflation. It rejected those assumptions in favour of 2% for non-labour capital costs and 3% for labour costs to moderate bill impacts. Hydro One retains the risk of managing within the OEB-approved capital envelopes if actual inflation is higher.

6.0 BALANCE OF RISK AND CUSTOMER PROTECTION

Hydro One's proposed rates framework balances the need to fund a materially larger and more complex program of work with meaningful incentives, customer protections and continued utility risk. The proposal does not insulate Hydro One from ordinary forecasting, inflation, productivity, execution or earnings risk. Rather, it provides funding mechanisms responsive to the principal cost drivers expected during the 2028 to 2032 period, while maintaining clear limits on recovery and providing customers with upfront and ongoing benefits.

The Custom IR framework incorporates several direct customer protections. The X-factors are supported by independent econometric benchmarking, and Hydro One has capped the Transmission X-factor at zero rather than applying the negative factor supported by the analysis. Hydro One has also proposed an additional 0.15% supplemental stretch factor on capital for both Transmission and Distribution, even though this additional stretch is not supported by econometric analysis and principles. The X-factor and supplemental stretch are applied cumulatively to capital-related revenue requirement, providing customers with an upfront reduction in forecast funding.

Hydro One has also moderated elements of its broader revenue requirement proposal in consideration of affordability, including its proposed equity thickness of 45%, at the low end of Concentric's range (rather than the recommended midpoint of 47.5%), and retaining the existing 100-basis-point ESM deadband and sharing 50% of earnings above that threshold with customers, while continuing to bear all downside earnings risk. Hydro One also retained moderate capital escalation assumptions and did not propose a capital IPD, a utility-specific capital inflation index, an actual-cost true-up or modify the C-factor treatment by fixing its value and allowing capital related revenue requirement to be updated by the OEB's Inflation Factor.

At the same time, the framework includes flexibility mechanisms for material uncertainty that cannot reasonably be forecast or controlled over a five-year rate period. These mechanisms are distinct from broad protection against normal business risk. They are

directed to mandatory, externally driven or rapidly evolving requirements, including externally driven work, changes in law, cybersecurity obligations and essential digital technology operating costs. Recovery is not automatic and remains subject to defined eligibility requirements, materiality, prudence and OEB review. Where the accounts are symmetrical, customers also receive the benefit of eligible underspending.

Overall, Hydro One retains substantial risk that actual costs, demand, inflation and productivity requirements may differ from forecast. The proposed framework addresses only those risks for which a tailored mechanism is reasonably necessary to preserve required work and customer outcomes. The C-factor treatment transfers all capital inflation risk to Hydro One. Customers receive the benefit of stable capital related revenue requirement over the 5-year rate period, while Hydro One remains responsible for managing its work programs based on its actual capital-input inflation and the funding produced by the formula. This approach should be considered together with the cumulative X-factor, supplemental capital stretch, ESM and OEB review of the underlying capital plan.

Benchmarking, Productivity, and Incentive Regulation Parameter Study for Hydro One Networks' Joint Rate Application

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Clearspring Energy Advisors LLC

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1 Executive Summary

Hydro One Networks ("Hydro One" or "Company") engaged Clearspring Energy Advisors, LLC ("Clearspring") to conduct total cost benchmarking, industry productivity trend research, and analysis and recommendations in respect of certain revenue escalation parameters for the Company's upcoming transmission and distribution joint rate application ("JRAP") to the Ontario Energy Board ("OEB" or "Board") and the transmission business of Hydro One Sault Ste. Marie ("HOSSM"). The lead researcher of the research is Mr. Steven A. Fenrick. Mr. Fenrick provided research reports and expert witness testimony on behalf of Hydro One in the Company's prior JRAP[1] and has led numerous empirical studies in Ontario regarding incentive regulation. A copy of Mr. Fenrick's summary *curriculum vitae* is provided in Appendix B.

1.1 Research Study Components

The research conducted and described in this report includes studies that apply to the transmission and distribution businesses of Hydro One and HOSSM. These studies and the recommendation(s) they support are as follows:

1. **Transmission total cost benchmarking of Hydro One**. This study is the basis for our recommendation for the stretch factor for Hydro One's transmission custom incentive regulation ("CIR") proposal.

2. **Transmission total cost benchmarking of HOSSM**. This study is the basis for our recommendation for the stretch factor for HOSSM's transmission CIR proposal.

3. **Distribution total cost benchmarking of Hydro One.** This study is the basis for our recommendation for the stretch factor for Hydro One's distribution CIR proposal.

4. **Transmission U.S. industry Total Factor Productivity ("TFP") trend**. This study is the basis for our recommendation for the transmission base productivity factor component of the X-factor. This result applies to both Hydro One's transmission business and HOSSM.

5. **Distribution U.S. and Ontario industry TFP trend**. These two studies are the basis for our recommendation for the distribution base productivity factor component of the X-factor. We averaged the U.S. and Ontario TFP trends as the basis of Clearspring's recommendation.

6. **Expected cost escalation resulting from Hydro One's transmission business forecasted growth, Hydro One's distribution business forecasted growth, and HOSSM's forecasted growth.** These studies are the basis for our recommendation for the G Factor for each line of business. This G Factor enables the CIR formula to account for expected cost increases related to measured output growth.

7. **Expected OM&A input price inflation for Hydro One transmission, distribution, and HOSSM.** This

[1] EB-2021-0110.

study compares the customized OM&A input price inflation forecasts to the Board's Input Price Index ("IPI") forecasted inflation to calculate and recommend an OM&A input price differential ("IPD") for each line of business. The IPD enables the CIR formula to better account for cost increases related to inflation.

1.2 Study Results and Clearspring Recommendations

A summary of study results and our recommendations is as follows:

1. **Hydro One Transmission stretch factor = 0.15%**. The total cost benchmarking score of -24.7% during the 2028 to 2032 period shows that costs are notably below benchmark expectations, and based on 4GIR precedent, a 0.15% stretch factor is indicated.[2] We understand the Company is proposing a 0.15% incremental stretch factor on capital in addition to the 4GIR 0.15% stretch factor. The 4GIR stretch factor by itself is a considerable productivity challenge given the low-cost benchmarking score.

2. **HOSSM stretch factor = 0.00%**. The HOSSM total cost benchmarking score of -32.8% during the 2028 to 2032 period shows that costs are notably below benchmark expectations, and based on 4GIR precedent, a 0.00% stretch factor is indicated.[3] We understand the Company is also proposing a 0.15% incremental stretch factor on capital.

3. **Hydro One Distribution stretch factor = 0.60%**. The total cost benchmarking score of 25.8% during the 2028 to 2032 period shows that costs are notably above benchmark expectations and indicates a 0.60% stretch factor, based on 4GIR precedent. A positive stretch factor is warranted due to the high-cost benchmarking score. A 0.6% stretch factor plus the 0.15% incremental stretch factor on capital is a considerable productivity challenge for a utility that has already operated within incentive regulation for several years.

4. **Hydro One Transmission base productivity factor = -2.30%**. The U.S. transmission industry TFP trend has declined annually by 2.30% during the most recent 15-year period (2009-2024). Economic theory indicates that a negative base productivity factor should be implemented and would better align cost escalation expectations with the revenue escalation formula. Clearspring therefore recommends that a base productivity factor of -2.30% is warranted for both Hydro One Transmission and HOSSM. Clearspring understands that the Company is proposing a less negative base productivity factor, to the benefit of ratepayers. This is tantamount to adding an additional incremental stretch factor.

5. **Hydro One Distribution base productivity factor = -0.31%**. Clearspring recommends a base productivity factor of -0.31% for Hydro One's distribution plan, which is the average of the U.S.

[2] In the 4th Generation IR proceeding, five stretch factor groupings (cohorts) were established, based on the most recent average three-year total cost benchmarking scores. In that proceeding, a score better than -25% (i.e. costs were more than 25% below benchmark) received the lowest stretch factor of 0.00%. A score between -25% and -10% received a 0.15% stretch factor. Scores that were +/- 10% received 0.30%. Scores between 10% and 25% received a 0.45% stretch factor, and scores exceeding 25% (i.e. costs were 25% or more than benchmark) received the highest stretch factor of 0.60%.

[3] We are of the view for HOSSM and Hydro One Transmission, that a negative stretch factor could be considered.

distribution industry 15-year TFP trend of -0.33% and the Ontario distribution industry 10-year TFP trend of -0.29%.[4]

6. **Hydro One Transmission growth factor = 0.99%, Hydro One Distribution growth factor = 1.17%, and HOSSM growth factor = 0.89%.** Clearspring calculated each growth factor by combining the forecasted growth rates in measured outputs in each econometric model during the CIR period. The weights used to combine the multiple outputs are based on estimated cost elasticity weights in the econometric total cost models. The growth factor estimates the expected cost increases during the CIR period resulting from measured output growth.[5]

7. **Hydro One Transmission OM&A IPD = 0.26%, Hydro One Distribution OM&A IPD = 0.24%, and HOSSM OM&A IPD = 0.24%.** The OM&A IPD is the difference between the Company's expected OM&A input price inflation and the Board's expected IPI inflation during the CIR period. This improves the ability for the revenue escalation formula to track expected OM&A input price inflation.

[4] A 15-year trend for the Ontario industry shows a TFP trend of -0.35% but is being unduly influenced by the transition to IFRS accounting and AMI deferral accounts which mostly cleared prior to 2014. Due to these influences, Clearspring recommends using a 10-year period (2014 to 2024) as the basis for calculating the Ontario productivity trend.

[5] The Growth Factor does not account for unmeasured outputs. This can include several items (e.g., increasing cybersecurity, reliability, DER).

2 The Revenue Escalation Formula

Since the research found in this report ultimately relates to the custom IR revenue escalation formula, an overview of the mathematics underlying the formula is warranted. This section gives a general equation for a generic revenue escalation formula and explains how this formula is determined. It discusses the foundation for including an IPD and a G Factor in the revenue escalation formula, and X Factor considerations.

The following discussion is based on Clearspring's understanding of the Company's proposal in this application. Notably, we understand the Company is not proposing a Capital IPD term in the escalation formula and has opted to have the Capital Factor incorporate the inflation-related capital cost growth.[6] Given the mechanics of the Company's proposal, if a Capital IPD term were to be added to the escalation formula it would reduce the Capital Factor proportionately. Thus, there would be no change to the allowed revenue amounts with or without a Capital IPD.

2.1 Derivation of the Escalation Formula

The following equation explains the components of the custom IR formula that Clearspring has studied and concluded are appropriate to escalate allowed revenue during the CIR period.

$$\boldsymbol{Growth\ Revenue = OEB\ IPI - X + G\ Factor + OM\&A\ IPD * \%\ OM\&A + Capital\ IPD * \%Capital} \quad \textbf{[Equation 1]}$$

This section shows how Equation 1 was determined.

The allowed revenue escalation within the formula should mimic the expected growth in costs. Production theory postulates that there are three main components within the escalation formula. These three components are: input price inflation (I), a productivity expectation (X), and output growth (G).

$$Growth\ Costs = \ Growth\ Revenue = I - X + G \qquad \text{[Equation 2]}$$

The mathematical derivation of Equation 2 is provided below. It begins with the assumption that the allowed growth in revenue should be equal to the expected growth in costs.

$$Growth\ Allowed\ Revenue = Growth\ Cost \qquad \text{[Equation 3]}$$

Basic production theory states that costs equal the product of input prices and input quantities (Q). In turn, the growth in costs will equal the growth in input prices (I) plus the growth in input quantities.

[6] The portion of inflation-related cost growth that the forecasts will incorporate is the rise in asset prices that has already occurred. Since replacement asset prices have embedded multiple years of inflationary price increases relative to the asset they are replacing (since most utility capital assets have useful service lives measured in decades), forecasts are able to account for the increased price levels and this embedded inflationary challenge. However, it is Clearspring's understanding that Hydro One used a conservative estimate of around 2% for future asset price inflation. This assumption is significantly lower than historic asset price inflation levels and likely produces an understated asset price inflation forecast.

$$Growth\ Cost = I + Growth\ Q \qquad \text{[Equation 4]}$$

If we add and subtract the same term to the right-hand side of the equation, that is the same as adding zero, and the equation remains unchanged. We will both add and subtract output growth (G) to Equation 4 to develop Equation 5 below.

$$Growth\ Cost = I + Growth\ Q + (G - G) \qquad \text{[Equation 5]}$$

The total factor productivity ("TFP") trend is defined as the change in output quantity minus the change in input quantity. In equation form:

$$TFP\ trend = G - Growth\ Q \qquad \text{[Equation 6]}$$

We can rearrange the terms in Equation 5 to the following equation.

$$Growth\ Cost = I - (G - Growth\ Q) + G \qquad \text{[Equation 7]}$$

And then insert Equation 6 into Equation 7.[7]

$$Growth\ Cost = I - TFP\ trend + G \qquad \text{[Equation 8]}$$

The last step in getting to Equation 2 is to insert Equation 3, redefine the TFP trend and call it the productivity factor ("PF").

$$Growth\ Allowed\ Revenue = I - PF + G \qquad \text{[Equation 9]}$$

Now let's turn to the "I" portion of the formula. Production theory assumes the "I" in the formula captures the input price inflation faced by the Company. The Board's Input Price Index is not specifically customized to the input price inflation expected by the Company in its OM&A inputs, but rather was constructed with both capital and OM&A weights in mind (although the index chosen to account for capital has been widely inadequate). In the 4GIR Report of the Board the IPI 30/70 weighting included an assumption for capital and was not specifically designed for OM&A.[8] On page 9 of that report, the assumption used for the OM&A specific components was a 70% weight on labour and only a 30% weight on non-labour but the weights flipped to only a 30% weight on labour due to adding capital into the 4GIR input price index.[9] The appropriateness of the inflation adjustment for the OM&A portion of costs can be improved upon by

[7] The "G" should be calculated the same for both the TFP study and the G Factor study and should be based on a multi-dimensional output quantity index that uses cost-elasticity weights. This enables both the TFP trend and the Growth Factor to be consistent and properly track the impact of output growth onto cost growth.

[8] Mr. Fenrick, in the 4GIR proceeding, recommended including an asset price inflation index into the IPI that would be weighted based on historical asset price inflation rates. This three-part inflation factor proposal was not approved. The current two-part inflation factor has provided insufficient inflationary adjustments to distributors for both OM&A and capital costs. Please see section 2.5.1 for more details regarding the insufficiency of the IPI regarding capital costs.

[9] Please see footnote 9 of the Report of the Board in EB-2010-0379 issued on November 21, 2013 and corrected on December 4, 2013.

aligning it with the actual component weights of OM&A. This difference between the customized input price inflation of the Company and the IPI is what is called the input price differential (the IPD). The IPD could be positive or negative. It is an adjustment made to better align the "I" with the expected input price inflation of the Company in its OM&A expenses.

$$I = IPI + IPD \qquad \text{[Equation 10]}$$

If Equation 10 is inserted into Equation 9 we have the following result.

$$Growth\ Allowed\ Revenue = (IPI + IPD) - PF + G \quad \text{[Equation 11]}$$

Since capital asset inflation and OM&A inflation are different (and in recent decades markedly different) the IPD term needs to be broken into an OM&A and Capital component. The equation, therefore, lowers the OM&A IPD by the percentage of the OM&A-related revenue in total revenue and lowers the Capital IPD by the percentage of Capital-related revenue.

$$Growth\ Allowed\ Revenue = (IPI + OM\&A\ IPD * \%OM\&A + Capital\ IPD * \%Capital) - PF + G$$
[Equation 11a]

A stretch factor is sometimes added to the escalation formula. Because this term is not warranted based on economic theory and mathematical reasoning, it should be added with caution, not be overly burdensome, and be connected to robust performance evaluations, such as the econometric total cost benchmarking research found in this report. Expecting a utility to exceed the productivity trend of the industry, even by a small amount, when it is already outperforming the industry is a significant challenge. While Clearspring uses the stretch factor groupings found in the 4GIR proceeding as the basis for our recommended stretch factor, we nonetheless consider that a more symmetric system of stretch factors which could be negative for strong performing utilities would better mimic a competitive industry and provide a reasonable productivity target for those utilities found to have strong cost performance.

The stretch factor ("SF") is added to the PF term and the sum of them is called the X Factor ("X").

$$X = PF + SF \qquad \text{[Equation 12]}$$

If we substitute X for the PF term to denote the addition of the stretch factor, we have the following equation.

$$Growth\ Allowed\ Revenue = (IPI + IPD * \%OM\&A + Capital\ IPD * \%Capital) - X + G \quad \text{[Equation 13]}$$

By rearranging terms, we have derived Equation 1 from the universally agreed upon production theory equation of costs equalling input prices multiplied by quantity.

$$\boldsymbol{Growth\ \ Allowed\ Revenue = OEB\ IPI - X + Growth\ Factor + IPD * \%\ OM\&A\ + Capital\ IPD * \%Capital} \quad \textbf{[Equation 1]}$$

In the context of Hydro One's application, it is Clearspring's understanding that the Company is not including a Capital IPD term but is including a Capital Factor term. The Company has determined that its

capital investment needs outpace the general formula in Equation 1. Given the mechanics in the Company's proposal of calculating the Capital Factor, including or excluding a Capital IPD term in the presence of a Capital Factor will not impact allowed revenue. This is because the Capital Factor would decrease by the corresponding amount of the Capital IPD. Setting the Capital IPD term has no current precedent despite it clearly being very large and imperative to account for in some manner. Since the allowed revenue is unaffected due to the Capital Factor and setting the right Capital IPD value may involve considerable analysis and discussion, it is reasonable to not include a Capital IPD and address capital inflation through the Capital Factor.

If capital revenue were to be indexed without a Capital Factor (such as in the case of the Price Cap IR option), there would be a need for a sizeable Capital IPD term to be added in the I-X formula or to address capital asset inflation directly in the "I" term. The current I-X formula includes an "I" that has and will likely continue to vastly underestimate capital inflation.

Equation 1, derived above, shows the necessity of a G Factor and IPD. The following subsections briefly discuss how each term should be calculated. Sections 9 and 10 provide the calculations and results that Clearspring undertook for each factor for Hydro One Transmission, Hydro One Distribution, and HOSSM.

2.2 Discussion of the G Factor

The G Factor is determined based on how the growth of the system will impact incurred costs. Cost elasticity parameters are found in the econometric cost model. These are estimates of the percentage change in cost given a percentage change in the output variable. The cost elasticity weights are the best method for estimating the impacts of output growth onto cost levels and, therefore, are used as the basis for the construction of the G Factor.

Using a cost-elasticity based weighting is the same approach used for the calculation of the total factor productivity ("TFP") trends used as the basis for the base productivity factor that partially comprises the X Factor. Having the same procedure for the G Factor assures the proper implementation of the factor in the escalation formula.

The Company has proposed the inclusion of a G Factor in its formula to account for the output-related growth in costs for all three businesses. We note that the G Factor is different from billing determinant growth because the G Factor measures the estimated impact on costs from output growth, whereas billing determinant output growth measures the impact on revenues at given price levels. This is why the G Factor uses the total cost econometric model cost elasticities of the outputs. The proper allowed revenue or price escalation needs to account for the cost impacts of output growth.[10] Section 9 provides the calculations and G Factor results for each Company.

[10] In a revenue cap approach, only the G Factor needs to be used in the formula. If the distributor wants to enact a price cap approach then revenues should first be escalated by the G Factor but the resulting prices in the formula should then be reduced by the billing determinant output growth because the utility will receive that added revenue from billing determinant growth.

2.3 Discussion of the Input Price Differential

The OM&A IPD accounts for the expected difference in OM&A input price inflation for each Company from the IPI. The inputs for OM&A are labour and non-labour. In the 4GIR decision, the index used to measure labour inflation was the Average Weekly Earnings (AWE) for Ontario, published by Stats Canada. The index used to measure non-labour was the Gross Domestic Product-Implicit Price Index, Final Domestic Demand (GDP-IPI FDD) for Canada.[11] For transmitters, the weighting is set at 14% of the growth rate in AWE and 86% of the growth rate on GDP-IPI FDD. For the distributors, the weighting in the 4GIR decision is set at 30% on AWE and 70% on GDP-IPI FDD. This places a 30% weight on labour inflation and a 70% weight on the non-labour inflation component. These two metrics are defined as follows:

1. **AWE:** Annual percentage change in average weekly earnings for all employees in Ontario (from Statistics Canada CANSIM Table 281-0027).

2. **GDP-IPI:** Annual percentage change in the GDP-IPI FDD for Canada (from Statistics Canada CANSIM Table 380-0066).

As discussed above, the 4GIR weights were set in the context of a price cap that would apply to <u>both</u> capital and OM&A related revenue. Hydro One's actual labour and non-labour portions in their OM&A spending are weighted more heavily towards labour than the 30% weighting that is assumed in the IPI calculation (or the 14% assumed for the transmission business). Since the labour component of the IPI (AWE) tends to grow at a faster rate than the non-labour component (GDP-IPI), the IPI provides an insufficient inflation growth rate for Hydro One and HOSSM's OM&A inputs.

The IPD adjusts the escalation formula for the incremental difference between what the inflation index would be using the Company's true proportion of labour in its OM&A expenses relative to the 14/86 (transmission) or 30/70 (distribution) calculation of the IPI. This calibrates the escalation formula to better reflect the actual input price inflation of OM&A expenses which will encountered by the Company. Section 10 provides the calculations and IPD results for each Company.

2.4 Discussion of the X Factor

The X Factor is the sum of a productivity expectation, called the base productivity factor, and a stretch factor. The stretch factor is a term that is oftentimes added to the formula. However, the term itself is not derived from the mathematical formula. It is an add-on term that increases the productivity expectation of the firm beyond (assuming the stretch factor is positive) what the empirically derived productivity results show. We turn first to a discussion of the base productivity factor.

2.4.1 Base Productivity Factor

The base productivity factor should be based on an external measure of the industry TFP trend. The utility

[11] November 21, 2013, *EB-2010-0379 Report of the Board, Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, p. 11.

that it is being applied to should have no (or very little) impact on the measured industry TFP trend. This is because incentive regulation seeks to decouple the link between a utility's cost increases to the allowed revenue escalation.[12]

In the 4GIR proceeding, there was strong evidence of the Ontario electric distribution industry TFP trend being negative.[13] Mr. Fenrick, while working for another consulting firm at the time, argued for a negative productivity factor as being the fair, principled, and empirically driven result. Rather than set a negative base productivity factor at the time, the Board decided to set a productivity factor of zero. Economic theory would indicate that a negative base productivity factor should be implemented and would align cost escalation expectations with the revenue escalation formula.

In Hydro One's last joint rate application, EB-2021-0110, Clearspring and Board Staff's consultant (PEG) issued a report titled, *Clearspring/PEG Joint Report on Hydro One Benchmarking and Productivity Research* ("Joint Report"). On page 2 of the Joint Report was a list of items that both consultants agreed with and included the following statement: *"Negative productivity factors and X-factors should be considered reasonable parameter possibilities within incentive regulation if industry data support them."*

The calculation of the industry productivity trend is a comparison of the measured output trend and the measured input quantity trend. If the measured output trend is greater than the measured input quantity trend, then the productivity trend result will be positive. If, however, the measured input quantity trend is greater than the measured output trend, then the productivity trend result will be negative.

$$Productivity\ Trend = Measured\ Output\ Trend - Measured\ Input\ Quantity\ Trend$$

It is a reasonable expectation that productivity, if it can be calculated perfectly in its complete and fully comprehensive form, should not be getting worse (i.e., a negative trend) but that continuous improvement within the industry should be expected. However, there needs to be a recognition that industry productivity trend calculations and studies in the real world, no matter how well done, cannot be "perfect", "complete", or "fully comprehensive". Yet, the mathematics of the cost escalation formula do meet these criteria and the math makes no distinction on the productivity trend being above or below zero. A negative productivity trend result for the industry or a company could mean something other than the industry becoming less efficient. More probable are unmeasured causes. Some possibilities include, but might not be limited to, the measured output trend is not capturing the full extent of the cost pressures of needing to do more (increasing unmeasured outputs) or the measured input quantity trend is not fully accounting for the input price inflationary pressures faced by utilities.[14]

The negative productivity trend result is revealing that utility costs are increasing above the study's

[12] This is the reason why we exclude Hydro One from the Ontario productivity calculations.

[13] In the 4GIR proceeding a TFP trend of -1.10% was calculated by the Board Staff consultant for the 2002-2012 time period when including all Ontario distributors, even after only large negative outliers were excluded (which causes a bias) from the analysis, the TFP trend remained negative at -0.33%.

[14] This could be due to a changing employment composition mix within utilities as grid technology advances that may cause a higher proportion of higher paid positions.

assumptions on input price inflation and measured output growth. It is necessary to account for this reality in the escalation formula for it to be reflective of industry expectations regarding cost escalation. Rather than ignore a negative productivity trend finding, it must be incorporated into the escalation formula for the mathematical derivation of the formula to be followed.[15] If ignored, the escalation formula is not reflective of the industry experience and not reflective of cost escalation expectations.

In 4GIR, distributors encountered and have had to deal for more than a decade with two substantial challenges. The first is that the inflation factor is not properly tracking the assumed input price inflation in the productivity study. The inflation factor, to properly follow economic theory, needs to track the same input prices as what are assumed in the productivity study or have an IPD adjustment made that aligns the inflation factor with the input price inflation assumed in the productivity study. This was not done in 4GIR and has resulted in widely inadequate inflation adjustments. The proper approach would be either to have an IPI that properly tracks inflation for both OM&A and capital or include an IPD in the formula that adjusts for this disparity. Mr. Fenrick's recommendation during the 4GIR proceeding was to implement a 3-part inflation factor that would adequately address the capital input price component. This would have substantially addressed the large inflation deficiency encountered by distributors across Ontario for over the last decade.

The second substantial challenge is that the negative productivity trend in the industry has continued to persist and be ignored. The unmeasured output increases and/or more rapid input price inflation that likely caused the negative industry productivity trend has not been recognized or accounted for in the escalation formula. This means that the I-X formula assumes Ontario utilities can continually outperform the industry, even before a stretch factor is added to the formula.

By not aligning the IPI with actual input price inflation (either directly or through an IPD) and ignoring negative productivity trends, the I-X formula has provided substantially inadequate escalation. In our view, productivity factors should be allowed to be negative to better align with economic theory and real-world realities and to better align the inflation adjustment with the input price inflation faced by utilities.

2.4.2 Stretch Factor

The stretch factor is included in the X Factor to adjust the productivity expectation for the utility relative to what the industry experience dictates. The 4GIR proceeding established five stretch factor groups based on econometric total cost benchmarking results. The best cost performers receive a 0.00% stretch factor and then the stretch factors increase by 0.15% increments (based on econometric total cost results) and are capped at 0.60%.

Ontario has a lengthy history of incentive regulation and providing cost containment incentives to its utilities. Continually requiring utilities to beat the industry's productivity trend after multiple cycles of incentive regulation is a significant challenge. When it is the Ontario distribution industry itself that sets the industry productivity expectation, it becomes a mathematical impossibility for most of the Ontario

[15] This could be done either through the productivity factor being negative or, if higher than assumed inflation in the study is suspected, increasing the allowed inflationary adjustment in the formula would also address the issue.

distributors to substantially outpace the Ontario industry productivity trend.

It is Clearspring's view that more symmetrical stretch factors be considered, including ones that are below zero for the best cost performers now that utilities have been under incentive regulation for an extended time. Symmetric stretch factors would align with incentives of competitive markets. In competitive markets, the most efficient firms will tend to earn higher returns than average, whereas firms that are less efficient tend to receive lower returns. Symmetric stretch factors would also recognize the mathematical reality that less than half of Ontario utilities can substantially beat the industry productivity trend of the Ontario industry.

The utilities that should be expected to beat that industry productivity trend are those that do not perform well in total cost benchmarking studies. However, a reasonable expectation for utilities that do perform well in total cost benchmarking studies is that they have far less ability to find efficiencies than their peers and, thus, will tend to have slower productivity trends.

The Company's proposal includes several stretch factors:

1. the 4GIR standard stretch factors;
2. the proposed incremental stretch factor of 0.15% on capital;
3. assuming an asset price inflation rate of 2% when forecasting assets, even though asset price inflation has in fact been substantially higher (see the following section); and
4. on the transmission side, not proposing the use of the full negative productivity trend in the escalation formula.

2.5 Discussion of Why Capital Spending Is Expected to Exceed I-X Formula

Capital-related costs within the Ontario industry are increasing at a rate faster than the IPI minus X formula would indicate. In this formula, the productivity factor has been set to zero but for most distributors is a positive number due to stretch factors. Several utilities in Ontario throughout the years have proposed ways of increasing allowed capital spending due to the infrastructure needs of their systems significantly outpacing the I-X formula.

PEG produced a report on behalf of OEB staff on January 8, 2026 titled, *Report on Spending Patterns and Capitalization Policy*. On page 28 of this report, PEG displays Table 3. This table shows that in the later cycle years of Ontario distributors' IR plans, the achieved ROE declines considerably. In the earlier cycle years the achieved ROE is 7.97% across the distributor sample but in the later years it drops to 6.54%. This resulted from distributor costs escalating higher than the I-X formula allowed revenues to rise. This deterioration of achieved ROEs as the IR plan matures is evidence that the I-X formula is inadequate due to the input price inflation relief being too low and the X factor (productivity factor plus stretch factor) productivity expectations being too high.

This section provides some reasons related to production economics and cost benchmarking for causes of this phenomenon. As a result of these causes, relatively large capital needs and capital forecasts that exceed the I-X formula should not be a surprise. Recognizing these causes and providing adequate parameters in escalation formulas, that align with economic theory, can provide a sustainable regulatory

path forward while still maintaining the incentives that are crucial to efficient operations and cost containment.

The math and production economic theory provided earlier in this Chapter is applicable to both capital costs and OM&A expenses. However, the magnitude of the factors that drive capital costs and OM&A expenses will differ for various reasons. We list below some possible factors driving capital cost increases above the I-X formula, followed by a brief explanation of each factor:

- Capital Input Price Differential ("Capital IPD") relative to the IPI is substantial;
- Growth will tend to increase capital costs;
- X Factor is higher than the empirical evidence dictates; and
- increase in unmeasured outputs.

2.5.1 Capital IPD Relative to the Inflation Factor is Large

For over a decade the electric transmission and distribution industry has faced asset input price inflation that has exceeded the IPI. Historically, even though it was not explicitly measured or used within Ontario regulation, the Capital IPD has been positive and large and has put utilities in the difficult circumstance of trying to contain capital cost growth at or below the IPI when input prices of the capital assets are growing at a significantly faster pace.

While the historical Capital IPD has been large for decades, since the COVID pandemic the Capital IPD has accelerated. The best available measure of asset price inflation in the industry is the Handy Whitman indexes ("HW"), which provide detailed information on the price levels and inflation rates specific to the electric transmission and distribution industry in the States. The HW index inflation rates are good measures of the asset inflation experienced by North American utilities.

The total electric distribution HW for the U.S. North Atlantic region grew at an average annual rate of 6.2% from 2002 to 2025. At the same time, the IPI grew at an average annual rate of 2.4%. This difference of 3.8% implies a large Capital IPD during the last two decades. The Capital IPD has significantly accelerated in the last five years. The HW index grew at an average annual rate of 10.8% from 2020 to 2025, while the IPI grew at a rate of 3.8%. This is a difference of 7.0% and implies an increasingly large Capital IPD. The IPI has provided inadequate inflation relief for capital-related prices and the discrepancy is worsening. If we look at the last 20 years (2005 to 2025), the HW indexes for electric distribution have grown at an average annual rate of 6.3% compared to the IPI's annual rate of 2.4%. This is a difference of 3.9% during the most recent 20-year period.

Table 1 Difference in Handy Whitman Indexes for Distribution and IPI

Time Period	Electric Distribution Asset Price Inflation (Measured by Handy Whitman North Atlantic Index)	30/70 Weighting of AWE and GDP IPI Inflation (Board IPI)	Difference
2002-2025	6.2%	2.4%	**3.8%**
Last 5 Years (2020-2025)	10.8%	3.8%	**7.0%**
Last 20 Years (2005-2025)	6.3%	2.4%	**3.9%**

While less pronounced than distribution, the electric transmission HWIs have also grown substantially faster than the IPI over the last two decades. If we look at the last 20 years (2005 to 2025), the HW indexes for electric transmission have grown at an average annual rate of 4.7% compared to the IPI's annual rate of 2.4%. This is a difference of 2.3% during this 20-year period.

Table 2 Difference in Handy Whitman Indexes for Transmission and IPI

Time Period	Electric Transmission Asset Price Inflation (Measured by Handy Whitman North Atlantic Index)	14/86 Weighting of AWE and GDP IPI Inflation (Board IPI)	Difference
2002-2025	4.8%	2.3%	**2.5%**
Last 5 Years (2020-2025)	8.0%	3.9%	**4.1%**
Last 20 Years (2005-2025)	4.7%	2.4%	**2.3%**

Due to the historical cost basis of capital costs, the extremely high inflation rates of recent years will cause future increases in the rate base, and thus capital-related costs, to be high even if future year annual asset price inflation drops at or below future IPI inflation rates.[16] Due to the long life of capital assets, it will take several years (likely more than a decade) for the Capital IPD to drop to zero even in the unlikely event the annual asset price inflation matches or is below the IPI in upcoming years. The Capital IPD has been and will be a large positive number during the Custom IR years (and likely well beyond). This pushes expected capital cost increases above what the I-X formula provides and is beyond the control of utilities.

2.5.2 Growth Increases Capital Costs

Earlier in this chapter, the rationale was provided for a G Factor to be included in the revenue escalation

[16] The reason for this is that when a utility replaces assets, the new price paid is an accumulation of several years of inflation rates relative to the price of the asset being replaced. For example, if a utility paid $1,000 for a transformer 20 years ago, the price today will be over $8,000 (eight times higher) regardless of the current year's inflation rate. The price of the asset replacing another asset is a function of the price increases over multiple years. The rate base and subsequent depreciation expenses, and thus capital costs, will both increase based on this "embedded inflation" of the substantially higher prices paid for assets relative to the asset they are replacing regardless of contemporary inflation rates.

formula. As outputs increase, they will tend to increase costs by a corresponding amount. This applies to both OM&A and Capital costs.

2.5.3 X Factor is Higher Than the Empirical Evidence Dictates

The Ontario TFP trend was found to be negative back in the 4GIR proceeding by both Mr. Fenrick (working on behalf of the Coalition of Large Distributors) and PEG (working on behalf of Board Staff). In that proceeding, Mr. Fenrick found that the Ontario industry TFP was declining by more than 1% per year. PEG's findings were also around that amount for the entire Ontario electric distribution industry.[17]

Both the transmission and distribution productivity trends have continued to be negative. The Clearspring study for transmission shows a strongly negative U.S. industry productivity trend over the last two decades. The Clearspring studies for distribution show that in both the Ontario and U.S. distribution industry productivity trends have been negative.

As the equations showed in the beginning of this chapter, the productivity factor needs to align with the industry TFP trend for costs to track allowed revenues (or rates). Since the base productivity factor was set at a higher value, this placed an "implicit stretch factor" on the utilities. Additionally, a stretch factor has then also been added to the implicit stretch factor, even for strong cost performers, which further exacerbates the misalignment of economics and the actual formula. Unrealistic productivity targets can lead to undesired outcomes and, ultimately, reduced incentives as utilities are forced to deviate from what would be the economically correct escalation formula parameters and find other ways of funding necessary investments.

2.5.4 Increase in Unmeasured Outputs

Utilities are now being asked to do more than the traditional wires and poles business of the past. New areas of responsibility include provision of enhanced technology, evolving customer service, environmental regulations, cyber security, distributed energy resources, and delivering on future beneficial electrification opportunities including the energy transition. Increasing these outputs can bring value to customers and society but also lead to increased costs for the utilities achieving them.

The Ontario electric industry is encountering rapid forecasted future load growth for upcoming decades that utilities must be preparing for through asset investments. This transition requires increased capacity that will require investments be made prior to the actual output growth, increased resiliency, and grid modernization. These new, or substantially increasing, challenges will increase costs with little to no corresponding output increases during the CIR period.

Utilities may have higher unmeasured outputs in the form of enhanced cyber security or achieving the requirements of more stringent environmental regulations, among other possibilities. While increasing cyber security and protecting the environment should provide valuable outcomes, they will tend to increase the costs of the utility without a requisite increase in measured outputs. This will push

[17] PEG did also suggest excluding two of the largest utilities for the sample. This abbreviated sample resulted in a higher TFP trend, however, it remained negative at around -0.3%.

productivity down and possibly into negative territory even if the industry is becoming more efficient in its “status quo” basket of operations.

3 Total Cost Benchmarking Methodology

Clearspring used the same methodology for both the transmission and distribution total cost benchmarking studies. Other than the sample of utilities and the specific variables used, all other calculations and approaches are consistent. Both studies build upon prior benchmarking studies submitted in Ontario, including the Joint Report put forth by Clearspring and PEG in Hydro One's prior JRAP, and are based on the best practices that have improved and evolved in the province.[18]

The transmission total cost model methodology and included variables are unchanged relative to the methodology Clearspring employed in the Joint Report. Regarding the distribution total cost methodology there are two changes relative to the research Clearspring conducted in the Joint Report. These are:

- In subsequent research, Clearspring improved its percent congested urban core variable by enabling it to vary over time. Instead of one value based on the percentage of urban core for each sampled utility in 2016, the variable now varies based on the growth rate in skyscrapers above 100 metres in the service territories. Hydro One does not serve any areas that are designated as congested urban core and, thus, this change will have a limited impact on Hydro One's benchmark score.

- Clearspring has taken out of the model the "distribution work" variable. PEG did not include this variable in its Joint Report research and offered a critique of the variable in the recent Elexicon CIR application. While both consultants agree that a variable that captures the differences in the T&D demarcation between distributors is desirable, there is a valid argument that the available data does not allow a sufficient measurement of the added work and cut-off of each utility's distribution systems.

The model's explanatory variables measure the impact of the variable on total cost; thus, some variables will impact transmission costs (e.g., transmission line lengths), others will impact distribution costs (e.g., customers served), and some variables will impact both costs (e.g., peak demand). Therefore, each model has its own variable specification. The samples are different because not all U.S. utilities serve both a transmission and distribution function. However, our prospective sample for each model started with the same sample "universe" of U.S. investor-owned utilities, and each sample was then based on which utilities serve the applicable function and had plausible data observations for all included variables.[19]

The studies employed the econometric benchmarking approach. This is the most accurate and fair method when comparing utility cost levels because it explicitly adjusts for the quantifiable differences

[18] EB-2021-0110, *Clearspring/PEG Joint Report on Hydro One Benchmarking and Productivity Research*. June 11, 2022.

[19] The U.S. sample is comprised of investor-owned utilities who are required to file a FERC Form 1. The FERC Form 1 report includes expenses according to the Uniform System of Accounts, customers, peak demands, and plant information by function that allows us to ensure definitional consistency between Hydro One and the sample.

between utility service territories and business conditions. It is also the method preferred by the OEB in the 4GIR Report of the OEB and used for all our past CIR benchmarking research.[20]

Simple comparisons of "raw" (unadjusted) metrics such as rates, unit costs, or reliability indices do not typically allow regulators to compare utilities in a fair manner. Comparing a utility's costs or rates to those of a peer group utilities' costs or rates usually presents an inaccurate picture of the target utility's performance. Factors that cannot be controlled by the utility affect cost levels. Such factors include geographical size, regional wage levels, rural density, or serving a congested urban territory. It is often difficult or impossible to account for these factors using a peer group approach.

Adjusting for these and other influencing factors is necessary to accurately evaluate performance. With this concept in mind, Clearspring has estimated two econometric models (one for transmission and one for distribution) from a large sample of utilities, using variable parameters that statistically are drivers of transmission and distribution utility costs.[21] The econometric method adjusts for service territory conditions and other factors that affect total costs.

Using a large sample of utilities, the econometric model produces an industry-wide estimation of how the variables affect the studied metric (e.g., total costs). For the present research, the sample used to estimate the models includes U.S. observations from multiple utilities for multiple years.

The model is then used to predict Hydro One's "expected" (or benchmarked) costs, using the estimated relationship between the costs and the explanatory variables and Hydro One's values for the variables. The benchmark costs represent the costs that the model would expect a utility to have based on the actual operating conditions faced by that utility in that year.

The benchmark score is defined as the logarithmic percentage difference of the actual costs to the benchmark costs for a given year, as shown below.[22]

$$Benchmark\ Score = \text{Natural Log}\left(\frac{Historic\ or\ Projected\ Costs}{Benchmark\ Costs}\right)$$

The general approach of our benchmarking analysis is as follows:

1. Clearspring assembled the historical variables and costs of all utilities in the dataset.
2. Using the historical data, Clearspring estimated an econometric model that expresses the relationship between the variables and cost.

[20] EB-2010-0379.

[21] To "estimate" a model means, roughly, to examine the drivers or variables that affect the given metric (e.g., cost), and to use the data to create a model that measures how each variable affects that metric.

[22] We use the logarithmic percentage difference rather than the arithmetic percentage difference, because this is convention within the benchmarking profession, including in 4GIR and all other CIR applications we and PEG have been involved in. The approach provides a more intuitive result when averaging increases and decreases over time.

3. Using this model, Clearspring can then produce "benchmark" values for a given utility in each year. The benchmark values are determined from the model, using the specific variable values for a given year. In Hydro One's case, the benchmark represents the total cost amount expected for a utility with the same variable values as Hydro One.
4. We then compare the total costs that are expected by the model to Hydro One's actual historical and projected costs in each year, which allows us to: (1) evaluate the historical and projected cost performance, and (2) recommend a stretch factor.

For a more detailed description of the methodology, please see Appendix A.

3.1 Prior Methodological Differences Addressed

While PEG and Clearspring follow much of the same best practice research methods, some research differences have surfaced in past proceedings. Both consultants undertook a conferral process during Hydro One's last JRAP proceeding (EB-2021-0110). This resulted in both transmission and distribution cost models that were similar with somewhat similar results, as referred to in the Clearspring/PEG Joint Report.

Clearspring in subsequent CIR studies for Ontario utilities (Toronto Hydro, Alectra, and Elexicon) maintained the advancements made in the Joint Report. Our transmission total cost model and methodology is identical to the research conducted for the Joint Report, the distribution cost model has two changes that have small impacts on Hydro One's benchmark score.

The following list summarizes past differences and the approach Clearspring has taken to address them.

- Sample Period: In the current research, Clearspring used the same start year as we used in the Joint Report. The sample period for the distribution model begins in 2000 and ends in 2024 (25 years).[23] The sample period for the transmission model begins in 2004 and ends in 2024 (21 years).[24] This closely aligns with PEG's benchmarking work in EB-2021-0110. PEG had a start year for its distribution cost models of 2002. PEG had a start year for its transmission cost models of 2004.

- Estimation Procedure: Clearspring is using the same estimation procedure that we used in the last JRAP and other recent CIR benchmarking research. This procedure is known as the Driscoll-Kraay ("DK") method, which uses the ordinary least squares ("OLS") coefficients and then adjusts the standard errors due to heteroscedasticity and autocorrelation.[25] In the last several CIR applications, PEG has also moved to using the DK estimation method.[26]

[23] This is for the U.S. sample. Hydro One has data beginning in 2003 and going through 2032, with future years using the proposed spending amounts.

[24] 2004 is the first year transmission peak demand data is available for the U.S. sample.

[25] Please see, Driscoll, J., and A. C. Kraay, 1998. "Consistent covariance matrix estimation with spatially dependent data," *Review of Economics and Statistics* 80: 549–560.

[26] PEG implements a slightly different method for estimating the standard errors of the coefficients but this has no impact on benchmarking results.

- Model Specification: Model specification is the process of determining which variables to include within the econometric models. There has been an evolution in these proceedings that has resulted in an improvement of the model specification as new or improved variables are developed and vetted. Clearspring is using the same model specification for our transmission total cost model that we used in EB-2021-0110. Regarding distribution, we have improved the percent congested urban variable by making it time variant and have removed the distribution work variable. PEG did not include the distribution work variable in its models in EB-2021-0110.

- Hydro One Distribution Service Area: The variable value used for Hydro One's service area was discussed and mentioned in the OEB's Decision in Hydro One's previous distribution-only application.[27] The variable then received considerable attention in Hydro One's last JRAP proceeding, and Clearspring has continued to refine the variable value. Both PEG and Clearspring have worked towards consensus and agree this is a difficult issue. The Joint Report stated on page 8, *"PEG uses a Hydro One service area value of 413,277 sq. km for Hydro One which PEG developed in response to M-Hydro One-21 (d). Clearspring uses an estimate of 529,313 sq. km for Hydro One developed by Hydro One, with details provided in Clearspring's Reply Report. Both consultants have, in advocating these values, moved towards each other's positions during this conferring process. Both consultants acknowledge the difficulty and challenge in getting a perfect number for this variable."*

  In Hydro One's previous distribution-only application (EB-2017-0049), we used the full licensed service area of around 960,000 square kilometres to match the calculation method for the rest of the sample. While the measured service area for the rest of the sample is the full licensed service area for each utility (including unserved areas), we acknowledge that Hydro One is unique in that it has an abnormally large area that is unserved. In recognition of this and to reduce research differences in our original report in EB-2021-0110, Clearspring adopted the variable value for Hydro One that PEG used in its benchmarking model in a Hydro Ottawa proceeding subsequent to EB-2017-0049.[28] This variable value substantially reduced Hydro One's measured service area by about one-third to a value around 650,000 square kilometres.[29]

  Despite the large reduction in the measured service area and the decision to use PEG's own value, PEG criticized the 650,000 square kilometre value as being too large in the last JRAP. After additional research and discussions, the consultants ended up not entirely agreeing but both moved closer to agreement. In the Joint Report, PEG used a value of 413,277 square kilometres for Hydro One's distribution territory. Hydro One, after discussions with Clearspring, conducted a GIS analysis of the locations of its distribution substations to formulate a more precise service area for Hydro One. This analysis was described in Clearspring's Reply Report in EB-2021-0110

[27] EB-2017-0049, Board Decision, p. 29.

[28] EB-2019-0261.

[29] The variable value for Hydro One changed from 961,498 to 651,974 square kilometres.

and used as the variable value in that report and in the Joint Report. The analysis estimated Hydro One's service area at 529,313 square kilometres. This detailed GIS analysis and result is the value we are using in the research found in this report. For a further discussion on the reasonableness and calculations of the distribution area of Hydro One please see Section 5.1.2.

- Transmission Peak Demand Variable Definition: In the last JRAP both consultants agreed that using the transmission peak demand (reported on the FERC Form 1 for U.S. utilities) was the best measure of transmission peak demands.

- Canadian Asset Input Price Inflation for Hydro One: Regarding the capital asset price inflation assumption for Hydro One, we are using the Handy-Whitman Indexes for total transmission (in the transmission benchmarking study) or total distribution (in the distribution benchmarking study). PEG had previously argued against using the Handy-Whitman Indexes but has recently agreed with Clearspring that they are the preferred asset price indexes and has used them in its studies in the most recent CIR proceedings of both Alectra and Elexicon.

- Transmission Depreciation Rate: In the previous Hydro One transmission-only proceeding, PEG put forth an alternative that produced a slightly different result than Clearspring put forth at the time. We used the Bureau of Economic Analysis (BEA) assumptions for electrical transmission, distribution, and industrial equipment as the basis for the depreciation rate assumption. This resulted in a transmission depreciation rate of 3.59%. PEG added the BEA's assumptions for electrical light and power structures and weighted transmission plant and general plant using cost share weights. All told, PEG's calculations led to a transmission depreciation rate assumption of 3.30%. We agreed that PEG's approach is more detailed, and we use this 3.30% assumption in the current transmission research.[30]

- Older Capital Benchmark Year: The capital stock and cost calculations that are used by both Clearspring and PEG depend upon building up capital quantities and costs using the historical plant addition data for each utility. This method is called the perpetual inventory capital method.[31] PEG and Clearspring also apply a geometric decay assumption that uses a depreciation rate to depreciate historical capital additions in each year (see the prior point for the transmission depreciation rate assumption). In other incentive regulation proceedings, both inside and outside of Ontario, these capital quantity and costing assumptions can generate considerable debate, as some consultants make different assumptions on capital which can have large impacts on the study results. In our opinion, geometric decay is the proper assumption to use; it aligns best with theory and the realities of how a basket of utility assets depreciates over time for a utility.

[30] For the distribution depreciation rate, we continue to use the 4.59% depreciation rate assumption that is used in all the CIR distribution applications submitted by our team and PEG.

[31] In Appendix A we provide more details on the perpetual inventory method, including the equations used.

Despite our agreement on that major issue, there have been a few minor differences regarding the treatment of capital that have been brought forth in past CIR proceedings. Our approach in the present application represents that evolution regarding items such as the asset price levels, inflation, and depreciation rate assumptions. A large undertaking was the starting year that we have used for the perpetual inventory method for the U.S. sample. This start year is called the "capital benchmark year". The capital benchmark year begins the perpetual inventory calculation in that start year, and then the capital stock is depreciated in subsequent years and plant additions are added to the capital stock to build the capital quantities and costs consistently over time for the entire sample.

The earlier the capital benchmark year is, the more actual plant addition data can be used to calculate the capital quantity and costs of each utility. Given the fact that PEG and Clearspring assume geometric decay, much of the capital quantity assumed in the capital benchmark year will have depreciated by the relevant years in the study. Clearspring has collected all the necessary data to begin the capital benchmark year in 1947 for most of the U.S. utilities, and in 1959 for the rest that were missing data between 1947 and 1959.[32] We have therefore used the actual transmission or distribution plant addition data for the U.S. sample for the years 1948 to 2024 in the perpetual inventory capital method to calculate capital quantities and costs. This is over 75 years' worth of actual plant addition data.

- Customized labour and non-labour OM&A weights: For the OM&A input price index, an assumption as to the weights to use, between labour and non-labour, is required. In the 4GIR research conducted by PEG, a 70% labour and 30% non-labour assumption was used for the entire Ontario sample. In Mr. Fenrick's past CIR research, he continued to use this 4GIR assumption of a 70/30 weight for all the sampled utilities. This enables consistent treatment between a U.S. sample and Ontario utilities, since Ontario utilities do not report labour/non-labour OM&A breakdowns. PEG has responded in past proceedings by saying that salary and wage data, while not publicly available for Ontario utilities, is available for the U.S. sample and should be used for the U.S. observations.

  Modifying this treatment and assumption will have a negligible impact on the results and Hydro One was able to provide us with an estimate of Hydro One's labour/non-labour breakdown to be consistent with the U.S. sample. We have gathered the salaries and wages for the U.S. sample, located on the FERC Form 1s and requested Hydro One to estimate the labour and non-labour

[32] In the data for 1947, the total utility net plant data is available but not the breakdowns for transmission or distribution net plant. However, breakdowns for gross plant in service are available. Therefore, we took the proportion of transmission gross plant in service to total gross plant in service to estimate the transmission net plant in service. We did the same for the distribution calculation. Any possible inaccuracy in this calculation will be miniscule by the time we consider the sampled years of the study and starting in 1947 allows us to use the actual plant additions for transmission and distribution in all years after 1947.

components within their OM&A expenses. We have used this estimate, along with the salary and wages data for the U.S. sample, to customize the labour and non-labour weights and to calculate the OM&A input prices for each sampled utility.

- Pensions and Benefits Treatment: Including or excluding pensions and benefits has been a topic of discussion in several CIR proceedings. Driving the issue is that Ontario distributors do not consistently report OM&A pensions and benefits expenses. Further, the different health care and other regulatory differences between the U.S. and Ontario can cause pensions and benefits to be higher in the U.S. than in Ontario, creating a small bias in favor of Ontario utilities when they are included. We believe it is fair to say that both consultants would prefer to exclude these expenses when it is possible to consistently do so. In the current research, we requested that Hydro One provide Clearspring with their OM&A pensions and benefits estimates for each year for transmission and distribution. This enabled us to exclude these expenses from both the U.S. sample and Hydro One.

3.2 Output and Business Condition Variables

In general, there are two types of variables used in econometric cost benchmarking: output variables and business condition variables. Output variables measure the output of the utility in question (i.e., what the utility "produces"). Business condition variables quantify the factors that drive costs in a particular service territory, such as regional input prices, highly congested urban areas, forestation, etc. Details of the output variables and business condition variables used for the transmission and distribution benchmark studies are described in Appendix A.

3.3 Benchmarks for Future Years

The same econometric model and its associated parameter values that are estimated using historical data (and used to develop Hydro One's historical benchmarks) are also used to calculate the Company's benchmarks for the forecasted years through 2032. These parameter values are combined with projected variable values to calculate the expected total costs of Hydro One in the future years of the Custom IR period.

Clearspring was provided OM&A expense, plant addition, physical asset, customer count, and peak demand projections from Hydro One. We used these projections to calculate variables for each future year and then inserted these variable projections into the estimated econometric model.

3.4 Other Model Details

Other model details are provided in Appendix A. These details include the method used to calculate capital quantities and costs (perpetual inventory method), model estimation approach, model specification, and variable parameter hypothesis testing.

4 Transmission Cost Benchmarking

Clearspring undertook a total cost econometric benchmarking study of Hydro One's transmission costs. This study provides a comparison of Hydro One's actual and projected transmission total costs to the model-calculated benchmark costs after adjusting for the specific output levels, input prices, and business conditions that the Company operates within. These comparisons are made for both historical and forecasted years through 2032. For more information on the benchmarking methods please see Chapter 3 and Appendix A.

4.1 Transmission Variables

The two output variables used in the transmission benchmarking research are:

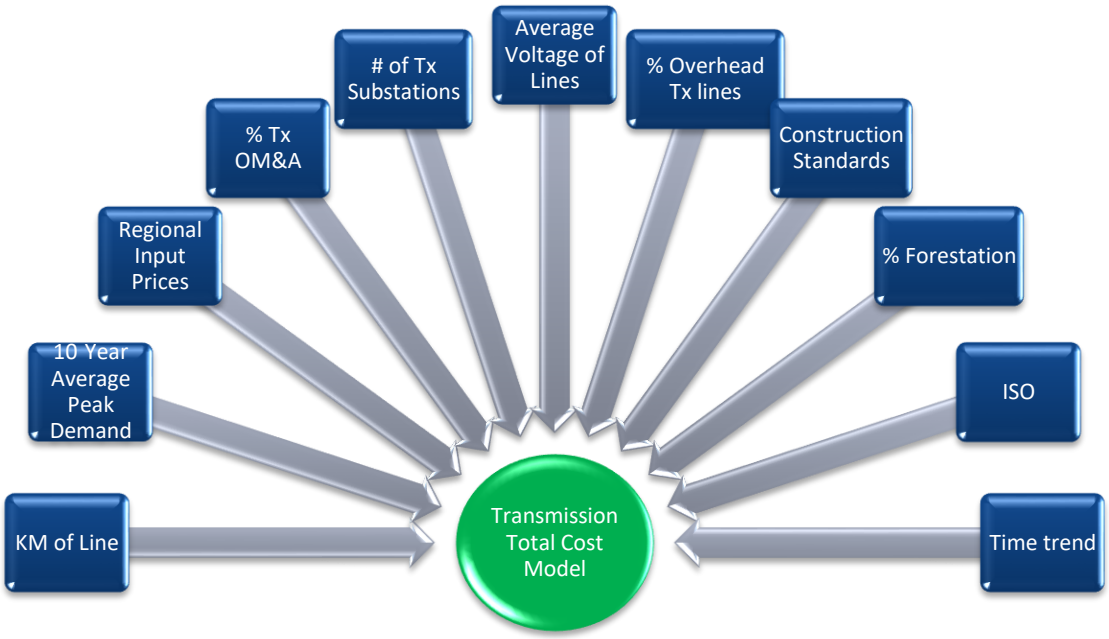
- Total kilometres of transmission line, and
- A 10-year rolling average of transmission peak demand.

The business condition variables used in the transmission benchmarking research are:

- Regional input prices (total costs in the model are divided by the input price index),
- Percent of transmission OM&A in G, T, and D OM&A (economies of scope),
- Number of transmission substations,
- Average voltage of transmission lines,
- Percent of transmission lines that are overhead,
- Construction standards index,
- Percent Forestation,
- Independent System Operator (a binary value), and
- A time trend variable.

The variables included in the transmission benchmark analysis are shown in the figure below.

Figure 1 Variables in Transmission Cost Model



These variables provide a robust accounting of the varying service territory conditions faced by transmission utilities. All first order variables are statistically significant at a 90% confidence level and all variables are correctly signed (i.e., they are signed the way we would expect).

4.1.1 The Definition of Transmission Costs

Transmission OM&A and capital costs used in the benchmarking models for the U.S. transmission utilities are derived using FERC Form 1 filing data.[33] United States investor-owned utilities are required to file FERC Form 1 data annually, which includes operation and maintenance expenses broken down into specific cost categories (e.g., distribution, transmission, customer billing, administrative and general). Form 1s also include information regarding plant in service additions that are used in constructing capital costs.[34]

Clearspring used a definition of "cost" for Hydro One that allowed us to achieve comparability with the definition used for the U.S. sample. This definition matches the transmission cost definition agreed to by PEG and Clearspring in the Joint Report. The cost of transmission services purchased by U.S. utilities from other utilities is removed from the transmission cost definition for the U.S. sample. Subtracting "transmission of electricity by others" expenses (Uniform System of Accounts category 565, on page 321 of FERC Form 1) creates a more comparable cost definition to Hydro One and, if not removed, would yield

[33] Some of the FERC Form 1 data was gathered using HData's and SNL Energy's database tool.

[34] Clearspring gathered plant addition data going back to 1947. Older data was collected from various EIA annual reports.

an unfair advantage to Hydro One, since certain U.S. utilities would have inflated expenses without commensurate output values. Clearspring also continues to subtract pensions and benefit expenses from the cost definition for both the U.S. and Hydro One.

Clearspring's transmission cost definition also excludes transmission dispatching and miscellaneous expenses. This exclusion aligns with PEG's stance that these expenses can be large and implausibly high and impact the transmission benchmarking study.[35] Excluding these expense categories is consistent with the approach both consultants took in the Joint Report.[36]

The transmission cost definition also includes an allocated amount of administrative and general (A&G) expenses (see page 323 of FERC Form 1).[37] Some of the U.S. utilities own and operate power plants and/or conduct distribution functions. We allocated A&G expenses for those utilities based on the ratio of transmission expenses to the total expenses of the utility minus the expenses of fuel, purchased power, transmission of electricity by others, regional market expenses, and A&G expenses. Similarly, general capital costs are allocated for the U.S. sample by the ratio of transmission gross plant in service to total plant in service minus general and intangible plant in service.

4.1.2 Transmission Output Variables

The transmission total cost model includes two output variables. The first is the total kilometres of transmission line, the second is the ten-year rolling average of peak demand for each utility. The output variables are gathered from FERC Form 1 data. The historical output data for Hydro One comes directly from the company. The peak demand variable is calculated based on taking the ten-year rolling average of annual peak demand on the system in the sample that has occurred up to that observation's year. For years without ten years' worth of historical data, the years that are available are averaged.[38]

4.1.3 Transmission Business Condition Variables

Beyond the two output variables and the input price index, there are seven business condition variables

[35] In PEG's Report in EB-2021-0110, page 21, the first item mentioned regarding PEG's biggest concerns in Clearspring's transmission benchmarking research was that Clearspring's sample included several companies that reported large values for dispatch-related and/or miscellaneous transmission expenses.

[36] On page 3 of the Joint Report it states, "Clearspring recommended in its Reply Comments that PEG add six companies and exclude transmission dispatching and miscellaneous expenses from the cost definition for both the benchmarking and productivity samples. PEG has done this and, in turn, Clearspring will also remove those expenses from their cost definition.

[37] The A&G expenses are after pensions and benefits expenses are subtracted.

[38] This is an advantage of the 10-year rolling average method. There is no bias if fewer than ten years for a utility are available since we are taking an average rather than a maximum of the peak demands. An alternative approach is conducting a ratchet peak demand approach. This can create a bias in results over time if the researcher is taking a maximum over a different length for different years. A ratchet approach never declines, which is not consistent with the thought that costs are sensitive to peak demands in the long run.

included in the model (plus a time trend). Each variable is discussed below.

The **percentage of transmission OM&A in non-fuel generation, transmission, and distribution electric OM&A**. This variable is calculated using the transmission operation and maintenance ("O&M") cost definition divided by non-fuel generation, transmission, and distribution O&M expenses. The variable measures the ability for a transmission utility to reduce costs through economies of scope: if the utility is also a generation and/or distribution utility, in addition to transmission services, there may be cost savings to the transmission utility because of this added scope. The coefficient on the variable is expected to be positive: the higher the percentage of transmission O&M in G, T, and D O&M, the higher we would expect total costs to be.

The **number of transmission substations** is based on FERC Form 1 data reported each year for the U.S. sample and based on asset information reported to Clearspring by Hydro One.[39] We would expect a positive correlation between the number of transmission substations and total costs.

The **average voltage of transmission lines** measures the differences in voltage levels across transmission systems. This variable is constructed by calculating a weighted average by length of the different voltage levels found on each utility's transmission system. Serving higher voltages will be more costly than serving lower voltages, *ceteris paribus*. Therefore, we would expect a positive coefficient.

The **percentage of overhead lines** measures the percentage of overhead transmission lines to total transmission lines. Constructing underground transmission lines is costlier than constructing overhead transmission lines. As the percentage of overhead lines decreases, we would expect total costs to increase since this implies a higher percentage of lines that are underground. This implies a negative coefficient value is expected from this variable.

The **construction standards index (or loading)** variable measures the minimum requirements for strength of transmission structures, which vary by geographic region. Transmission lines constructed in different regions must withstand different combinations of ice and wind due to local weather. A line designed for harsher loading conditions is more expensive to construct because it may require higher class poles, greater set depth, specialized insulators, and/or stronger hardware. We would expect that a higher minimum construction requirement for a utility would result in higher total costs.

The **percentage of forestation** variable is based on GIS land cover maps (for percent forestation). These maps used the GlobCover 2009 product produced by the European Space Agency ("ESA") and the Université Catholique de Louvain. These maps are matched with the areas served by each utility to create the forestation variable. We would expect that the higher the level of forestation, the higher costs required for right-of-way clearing and service restoration activities.

The **Independent System Operator (ISO)** variable indicates if the utility was operating under an ISO or Regional Transmission Operator (RTO) in the observed year. This variable is a binary variable that will equal "1" if in the observed year the utility is in an ISO or RTO and will equal "0" if this is not the case. We

[39] Clearspring used HData's Gateway data service to export FERC Form 1 substation data found on pages 426 and 427 for years after 2010.

do not have an a priori expectation of the variable sign. While the ISO may take on some planning costs that the utility would have engaged in otherwise, the transmission utility may still be required to undertake some planning costs as well as added investments that the ISO may request to encourage a more efficient energy market. In the model, we find that the ISO parameter estimate is positive, indicating a positive relationship between being in an ISO and transmission total costs.

The **time trend** variable captures a general industry total cost level trend over the studied period. Time trend variables are often found in translog cost functions and econometric total cost benchmarking research. In the present study, the variable is calculated by taking the current year of the observation and subtracting 2,003. For observations in the year 2004, the time trend variable equals 1. In 2024, the variable equals 21 (2,024 – 2,003). The coefficient value shows how adding an additional year increases or decreases total costs.

4.2 Transmission Sample

The transmission benchmarking sample is comprised of 57 U.S. utilities. The benchmark sample period begins in 2004 and extends to 2024. The sample is of an unbalanced panel form which allows utilities that do not have available and plausible data for all sampled years to still be present in the sample for the years in which they do have available and plausible data. There are 1,147 U.S. utility observations in the sample. This large number of observations enables robust parameter estimates and a strong statistical model.

The sample of utilities within the transmission benchmarking sample is provided in the following table.[40] In order to create an external benchmark, Hydro One is not included in the sample used to estimate the model. However, we show Hydro One's data in the sample table for comparison purposes.

[40] Data shown for the sample is from the most recently available year for each utility. For most of the sample this is for the year 2024. For Hydro One, we also show the year 2024.

Table 3 Transmission Benchmarking Sample

Transmission Benchmarking Sample					
Company	Tx Line Length	10-Year Average Peak Demand	Company	Tx Line Length	10-Year Average Peak Demand
Alabama Power Company	17,461	13,625	Kentucky Utilities Company	6,545	5,336
ALLETE (Minnesota Power)	4,608	1,588	Louisville Gas and Electric Company	1,479	3,018
Appalachian Power Company	10,192	7,102	MDU Resources Group, Inc.	5,539	812
Arizona Public Service Company	9,505	9,131	Mississippi Power Company	3,594	2,796
Atlantic City Electric Company	2,277	2,499	Monongahela Power Company	3,244	2,082
Avista Corporation	3,629	2,958	Nevada Power Company	3,098	7,242
Baltimore Gas and Electric Company	1,453	6,588	New York State Electric & Gas Corporation	7,326	2,938
Black Hills Power, Inc.	1,236	979	Niagara Mohawk Power Corporation	17,611	7,674
Central Hudson Gas & Electric Corporation	934	1,095	Northern States Power Company - MN	9,524	10,320
Central Maine Power Company	4,618	1,622	Oklahoma Gas and Electric Company	9,793	6,899
Cleco Power LLC	4,850	3,581	Orange and Rockland Utilities, Inc.	919	1,318
Commonwealth Edison Company	8,061	20,895	PacifiCorp	29,902	19,393
Consolidated Edison Company of New York, Inc.	1,673	12,169	PECO Energy Company	1,993	8,366
Duke Energy Carolinas, LLC	13,322	24,045	Potomac Electric Power Company	1,302	5,388
Duke Energy Florida, LLC	8,451	11,192	PPL Electric Utilities Corporation	6,878	7,329
Duke Energy Indiana, LLC	8,497	7,326	Public Service Company of Colorado	7,828	7,537
Duke Energy Progress, LLC	10,157	14,500	Public Service Company of New Hampshire	1,698	2,258
Duquesne Light Company	1,092	2,731	Public Service Company of Oklahoma	4,299	4,121
El Paso Electric Company	2,997	2,064	Public Service Electric and Gas Company	3,523	9,817
Empire District Electric Company	2,097	1,174	Rochester Gas and Electric Corporation	1,808	1,541
Entergy Arkansas, Inc.	7,944	7,086	San Diego Gas & Electric Co.	3,090	4,349
Entergy Mississippi, Inc.	4,867	3,835	South Carolina Electric & Gas Co.	6,864	5,005
Entergy New Orleans, Inc.	222	1,134	Southern California Edison Company	19,788	22,858
Florida Power & Light Company	12,057	25,018	Southern Indiana Gas and Electric Company, Inc.	1,654	1,224
Gulf Power Company	2,707	12,552	Southwestern Public Service Company	12,828	6,015
Hydro One Networks	**21,031**	**24,964**	Tampa Electric Company	2,168	4,805
Idaho Power Co.	7,629	4,971	Tucson Electric Power Company	3,594	5,231
Indianapolis Power & Light Company	1,390	2,738	Union Electric Company	4,969	7,691
Jersey Central Power & Light Company	4,199	5,940	West Penn Power Company	3,510	3,918

4.3 Transmission Model

The parameter estimates from the transmission total cost model are presented in the following table.

Table 4 Total Cost Model Estimates (Transmission)

Variable	Coefficient	Standard Error	T-Statistic	P-Value
Constant	10.916	0.260	41.970	0.000
KM of Transmission Lines (KM)	0.327	0.009	35.990	0.000
Peak Demand (D)	0.628	0.005	127.510	0.000
KM*KM	-0.132	0.013	-10.000	0.000
D*D	0.009	0.016	0.590	0.562
KM*D	0.261	0.032	8.200	0.000
% Tx OM&A	0.199	0.008	26.430	0.000
# of Subs	0.088	0.009	9.390	0.000
Average Line Voltage	0.261	0.048	5.450	0.000
% Overhead	-1.825	0.147	-12.410	0.000
Tx Construction Index	0.334	0.039	8.510	0.000
% Forestation	0.021	0.002	12.120	0.000
ISO	0.191	0.020	9.510	0.000
Trend	0.019	0.002	8.030	0.000

All the parameter estimates are plausibly signed and have reasonable magnitudes. The first order terms of all variables have the theoretically expected signs and are statistically significant at a 90% level of confidence. In fact, all the first order explanatory variables are statistically significant at a 99% confidence level.

4.4 Hydro One Transmission Benchmarking Results

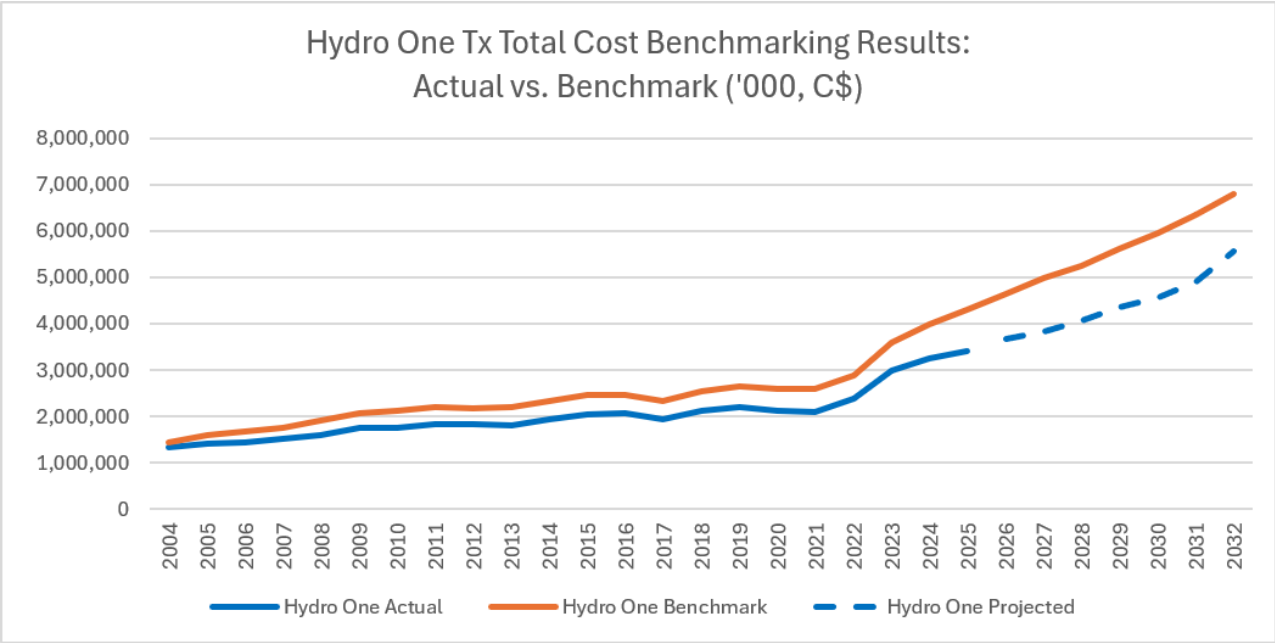
The following table breaks down the historical and forecast benchmark scores from 2004 through 2032. We note that the benchmark scores for future years assume that all the proposed spending will be incurred. If spending is less than the proposed amounts, the scores will improve; if spending is more than the proposed amounts, the scores will get worse.

Table 5 2004-2032 Transmission Total Cost Benchmark Score for Hydro One

Year	% Difference from Total Cost Benchmark
2004	-7.6%
2005	-12.4%
2006	-15.5%
2007	-15.1%
2008	-18.5%
2009	-17.1%
	-18.3%
2011	-18.6%
2012	-17.1%
2013	-19.3%
2014	-18.7%
2015	-18.0%
2016	-18.0%
2017	-19.1%
2018	-17.4%
2019	-19.3%
	-20.6%
2021	-20.8%
2022	-19.2%
2023	-18.6%
2024	-20.8%
	-23.4%
2023-2025 average score	**-20.9%**
2026	-24.1%
2027	-26.3%
2028	-25.9%
2029	-25.4%
2030	-26.3%
2031	-25.9%
2032	-20.0%
2028-2032 average score	**-24.7%**

The following graph displays how Hydro One's actual and projected transmission total costs have compared to the benchmark costs over time and through the Custom IR period, respectively.

Figure 2 Hydro One Transmission Total Cost Actual vs. Benchmark



Hydro One's transmission total cost benchmarking scores indicate the Company's transmission costs have been significantly below benchmark expectations both historically and through the CIR period. The Company's benchmark score during the CIR period is -24.7%, assuming full funding of the Company's proposed plan. Based on the 4GIR stretch factor cohorts this indicates a stretch factor of 0.15%.

4.5 HOSSM Benchmarking Results

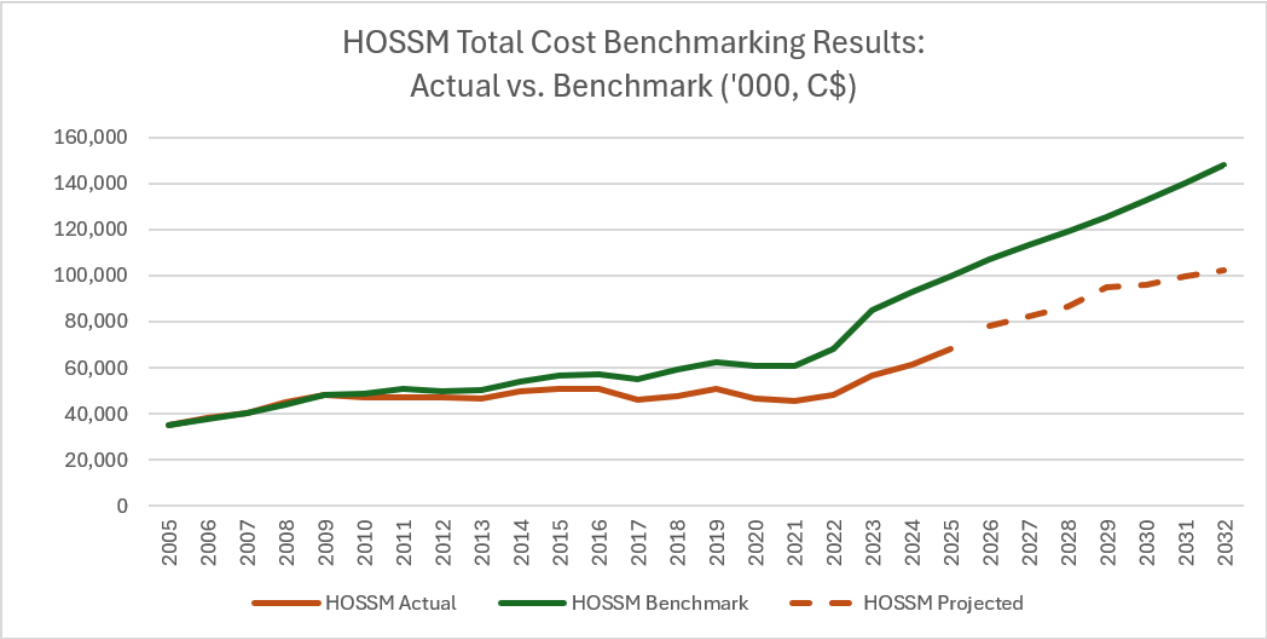
The study for HOSSM used the same sample and model specification as the Hydro One transmission study. The only difference was HOSSM data was inserted and examined instead of Hydro One Transmission. The following table breaks down the historical and forecast benchmark scores from 2005 through 2032. We note that the benchmark scores for future years assume that all the proposed spending will be incurred. If spending is less than the proposed amounts, the scores will improve; if spending is more than the proposed amounts, the scores will get worse.

Table 6 2004-2032 Transmission Total Cost Benchmark Score for HOSSM

Year	% Difference from Total Cost Benchmark
2005	-0.3%
2006	1.0%
2007	1.1%
2008	1.5%
2009	0.8%
	-3.3%
2011	-7.2%
2012	-5.2%
2013	-7.4%
2014	-7.6%
2015	-11.4%
2016	-12.4%
2017	-17.9%
2018	-21.6%
2019	-20.8%
	-26.1%
2021	-29.0%
2022	-35.0%
2023	-40.7%
2024	-41.1%
	-38.2%
2023-2025 average score	**-40.0%**
2026	-31.5%
2027	-31.8%
2028	-32.1%
2029	-28.2%
2030	-32.5%
2031	-34.0%
2032	-37.2%
2028-2032 average score	**-32.8%**

The following graph displays how HOSSM's actual and projected transmission total costs have compared to the benchmark costs over time and through the Custom IR period, respectively.

Figure 3 HOSSM Total Cost Actual vs. Benchmark



HOSSM's transmission total cost benchmarking scores indicate the Company's transmission costs have been below benchmark expectations over the last decade. The Company's benchmark score during the CIR period is -32.8%, assuming full funding of the Company's proposed plan. Based on the 4GIR stretch factor cohorts this indicates a stretch factor of 0.00%.

5 Distribution Cost Benchmarking

Clearspring undertook a total cost econometric benchmarking study of Hydro One's distribution costs. This study provides a comparison of Hydro One's distribution total costs to the benchmark costs after adjusting for the specific output levels, input prices, and business conditions that the Company operates within. These comparisons are made for both historical and forecasted years through 2032. For more information on the benchmarking methods please see Chapter 3 and Appendix A.

5.1 Distribution Variables

The three output variables used in the distribution benchmarking research are:

- Total customers served,
- A 10-year rolling average of peak demand, and
- The total distribution service territory of the utility.

The business condition variables used in the distribution benchmarking research are:

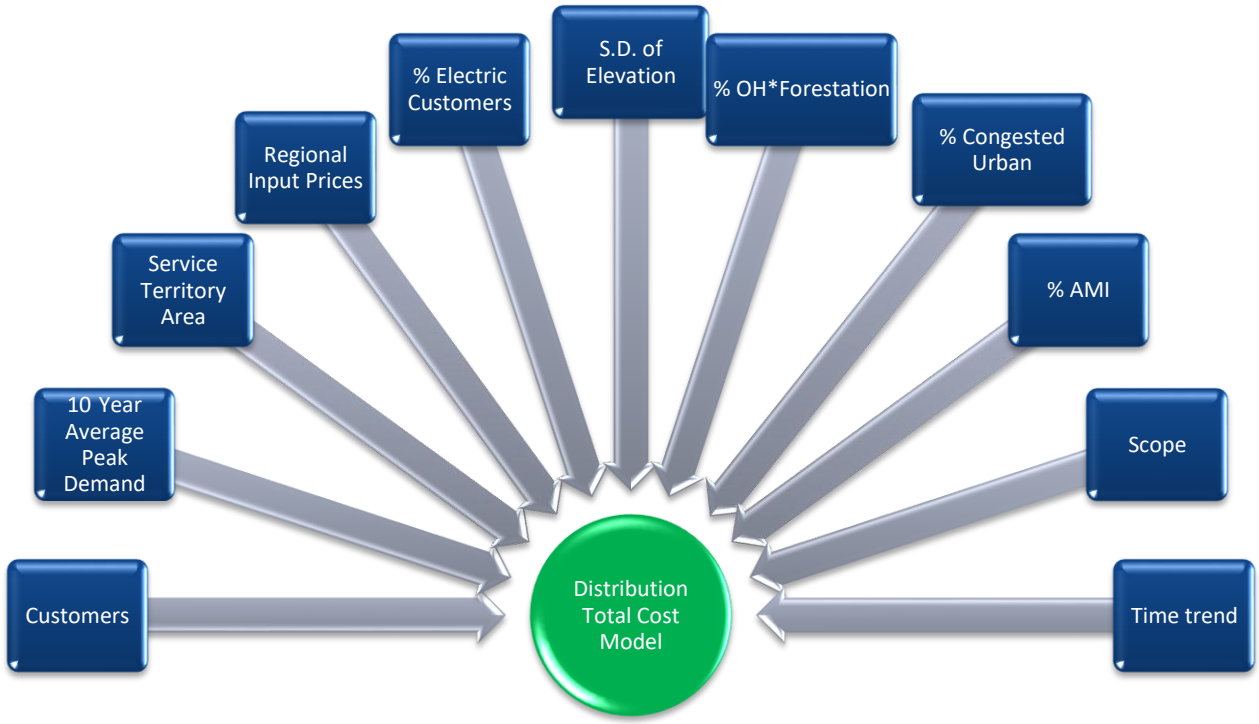
- Regional input prices (total costs in the model are divided by the input price index),
- Percent of electric customers in the total of electric and gas customers,
- Standard deviation of elevation,
- Percent of distribution plant that is overhead multiplied by the percent of forestation,
- Percent of congested urban area within each utility's service territory,
- Percent of AMI (smart meters) deployed by the utility in each year,
- The O&M based economies of scope variable which measures the percentage of distribution O&M expenses in total distribution, transmission, and generation expenses, and
- A time trend variable.

These are the same variable definitions, with the exception of the two changes discussed below, used by Clearspring in the Hydro One Joint Report with which PEG had no significant issues, and closely matched PEG's model specification. There are two changes relative to the Joint Report. The first is the variable refinement to the percent congested urban variable which now is allowed to vary by time based on the annual changes in high-rise buildings. The second is the Dx Work variable has been removed due to the variable being difficult to gather data and not capturing the differences between distribution utilities consistently.[41] Other than the Dx work variable being excluded, the variables and methodology used for this study matches those used in the latest Alectra Utilities and Elexicon Energy studies.

[41] PEG also decided not to include this variable in its latest distribution benchmarking work in the Elexicon application (EB-2025-0312). On page 42 of PEG's Empirical Report for Elexicon it states, "PEG acknowledges the desirability of a variable to measure the extent of high voltage work that a distributor performs since this can be costly and varies between distributors. However, the variable that Clearspring uses is too problematic for inclusion." Clearspring agrees with PEG that the variable is difficult to explain, understand, and does present some issues in that it is calculated using transmission utility data. For these reasons, we have decided to not include this variable in our current study.

The variables included in the distribution benchmark analysis are shown in the figure below.

Figure 4 Variables in Distribution Cost Model



These variables provide a robust accounting of the varying service territory conditions faced by distribution utilities. All first order variables are statistically significant at a 90% confidence level and all variables are correctly signed (i.e., they are signed the way we would expect).[42]

5.1.1 The Definition of Distribution Costs

OM&A and capital costs used in the benchmarking models for the U.S. distribution utilities are derived using FERC Form 1 filing data.[43] U.S. investor-owned utilities are required to file FERC Form 1 data annually, which includes operation and maintenance expenses broken down into specific cost categories (e.g., distribution, transmission, customer billing, administrative and general). Form 1s also include information regarding gross plant in service and accumulated depreciation that are used in constructing capital costs.[44]

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[42] All first order variables are also statistically significant at a 99% confidence level.

[43] Some of the FERC Form 1 data was gathered using HData's database tool and also SNL Energy's database tool.

[44] Clearspring gathered plant addition data going back to 1947. This data was collected from various EIA annual reports.

We used a cost definition that is consistent between both the U.S. sample and Hydro One Distribution. The cost definition is the same as Clearspring has used in its last several Ontario CIR total cost benchmarking studies, including the Hydro One Joint Report total cost benchmarking study. Clearspring began with the benchmark-based cost definition used by PEG in the 4GIR proceeding. To be consistent with the U.S. sample, we added high-voltage expenses to the cost definition for Hydro One. The FERC Form 1 does not break down high- versus low-voltage distribution expenses, as Ontario reporting does. For the same reasons, contributions in aid of construction ("CIAC") have been excluded from Hydro One's cost definition, due to those expenses not being included in the U.S. Form 1 data. Bad debt expenses (called uncollectible expenses in the FERC Form 1) have been excluded for all utilities, to match the 4GIR benchmark-based definition.

The cost definition also excludes customer service and information ("CSI") expenses from total costs for all utilities. This is due to the possibility that the U.S. utilities include conservation demand management ("CDM") expenses in the CSI expense category. This assures cost consistency between the U.S. sample and Hydro One. Pensions and benefits are also excluded from the cost definition for both the U.S. sample and Hydro One to assure consistency and not permit the different health care systems of the two countries to impact results. The table below summarizes the cost definition treatment.

Table 7 Distribution Cost Definitions

Cost Element	Treatment
4th Generation IR Benchmark-Based Costs	This is the starting point for the sample.
Contributions in Aid of Construction (CIAC)	We subtracted from Hydro One distributor costs, since U.S. cost data does not include CIAC.
High Voltage Expenses	We added to Hydro One costs, since U.S. cost data includes distribution high voltage costs.
Customer Service and Information (CSI) Expenses	We excluded CSI expenses for both the U.S. and Hydro One, given the possible inconsistency in CDM reporting.
Pensions and Benefits	We excluded OM&A pensions and benefits from both the U.S. and Hydro One data.

5.1.2 Distribution Output Variables

The distribution total cost model includes three output variables.[45] The first is the total number of customers served, the second is the ten-year rolling average of peak demand for each utility, and the third

[45] This three-output specification closely matches PEG's distribution total cost model specification found in the Hydro Ottawa proceeding (EB-2019-0261) and in the Hydro One Joint Report.

is the total service territory area for each utility. The first two output variables are gathered from FERC Form 1 data. The third uses GIS information on the utility service territory area; this variable uses the same values for the U.S. sample as used by Clearspring and PEG in the Joint Report. The historical output data for Hydro One regarding the number of customers and peak demands comes directly from the company. The peak demand variable is calculated based on taking the ten-year rolling average of annual peak demand on the system in the sample that has occurred up to that year. For years without ten years' worth of historical data, the years that are available were averaged.[46]

Clearspring is using a service territory variable for Hydro One that was calculated by the Company based on actual locations of its distribution substations. This is the same value as the one used in Clearspring's Reply Report in EB-2021-0110 and in the Joint Report.

Clearspring understands that Hydro One's full licensed service area is around 960,000 square kilometers. The area used by Clearspring in this study (which is around 530,000 square kilometres) therefore reduced Hydro One's licenced service area by 430,000 square kilometers. This methodology departs from the rest of the sample, where the full licensed service territory is used as the basis for the variable value. However, we acknowledge that Hydro One is unique in its licensed service territory, specifically in northern Ontario where there is an abnormally large portion of area that is unserved. We have, accordingly, lowered Hydro One's service territory to include only the portion that has a reasonable proximity to a distribution substation. This area estimate provides sufficient credit for the expansiveness and challenges of serving such a vast and spread-out area but is reduced to not give undue credit for unserved areas.

While there remain some unserved areas in this estimate, the U.S. sample distribution area values also include unserved areas.[47] The key is making the variable value comparable, given the extreme level of ruralness of Hydro One, to the rest of the sample. We would expect Hydro One to have the lowest customer per square km in the sample since most of the cities and towns near its service territory are being served by other LDCs and Hydro One serves large portions of northern Ontario and most of the rural areas of Ontario. The rest of the utilities in the U.S. sample do not have most of the cities and towns carved out of their service territory like Hydro One has. In fact, most of the U.S. sample has many of the rural areas carved out of its territory as those areas are served by rural electric cooperatives.

Yet despite this, Hydro One does not have the lowest customer density in the benchmarking dataset using Clearspring's 529,313 sq. km measure. Hydro One's customers per square km in 2024 is 2.74 in our dataset, whereas Montana Dakota Utilities ("MDU") is measured at 2.25. This despite MDU's territory not including many rural areas of the Dakotas, Wyoming, and Montana and MDU serving Bismarck which has a population of 73,622 according to the 2020 U.S. Census. MDU also serves three other cities with populations above 20,000, whereas Hydro One only serves two cities above 20,000 with populations around 23,000 (Owen Sound and Brockville). Clearspring is of the view that the service area estimate of

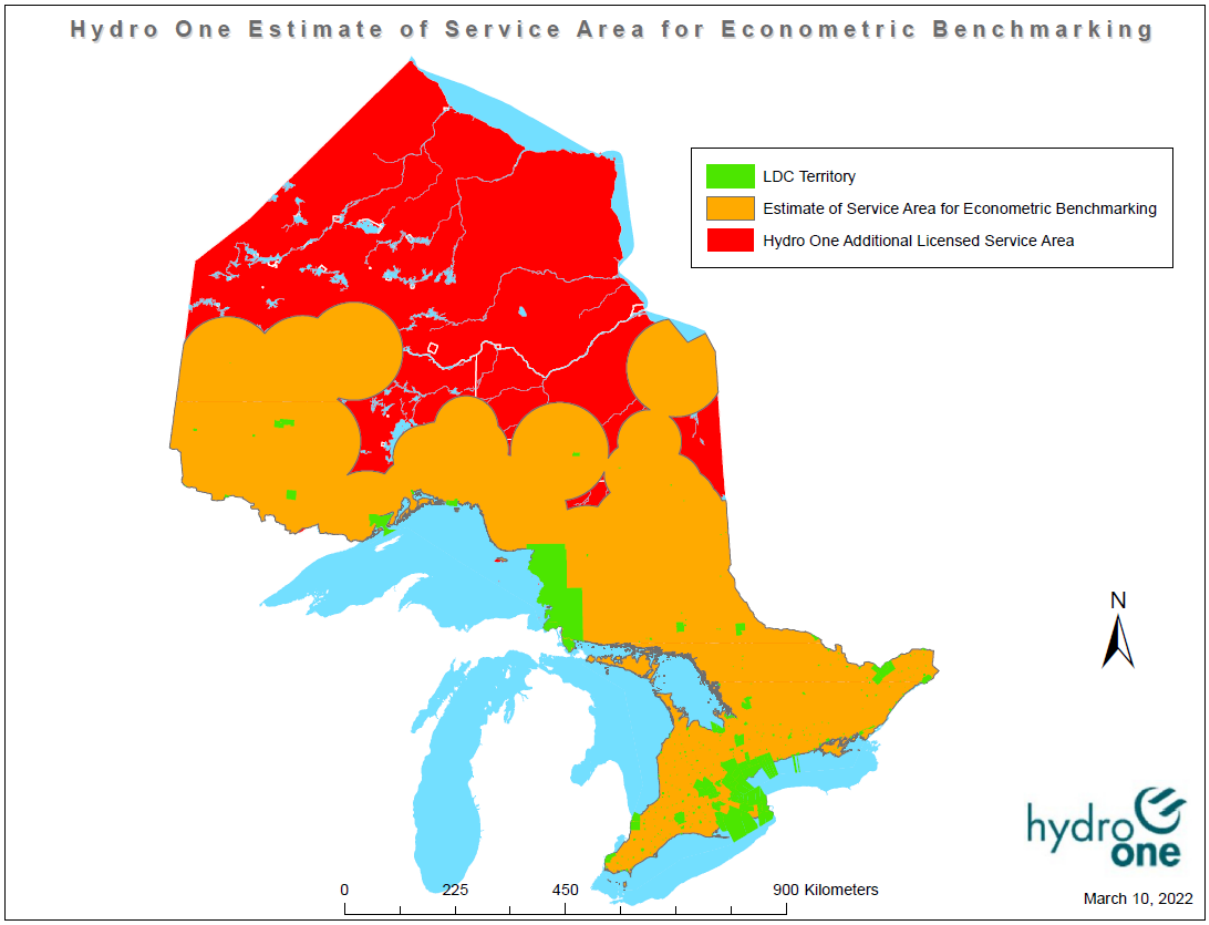
[46] This is another advantage of the 10-year rolling average method. There is no bias if fewer than ten years for a utility are available since we are taking an average rather than a maximum of the peak demands.

[47] PEG agreed with this statement in EB-2021-0110, Exhibit N, Tab 1, Schedule 21, part c.

529,313 for Hydro One is not comparably high and, if anything, is on the low end of a range of reasonable values relative to how the U.S. sample values are constructed.

The map below provides the service territory used to estimate the distribution area of 530,000 square kilometers. The orange-colored portion is approximately 530,000 square kilometers and is based on the service areas where Hydro One has distribution stations within a given radius.[48] This number subtracts out the service territories of the other LDCs (colored in green).[49] As shown in red, the value used for Hydro One does not include a large portion of the Company's licensed territory.

Figure 5 Hydro One Estimated Distribution Service Area



5.1.3 Distribution Business Condition Variables

Beyond the three output variables and the input price index, there are six business condition variables

[48] For high voltage distribution substations, Hydro One used a radius of 100 kilometers. For lower voltage substations the radius was 65 km.

[49] Five Hydro One Remotes communities fall within the orange-coloured portion but the area of these Remotes communities (Hillsport, Oba, Sultan, Biscotasing, and Pikangikum) is not material.

included in the model (plus a time trend). Each variable is discussed briefly below.

The **percentage of electric customers** measures the percentage of electric customers served by a utility out of total gas and electric customers. This variable measures the economies of scope available from serving both electric and gas customers. Billing and other customer-related activities can be shared between the gas and electric divisions when a utility serves its customers with both commodities. The value is set to 100% for Hydro One since they do not serve natural gas customers. We would expect a positive parameter estimate on this variable.

The **standard deviation of elevation** variable is calculated based on geographic information system ("GIS") elevation topography maps. A higher standard deviation of the elevation indicates increased elevation changes and variance within the utility's service territory. We would expect that a service territory with more hills, mountains, and other elevation changes would be more challenging and costly to serve, *ceteris paribus*. Therefore, a positive parameter estimate is expected (indicating a positive correlation between standard deviation of elevation and costs).

The **overhead percentage times percentage of forestation** variable is based on the overhead plant in service for each utility (for the percent overhead) and GIS land cover maps (for percent forestation). These maps used the GlobCover 2009 product produced by the European Space Agency ("ESA") and the Université Catholique de Louvain. These maps are matched with the areas served by each utility to create the forestation variable. We would expect that the higher the level of overhead lines and forestation, the higher OM&A costs required for right-of-way clearing and service restoration activities.

The **congested urban** variable measures the percentage of a utility's service territory that consists of a major urban load center that is "congested." Congested urban areas have physical constraints that necessitate complex and costly subterranean civil infrastructure for housing and operating electric distribution plant. Congested urban areas also often necessitate electrical equipment unique to such subterranean infrastructure. The variable measures the percentage of service territory classified as "congested urban" area. This variable has been refined and improved to now vary by year based on the estimated impact of the percentage change in skyscrapers in the service territory.

We expect a utility that has a congested urban area within its service territory would experience substantial incremental costs as compared to a utility that does not have such an area within its service territory. The parameter value for this variable is expected to be positive, indicating a positive correlation of percent congested urban with total costs.

The **percentage of smart meters** variable measures the percentage of customers that have an installed smart meter. Smart meters enable hourly or sub-hourly interval use data to be collected from the meter. While installing more capable meters and the necessary infrastructure is expected to increase distribution costs, these meters enable time-of-use ("TOU") electricity rates that can create efficiencies mainly in the realm of power supply. Since this study is focused on distribution total costs, we would expect a positive coefficient on the percent smart meter variable.

The **O&M based scope variable** measures the percentage of distribution operation and maintenance expenses in the sum of distribution, transmission, and generation expenses. This variable measures the possible cost savings of serving multiple electric utility functions. We would expect that the increased availability of economies of scope would lower expenses and, therefore, a higher proportion of distribution-related expenses in total expenses is expected to have a positive parameter value.

The **time trend** variable captures a general industry total cost level trend over the studied period. Time trend variables are often found in translog cost functions and standard in econometric total cost benchmarking research. In the present study, the variable is calculated by taking the current year of the observation and subtracting 1,999. For observations in the year 2000, the time trend variable equals 1. In 2019, the variable equals 20 (2,019 – 1,999). The coefficient value shows how adding a year impacts expected total costs.

5.2 Distribution Sample

The distribution benchmarking sample is comprised of 81 U.S. utilities. The benchmark sample period begins in 2000 and extends to 2024. The sample is an unbalanced panel, which enables utilities that do not have available and plausible data for all sampled years to still be present in the sample for the years in which they do have available and plausible data. There are 1,964 U.S. utility observations in the sample. This large number of observations enables robust parameter estimates and a strong statistical model.

The sample of utilities within the sample is provided in the following table.[50] In order to create an external benchmark, Hydro One is not included in the sample used to estimate the model. However, we show Hydro One's data in the sample table for comparison purposes.

[50] Data shown is from the most recently available year for each utility. For most of the sample this is for the year 2024. For Hydro One, it is 2025.

Table 8 Distribution Benchmarking Sample

U.S. Distribution Benchmarking Sample			
Company	**Customers**	**Company**	**Customers**
Alabama Power Company	1,547,153	Madison Gas and Electric Company	166,128
ALLETE (Minnesota Power)	152,342	MDU Resources Group, Inc.	145,478
Appalachian Power Company	967,408	Metropolitan Edison Company	588,329
Arizona Public Service Company	1,400,036	Mississippi Power Company	192,416
Atlantic City Electric Company	572,774	Monongahela Power Company	397,165
Avista Corporation	418,963	Nevada Power Company	1,035,146
Baltimore Gas and Electric Company	1,342,757	New York State Electric & Gas Corporation	921,367
Black Hills Power, Inc.	77,523	Niagara Mohawk Power Corporation	1,559,866
Central Hudson Gas & Electric Corporation	268,174	Northern Indiana Public Service Company	490,666
Central Maine Power Company	672,682	Northern States Power Company - MN	1,577,476
Cleco Power LLC	295,385	Northern States Power Company - WI	271,318
Cleveland Electric Illuminating Company	758,454	Ohio Edison Company	1,074,067
Commonwealth Edison Company	4,130,749	Oklahoma Gas and Electric Company	902,714
Connecticut Light and Power Company	1,290,879	Orange and Rockland Utilities, Inc.	244,791
Consolidated Edison Company of New York	3,759,848	Pacific Gas and Electric Company	5,479,889
Consumers Energy Company	1,893,531	PacifiCorp	2,104,050
Delmarva Power & Light Company	554,789	PECO Energy Company	1,704,093
DTE Electric Company	2,279,071	Pennsylvania Power Company	171,046
Duke Energy Carolinas, LLC	2,907,066	Portland General Electric Company	943,944
Duke Energy Florida, LLC	2,009,463	Potomac Electric Power Company	949,732
Duke Energy Indiana, LLC	909,011	PPL Electric Utilities Corporation	1,487,306
Duke Energy Kentucky, Inc.	154,073	Public Service Company of Colorado	1,535,755
Duke Energy Ohio, Inc.	759,800	Public Service Company of New Hampshire	542,057
Duke Energy Progress, LLC	1,753,575	Public Service Company of Oklahoma	580,734
Duquesne Light Company	613,787	Public Service Electric and Gas Company	2,390,225
El Paso Electric Company	459,472	Puget Sound Energy, Inc.	1,239,245
Empire District Electric Company	187,269	San Diego Gas & Electric Co.	1,370,621
Entergy Arkansas, Inc.	732,671	South Carolina Electric & Gas Co.	806,434
Entergy Mississippi, Inc.	460,181	Southern California Edison Company	5,071,773
Entergy New Orleans, Inc.	208,845	Southern Indiana Gas and Electric Company	153,433
Florida Power & Light Company	5,214,245	Southwestern Public Service Company	408,769
Gulf Power Company	477,672	Tampa Electric Company	849,877
Hydro One Dx	**1,461,391**	Toledo Edison Company	316,086
Idaho Power Co.	641,566	Tucson Electric Power Company	451,936
Indiana Michigan Power Company	614,578	Union Electric Company	1,264,469
Indianapolis Power & Light Company	530,802	United Illuminating Company	345,877
Jersey Central Power & Light Company	1,171,836	Virginia Electric and Power Company	2,783,257
Kansas Gas and Electric Company	337,830	West Penn Power Company	737,355
Kentucky Power Company	162,506	Wisconsin Electric Power Company	1,170,318
Kentucky Utilities Company	574,094	Wisconsin Power and Light Company	499,391
Louisville Gas and Electric Company	437,737	Wisconsin Public Service Corporation	467,910

5.3 Distribution Model

The parameter estimates from the distribution total cost model are presented in the following table.

Table 9 Total Cost Model Estimates (Distribution)

Variable	Coefficient	Standard Error	T-Statistic	P-Value
Constant	13.224	0.025	536.850	0.000
Customers (N)	0.506	0.014	36.320	0.000
Peak Demand (D)	0.475	0.016	30.380	0.000
Area (A)	0.044	0.006	7.020	0.000
N*N	0.683	0.067	10.200	0.000
D*D	0.909	0.061	14.930	0.000
A*A	0.021	0.005	4.510	0.000
N*D	-1.557	0.129	-12.060	0.000
N*A	0.063	0.011	5.480	0.000
D*A	-0.064	0.013	-5.080	0.000
% Electric	0.132	0.019	6.940	0.000
Standard Deviation of Elevation	0.017	0.003	5.950	0.000
% OH*% Forest	0.039	0.002	23.170	0.000
% Congested Urban	17.363	0.909	19.090	0.000
% AMI	0.066	0.014	4.730	0.000
O&M Scope	0.056	0.006	9.620	0.000
Trend	-0.003	0.001	-2.310	0.030

All the parameter estimates are plausibly signed and have reasonable magnitudes. The first order terms of all variables have the theoretically expected signs and are statistically significant at a 90% level of confidence. In fact, all the first order explanatory variables, except the trend variable, are statistically significant at a 99% confidence level.

5.4 Distribution Results

The following table breaks down the historical and forecast year benchmark and Company distribution total costs from 2005 through 2032. We note that the benchmark scores assume that all the proposed spending will be incurred. If spending is less than the proposed amounts, the scores will improve; if

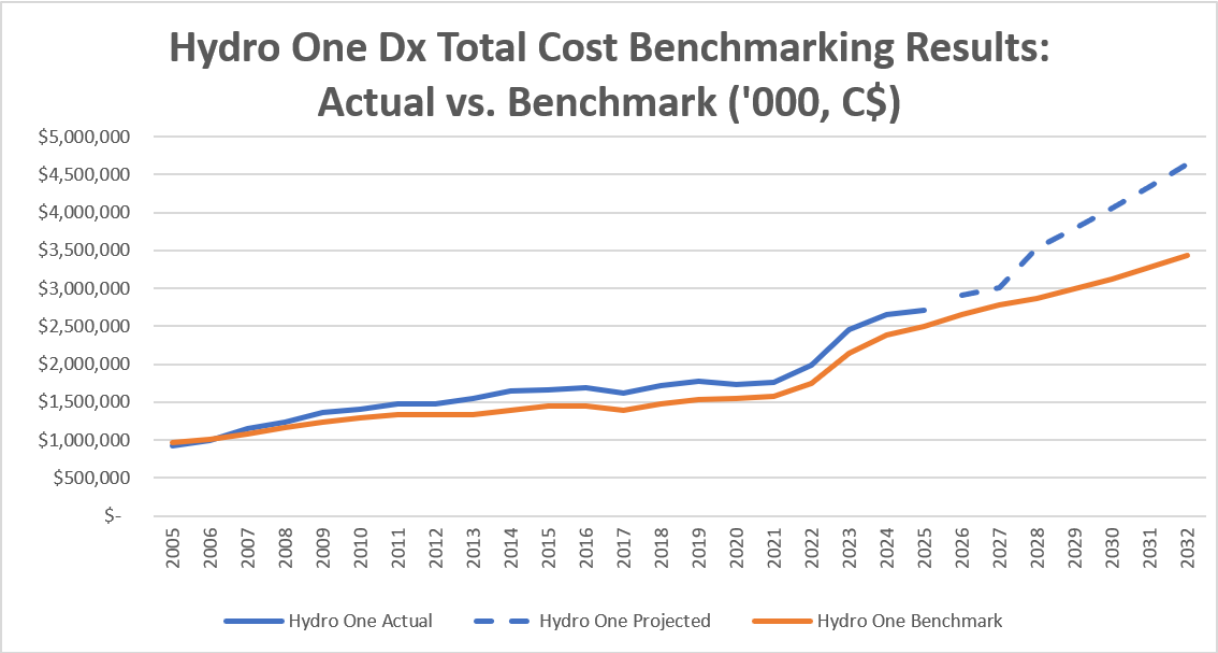
spending is more than the proposed amounts, the scores will get worse.

Table 10 2005-2032 Distribution Total Cost Benchmark Score for Hydro One

Year	% Difference from Total Cost Benchmark
	-4.6%
2006	-0.2%
2007	6.8%
2008	5.8%
2009	9.7%
	9.3%
2011	10.4%
2012	10.8%
2013	14.7%
2014	17.4%
2015	14.0%
2016	15.9%
2017	15.2%
2018	15.1%
2019	14.4%
	10.6%
2021	11.0%
2022	12.7%
2023	13.9%
2024	11.1%
2025	8.4%
2023-2025 average score	**11.1%**
2026	9.2%
2027	7.6%
2028	20.9%
2029	23.7%
2030	26.1%
2031	28.2%
2032	30.2%
2028-2032 average score	**25.8%**

The following graph displays how Hydro One's actual and projected distribution total costs have compared to the benchmark costs over time and through the Custom IR period, respectively.

Figure 6 Hydro One Distribution Total Cost: Actual vs. Benchmark



5.5 Reasons for Different Transmission and Distribution Benchmark Results

In a prior transmission application, the OEB Decision noted the different benchmark results for the transmission and distribution businesses of the Company and asked for an explanation for the different results to be provided at the next rebasing application.[51] A similar difference in benchmarking results persists through the current research found in this report. Hydro One's transmission operations have benchmark scores indicating costs are well below benchmark expectations, while Hydro One's distribution operations have benchmark scores that indicate costs are well above benchmark expectations. The rest of this section provides some explanatory factors for this difference.

At a high level, Hydro One's transmission system is more similar to its peers and the benchmarking sample than the distribution system is with no available distribution model variables to adjust for this dissimilarity. The transmission system is vast and transmits electricity to rural, municipal, and urban centers. This is similar to many of the transmission utilities in the sample. However, Hydro One's distribution system is unique in serving remote areas, the density of its service territory, and having most of the lower-cost municipal and suburban areas carved out of its service territory.[52] This leaves Hydro One with the much higher-cost rural territories to which the Company is required to deliver electricity. This contrasts with its U.S. sampled peers whose service territories extensively include these lower cost suburban areas and have much of the higher cost rural areas carved out of their service territories. Since Hydro One is the only utility with this disadvantage, we cannot develop a variable to adjust for this service territory condition

[51] OEB Decision in EB-2019-0082 at pg. 34.

[52] By lower cost or higher cost in this discussion we mean lower (or higher) cost per unit of output. A rural area will tend to cost a utility more to serve one customer or one kW of demand relative to a suburban area.

present on the distribution system. Given this reality, we would expect the Company's transmission operations to score better than its distribution operations.

Related to the above point, Clearspring is using a distribution service area value for Hydro One that is on the low end of the range of reasonable values. The value being used of around 530,000 square KM placed Hydro One as having a higher customer density than one other U.S. comparator (MDU) despite MDU serving several larger cities. This provides evidence that the value being used by Clearspring is not too high comparative to the sample. If a higher value for this variable would have been applied to Hydro One, this would improve Hydro One's distribution total cost benchmarking score.

Some additional underlying explanations for the differences in benchmark results could be the historical realities of Hydro One's distribution system. These historical facts of Hydro One's distribution system still may have a lasting impact on cost levels and, thus, the benchmark scores. It is Clearspring's understanding (based on information from the Company) that several mergers throughout the years (particularly at the turn of this century) meshed diverse systems together into one Company.

One challenge resulting from the historical mergers is that Hydro One has a distribution system that is comprised of many different voltage levels. Our understanding (based on information from the Company), is that these numerous voltage levels create cost challenges that would not otherwise exist (such as increased inventory requirements for station transformers and a need for a more diverse fleet of mobile unit substations). Most other distribution utilities in the sample do not have this historical challenge. This creates a disadvantage to Hydro One that is not being adjusted for within the benchmark model.[53] The transmission system does not have this same historical challenge of meshing different systems together on such a large scale; therefore, this could be a further explanation for the different performance results.

In its Decision in the prior transmission-only application, the OEB noted that it did not have the evidence to make conclusions on why the same company has different transmission and distribution benchmark scores,[54] and also noted that there are significant common costs allocated between the two operations. Although examining this allocation of common costs is outside the realm and scope of our research, we note that common costs are a relatively small percentage of the total costs being evaluated in our benchmarking research and are unlikely to be a significant reason for the benchmark score differences.

The benchmarking research deals with the transmission and distribution businesses of Hydro One independently. The models are separate, with a different sample, and a diverse set of variables in each model. However, if the transmission and distribution actual/proposed and benchmark costs for each study are summed to create a full Hydro One T&D total cost benchmarking evaluation, the full Company has a total cost benchmark score during the CIR period of -3.3%.

[53] Distribution line voltage data is not available for the sample to create a variable that could adjust for this.

[54] See p. 33 of the Decision and Order dated April 23, 2020 in EB-2019-0082.

6 Productivity Trend Methodology

In Section 2, Clearspring provided the mathematical rationale for including a productivity trend in a revenue (or price) escalation formula. This trend is designed to measure the expected change in the ratio of measured outputs to measured inputs.

External industry TFP trends typically form the basis for the base productivity factor ("Base PF") used in the proposed CIR formula. The Base PF should be based on an external measure of the industry TFP trend. Hydro One should have no impact on the measured industry TFP trend. This is because incentive regulation seeks to decouple the link between a utility's costs to the allowed revenue escalation. If a utility's own TFP is used within the formula, it will weaken the incentives to enhance productivity and reduce costs.

Clearspring examined three industry trends separately to provide the basis for our Base PF recommendations. We calculated the U.S. electric transmission TFP trend, the U.S. electric distribution TFP trend, and the Ontario electric distribution TFP trend. In all three calculations, we used the same basic methodology and calculation methods, which are described in this section.

6.1 Methodology Overview for Productivity Research

The output variables, input prices, and cost definitions used for the TFP analysis for each respective study match those used in the total cost econometric benchmarking research for that functional area (distribution or transmission). That is, the distribution TFP analysis uses the same outputs, cost definitions, and input prices as what is used in the distribution total cost benchmarking research.[55] The same is true for the transmission study.

Productivity is defined as the ratio of an output quantity index to an input quantity index. In the case of TFP, the Input Quantity Index includes both capital and OM&A inputs. For a partial factor productivity ("PFP") study, the input quantity index only encompasses capital (for a capital PFP trend) or OM&A (for an OM&A PFP trend).

$$Productivity = \frac{Output\ Quantity\ Index}{Input\ Quantity\ Index}$$

The output quantity index measures the level of output produced by the utility or industry based on the available output measurements. The input quantity index measures the level of resources used, such as labour, non-labour OM&A, or capital inputs. Clearspring employs commonly used indexing techniques to capture a comprehensive measure of outputs and inputs, which are in turn used to calculate the productivity term.

[55] The one caveat is the distribution outputs for the TFP does not include service area since this variable is time invariant which does not enable it to be included in a trend analysis. The variable has the smallest cost elasticity of the outputs.

To translate into how productivity changes over time, we calculate how the productivity ratio changes over time to determine the productivity index trend. The annual TFP trend for a given year *t* for a given utility *i* is the difference between the annual growth rate in the output quantity index in that year and the input quantity index growth rate in that same year.

$$\boldsymbol{TFP\ trend_{i,t} = Output\ Quantity\ trend_{i,t} - Input\ Quantity\ trend_{i,t}}$$

It may be helpful to note that TFP trend measurement differs from total cost benchmarking. With cost benchmarking, utilities are compared relative to the average efficiency level of other utilities within the industry after adjusting for the differences between utilities. Conversely, TFP trends measure how productivity is changing over time for that same utility.

6.1.1 Output Quantity Index

Both the transmission and distribution productivity studies include multiple outputs. In order to calculate a comprehensive productivity trend, it is necessary to combine these multiple outputs into one output quantity index. This section describes the calculations to combine multiple outputs into one index.

The transmission and distribution studies use two outputs. The outputs for each study will be further described in following sections. The two outputs need to be combined into one comprehensive output quantity index. To align with the mathematics of the cost escalation formula discussed in Section 2, the output quantity index should be constructed based on how each output impacts a utility's costs. We accomplish this using cost elasticities for each output at the mean of the sample, derived from the econometric total cost model and scaling them up so the sum of the weights equals "1".

The following equation provides the output quantity growth rate in year *t* for utility *I* when combining two outputs (Output 1 and Output 2).[56]

$$Output\ Quantity\ Trend_{i,t} = Weight\ 1 * Output\ 1\ Trend_{i,t} + Weight\ 2 * Output\ 2\ Trend_{i,t}$$

Where, $Weight\ 1 = \frac{Cost\ Elasticity\ of\ Output\ 1}{(Cost\ Elasticity\ Output\ 1 + Cost\ Elasticity\ Output\ 2)}$ and

$$Weight\ 2 = \frac{Cost\ Elasticity\ of\ Output\ 2}{(Cost\ Elasticity\ Output\ 1 + Cost\ Elasticity\ Output\ 2)}$$

By using the econometric cost elasticity weights as the basis for combining multiple outputs, the output quantity index is constructed in such a way that it approximates the expected growth of real costs due to output growth absent efficiency or scale economy gains.

6.1.2 Input Quantity Index

The input quantity index is comprised of an OM&A quantity index and capital quantity index.

[56] Each output trend is calculated logarithmically. The formula is the natural log of the current year divided by the prior year.

The OM&A quantity used in the TFP calculation is derived by dividing annual OM&A expenses in year *t* for utility *i* by the OM&A input price index in year *t* for utility *i*. Clearspring used the same cost and price definitions for both the TFP and the benchmarking research.

$$OM\&A\ Quantity\ Index_{i,t} = \frac{OM\&A\ Expenses_{i,t}}{OM\&A\ Input\ Price_{i,t}}$$

Clearspring used the same procedures in both the benchmarking and productivity research for the capital quantity index, using the Perpetual Inventory Method with a capital benchmark year of 1947 for most of the sample. The capital quantity index begins with that capital benchmark year and then in every subsequent year adds capital based on the report plant additions for that year divided by the asset price index and subtracts a portion out of the capital quantity for depreciation. Please see the section on the Perpetual Inventory Method found in Appendix A for more details.

Like the output quantity trend construction, the capital quantity and OM&A quantity trends are combined into a comprehensive input quantity index trend. This is done using Tornqvist indices based on using the cost shares of each input component. Tornqvist indices are a commonly used indexing methodology, and this is the same approach used in all our prior research. The method averages the cost shares in the current year and the prior year in weighting the two input quantity trends.

The equation for the input quantity trend for utility *i* in year *t* is shown below.

$$Input\ Quantity\ Trend_{i,t} = \left(\frac{S_{i,t}^{K}+S_{i,t-1}^{K}}{2}\right) * Capital\ Q\ Trend_{i,t} + \left(\frac{S_{i,t}^{OM\&A}+S_{i,t-1}^{OM\&A}}{2}\right) * OM\&A\ Q\ Trend_{i,t}$$

Where, $S^{K} = Share\ of\ Capital\ Costs\ in\ Total\ Costs,$

$S^{OM\&A} = Share\ of\ OM\&A\ Costs\ in\ Total\ Costs,$

$Capital\ Q\ Trend = \ln\left(\frac{Capital\ Quantity_{t}}{Capital\ Quantity_{t-1}}\right),$

$OM\&A\ Q\ Trend = \ln\left(\frac{OM\&A\ Quantity_{t}}{OM\&A\ Quantity_{t-1}}\right),$

6.2 Industry Aggregation Method

The calculated trends are conducted for each individual utility and in each year. There are two general methods for aggregating the individual utility trends in each year into industry aggregates. The first is taking an average of the productivity trends. This is equivalent to giving each utility an equal weight. The second method is aggregating using a size-weighting approach which will give a larger weight to the bigger utilities in the sample.

Clearspring recommends the averaging, or even-weighted, approach. This approach does not favor larger utilities compared to smaller ones but gives an equal weight to the productivity experience of all sampled utilities. The averaging approach will tend to be far more stable year-to-year and will not be influenced by only a handful of observations.

The industry aggregation should not include the utility that the productivity trend is being applied to. This provides a fully externalized measurement of the productivity trend of the utility's peers and does not enable the utility itself to impact the productivity factor.

6.3 Interpretation of Negative TFP Growth

Both the distribution and transmission productivity studies reveal negative productivity average annual growth rates. A negative industry TFP trend implies higher electricity costs for the industry (above and beyond inflationary and output-driven cost increases). The OEB addressed this possibility in the Board's Decision dated November 21, 2013 in EB-2010-0379 (page 17):

> The Board acknowledges that achieved industry TFP may be negative due to unforeseen events and/or situations in which costs may be incurred with no corresponding increase in output.

It is important to note that a negative TFP growth rate does not necessarily indicate declining efficiency, at either the industry or the utility level. Recall that the TFP trend equals the Output Quantity Index trend minus the Input Quantity Index trend. Negative TFP trends indicate that measured outputs are growing slower than measured inputs. As the Board acknowledged in the statement above, there may be reasons that utilities will need to increase costs other than output growth.

While declining efficiency is one possibility when observing negative TFP trends, there are several other possibilities. Systemic possibilities include:

1. The increasing of "outputs" that are not being measured within the TFP calculation. While Clearspring's output measure incorporated two key outputs for both transmission and distribution, there are other valued utility functions that are difficult, if not impossible, to incorporate and quantify. These other valued functions could include reliability, cybersecurity, safety, meeting increased regulatory requirements, evolving customer service, increasing generation interconnections from wind or solar, providing enhanced environmental stewardship, geomagnetic disturbances, and increasing other aspects of power quality and security.

   In this category of increasing outputs that are not measured is the energy transition and the future grid needs. Utilities are beginning to make investments today to prepare for the future output expectations prior to the outputs being realized. These preparatory investments for higher output levels will drive down current productivity trends as the utility is aiming to serve a future higher output that is currently not being measured in the productivity study.

2. A common external circumstance that is changing across the electric industry, but is problematic to quantify, is the aging of capital infrastructure. Due to the post-World War II population boom and increasing use per customer during the 1950s, 60s, and 70s, utilities needed to heavily invest in capital infrastructure to meet the higher peak demands. When this infrastructure needs to be replaced, it will put downward pressure on productivity trends.

3. Another possibility is that the productivity study's input price inflation assumptions are too low and actual input price inflation for the industry is higher than assumed. For example, the Ontario productivity study in this report uses the 4GIR established indexes for OM&A labour (AWE) and non-labour (GDP-IPI) for the assumption for OM&A input price inflation and uses the Handy-Whitman indexes for the asset price inflation assumption. If these inflationary assumptions are lower than reality, i.e. price pressures are higher for industry participants than assumed in the study, that may reveal itself in a negative productivity finding. The inflation adjustment in the escalation formula should reflect the input price assumptions used in the productivity study (which the 4GIR price cap option is not currently doing) and a negative productivity finding should either be reflected in the productivity factor and/or used as a basis to increase the inflationary adjustment above what is assumed in the productivity study.

These possible causes, along with the math found in Section 2, helps demonstrate the importance of designing a consistent revenue escalation formula that calculates the escalation parameters in a consistent manner and does not discard a negative productivity finding. Even without perfect assumptions regarding input price inflation and/or output definitions, if consistency in how the parameters are calculated and used is followed, the indexing math in the escalation formula will still provide a dependable expectation of cost growth.[57] Consistency requires that:

1. The inflation factor in the escalation formula be consistent with the input price inflation assumed in the productivity study,

2. The G Factor in the escalation formula be consistent with the method of construction for the output quantity index in the productivity study, and

3. A negative productivity trend finding, if present, is incorporated into the revenue escalation formula.

[57] This does not mean that perfection should not be pursued or that an incomplete or wrong output quantity index or inflation assumptions should be used.

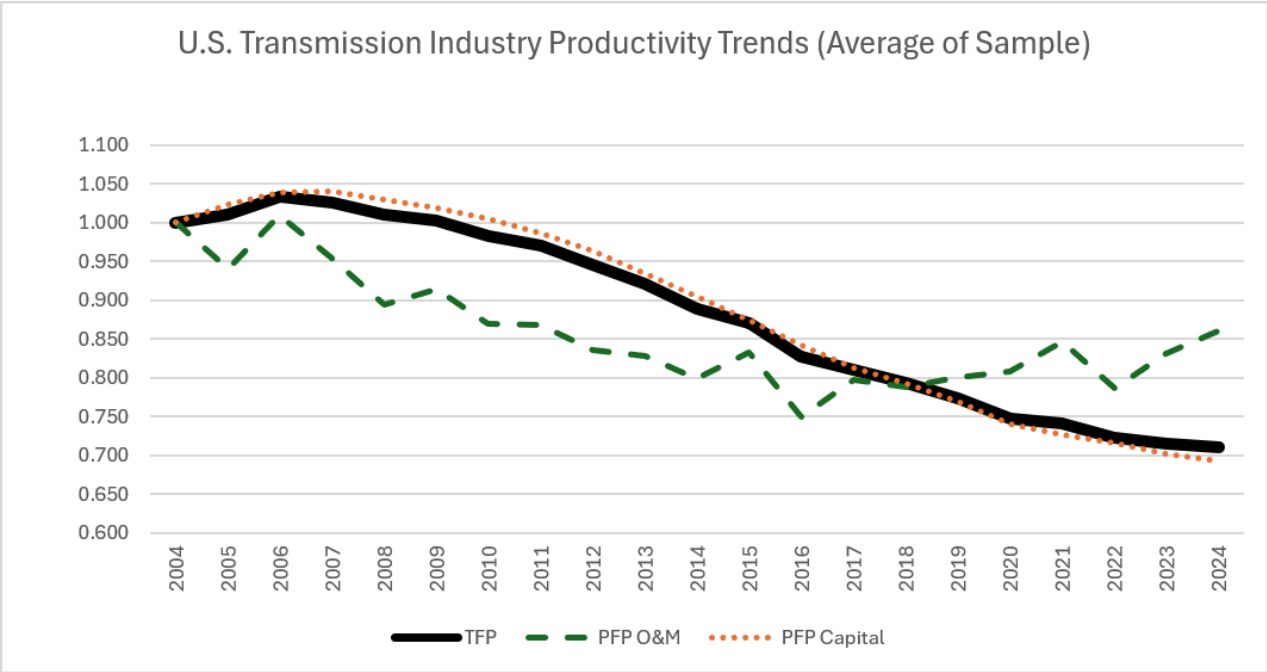
7 Transmission Industry TFP Results

The transmission productivity trend results are provided in the following table and figure. They display the TFP, OM&A PFP, and Capital PFP using the even-weighted (average) aggregation approach for the U.S. transmission industry.

Table 11 U.S. Transmission Industry Productivity Results (Average of the Sample)

Year	TFP Index	OM&A PFP Index	Capital PFP Index
2004	1.000	1.000	1.000
2005	1.010	0.940	1.024
2006	1.034	1.009	1.039
2007	1.026	0.953	1.041
2008	1.011	0.894	1.030
2009	1.003	0.914	1.019
2010	0.983	0.870	1.004
2011	0.970	0.868	0.987
2012	0.945	0.836	0.963
2013	0.922	0.828	0.934
2014	0.888	0.798	0.905
2015	0.871	0.833	0.875
2016	0.827	0.750	0.842
2017	0.811	0.797	0.813
2018	0.793	0.788	0.793
2019	0.774	0.800	0.770
2020	0.748	0.809	0.740
2021	0.741	0.846	0.727
2022	0.723	0.786	0.715
2023	0.715	0.831	0.702
2024	0.710	0.860	0.692
Average Annual Growth Rate			
2004 - 2024 (20 Years)	-1.71%	-0.75%	-1.84%
2009 - 2024 (15 Years)	**-2.30%**	-0.41%	-2.58%
2014 – 2024 (10 Years)	-2.24%	0.74%	-2.69%
2019 – 2024 (5 Years)	-1.73%	1.45%	-2.13%

Figure 7 U.S. Transmission Industry Productivity Trends (Average of Sample)



The TFP trends increased in 2005 and 2006 but have been negative in every single year since 2006. The 15-year trend, which is the period Clearspring is basing its base productivity factor recommendation on, showed an average annual growth rate of -2.30%. The trend in the OM&A PFP trend is far less consistent. It has shown both increases and decreases during the last 20 years. In the last 15 years it has had an average annual growth rate of -0.41%. The capital PFP trend tracks the TFP trend closely, with increases in 2005, 2006, and 2007 but then consistent declines since then.

Clearspring maintains that the TFP trends should be the results that support the productivity factor, rather than the disaggregated PFP results. One reason is due to the stability of the TFP trend versus the OM&A PFP trend. The growth rates of the TFP during the last 20 years had a standard deviation of 1.6%, whereas the OM&A PFP had a standard deviation of 5.1%, which is over 3 times higher.

7.1 Transmission Output Quantity Index

Clearspring used the same definition of outputs for the transmission TFP study as we did for the transmission total cost benchmarking study. There are two outputs: kilometers of transmission lines and 10-year rolling average peak demand.

The two outputs need to be combined into one output quantity index. We accomplished this using output cost elasticity estimates derived from the transmission econometric total cost model. The weights are 34.2% and 65.8% for KM of line and 10-year rolling average peak demand, respectively.

The two components of the output quantity index for the industry are provided in the following tables. After combining the components, the overall index is provided in the last column. These are using the even-weighted or average method of aggregation.

Table 12 Output Indexes for the U.S. Tx Industry (Average of the Sample)

Year	Tx KM of Line	Tx Peak Demand	Output Quantity Index
2004	1.000	1.000	1.000
2005	0.998	1.033	1.021
2006	1.005	1.053	1.036
2007	1.018	1.066	1.049
2008	1.013	1.072	1.052
2009	1.010	1.073	1.051
2010	1.017	1.079	1.058
2011	1.021	1.085	1.063
2012	1.015	1.088	1.063
2013	1.021	1.088	1.065
2014	1.037	1.095	1.075
2015	1.036	1.097	1.076
2016	1.044	1.095	1.077
2017	1.051	1.090	1.076
2018	1.056	1.090	1.078
2019	1.066	1.090	1.082
2020	1.063	1.084	1.077
2021	1.097	1.080	1.086
2022	1.099	1.080	1.086
2023	1.092	1.081	1.085
2024	1.097	1.085	1.089
Average Annual Growth Rate			
2004 - 2024 (20 Years)	0.46%	0.41%	0.43%
2009 - 2024 (15 Years)	0.55%	0.08%	0.24%
2014 – 2024 (10 Years)	0.56%	-0.09%	0.13%
2019 – 2024 (5 Years)	0.57%	-0.10%	0.13%

The transmission industry has experienced output growth around 0.43% per year for the output quantity index over the last 20 years. However, the peak demand component of output growth has experienced a slowdown in more recent years. The output quantity index has slowed to 0.24% for the 15-year trend and to 0.13% in the 10- and 5-year trends. Clearspring's recommendation is to use the 15-year period as this provides a good balance between the advantage of having more observations and the preference for the results to reflect more recent trends.

7.2 Input Quantity Index

The transmission industry's two input components and the input quantity index are provided in the following table. The table displays the industry capital quantity index, OM&A quantity index, and then the combined input quantity index from 2004 to 2024. These are using the even-weighted or average method of aggregation.

Table 13 Input Quantity Indexes for the U.S. Tx Industry (Average of the Sample)

Year	OM&A Input Quantity Index	Capital Input Quantity Index	Input Quantity Index
2004	1.000	1.000	1.000
2005	1.086	0.997	1.010
2006	1.027	0.997	1.003
2007	1.100	1.008	1.022
2008	1.176	1.021	1.041
2009	1.150	1.032	1.048
2010	1.216	1.053	1.076
2011	1.224	1.077	1.095
2012	1.272	1.104	1.124
2013	1.285	1.140	1.155
2014	1.347	1.188	1.210
2015	1.291	1.230	1.235
2016	1.435	1.280	1.302
2017	1.350	1.324	1.327
2018	1.367	1.359	1.359
2019	1.353	1.406	1.398
2020	1.332	1.455	1.440
2021	1.283	1.493	1.465
2022	1.382	1.519	1.503
2023	1.305	1.546	1.517
2024	1.266	1.574	1.534
Average Annual Growth Rate			
2004 - 2024 (20 Years)	1.18%	2.27%	2.14%
2009 - 2024 (15 Years)	0.64%	2.82%	2.54%
2014 – 2024 (10 Years)	-0.61%	2.82%	2.37%
2019 – 2024 (5 Years)	-1.31%	2.27%	1.86%

The transmission industry has experienced input quantity growth around 2.14% per year over the last 20 years. The capital quantity index has outpaced the OM&A index during all four of the periods examined. Capital quantities (which adjusts for inflation) have risen by over 2% per year for the last two decades.

7.3 Transmission Productivity Sample

Clearspring employed a sample of U.S. transmission utilities to calculate the TFP trends of the industry starting in a base year of 2004 and going through 2024. The sample is comprised of 49 U.S. transmission utilities and is shown in the table below. Hydro One is shown in the table below for comparison purposes only. Hydro One observations are not included in the TFP calculations.

Table 14 Transmission TFP Sample

Transmission TFP Sample

Company	Tx Line Length	10-Year Average Peak Demand	Company	Tx Line Length	10-Year Average Peak Demand
Alabama Power Company	17,461	13,625	Jersey Central Power & Light Company	4,199	5,940
Appalachian Power Company	10,192	7,102	Kentucky Utilities Company	6,545	5,336
Arizona Public Service Company	9,505	9,131	Louisville Gas and Electric Company	1,479	3,018
Atlantic City Electric Company	2,277	2,499	MDU Resources Group, Inc.	5,539	812
Avista Corporation	3,629	2,958	Mississippi Power Company	3,594	2,796
Baltimore Gas and Electric Company	1,453	6,588	Monongahela Power Company	3,244	2,082
Black Hills Power, Inc.	1,236	979	Nevada Power Company	3,098	7,242
Central Hudson Gas & Electric Corporation	934	1,095	New York State Electric & Gas Corporation	7,326	2,938
Central Maine Power Company	4,618	1,622	Niagara Mohawk Power Corporation	17,611	7,674
Cleco Power LLC	4,850	3,581	Northern States Power Company - MN	9,524	10,320
Commonwealth Edison Company	8,061	20,895	Oklahoma Gas and Electric Company	9,793	6,899
Consolidated Edison Company of New York, Inc.	1,673	12,169	Orange and Rockland Utilities, Inc.	919	1,318
Duke Energy Carolinas, LLC	13,322	24,045	PacifiCorp	29,902	19,393
Duke Energy Florida, LLC	8,451	11,192	PECO Energy Company	1,993	8,366
Duke Energy Indiana, LLC	8,497	7,326	Potomac Electric Power Company	1,302	5,388
Duke Energy Progress, LLC	10,157	14,500	PPL Electric Utilities Corporation	6,878	7,329
Duquesne Light Company	1,092	2,731	Public Service Company of New Hampshire	1,698	2,258
El Paso Electric Company	2,997	2,064	Public Service Company of Oklahoma	4,299	4,121
Empire District Electric Company	2,097	1,174	Public Service Electric and Gas Company	3,523	9,817
Entergy Arkansas, Inc.	7,944	7,086	Rochester Gas and Electric Corporation	1,808	1,541
Entergy Mississippi, Inc.	4,867	3,835	South Carolina Electric & Gas Co.	6,864	5,005
Entergy New Orleans, Inc.	222	1,134	Southwestern Public Service Company	12,828	6,015
Hydro One Networks	**21,031**	**24,964**	Tampa Electric Company	2,168	4,805
Idaho Power Co.	7,629	4,971	Tucson Electric Power Company	3,594	5,231
Indianapolis Power & Light Company	1,390	2,738	Union Electric Company	4,969	7,691

8 Distribution Industry Total Factor Productivity

The distribution productivity study examined the trends in both the U.S. electric distribution industry and the Ontario distribution industry. In our recommendation for the base productivity factor for Hydro One, Clearspring took an average of the U.S. and Ontario TFP trend results.

For the U.S. industry, Clearspring recommends using the 15-year period of 2009 to 2024 as the basis for the distribution base productivity factor. This is consistent with the transmission study and is a good balance between including an adequate number of observations and the desire for recent observations to better reflect current circumstances. Regarding the Ontario industry, Clearspring recommends using the 10-year period of 2014 to 2024 as the basis for the distribution base productivity factor. The rationale is that the Ontario industry transitioned its accounting standard from GAAP to MIFRS in 2012 and there appear to be substantial clearances of AMI deferral accounts prior to 2014. By starting the period in 2014, these changes will not have an undue influence on the productivity study results.

The U.S. 15-year distribution TFP trend equals an average annual growth rate of -0.33%. The 10-year distribution Ontario TFP trend equals an average annual growth rate of -0.29%. The average of the two average annual growth rates equals -0.31%.

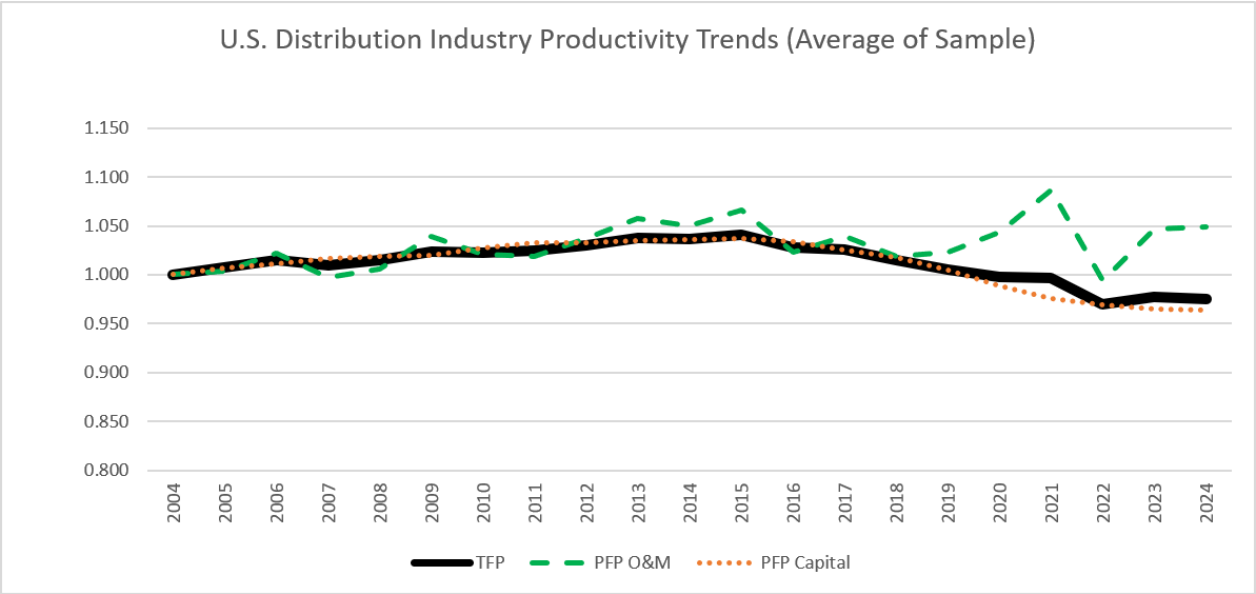
8.1 U.S. Distribution Industry Productivity Results

The U.S. distribution productivity trend results are provided in the following table and figure. They display the TFP, OM&A PFP, and Capital PFP using the even-weighted (average) aggregation approach.

Table 15 U.S. Distribution Industry Productivity Results (Average of the Sample)

Year	TFP Index	OM&A PFP Index	Capital PFP Index
2004	1.000	1.000	1.000
2005	1.007	1.004	1.007
2006	1.015	1.022	1.011
2007	1.010	0.997	1.017
2008	1.015	1.005	1.019
2009	1.024	1.039	1.020
2010	1.023	1.021	1.027
2011	1.025	1.019	1.032
2012	1.030	1.037	1.032
2013	1.038	1.057	1.035
2014	1.036	1.050	1.036
2015	1.041	1.066	1.037
2016	1.028	1.023	1.034
2017	1.025	1.039	1.025
2018	1.015	1.018	1.018
2019	1.005	1.023	1.005
2020	0.998	1.043	0.989
2021	0.997	1.086	0.976
2022	0.970	0.994	0.969
2023	0.977	1.047	0.965
2024	0.975	1.048	0.964
Average Annual Growth Rate			
2004 - 2024 (20 Years)	-0.13%	0.24%	-0.18%
2009 - 2024 (15 Years)	**-0.33%**	0.06%	-0.38%
2014 – 2024 (10 Years)	-0.61%	-0.01%	-0.72%
2019 – 2024 (5 Years)	-0.61%	0.49%	-0.84%

Figure 8 U.S. Distribution Industry Productivity Trends (Average of Sample)



The U.S. distribution TFP trends generally increased in the first decade until around 2015. Since 2015, the TFP trend has declined in every year except in 2023. The 15-year trend, which is the period Clearspring is basing its base productivity factor recommendation on, showed an average annual growth rate of -0.33%. The trend in the OM&A PFP trend is less consistent. It has shown both increases and decreases during the last 20 years. In the last 15 years it has had an average annual growth rate of 0.06%. The capital PFP trend tracks the TFP trend closely, with positive growth in every year from 2004 to 2015 and then declines in every year thereafter.

Clearspring maintains that the TFP trends should be the results that support the productivity factor rather than the disaggregated PFP results. One reason is due to the stability of the TFP trend versus the OM&A PFP trend. The growth rates of the TFP during the last 20 years had a standard deviation of 0.9%, whereas the OM&A PFP had a standard deviation of 3.0%, similar to the transmission finding, this is over 3 times higher.

8.2 U.S. Distribution Output Quantity Index

Clearspring used the same definition of outputs for the distribution TFP study as we did for the distribution total cost benchmarking study. There are two outputs: customers and 10-year rolling average peak demand.

The two outputs need to be combined into one output quantity index. We accomplished this using output cost elasticity estimates derived from the distribution econometric total cost model. The weights are 51.6% and 48.4% for customers and 10-year rolling average peak demand, respectively.

The two components of the output quantity index for the industry are provided in the following tables. After combining the components, the overall index is provided in the last column. These are using the even-weighted or average method of aggregation.

Table 16 Output Indexes for the U.S. Dx Industry (Average of the Sample)

Year	Customers	Dx Peak Demand	Output Quantity Index
2004	1.000	1.000	1.000
2005	1.013	1.019	1.016
2006	1.016	1.043	1.029
2007	1.026	1.062	1.043
2008	1.033	1.076	1.054
2009	1.037	1.084	1.060
2010	1.040	1.097	1.067
2011	1.041	1.108	1.073
2012	1.045	1.116	1.079
2013	1.050	1.121	1.084
2014	1.056	1.126	1.089
2015	1.065	1.127	1.094
2016	1.076	1.122	1.098
2017	1.084	1.116	1.099
2018	1.094	1.117	1.105
2019	1.102	1.119	1.110
2020	1.113	1.115	1.114
2021	1.124	1.112	1.118
2022	1.135	1.112	1.124
2023	1.145	1.113	1.129
2024	1.155	1.119	1.137
Average Annual Growth Rate			
2004 - 2024 (20 Years)	0.72%	0.56%	0.64%
2009 - 2024 (15 Years)	0.72%	0.21%	0.47%
2014 – 2024 (10 Years)	0.90%	-0.07%	0.43%
2019 – 2024 (5 Years)	0.94%	-0.01%	0.48%

The U.S. distribution industry has experienced output growth around 0.64% per year for the output quantity index over the last 20 years. However, the peak demand component of output growth has experienced a slowdown in more recent years. The output quantity index has slowed to 0.47% for the 15-year trend. Clearspring's recommendations are to use the 15-year period as this provides a good balance between the advantage of having more observations and the preference for the results to reflect more recent trends.

8.3 Input Quantity Index

The distribution industry's two input components and the input quantity index are provided in the following table. The table displays the industry capital quantity index, OM&A quantity index, and then the combined input quantity index from 2004 to 2024. These are using the even-weighted or average method of aggregation.

Table 17 Input Quantity Indexes for the U.S. Dx Industry (Average of the Sample)

Year	OM&A Input Quantity Index	Capital Input Quantity Index	Input Quantity Index
2004	1.000	1.000	1.000
2005	1.012	1.009	1.009
2006	1.007	1.018	1.013
2007	1.046	1.026	1.033
2008	1.048	1.034	1.039
2009	1.020	1.039	1.035
2010	1.045	1.039	1.043
2011	1.053	1.039	1.047
2012	1.040	1.045	1.047
2013	1.025	1.047	1.044
2014	1.038	1.052	1.051
2015	1.027	1.055	1.051
2016	1.074	1.062	1.069
2017	1.058	1.073	1.072
2018	1.085	1.086	1.089
2019	1.085	1.105	1.105
2020	1.067	1.126	1.116
2021	1.029	1.146	1.121
2022	1.131	1.159	1.159
2023	1.078	1.170	1.156
2024	1.085	1.180	1.167
Average Annual Growth Rate			
2004 - 2024 (20 Years)	0.41%	0.83%	0.77%
2009 - 2024 (15 Years)	0.41%	0.85%	0.80%
2014 – 2024 (10 Years)	0.45%	1.15%	1.04%
2019 – 2024 (5 Years)	-0.01%	1.32%	1.09%

The distribution industry has experienced input quantity growth around 0.77% per year over the last 20 years. This has slowly risen during the time period, with the last 5 years growing at a 1.09% average annual growth rate.

8.4 U.S. Distribution Productivity Sample

Clearspring employed a sample of U.S. distribution utilities to calculate the TFP trends of the industry starting in a base year of 2004 and going through 2024. The sample is comprised of 67 U.S. distribution utilities and is shown in the table below. Hydro One is shown in the table below for comparison purposes only. Hydro One observations are not included in the TFP calculations.

Table 18 Distribution TFP Sample

U.S. Distribution Productivity Sample

Company	Customers	Company	Customers
Alabama Power Company	1,547,153	Kentucky Utilities Company	574,094
ALLETE (Minnesota Power)	152,342	Louisville Gas and Electric Company	437,737
Appalachian Power Company	967,408	Madison Gas and Electric Company	166,128
Arizona Public Service Company	1,400,036	MDU Resources Group, Inc.	145,478
Atlantic City Electric Company	572,774	Mississippi Power Company	192,416
Avista Corporation	418,963	Monongahela Power Company	397,165
Baltimore Gas and Electric Company	1,342,757	Nevada Power Company	1,035,146
Black Hills Power, Inc.	77,523	New York State Electric & Gas Corporation	921,367
Central Hudson Gas & Electric Corporation	268,174	Niagara Mohawk Power Corporation	1,559,866
Central Maine Power Company	672,682	Northern Indiana Public Service Company	490,666
Cleco Power LLC	295,385	Northern States Power Company - MN	1,577,476
Cleveland Electric Illuminating Company	758,454	Northern States Power Company - WI	271,318
Commonwealth Edison Company	4,130,749	Ohio Edison Company	1,074,067
Connecticut Light and Power Company	1,290,879	Oklahoma Gas and Electric Company	902,714
Consolidated Edison Company of New York	3,759,848	Orange and Rockland Utilities, Inc.	244,791
Consumers Energy Company	1,893,531	PacifiCorp	2,104,050
Delmarva Power & Light Company	554,789	Portland General Electric Company	943,944
DTE Electric Company	2,279,071	Potomac Electric Power Company	949,732
Duke Energy Carolinas, LLC	2,907,066	PPL Electric Utilities Corporation	1,487,306
Duke Energy Florida, LLC	2,009,463	Public Service Company of New Hampshire	542,057
Duke Energy Indiana, LLC	909,011	Public Service Company of Oklahoma	580,734
Duke Energy Kentucky, Inc.	154,073	Public Service Electric and Gas Company	2,390,225
Duke Energy Progress, LLC	1,753,575	Puget Sound Energy, Inc.	1,239,245
Duquesne Light Company	613,787	South Carolina Electric & Gas Co.	806,434
El Paso Electric Company	459,472	Southwestern Public Service Company	408,769
Empire District Electric Company	187,269	Tampa Electric Company	849,877
Entergy Arkansas, Inc.	732,671	Toledo Edison Company	316,086
Entergy Mississippi, Inc.	460,181	Tucson Electric Power Company	451,936
Entergy New Orleans, Inc.	208,845	Union Electric Company	1,264,469
Hydro One Dx	**1,461,391**	United Illuminating Company	345,877
Idaho Power Co.	641,566	Virginia Electric and Power Company	2,783,257
Indiana Michigan Power Company	614,578	Wisconsin Electric Power Company	1,170,318
Indianapolis Power & Light Company	530,802	Wisconsin Power and Light Company	499,391
Kentucky Power Company	162,506	Wisconsin Public Service Corporation	467,910

8.5 Ontario Distribution Industry Productivity Study

Clearspring used the same productivity procedures for the Ontario distribution industry productivity calculations as used for the U.S. transmission and distribution industries. The data for the analysis was gathered from files published by the OEB. OM&A and output data from 2002 to 2012 was gathered from the OEB's "Benchmarking Update Calculations 2025.xls" file, worksheet "2. BM Database". Capital data for those years was gathered from, "EB-2010-0379 PEG TFP and BM database calculations (Latest 2012 data).xls" file, worksheet "5. Capital Calculations for TFP". Data for 2013 to 2024 was gathered from the "Benchmarking Update Calculations 2025.xls" file in each specific year of the calculations.

Over the sample period there have been several amalgamations within the industry. The 2024 composition of utilities, as defined by the "Benchmarking Update Calculations 2025.xls" file, served as the basis for the sample. If utilities had merged prior to 2024, we added the data of the predecessor utility into the values of the continuing utility for all years to make a consistent sample. The sample period displayed is from 2003 to 2024. However, due to the recency of available capital data, the capital benchmark year for the Ontario industry begins in 2002. This will cause inaccuracy issues in the earlier years of the sample period but will continually diminish in the later years of the sample period.

While Clearspring's preference would be to use the latest 15-year productivity trends, like we feature for the U.S. productivity research, Clearspring recommends that the 10-year trend results be used for the Ontario industry for multiple reasons. This means the start year for the 10-year period is 2014 and the end year is 2024. There are 10 growth rate years during that time. The reasons for the 10-year trend are:

- The 10-year trend having a start year of 2014 provides more time for the 2002 capital benchmark inaccuracy to diminish.

- The Ontario industry underwent an accounting transition from GAAP accounting standards to MIFRS. Most distributors made this transition in 2012, Hydro One being an exception. Beginning the productivity sample period after this transition enables the differing capitalization accounting standards to be consistent during the sample period.

- AMI clearance accounts 1555 and 1556 accumulated substantial balances. Those accounts had mostly, although not entirely, been cleared by the end of 2013. By starting the analysis in 2014, this greatly diminishes the impact on the study results of these clearances.

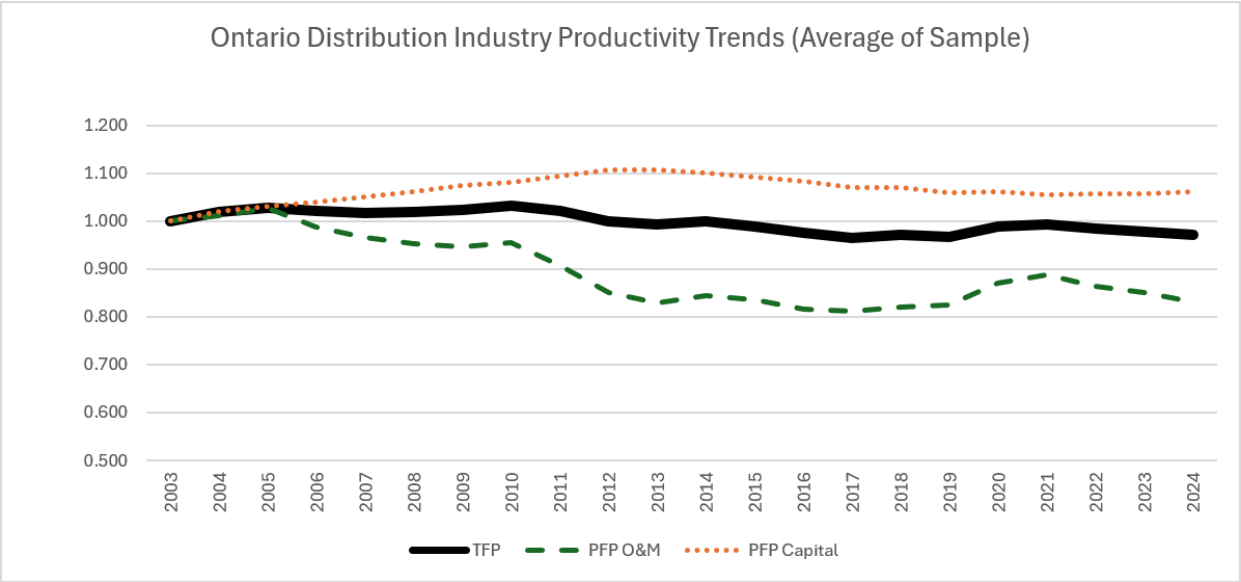
8.6 Ontario Distribution Industry Productivity Results

The Ontario distribution productivity trend results are provided in the following table and figure. The results do not include Hydro One itself in order to be a fully externalized measure of productivity that is not influenced by Hydro One. The table and figure display the TFP, OM&A PFP, and Capital PFP using the even-weighted (average) aggregation approach.

Table 19 Ontario Distribution Industry Productivity Results (Average of the Sample)

Year	TFP Index	OM&A PFP Index	Capital PFP Index
2003	1.000	1.000	1.000
2004	1.019	1.011	1.019
2005	1.028	1.027	1.031
2006	1.020	0.987	1.040
2007	1.017	0.967	1.051
2008	1.019	0.954	1.061
2009	1.024	0.946	1.074
2010	1.032	0.956	1.082
2011	1.020	0.908	1.093
2012	1.000	0.851	1.106
2013	0.992	0.829	1.107
2014	1.000	0.843	1.100
2015	0.989	0.835	1.091
2016	0.976	0.816	1.083
2017	0.966	0.811	1.070
2018	0.971	0.819	1.070
2019	0.966	0.826	1.059
2020	0.989	0.871	1.061
2021	0.994	0.888	1.055
2022	0.984	0.863	1.058
2023	0.977	0.851	1.057
2024	0.971	0.832	1.060
Average Annual Growth Rate			
2004 - 2024 (20 Years)	-0.24%	-0.98%	0.20%
2009 - 2024 (15 Years)	-0.35%	-0.86%	-0.08%
2014 – 2024 (10 Years)	**-0.29%**	-0.14%	-0.37%
2019 – 2024 (5 Years)	0.10%	0.15%	0.02%

Figure 9 Ontario Distribution Industry Productivity Trends (Average of Sample)



The 10-year TFP trend, which is the period Clearspring is basing its base productivity factor recommendation on, showed an average annual growth rate of -0.29%. The trend in the OM&A PFP trend shows an average annual growth rate of -0.14% during the 10-year period. The capital PFP trend shows an average annual growth rate of -0.37% during the 10-year period.

Clearspring maintains that the TFP trends should be the results that support the productivity factor rather than the disaggregated PFP results. One reason is due to the stability of the TFP trend versus the OM&A PFP trend. The growth rates of the TFP during the last 10 years had a standard deviation of 1.1%, whereas the OM&A PFP had a standard deviation of 2.3%, which is over 2 times higher.

8.7 Ontario Distribution Industry Output Quantity Index

Clearspring used the same definition of outputs for the Ontario distribution TFP study as we did for the distribution total cost benchmarking study and the U.S. distribution TFP study. There are two outputs: customers and 10-year rolling average peak demand.

The two outputs need to be combined into one output quantity index. We accomplished this using output cost elasticity estimates derived from the distribution econometric total cost model. The weights are 51.6% and 48.4% for customers and 10-year rolling average peak demand, respectively.

The two components of the output quantity index for the industry are provided in the following tables. After combining the components, the overall index is provided in the last column. These are using the even-weighted or average method of aggregation.

Table 20 Output Indexes for the Ontario Dx Industry (Average of the Sample)

Year	Customers	Dx Peak Demand	Output Quantity Index
2003	1.000	1.000	1.000
2004	1.018	1.013	1.015
2005	1.032	1.022	1.027
2006	1.040	1.026	1.033
2007	1.055	1.032	1.044
2008	1.066	1.028	1.047
2009	1.074	1.024	1.049
2010	1.083	1.024	1.054
2011	1.093	1.024	1.059
2012	1.101	1.019	1.061
2013	1.112	1.021	1.067
2014	1.123	1.014	1.068
2015	1.131	1.005	1.068
2016	1.142	0.998	1.070
2017	1.154	0.985	1.069
2018	1.165	0.985	1.074
2019	1.175	0.981	1.077
2020	1.186	0.978	1.080
2021	1.198	0.972	1.083
2022	1.211	0.977	1.091
2023	1.226	0.972	1.095
2024	1.236	0.974	1.102
Average Annual Growth Rate			
2004 - 2024 (20 Years)	0.97%	-0.19%	0.41%
2009 - 2024 (15 Years)	0.94%	-0.33%	0.33%
2014 – 2024 (10 Years)	0.97%	-0.39%	0.31%
2019 – 2024 (5 Years)	1.02%	-0.13%	0.46%

The Ontario distribution industry has experienced output growth around 0.41% per year for the output quantity index over the last 20 years. The output quantity index has slowed to 0.31% for the 10-year trend.

8.8 Input Quantity Index

The Ontario distribution industry's two input components and the input quantity index are provided in the following table. The table displays the industry capital quantity index, OM&A quantity index, and then the combined input quantity index from 2003 to 2024. These are using the even-weighted or average method of aggregation.

Table 21 Input Quantity Indexes for the Ontario Dx Industry (Average of the Sample)

Year	OM&A Input Quantity Index	Capital Input Quantity Index	Input Quantity Index
2003	1.000	1.000	1.000
2004	1.004	0.996	0.997
2005	1.001	0.997	0.999
2006	1.047	0.993	1.013
2007	1.080	0.993	1.026
2008	1.098	0.987	1.028
2009	1.109	0.977	1.024
2010	1.103	0.974	1.021
2011	1.167	0.969	1.038
2012	1.246	0.959	1.060
2013	1.288	0.964	1.075
2014	1.267	0.971	1.069
2015	1.279	0.979	1.080
2016	1.311	0.988	1.097
2017	1.318	0.999	1.107
2018	1.311	1.003	1.106
2019	1.304	1.016	1.114
2020	1.240	1.019	1.093
2021	1.220	1.026	1.090
2022	1.263	1.032	1.109
2023	1.288	1.036	1.121
2024	1.325	1.039	1.134
Average Annual Growth Rate			
2004 - 2024 (20 Years)	1.39%	0.21%	0.65%
2009 - 2024 (15 Years)	1.19%	0.41%	0.68%
2014 – 2024 (10 Years)	0.45%	0.67%	0.60%
2019 – 2024 (5 Years)	0.32%	0.44%	0.36%

The Ontario distribution industry has experienced input quantity growth around 0.65% per year over the last 20 years. This has stayed steady at 0.60% over the last 10 years. The capital quantity index has had slightly higher growth than the OM&A index over the last 10 years.

8.9 Ontario Distribution Productivity Sample

Clearspring employed a sample of Ontario distribution utilities, based on the industry in 2024, to calculate the TFP trends of the industry starting in a base year of 2003 and going through 2024. The sample is comprised of 52 Ontario distribution utilities and is shown in the table below. Hydro One is shown in the table below for comparison purposes only. Hydro One observations are not included in the TFP calculations. The reason for excluding Hydro One is to align the parameter recommendations with the IR principle of de-linking a utility's allowed revenues from its costs. By excluding Hydro One this assures that Hydro One has no impact on the productivity trends and, thus, its productivity factor recommendation.

Table 22 Ontario Distribution TFP Sample

Ontario Distribution TFP Sample

Company	Customers	Company	Customers
Alectra Utilities Corporation	1,086,178	Innpower Corporation	23,506
Algoma Power Inc.	12,510	Kingston Hydro Corporation	28,423
Atikokan Hydro Inc.	1,620	Lakefront Utilities Inc.	11,371
Bluewater Power Distribution Corporation	37,404	Lakeland Power Distribution Ltd.	14,773
Burlington Hydro Inc.	69,561	London Hydro Inc.	168,224
Canadian Niagara Power Inc.	30,921	Milton Hydro Distribution Inc.	44,067
Centre Wellington Hydro Ltd.	7,553	Newmarket-Tay Power Distribution Ltd.	45,039
Cooperative Hydro Embrun Inc.	2,705	Niagara Peninsula Energy Inc.	59,172
E.L.K. Energy Inc.	12,743	Niagara-on-the-Lake Hydro Inc.	10,083
Toronto Hydro-Electric System Limited	179,017	North Bay Hydro Distribution Limited	27,852
Westario Power Inc.	163,411	Northern Ontario Wires Inc.	5,952
E.L.K. Energy Inc.	63,484	Oakville Hydro Electricity Distribution Inc.	78,368
EnWin Utilities Ltd.	92,004	Orangeville Hydro Limited	13,021
Centre Wellington Hydro Ltd.	19,052	Oshawa PUC Networks Inc.	62,880
ERTH Power Corporation	24,962	Ottawa River Power Corporation	11,775
Essex Powerlines Corporation	31,547	PUC Distribution Inc.	34,142
Festival Hydro Inc.	22,581	Renfrew Hydro Inc.	4,418
Fort Frances Power Corporation	3,745	Rideau St. Lawrence Distribution Inc.	6,074
Westario Power Inc.	115,328	Sioux Lookout Hydro Inc.	2,973
Fort Frances Power Corporation	48,230	Synergy North Corporation	57,373
Grimsby Power Incorporated	11,946	Tillsonburg Hydro Inc.	8,553
Halton Hills Hydro Inc.	23,128	Toronto Hydro-Electric System Limited	795,394
Hearst Power Distribution Company Limited	2,680	Wasaga Distribution Inc.	15,675
Hydro 2000 Inc.	1,280	Welland Hydro-Electric System Corp.	26,253
Hydro Hawkesbury Inc.	5,656	Wellington North Power Inc.	4,388
Hydro One Networks Inc.	**1,477,590**	Westario Power Inc.	24,829
Hydro Ottawa Limited	371,749		

9 Growth Factor Parameter Calculation

Section 2 provided the mathematical and theoretical grounds for including a G Factor in the revenue escalation formula. As shown, the factor escalates revenue based on how the outputs are expected to increase utility costs. This is different from billing determinant output growth because allowed revenue escalation should track how costs are expected to increase rather than track how price increases will increase revenue (which is what the billing determinant output growth would estimate). This section provides the calculation and results for the estimate of the G Factor value for Hydro One's transmission and distribution operations and HOSSM.

There are two time-variant output variables in both the transmission and distribution econometric total cost models. For transmission, these are the length of kilometres of transmission line and transmission peak demand. For distribution, these are the number of customers and system peak demand. These output variables have been tested in Clearspring's models and found to be highly statistically significant. At an extremely high level of confidence, we can state these variables impact the cost levels of transmitters and distributors.

It is appropriate to calculate the G Factor using a weighted average of the two output growth rates during the CIR period. This approach aligns with the benchmark model findings that the two outputs are statistically significant cost drivers, and the same way TFP trends are calculated. Clearspring uses the output forecasts during the CIR period as these are the best indicators of how output increases are expected to drive cost levels for the Company during the CIR period. Regarding peak demand, this approach does differ from the 10-year rolling average used in the productivity study. The 10-year rolling average is used on the historical data to smooth out annual fluctuations in peak demand due to weather variations. Since the forecasted peak demands are produced using average or normal weather assumptions, these values are already smoothed out. In Clearspring's view it is best to use the growth rate in the forecasts for the G Factor as this will be the best reflection of how peak demand changes during the CIR period are expected to impact cost levels during the CIR period.

Clearspring uses the cost elasticity output weights found in its econometric total cost models as the basis for weighting the projected growth in the two outputs. These weights sum to "one" and match the weights for the output quantity index in the TFP study.[58]

[58] For a more detailed discussion on why cost elasticity weights are necessary for both the growth factor and productivity study, please see Clearspring's reply report dated November 11, 2025 in Hydro Ottawa's custom IR application in EB-2024-0115.

9.1 G Factor Parameter Calculation and Result for Hydro One Transmission

The following table shows the projected growth rates for kilometres of transmission line and peak demand for Hydro One Transmission from 2028 to 2032 and how they are weighted to produce the recommended G Factor value.

Table 23 G Factor Calculation for Hydro One Tx

Year	Tx Line Lengths Growth Rate	Line Length Weight	Peak Demand Growth Rate	Peak Demand Weight	G Factor Annual Growth Rate
	[A]	[B]	[C]	[D]	A*B+C*D
2028					
2029	0.12%	.342	0.81%	.658	0.58%
2030	0.12%	.342	1.44%	.658	0.99%
2031	0.02%	.342	1.68%	.658	1.11%
2032	0.30%	.342	1.78%	.658	1.27%
Average	**0.14%**		**1.43%**		**0.99%**

9.2 Growth Factor Parameter Result for Hydro One Distribution

The following table shows the projected growth rates for customers and peak demand for Hydro One Distribution from 2028 to 2032 and how they are weighted to produce the recommended G Factor value.

Table 24 G Factor Calculation for Hydro One Dx

Year	Customers Growth Rate	Customers Weight	Peak Demand Growth Rate	Peak Demand Weight	G Factor Annual Growth Rate
	[A]	[B]	[C]	[D]	A*B+C*D
2028					
2029	0.77%	.516	1.69%	.484	1.22%
2030	0.73%	.516	1.63%	.484	1.16%
2031	0.72%	.516	1.60%	.484	1.15%
2032	0.72%	.516	1.58%	.484	1.14%
Average	**0.73%**		**1.63%**		**1.17%**

9.3 Growth Factor Parameter Result for HOSSM

The following table shows the projected growth rates for kilometres of transmission line and peak demand for HOSSM from 2028 to 2032 and how they are weighted to produce the recommended G Factor value.

Table 25 G Factor Calculation for HOSSM

Year	Tx Line Lengths Growth Rate	Line Length Weight	Peak Demand Growth Rate	Peak Demand Weight	G Factor Annual Growth Rate
	[A]	[B]	[C]	[D]	A*B+C*D
2028					
2029	0.00%	.347	0.78%	.653	0.51%
2030	0.00%	.347	1.37%	.653	0.90%
2031	0.00%	.347	1.60%	.653	1.04%
2032	0.00%	.347	1.70%	.653	1.11%
Average	**0.00%**		**1.36%**		**0.89%**

10 OM&A Input Price Differential Parameter Calculation and Results

Section 2 provided the mathematical and theoretical grounds for including an input price differential, or IPD, in the revenue escalation formula. As shown, the factor is a customized adjustment to the inflation factor that better accounts for the actual OM&A related input price inflation faced by the Company. This section discusses the methodology in calculating the IPD value and provides results for Hydro One Transmission, Distribution, and HOSSM.

The IPD calculation utilizes the same inflation indexes that comprise the IPI calculation but customizes and adjusts the index to be specific to OM&A expenses. The difference is derived from using Hydro One's labour and non-labour OM&A expenses to provide the weights for the inflation indexes rather than the 30% weight on labour and the 70% weight on non-labour assumed in the 4GIR IPI distribution calculation which was designed with both capital and OM&A expenses in mind. The same is true for the transmission IPI calculation but with weights of 14% on labour and 86% on non-labour.

The need for an OM&A IPD arises due to the labour shares of OM&A being higher than what is used in the IPI calculation. The IPD discussed below pertains only to OM&A expenses. A capital-related IPD would focus on asset price inflation and the Handy-Whitman indexes. This was discussed in Section 2.5.

Clearspring requested Hydro One and HOSSM's estimated OM&A salaries and wages, OM&A pensions and benefits, and OM&A outside service provider expenses during the Custom IR period. Hydro One was unable to disaggregate the outside service provider ("OSP") expenses. Therefore, we are unable to take out the OSP expenses from the calculations. The OSP expenses are included in the non-labour portion, and this treatment will have the effect of lowering the IPD. We are basing the IPD calculations on the 2025 data as this is the most recent data available from the Company on the labour breakdown.

The proportion of labour in OM&A expenses in 2025 is calculated as the sum of OM&A salaries and wages plus pensions and benefits divided by the Company's total OM&A.[59]

$$\%\ Labour\ in\ OM\&A_{2025} = \frac{OM\&A\ Salaries\ and\ Wages_{2025} + OM\&A\ Pensions\ and\ Benefits_{2025}}{Total\ OM\&A_{2025}}$$

This 2025 labour weighting is the assumed labour proportion of the Company in each year of the CIR period. An input price index is constructed using this 2025 labour weight multiplied by the forecasted growth rate in the AWE-Ontario plus the non-labour weight (which is one minus the labour weight) multiplied by the forecasted growth rate in the GDP-IPI Canada index. The difference between this customized input price index and the Board's IPI equals the OM&A IPD.

$$OM\&A\ IPD = OM\&A\ Custom\ Input\ Price - IPI$$

[59] In Alectra and Elexicon's CIR applications we subtracted total OM&A by the OSP expenses. This assumes the OSP expenses have a similar labour proportion as the Company's other OM&A expenses. However, Hydro One is unable to provide the OSP expenses which causes us to assume the OSP expenses are fully non-labour.

This difference is averaged from 2028 to 2032 to formulate Clearspring's recommended OM&A IPD parameter value.

The importance of including an IPD for the OM&A portion of expenses is due to the expected faster growth rate of the AWE during the custom IR period relative to the GDP-IPI. AWE has historically grown faster than GDP-IPI and this difference is projected to continue by Signal49 (formerly the Conference Board of Canada).

Signal49 projects the AWE and GDP-IPI to 2030. Clearspring uses the 2030 forecasted growth rate for the years 2031 and 2032 in the calculation.[60] The forecasts project that the AWE will grow by an average of 2.45% over the Custom IR period and GDP-IPI will grow by 1.75%. The forecasted inflation difference in the two indexes is 0.70%.

The table below provides the annual growth rates forecasted for AWE and GDP-IPI for 2029 through 2032.

Table 26 Difference in AWE and GDP-IPI Forecasts

Year	AWE Growth Rate	GDP IPI Growth Rate	Difference
2029	2.47%	1.90%	0.57%
2030	2.44%	1.69%	0.75%
2031 (assumed 2030)	2.44%	1.69%	*0.75%*
2032 (assumed 2030)	2.44%	1.69%	*0.75%*
Average	**2.45%**	**1.75%**	**0.70%**

10.1 OM&A IPD Parameter Result for Hydro One Transmission

The estimated percentage of labour plus pensions and benefits in OM&A expenses for Hydro One Transmission is 51.6% in 2025. The table below provides the 2025 estimated labour and non-labour proportions.

Table 27 Hydro One Transmission's OM&A Labour and Non-Labour Percentages

Year	Labour OM&A Proportion	Non Labour OM&A Proportion
2025	51.6%	48.4%

The table below produces the customized OM&A input price growth rates for the Company using the above labour percentage. This is compared to the Board's forecasted IPI calculation using the 14% labour weight. The average difference in 2029 to 2032 will equal the recommended OM&A IPD.

[60] We use arithmetic growth rates to align with the mechanics of the revenue escalation formula.

Table 28 Custom OM&A Input Price versus IPI for Hydro One Tx

Year	Custom OM&A Input Price Growth Rate	IPI Growth Rate	Difference
2029	2.19%	1.98%	0.22%
2030	2.08%	1.80%	0.28%
2031	2.08%	1.80%	0.28%
2032	2.08%	1.80%	0.28%
Average	**2.11%**	**1.84%**	**0.26%**

10.2 OM&A IPD Parameter Result for Hydro One Distribution

The estimated percentage of labour plus pensions and benefits in OM&A expenses for Hydro One Distribution is 63.8% in 2025. The table below provides the 2025 estimated labour and non-labour proportions.

Table 29 Hydro One Distribution's OM&A Labour and Non-Labour Percentages

Year	Labour OM&A Proportion	Non Labour OM&A Proportion
2025	63.8%	36.2%

The table below produces the customized OM&A input price growth rates for the Company using the above labour percentage. This is compared to the Board's forecasted IPI calculation using the 30% labour weight. The average difference in 2029 to 2032 will equal the recommended OM&A IPD.

Table 30 Custom OM&A Input Price versus IPI for Hydro One Dx

Year	Custom OM&A Input Price Growth Rate	IPI Growth Rate	Difference
2029	2.26%	2.07%	0.19%
2030	2.17%	1.92%	0.25%
2031	2.17%	1.92%	0.25%
2032	2.17%	1.92%	0.25%
Average	**2.19%**	**1.96%**	**0.24%**

10.3 OM&A IPD Parameter Result for HOSSM

The estimated percentage of labour plus pensions and benefits in OM&A expenses for HOSSM is 47.5% in 2025. The table below provides the 2025 estimated labour and non-labour proportions.

Table 31 HOSSM's OM&A Labour and Non-Labour Percentages

Year	Labour OM&A Proportion	Non Labour OM&A Proportion
2025	47.5%	52.5%

The table below produces the customized OM&A input price growth rates for the Company using the above labour percentage. This is compared to the Board's forecasted IPI calculation using the 14% labour weight. The average difference in 2029 to 2032 will equal the recommended OM&A IPD.

Table 32 Custom OM&A Input Price versus IPI for HOSSM

Year	Custom OM&A Input Price Growth Rate	IPI Growth Rate	Difference
2029	2.17%	1.98%	0.19%
2030	2.05%	1.80%	0.25%
2031	2.05%	1.80%	0.25%
2032	2.05%	1.80%	0.25%
Average	**2.08%**	**1.84%**	**0.24%**

11 Conclusion and Clearspring Recommendations

Based on the empirical productivity trend study results, Clearspring recommends that negative base productivity components of the X Factor are warranted for both the distribution and transmission operations of Hydro One and HOSSM. Economic theory would indicate that a negative base productivity factor should be implemented and is necessary to align cost escalation expectations with the revenue escalation formula.

In Hydro One's last joint rate application, EB-2021-0110, Clearspring and PEG issued a report titled, *Clearspring/PEG Joint Report on Hydro One Benchmarking and Productivity Research* ("Joint Report"). As referred to in the Joint Report, both consultants agreed that: *"Negative productivity factors and X-factors should be considered reasonable parameter possibilities within incentive regulation if industry data support them."* Section 2.4.1 above discusses the considerations of implementing a negative productivity factor.

Clearspring's stretch factor recommendations are based on the continued use of the 4GIR stretch factor groupings, even though there are several reasons for stretch factors to be set lower given that Hydro One's proposal already contains substantial incremental stretch factors beyond the standard 4GIR stretch factors. These include: the Company proposing an incremental stretch factor on capital of 0.15%; the Company, when it put together its capital forecasts, assumed a lower asset price inflation than the historical and likely future asset price inflation will be; and on the transmission side of the business, not using the large negative productivity finding as the transmission base productivity factor.

The following are Clearspring's specific recommendations and the research findings that support them.

- **Hydro One Transmission stretch factor = 0.15%**. The total cost benchmarking score of -24.7% during the 2028 to 2032 period shows that costs are notably below benchmark expectations, and based on 4GIR precedent, a 0.15% stretch factor is indicated.

- **HOSSM stretch factor = 0.00%**. The HOSSM total cost benchmarking score of -32.8% during the 2028 to 2032 period shows that costs are notably below benchmark expectations, and based on 4GIR precedent, a 0.00% stretch factor is indicated.[61]

- **Hydro One Distribution stretch factor = 0.60%**. The total cost benchmarking score of 25.8% during the 2028 to 2032 period shows that costs are notably above benchmark expectations and indicates a 0.60% stretch factor, based on 4GIR precedent.

- **Hydro One Transmission base productivity component of the X-factor = -2.30%**. The U.S. transmission industry TFP trend has declined by 2.30% during the most recent 15-year period (2009-2024). Clearspring recommends that a base productivity factor of -2.30% for both Hydro One Transmission and HOSSM is warranted.

[61] We are of the view for HOSSM, like Hydro One Transmission, that a negative stretch factor should be considered.

- **Hydro One Distribution base productivity component of the X-factor = -0.31%**. This is the average of the U.S. distribution industry 15-year TFP trend of -0.33% and the Ontario distribution industry 10-year TFP trend of -0.29%. Clearspring recommends a base productivity factor of -0.31% for Hydro One's distribution plan.[62]

- **Hydro One Transmission growth factor = 0.99%, Hydro One Distribution growth factor = 1.17%, and HOSSM growth factor = 0.89%.** Clearspring calculated each growth factor by combining the forecasted growth rates in measured outputs in each econometric model during the CIR period. The weights using to combine the multiple outputs are based on estimated cost elasticity weights in the econometric total cost models. The growth factor estimates the expected cost increases during the CIR period resulting from measured output growth.

- **Hydro One Transmission OM&A IPD = 0.26%, Hydro One Distribution OM&A IPD = 0.24%, and HOSSM OM&A IPD = 0.24%.** The OM&A IPD is the difference between the Company's expected OM&A input inflation and the Board's expected IPI inflation during the CIR period. This improves the ability for the revenue escalation formula to track expected OM&A inflation.

[62] A 15-year trend for the Ontario industry shows a TFP trend of -0.35% but is being unduly influenced by the transition to IFRS accounting and AMI deferral accounts which mostly cleared prior to 2014. Due to these influences, Clearspring recommends using a 10-year period (2014 to 2024) as the basis for calculating the Ontario productivity trend.

Appendix A: Total Cost Benchmarking Methodology Details

Variable Types

In general, there are two types of variables used in econometric cost benchmarking: output variables and business condition variables. Output variables measure the output of the utility in question (i.e. what the utility "produces"). Business condition variables quantify the factors that drive costs in a particular service territory, such as regional input prices, highly congested urban areas, forestation, etc.

Output Variables

The two output variables for the transmission benchmark study are the length of transmission lines and a rolling ten-year average of peak demand. This matches the output variables used in the prior JRAP proceeding.

The three output variables for the distribution benchmark study are the number of customers, a rolling ten-year average of peak demand, and the service area of each utility. This matches the outputs specified in the prior JRAP proceeding.

For the U.S. utilities, the output variables are calculated from FERC Form 1s. The customers and line lengths are based on the reported data. The peak demand variable is defined for the transmission study using the transmission peak demand value found on p. 400 of the FERC Form 1. For the distribution study, we use the system peak demand variable found on p. 401b of the FERC Form 1. This variable consists of the distribution system peak demands plus the required sales for resale. We adjusted the data to take out the proportion of the required sales for resale.

The service area used for each U.S. utility is based on variables derived from GIS mappings of each utility's full licensed service area, which includes unserved areas. For the U.S. utilities, the values used correspond to what both Clearspring and PEG used in the last JRAP application. Unlike the rest of the sample, Clearspring did not use all of Hydro One's licensed service area but reduced the licensed service area considerably in recognition of the Company's abnormally large level of unserved area within its licensed service area. Section 5.1.2 has more details on the area calculation for Hydro One.

Business Condition Variables: Input Prices

Business condition variables are discussed in following sections. However, one important business condition variable merits detailed discussion: input prices. Input prices are divided into two categories: capital and OM&A. The capital input price calculation used in our research is called the Perpetual Inventory Method and is discussed in detail in a following section. The OM&A input price captures the regional market price level that each utility encounters when procuring OM&A inputs, such as employees or materials and services. There are two components used to construct the OM&A input price. These are labour and non-labour.

The labour component is calculated by taking wage levels of numerous job occupations and weighting them based on the U.S. Bureau of Labor Statistics ("BLS") estimates of job occupation weights in the Electric Power Generation, Transmission, and Distribution Industry. The BLS has estimates for wage levels for each job occupation by city and metropolitan area. For Hydro One, we gathered job occupation wage estimates from the 2011 Canadian Census, using wage data reported for Ontario, translated job occupations to match their U.S. counterparts, and then weighted the job occupation wages by the BLS estimates. This provides consistency from the U.S. and Ontario regarding labour input prices and also puts the input price in terms of each country's currency. We then escalated labour prices for U.S. utilities using BLS employment cost indices for the utility sector and escalated Hydro One prices using the Ontario average weekly earnings estimates.

The non-labour component of the OM&A input price uses the U.S. gross domestic product price index for the U.S. utilities. The Hydro One non-labour component uses the Canadian GDP-IPI in each year, but with a levelization adjustment using the purchasing power parity ("PPP") index in 2012. This translates the non-labour input price component into Canadian dollars.

To construct the overall OM&A input price we weighted each index using the customized labour and non-labour cost shares calculated from the FERC Form 1 data or based on data provided to us from Hydro One. We then took the OM&A input price and combined it with the capital price using the capital and OM&A cost shares. This produces the total input price index.

Total cost is divided by this comprehensive input price index to adjust for regional input price differences between utilities and to account for annual inflation. Dividing total cost by the input price index imposes the requirement that total costs display linear homogeneity with respect to input prices. As the prices of inputs increase by X%, total cost should increase by that same percentage. For example, if all utility input prices (including labour) increase by 10%, its costs would also increase by 10%. This is derived from economic production theory, which states that costs equal input quantity multiplied by input price.

Other Business Condition Variables

Beyond the output variables and input prices, each model contains business condition variables that provide cost adjustments for given service territory conditions. These variables enable unique service territory conditions to be accurately benchmarked on an "apples to apples" basis. This ability to adjust for specific conditions is why the econometric benchmarking approach is more accurate and fair than unit cost approaches. Unit cost benchmarking tends to only reveal which utility has the most challenging service territory, rather than indicating cost performance. This is because service territory conditions have a profound impact on the cost levels of transmission and distribution utilities. Their capital assets are spread across the entire service territory, and the overall cost levels are thus highly influenced by the conditions the utility is faced with. These cost drivers and specific service territory conditions need to be accounted for to reveal and estimate the performance of the utility.

The business conditions used for the transmission and distribution total cost models are described in each model's specific Chapter.

Perpetual Inventory Method

Total cost is defined as the sum of the annual OM&A expenses plus capital costs. Clearspring's calculation of capital cost is based on the capital service price approach. This approach has a solid basis in economic theory; it is the same method used in all the Ontario benchmarking and productivity studies conducted by Mr. Fenrick, and is the same method chosen by PEG in its 4GIR research and its other studies in CIR applications.[63] The approach allows for a consistent way to account for differences between utilities with respect to historical plant additions and depreciation rates. The service price approach is also prominent in government-sponsored cost research. The Bureau of Labor Statistics of the U.S. Department of Labor uses the capital service price approach in computing multi-factor productivity indices for the U.S. private business sector and for several subsectors, including the utility services industry.

The cost of capital in each year *(t)* is the product of the capital service price index and capital quantity index at the end of the prior year (*t-1)*. The formula for this is given by:

$$CK_t = WKS_t \cdot XK_{t-1}$$

CK_t is the cost of capital, WKS_t is the capital service price index, and XK_{t-1} is the capital quantity index value in the prior period.

The capital quantity index (*XK*) is constructed based on the value of net plant in a benchmark year, and on gross plant additions in years subsequent to the capital benchmark year. In an effort to address past concerns of PEG regarding the start year (capital benchmark year) of this capital series, we put considerable effort into gathering and processing U.S. utility data going back to 1947.[64] We use 1947 for most of the U.S. sampled utilities as the capital benchmark year. A few utilities only had consistent data beginning in 1959, for those utilities we used 1959 as the capital benchmark year. We used 2002 as the capital benchmark year for Hydro One, because this is the first year where data is available and can be readily verified.

A "triangulated weighted average" ("TWA") is used to divide the net plant value in order to adjust the net plant value for historical inflation.[65] This results in an estimate of the capital stock in 1947, 1959, or 2002 based on when the capital benchmark year begins for the utility. Subsequent years use the previous year's

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[63] See Hall and Jorgensen (1967) for a seminal discussion of the use of service price methods for measuring capital cost.

[64] In some of our past studies, we used 1989 for the capital benchmark year, as that was the first year of electronically available data. We considered 1989 to be a sufficient start year for the capital series. However, to reduce the research differences, considerable efforts were invested into gathering and processing these data.

[65] For the U.S. sample, the 1947 or 1959 net plant value is for the total utility. To calculate a transmission or distribution net plant value we multiplied the total net plant value by the percentage of transmission or distribution gross plant in service to total gross plant in service, respectively. We note that any error in this net plant value calculation in 1947 or 1959 will have an extraordinarily minimal impact on the cost levels once the sample starts in 2000. This is because any possible small error in 1947 will have also depreciated for 53 years by the time it enters the sample period.

capital stock multiplied by one minus the depreciation rate and then escalated by that year's plant additions divided by the asset price in that year.[66] This same method is used both Hydro One and U.S. distributors. The formulas for the capital quantity index in 1947 and in subsequent years are provided below.[67]

$$XK_{1947}^{i} = \frac{Net\ Plant_{1947}^{i}}{TWA_{1947}^{i}}$$

$$XK_{t}^{i} = XK_{t-1}^{i} * (1 - d) + \frac{Add_{t}^{i}}{WKA_{t}^{i}}$$

The capital service price (*WKS*) has two components: opportunity cost and depreciation. The capital service price index is thus given by the formula:

$$WKS_t = r_t * WKA_{t-1} + d_t * WKA_t$$

Here, r_t is the allowed rate of return based on the Board's historical calculated returns. This same annual value is also used in the capital service price computation for the U.S utilities in the dataset. Setting the same rate of return for all distributors provides consistency in determining the capital costs, so that decisions by regulators do not enter the benchmark evaluation, which is attempting to assess the performance of the utility itself. The parameter d_t is the economic depreciation rate. For the transmission study, to reduce research differences, we used the same depreciation rate that PEG used in their responding research during the Hydro One Transmission CIR application for Hydro One's depreciation rate. This value is 3.30%. For distribution, we use the same value as we have used in all our distribution CIR benchmarking applications and the same one PEG used in the 4GIR proceeding: 4.59%.

The asset price deflator (*WKA*) is an index of the price of capital assets in each year used in either transmission or distribution. In several CIR applications, this has been an area of contention between PEG and our research team but has recently been resolved. Historically, Clearspring uses the U.S.-based Handy-Whitman indices for both the U.S. sample and Canadian utilities, as these are well-known and provide asset inflation estimates that are specific to electric transmission or distribution.[68] In the last two CIR applications for Alectra and Elexicon, PEG is now using the Handy-Whitman indices for Ontario utilities as well. Both Clearspring and PEG use the Handy-Whitman indices for the U.S. sample.

The Handy-Whitman indexes have consistently outpaced general inflation, as measured by the GDP-IPI (or AWE for that matter) over the last two or three decades. In forecasting the increase in the Handy-Whitman indexes for the Company for upcoming years, Clearspring has escalated by 50% of the growth rate in GDP-IPI

[66] The historical data going back to 1948 and forward all have plant in service additions disaggregated by transmission and distribution, enabling us to build up a robust capital quantity and cost estimate for each function.

[67] For the Ontario distributors, the subscripts would change to 2002 in the first equation.

[68] For Canadian utilities we adjust the Handy-Whitman for the purchasing price parity (PPPs) in each given year to put the inflation estimate into Canadian dollars.

plus 50% of the growth rate in AWE plus an adder based on the 2002 to 2020 historical difference between the Handy-Whitman growth rate and the 50/50 GDP-IPI and AWE growth rate. We only took the difference ending in 2020 as the difference in growth rates accelerated even more in the years immediately after the COVID-19 pandemic. The adder for distribution is 2.5% and the adder for transmission is 1.5%.[69]

For the U.S. sample, we compute this index using data on differences in the cost of constructing utility plant between regions over time. For U.S. distributors, we use the Handy-Whitman indices for total power distribution plant; these indices vary over time and across six geographic regions.[70] We do the same for the U.S. transmission utilities, except using the index for total power transmission plant. For Hydro One, we use the same Handy-Whitman index for total distribution or transmission plant in the North Atlantic region and then adjust for the Canadian purchasing power parity in the given year.

We determine the relative levels of utility plant asset prices for 2024 by using the City Cost Indices for electrical work in the 2025 edition of RSMeans' *Heavy Construction Cost Data*. These indices measure differences among cities in the cost of labour needed to install electrical equipment and differences in equipment prices. The construction service categories covered are: raceways; conductors and grounding; boxes and wiring devices; motors, starters, boards, and switches; transformers and bus ducts; lighting; electric utilities; and power distribution.

We modified this calculation in response to concerns in prior Hydro One applications. The prior method was to calculate the level of the asset price index for each utility by the headquarter city in the service territory (or the closest available city). The concern was that Hydro One, while headquartered in Toronto, has most of its assets outside the City of Toronto, and Toronto tends to have relatively high price levels.

In response to this concern, we modified the asset price level calculation to be based on a population-weighted average of the RS Means value for each 3-digit zip code served by a given utility. This spreads the levelization across the entire service territory, rather than centering on the headquarter city. For Hydro One, we took a population-weighted average of all the Ontario values in the RS Means book. This spreads the levelization across all of Ontario rather than centering on Toronto. The index is already adjusted for currency differences between the two countries.

Model Estimation Procedure and Specification

We assume that the relationship between a utility's cost and the conditions that affect it, called "cost drivers," can be quantified and captured by a statistical function. This function, called a "cost function," allows Clearspring to specify cost as a dependent variable that can be explained by relevant independent or explanatory variables and associated parameters; the latter capture the effect of the independent

[69] If the growth rate from 2002 to 2024 had been used, the adder would have increased to 3.2% for distribution and 2.0% for transmission.

[70] Handy-Whitman indexes are widely used throughout the U.S. utility industry. They measure the construction cost trends for specific utility functions in six different regional areas of the U.S. For more information, please see: https://wrallp.com/about-us/handy-whitman-index

variables on cost. Such a cost function is estimated using econometric techniques that rest on certain fundamental assumptions.

As implied by the term "independent," one of these assumptions is that the explanatory variables used in the model are factors that are outside the control of utility decision-makers. For instance, the wage paid to labour is driven by market conditions in the service territory and is largely outside the control of a firm's managers. On the other hand, the number of employees hired is within management's control, and thus should not serve as an independent variable.

The data used to estimate this cost relationship can be from a single firm with multiple time observations (time series data), from many firms observed at a single time period (cross-sectional data), or from many firms with multiple time observations (cross-sectional time-series or panel data). The estimation procedure used to estimate model parameters is affected by the type of data used to estimate the model. In our present study, we have a panel dataset with cost data from multiple firms with observations starting in 2000 for the distribution study and 2004 for transmission, and extending to 2024.[71] For benchmarks of past years, we use the model to produce benchmarks for each year and compare Hydro One's benchmark costs with its actual costs.

Additionally, for future years we can take Hydro One's cost projections through 2032, allowing us to also benchmark those forecasts "out of sample."[72] We use the model (which is based on historical data) and apply the estimated coefficients and projected independent variable values for Hydro One to calculate a predicted benchmark value. This predicted benchmark value is then compared to Hydro One's projected total cost amount.

Statistical Tests on Parameter Estimates

The precision of parameter estimates is an important dimension of the cost estimation exercise. It identifies business condition variables that have a statistically significant effect on cost. Standard errors of parameter estimates, which measure the precision with which a parameter is estimated, are used to construct a test of a relevant hypothesis. The hypothesis to be tested is "the explanatory variable in question has no statistically significant effect on cost." This procedure is called the *t*-test. A variable is statistically significant if this hypothesis is rejected at a pre-specified level of confidence. We use a 90% confidence threshold in our research for all first order terms. This restriction is not placed on the quadratic and interaction output terms that comprise the translog cost function.

A cost model with plausibly signed and statistically significant parameter estimates is ultimately used to assess the cost performance of each firm in the sample. By "plausibly signed" we mean that its sign (positive/negative) accords with our intuitive understanding of the relationship between that parameter

[71] The data extends to 2032 for Hydro One.

[72] For Hydro One's OM&A, Clearspring Energy was given projections until 2028 and then we applied the I-X+G+IPD formula to escalate OM&A amounts in years 2029 to 2032. The formula matches how the Company is proposing to escalate OM&A revenue during those years.

and the variable. For example, we would expect to see distribution costs rise as the number of customers served increases (i.e. we expect that the customer parameter would be positively signed).

Once the industry cost model is estimated, the cost model with estimated parameters is fitted with the business conditions of each utility to generate cost benchmarks, against which actual cost is evaluated. A cost benchmark for a particular utility reflects the performance we would expect from an average hypothetical utility facing the business conditions of that utility.

If a given utility's actual cost is below the benchmark cost, its cost performance is better than average—it spent less than a hypothetical utility (with the same particular characteristics) would be expected to spend. If its actual cost is above the benchmark cost, its cost performance is worse than average. A statistical test of a cost efficiency hypothesis, based on the *t*-test, can also be constructed to identify whether the cost performance identified by the above exercise is statistically significantly different from average.

Model Specification

A translog function is selected for the total cost model estimated in this study. The translog cost function was the same functional form we have used in all our prior CIR research, and the one chosen by PEG in its 4GIR benchmarking research. The function's general form, after suppressing time and firm subscripts, is given by:

$$ln\left(\frac{C}{W}\right) = \propto_0 + \sum_i \alpha_i \, ln\, Y_i + \sum_j \alpha_j lnZ_j + \frac{1}{2}\left[\sum_{i,k} \propto_{ik} \, lnY_i * ln\, Y_k\right] + \alpha_t t + \varepsilon$$

In this specification, $\alpha's$ are model parameters, and ε is the random noise term. In addition, Y_i quantifies output, W is the input price, Z_j is the other business condition variables, and *t* is a time trend term. This form has been widely used in cost function research.[73] A major advantage is its flexibility, which permits it to provide a good approximation for the wide range of functional forms that the data can reflect.[74]

Estimation Approach

As discussed earlier, the estimation approach has generated considerable discussion between benchmarking consultants in prior CIR proceedings. This is especially difficult for intervenors and the Board, due to the intricacies and difficulties for non-econometricians to evaluate these different approaches. However, PEG has moved to using this same estimation approach in its recent CIR research. Our hope is that PEG will continue to use this same estimation approach (which uses the OLS parameter estimates but then adjusts the standard errors) in any possible benchmarking research in this application. Clearspring believes this would best serve the Ontario industry for the benchmarking consultants to use

[73] In their Monte Carlo studies of functional forms' performance, Gagne and Ouellette (1998) use the translog as a benchmark because "it is the most widely used" functional form.

[74] See Guilkey, et al. (1983)

consistent and pre-determined estimation approaches for all CIR benchmarking research.

In multivariate regression analysis, the constructed model is designed to use a set of independent (often called explanatory or right-hand-side) variables to "explain" movement in the dependent (often called the left-hand-side) variable. The numerical relationship between an independent variable and the dependent variable is provided through an estimated coefficient value. Under the assumptions of the model, this coefficient value is considered an unbiased estimator of the relationship. Multivariate regression analysis also makes statements about the precision of each coefficient value. Precision in this context is a statement about how confident or statistically valid the coefficient value is. When all the assumptions of multivariate regression are satisfied, the coefficient values are the best (or most precise) unbiased estimators that are available.

Two common issues arise in multivariate regression using real world data: heteroscedasticity and autocorrelation. Neither of these issues causes the coefficient values to be biased or less precise. This is important because it means the researcher does not need to worry about correcting the coefficient values: they are not misleading. However, both conditions render the standard error estimates which measure precision problematic. Specifically, the problem with heteroscedasticity and autocorrelation is that they increase the regression variance calculations, which means the researcher is less confident in the calculated coefficient values. For decades, the standard correction procedure involved trying to figure out the nature of each problem and strategically weighting the regression to render heteroscedasticity and autocorrelation less of a problem. One key issue with this strategy is that the researcher may have a hard time truly understanding how to reweight the regression. Additionally, the coefficient values will be different after the reweighting.

More recent treatments for dealing with heteroscedasticity and autocorrelation focus the correction procedures on methods that do not alter the regression or the coefficient values. Instead of reweighting the regression itself, these strategies leave the regression unaltered and focus on altering the way the variances of the coefficients are calculated. These procedures are systematic and do not depend on understanding the underlying reason for the heteroscedasticity and autocorrelation.

For our analysis, we have chosen to estimate the precision of our coefficients using Driscoll-Kraay standard errors.[75] Driscoll-Kraay standard errors have been coded and available in the STATA software suite since 2007.[76] The computer software calculates information crucial to understanding whether each relationship (as described by each coefficient) can be supported statistically.

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[75] Driscoll, J., and A. C. Kraay, 1998. "Consistent covariance matrix estimation with spatially dependent data," *Review of Economics and Statistics* 80: 549–560.

[76] Hoechle, Daniel, 2007 "Robust standard errors for panel regressions with cross-sectional dependence," *The Stata Journal* 7(3): 281-312.

Appendix B: Summary Curriculum Vitae

STEVEN A. FENRICK

SUMMARY OF EXPERIENCE AND EXPERTISE

- I have directed project teams and engaged in research in the fields of performance based regulation, performance benchmarking, DSM, load research and forecasting, and survey design and implementation
- I have been a expert witness in a number of cases involving incentive regulation and other utility research topics.

PROFESSIONAL EXPERIENCE

Clearspring Energy Advisors, LLC (2019 to Present)

Principal Consultant

Responsible for providing consulting services and expert witness testimony to utilities and regulators in the areas of reliability and cost benchmarking, productivity studies and other empirical aspects of performance-based ratemaking and incentive regulation. Direct activities in the areas of demand-side management programs, peak time rebate programs, load forecasting, and market research.

Power System Engineering, Inc.– Madison, WI (2009 to 2018)

Director of Economics

Responsible for providing consulting services to utilities and regulators in the areas of reliability and cost benchmarking, incentive regulation, value-based reliability planning, demand-side management including demand response and energy efficiency, ran peak time rebate programs, load research, load forecasting, end-use surveys, and market research.

Pacific Economics Group – Madison, WI (2001 - 2009)

Senior Economist

Co-authored research reports submitted as testimony in numerous proceedings in several states and in international jurisdictions. Research topics included statistical benchmarking, alternative regulation, and revenue decoupling. Managed and supervised PEG support staff in research and marketing efforts.

EDUCATION

University of Wisconsin - Madison, WI

Bachelor of Science, Economics (Mathematical Emphasis)

University of Wisconsin - Madison, WI

Master of Science, Agriculture and Applied Economics

Publications & Papers

- "Peak-Time Rebate Programs: A Success Story", *TechSurveillance*, July 2014 (with David Williams and Chris Ivanov).
- "Demand Impact of a Critical Peak Pricing Program: Opt-In and Opt-Out Options, Green Attitudes and other Customer Characteristics:, *The Energy Journal*, January 2014. (With Lullit Getachew, Chris Ivanov, and Jeff Smith).
- "Evaluating the Cost of Reliability Improvement Programs", *The Electricity Journal*, November 2013. (With Lullit Getachew)
- "Expected Useful Life of Energy Efficiency Improvements", Cooperative Research Network, 2013 (with David Williams).
- "Cost and Reliability Comparisons of Underground and Overhead Power Lines", *Utilities Policy*, March 2012. (With Lullit Getachew).
- "Formulating Appropriate Electric Reliability Targets and Performance Evaluations, *Electricity Journal*, March 2012. (With Lullit Getachew)
- "Enabling Technologies and Energy Savings: The Case of EnergyWise Smart Meter Pilot of Connexus Energy", Utilities Policy, November 2012. (With Chris Ivanov, Lullit Getachew, and Bethany Vittetoe)
- "The Value of Improving Load Factors through Demand-Side Management Programs", Cooperative Research Network, 2012 (with David Williams and Chris Ivanov).
- "Estimation of the Effects of Price and Billing Frequency on Household Water Demand Using a Panel of Wisconsin Municipalities", *Applied Economics Letters*, 2012, 19:14, 1373-1380.
- "Altreg Rate Designs Address Declining Average Gas Use", *Natural Gas & Electricity*. April 2008. (With Mark Lowry, Lullit Getachew, and David Hovde).
- "Regulation of Gas Distributors with Declining Use per Customer", *Dialogue*. August 2006. (With Mark Lowry and Lullit Getachew).
- "Balancing Reliability with Investment Costs: Assessing the Costs and Benefits of Reliability-Driven Power Transmission Projects." April 2011. *RE Magazine*.
- "Ex-Post Cost, Productivity, and Reliability Performance Assessment Techniques for Power Distribution Utilities". Master's Thesis.
- "Demand Response: How Much Value is Really There?" *PSE whitepaper.*
- "How is My Utility Performing" *PSE whitepaper*.
- "Improving the Performance of Power Distributors by Statistical Performance Benchmarking" *PSE whitepaper*.
- "Peak Time Rebate Programs: Reducing Costs While Engaging Customers" *PSE whitepaper*.
- "Performance Based Regulation for Electric and Gas Distributors" *PSE whitepaper*.
- "Revenue Decoupling: Designing a Fair Revenue Adjustment Mechanism" *PSE whitepaper.*

Expert Witness Experience

- Docket EB-2026-0152, Wataynikaneyap Power LP, Custom Incentive Regulation Application.
- Docket EB-2025-0312, Elexicon Energy Inc., Custom Incentive Regulation Application.
- Docket EB-2025-0252, Alectra Utilities Corporation, Custom Incentive Regulation Application.

- Docket EB-2024-0115, Hydro Ottawa Limited, Custom Incentive Regulation Application.
- Docket EB-2023-0195, Toronto Hydro Electric System Limited, Econometric Benchmarking research.
- Case No. 2023-00310, Big Rivers Electric Corporation, Integrated Resource Plan. Econometric Load Forecasting research.
- Docket EB-2022-0149, Wataynikaneyap Power LP, Benchmarking Research.
- Docket EB-2021-0110, Hydro One Networks, Joint Rate Application for Transmission and Distribution. Custom Incentive Regulation Benchmarking and Productivity research.
- Case No. 2020-00299, Big Rivers Electric Corporation, Integrated Resource Plan.
- Docket EB-2019-0261, Hydro Ottawa, Custom Incentive Regulation Application.
- Docket EB-2019-0082, Hydro One Networks Transmission, TFP and Econometric Benchmarking research.
- Docket EB-2018-0165, Toronto Hydro Electric System Limited, Econometric Benchmarking research.
- Docket EB-2018-0218, Hydro One Transmission Sault St. Marie, TFP and Econometric Benchmarking research.
- Docket EB-2017-0049, Hydro One Distribution, TFP and Benchmarking research.
- Docket EB-2015-0004, Hydro Ottawa, Custom Incentive Regulation Application.
- Docket 15-SPEE-357-TAR, Application for Southern Pioneer Electric Cooperative, Inc., Demand Response Peak Time Rebate Pilot Program.
- Docket EB-2014-0116, Toronto Hydro, Custom Incentive Regulation Application.
- Docket EB-2010-0379, The Coalition of Large Distributors in Ontario regarding "Defining & Measuring Performance".
- Docket No. 6690-CE-198, Wisconsin Public Service Corporation, "Application for Certificate of Authority for System Modernization and Reliability Project".
- Expert Witness presentation to Connecticut Governors "Two Storm Panel", 2012.
- Docket No. EB-2012-0064, Toronto Hydro's Incremental Capital Module (ICM) request for added capital funding.
- Docket No. 09-0306, Central Illinois Light rate case filing.
- Docket No. 09-0307, Central Illinois Public Service Company rate case filing.
- Docket No. 09-0308, Illinois Power rate case filing.

Conference Presentations

- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2019.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2018.
- Panel Moderator at WPUI conference on cost allocation and innovative rate designs at Madison WI. June 2018.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2017.

- Wisconsin Manager's Meeting, "Reliability Target Setting Using Econometric Benchmarking". November 2016.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2016.
- Wisconsin Electric Cooperative Association (WECA) Conference, "An Introduction to Peak Time Rebates". September 2016.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2015.
- EUCI conference chair, 2015. "Evaluating the Performance of Gas and Electric Distribution Utilities."
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2014.
- Cooperative Exchange Conference, Williamsburg VA. "Smart Thermostat versus AC Direct Load Control Impacts". August 2014.
- EUCI conference chair in Chicago. "The Economics of Demand Response". February 2014.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2013.
- EUCI conference chair in Chicago. "Evaluating the Performance of Gas and Electric Distribution Utilities." August 2013.
- Presentation to the Ontario Energy Board, "Research and Recommendations on 4th Generation Incentive Regulation".
- Presentation to the Canadian Electricity Association's best practice working group. 2013
- Conference chair for EUCI conference in March 2013 titled, "Performance Benchmarking for Electric and Gas Distribution Utilities."
- Presentation to the board of directors of Great Lakes Energy on benchmarking results, December 2012.
- Presentation on making optimal infrastructure investments and the impact on rates, Electricity Distribution Association, Toronto, Ontario. November 2012.
- Conference chair for EUCI conference in August 2012 titled, "Performance Benchmarking for Electric and Gas Distribution Utilities."
- 2012 presentation in Springfield, IL to the Midwest Energy Association titled, "Reliability Target Setting and Performance Evaluation".
- 2012 presentation in Springfield, IL to the Midwest Energy Association titled, "Making the Business Case for Reliability-Driven Investments".
- Conference chair for EUCI conference in 2012 titled, "Balancing, Measuring, and Improving the Cost and Reliability Performance of Electric Distribution Utilities". St. Louis.
- Conference chair for EUCI conference in 2012 titled, "Demand Response: The Economic and Technology Considerations from Pilot to Deployment". St. Louis.
- 2012 Presentation in the Missouri PSC Smart Grid conference entitled, "Maximizing the Value of DSM Deployments". Jefferson City.
- 2011 conference chair on a nationwide benchmarking conference for rural electrical cooperatives. Madison.
- 2011 presentation on optimizing demand response program at the CRN Summit. Cleveland.
- Conference chair for EUCI conference in 2011 titled, "Balancing, Measuring, and Improving the Cost and Reliability Performance of Electric Distribution Utilities". Denver.
- 2010 presentation on cost benchmarking techniques for REMC. Wisconsin Dells.

COMPONENTS OF CUSTOM IR FORMULA – TRANSMISSION

1.0 HYDRO ONE TRANSMISSION – RCI COMPONENTS

This section of the Exhibit describes the specific parameters of the Custom Revenue Cap Index (RCI) proposed for Hydro One Transmission. As described in Exhibit A-04-01, the RCI is expressed as follows:

$$RCI = I – X + G + IPD_{oma} + C$$

Where:

- "I" is the Inflation Factor;
- "X" is the Productivity Factor;
- "G" is the Growth Factor;
- "IPD_{oma}" is the Input Price Differential factor, pro-rated to the OM&A portion of the revenue requirement; and
- "C" is Hydro One's Custom Capital Factor.

2.0 INFLATION FACTOR

For its Transmission business, Hydro One is proposing to rely on the OEB's annually published Inflation Factor (I) for electricity transmitters, which is based on the weighted sum of:

- 86% of the annual percentage change in Canada's GDP-IPI (FDD) as reported by Statistics Canada; and
- 14% of the annual percentage change in the Average Weekly Earnings for workers in Ontario, as reported by Statistics Canada.

Hydro One Transmission has used an inflation forecast of 1.84% on a pro-forma basis in its RCI calculation for the years 2029 through 2032. The inflation forecast was prepared by Clearspring Energy Advisors (Clearspring), and is found in their report at Exhibit A-04-01 Attachment 1.

The Inflation Factor will be updated annually over the 2029-2032 period to reflect the OEB issued inflation factor for transmitters, applicable to those years.

2.1 PRODUCTIVITY FACTOR

Hydro One engaged Clearspring to undertake a study of the Total Factor Productivity (TFP) trend for the transmission industry in order to recommend the base productivity component of the X-factor, and to undertake an econometric total cost benchmarking study of Hydro One's transmission costs in order to recommend an appropriate stretch factor component of the X-factor. The Clearspring report is provided in Exhibit A-04-01 Attachment 1.

Taking into account the Clearspring study results, Hydro One proposes an X-factor of 0% for Transmission. This reflects the sum of the Industry TFP measure of -2.30% and a Custom Productivity Stretch Factor of 0.15% but adjusted to a neutral value of 0% for ratepayers' benefit, rather than implementing a negative X-factor. Clearspring's study concluded that the transmission industry TFP trend has declined by 2.30% from 2009 to 2024 and thus recommended the use of a negative base productivity factor as it would better align cost escalation expectations with the revenue escalation formula. Clearspring recommended a Stretch Factor of 0.15% for Transmission based on the results of its total cost benchmarking study, which shows Hydro One to be a very strong cost performer. In that study, Hydro One Transmission's projected total costs were found to average 24.7% below the benchmark costs throughout the Custom IR term. Cost performance of 24.7% below average would indicate Hydro One Transmission falls within Cohort 2 of the OEB's commonly used framework for assigning stretch factors to electricity distributors, which applies a stretch factor of 0.15%. Hydro One Transmission proposes adoption of 0.15% for the stretch factor component of the combined X Factor on this basis.

Consistent with the approach in previous applications, the X-factor used in the RCI will not be updated annually over the Custom IR term. In its total cost benchmarking study, Clearspring conducted a forward-looking analysis using Hydro One's forecast costs. This analysis concluded that Hydro One's projected total costs will remain significantly below

benchmark expectations throughout the Custom IR term. Further details are provided in Clearspring's report at Exhibit A-04-01 Attachment 1.

2.2 CAPITAL FACTOR

The Custom Capital Factor (C-factor) (line 19 of Table 1 below) is the percentage change in the Total Revenue Requirement attributable to capital investment (depreciation, return on equity, interest and taxes attributable to in-service capital) and Prepaid Cloud Computing Amortization that is not otherwise recovered from customers through the I – X + G adjustment each year of the Custom IR term. Hydro One is proposing to reduce the C-factor by a supplemental stretch factor of 0.15% (the Supplemental Stretch). The C-factor will be updated annually to reflect any changes to the inflation factor. The calculation of the C-factor is set out in Table 1.

The Total Capital Related & Prepaid Cloud Revenue Requirement (line 7 of Table 1) each year, is based on annual rate base. The final Capital Related & Prepaid Cloud Revenue Requirement in lines 1 to 13 of Table 1 will be calculated by Hydro One in conjunction with the Draft Rate Order using OEB-approved values. Consistent with prior OEB decisions, forecast working capital related revenue requirement has been removed from the C-Factor calculation (row 8) and an adjustment is made to fund working capital allowance revenue requirement on the basis of I-X for 2029 through 2032 (row 12). These metrics will not change over the Custom IR term.

The OM&A (line 14 of Table 1) for each year is determined based on the 2028 forecast included in the Application, increased by the Inflation Factor (I), Growth Factor (G), and Input Price Differential ($IPD_{OM\&A}$), and subject to the proposed X-factor, for a total increase of 3.09% per annum.

Table 1 - Summary of Revenue Requirement Components ($M)
for Hydro One Transmission

Line		Reference	2028	2029	2030	2031	2032
1	Average Rate Base	C-01-01	19,199.2	20,660.8	22,267.9	24,204.8	28,469.6
2	Return on Debt	F-01-03	463.0	504.0	548.0	606.6	722.2
3	Return on Equity	F-01-03	787.1	847.0	912.9	992.3	1,167.1
4	Depreciation & Amortization	E-08-01	714.2	757.5	818.3	873.6	950.8
5	Income Taxes	E-09-02-01	103.7	124.2	184.6	166.0	63.3
6	Prepaid Cloud Computing Amortization	E-08-01	24.1	48.1	55.6	44.0	46.9
7	**Total Capital Related & Prepaid Cloud Revenue Requirement**		2,092.1	2,280.9	2,519.3	2,682.5	2,950.2
8	Less Working Capital Related Revenue Requirement			3.5	4.1	4.9	5.4
9	**Total Capital Related and Prepaid Cloud Revenue Requirement (excluding working capital)**		2,092.1	2,277.3	2,515.2	2,677.6	2,944.9
10	Less Productivity Factor on Capital (0.00% + 0.15%)			-3.4	-3.8	-4.0	-4.4
11	Less Prior Year Productivity Factor on Capital				-3.4	-7.2	-11.2
12	Working Capital Adjustment			-0.5	-1.2	-1.6	-1.0
13	**Total Capital Related and Prepaid Cloud Revenue Requirement (including working capital and Productivity)**		**2,092.1**	**2,276.9**	**2,510.9**	**2,669.7**	**2,933.7**
14	OM&A (I - X + G + IPD)	E-02-01*	634.5	654.1	674.3	695.1	716.6
15	**Total Revenue Requirement**		**2,726.6**	**2,931.0**	**3,185.2**	**3,364.8**	**3,650.2**
16	Increase in Capital-Related Revenue Requirement			184.8	234.0	158.8	263.9
17	Increase in Capital-Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			6.78%	7.98%	4.99%	7.84%
18	Less Capital-Related Revenue Requirement in I-X+G			2.17%	2.20%	2.23%	2.25%
19	**C Factor**			**4.61%**	**5.78%**	**2.75%**	**5.60%**

**Exhibit Reference for 2028 OM&A*

For purposes of calculating the OM&A amounts in Table 1, the full IPD is applied directly to OM&A. By contrast, when the RCI is applied to the total revenue requirement, the IPD is scaled by the proportion of total revenue requirement attributable to OM&A, as described in Table 3. These approaches produce the same dollar adjustment and ensure that the IPD applies only to OM&A.

The 2028 Total Revenue Requirement of $2,726.6M (line 15 of Table 1) is determined based on a forward test year, cost of service approach and is the rebasing year for this Application.

In 2029, the Capital Related & Prepaid Cloud Revenue Requirement (line 7 of Table 1) increases from $2,092.1M (2028) to $2,280.9M. Hydro One will reduce the Capital Related & Prepaid Cloud Revenue Requirement adjusted for working capital and Productivity (line 9 of Table 1) by the approved X-factor and the Supplemental Stretch (line 10 of Table 1). In 2030-2032, Hydro One will also reduce the Capital Related & Prepaid Cloud Revenue Requirement by the cumulative capital-related productivity reductions from prior years (line 11 of Table 1), and Hydro One has reduced the Capital Related & Prepaid Cloud Revenue Requirement to account for the funding of working capital allowance revenue requirement on the basis of I-X indexing (line 12 of Table 1).[1] The change in Total Capital Related & Prepaid Cloud Revenue Requirement (including the working capital and Productivity) (line 13 of Table 1) in 2029 versus 2028 is $184.8M (line 16 of Table 1). This difference is equal to 6.78% of the 2028 Total Revenue Requirement of $2,726.6M ($184.8M divided by $2,726.6M).

The 6.78% increase in Total Capital Related & Prepaid Cloud Revenue Requirement is the total increase in revenue requirement arising from the higher 2029 Capital Related & Prepaid Cloud Revenue Requirement (line 13 of Table 1). However, the 6.78% increase must be reduced by the increase in revenue requirement that results from the application of the Inflation, Growth and Productivity Factors (I – X + G) of the RCI applicable to capital. This is done by determining the percentage of the Total Capital Related & Prepaid Cloud

[1] This is consistent with the approach approved by the OEB in EB-2017-0049 and EB-2019-0082.

Revenue Requirement excluding working capital and Productivity (line 13 of Table 1) that is already provided for by the Inflation, Growth and Productivity Factors. In 2029, this equals 2.17% ($2,092.1M x 2.83% / $2,726.6M). The net result of 4.61% (6.78% less 2.17%) is the 2029 Custom C-factor. As noted in Exhibit A-04-01, Hydro One's productivity factors have been applied on a cumulative basis. The cumulative application of the X-factor and Supplemental Stretch results in a significant revenue requirement reduction for customers that grows each year beginning in 2029.

2.3 CUSTOM RCI SUMMARY

Table 2 below summarizes the Custom RCI by component that Hydro One is proposing to use to determine the total revenue requirement for rate-making purposes for 2029 to 2032.

Table 2 - Transmission Custom Revenue Cap Index (RCI) by Component (%)

RCI = I – X + G + IPD_{oma} + C		**2029**	**2030**	**2031**	**2032**
Inflation Factor	I	1.84%	1.84%	1.84%	1.84%
Productivity Factor	X	0.00%	0.00%	0.00%	0.00%
Growth Factor	G	0.99%	0.99%	0.99%	0.99%
Input Price Differential (scaled to OM&A)	IPD_{oma}	0.06%	0.06%	0.06%	0.05%
Capital Factor*	C	4.61%	5.78%	2.75%	5.60%
Custom Revenue Cap Index	**RCI**	**7.50%**	**8.67%**	**5.64%**	**8.48%**

**Includes Supplemental Stretch on Capital*

As discussed in Exhibit A-04-01, for the purpose of applying IPD escalations only to OM&A within the total revenue requirement funding envelope, IPD values must be scaled to reflect the proportion of total revenue requirement allocated to OM&A. Table 3 below demonstrates the scaling of IPD to the OM&A portion of total revenue requirement based on prior year's figures, given the RCI will apply to prior year revenue requirement to yield current year revenue requirement. Hydro One proposes fixing IPD_{oma} values in this Application and does not propose updating these values in subsequent Annual Update applications.

Table 3 - Scaling Input Price Differential to OM&A - Transmission

		2029	2030	2031	2032
A	**Input Price Differential (IPD)**	**0.26%**	**0.26%**	**0.26%**	**0.26%**
B	Prior Year OM&A ($M)	634.5	654.1	674.3	695.1
C	Prior Year Total Revenue Requirement ($M)	2726.6	2931.0	3185.2	3364.8
D = B / C	OM&A as % of Total Revenue Requirement	23%	22%	21%	21%
E = A x D	**Input Price Differential scaled to OM&A (IPD_{oma})**	**0.06%**	**0.06%**	**0.06%**	**0.05%**

The Inflation Factor in Table 2 will be updated annually, as described above in section 1.1. Hydro One proposes that the X-factor remain unchanged throughout the Custom IR term. The Total Capital Related & Prepaid Cloud Revenue Requirement in line 13 of Table 1 would remain unchanged in subsequent annual update applications, however the 2029 to 2032 C-factors would be updated for the applicable year, to reflect the OEB's annual inflation factor, in subsequent annual update applications.

Table 4 below summarizes the Total Revenue Requirement that would result from the OEB's approval of Hydro One's Custom IR, as proposed.

Table 4 - Hydro One Transmission Revenue Requirement by Year

Year	Formula	Revenue Requirement ($M)
2028	Cost of Service	$2,726.6
2029	2028 Revenue Requirement x 1.0750	$2,931.1
2030	2029 Revenue Requirement x 1.0867	$3,185.2
2031	2030 Revenue Requirement x 1.0564	$3,364.8
2032	2031 Revenue Requirement x 1.0848	$3,650.2

**Calculations assume that Inflation Factor remains at 1.84% through term.*

2.4 HYDRO ONE SAULT STE. MARIE RCI DETAILS

This section of the Exhibit describes the specific parameters of the Custom Revenue Cap Index (RCI) proposed for Hydro One Sault Ste Marie (HOSSM).

In EB-2026-0170, the OEB approved HOSSM request to use its 2026 base revenue requirement of $49.2M on an interim basis effective January 1, 2027 for one year. HOSSM

indicated its intention to apply to rebase its 2027 revenue requirement. In this Application, HOSSM is seeking approval of a final 2027 total revenue requirement of $46.1M, determined using a cost-of-service, forward test year approach, with the resulting difference (between the final and interim 2027 revenue requirement) to be refunded to customers through an adjustment to the 2028 rates transmission revenue requirement.

HOSSM's 2028 total revenue requirement is also determined using a cost-of-service, forward test year approach, and serves as the base year for application of the RCI from 2029 through 2032. Further background on HOSSM is provided in Exhibits A-08-01 and further information on the revenue requirement is provided in D-01-01A.

HOSSM proposes to use the same RCI formula and approach outlined for Hydro One Transmission, to escalate its revenue requirement for the years 2029 through 2032, after 2028 total revenue requirement is established. HOSSM's RCI will be implemented consistent with Hydro One's proposed RCI as described above, using the following:

- HOSSM's 2028 Test Year OM&A and 2028 through 2032 forecast rate base;
- The same industry TFP for electricity transmission of -2.30%, as per the Clearspring report provided at Exhibit A-04-01 Attachment 1;
- A 0% stretch factor;
- A combined X-factor of 0% based on the sum of the industry TFP and stretch factor values set out above but without allowing the X-factor to be negative, consistent with the proposal for Hydro One Transmission;
- A Supplemental Stretch factor on capital of 0.15%, consistent with Hydro One's Transmission and Distribution proposals;
- A pro-forma OEB Inflation Factor for Transmission of 1.84%, consistent with Hydro One Transmission's forecast;
- A Growth Factor of 0.89% based on Clearspring's recommendation; and
- An Input Price Differential of 0.24%, as outlined by Clearspring and scaled to HOSSM's OM&A relative to total revenue requirement.

Table 5 below outlines the revenue requirement components and derivation of HOSSM's C-factor values for each year from 2029 through 2032 consistent with the methodologies outlined in this evidence.

Table 5 - Summary of Revenue Requirement Components ($M) for HOSSM

Line		Reference	2028	2029	2030	2031	2032
1	Average Rate Base	C-01-02	376.1	425.3	456.4	463.0	474.7
2	Return on Debt	F-02-03 D-01-01A-01 to 6	10.6	12.0	12.9	13.1	13.4
3	Return on Equity	F-02-03 D-01-01A-01 to 6	13.7	15.5	16.6	16.9	17.3
4	Depreciation & Amortization	E-08-02	14.3	14.7	15.5	15.9	16.6
5	Income Taxes	E-09-04-01	0.4	-1.1	2.0	1.8	2.6
6	**Total Capital Related Requirement**		39.1	41.1	47.1	47.7	49.9
7	Less Working Capital Related Revenue Requirement			0.0	0.1	0.1	0.1
8	**Total Capital Related Revenue Requirement (excluding working capital)**		39.1	41.1	47.0	47.6	49.9
9	Less Productivity Factor on Capital (0.15%)			-0.1	-0.1	-0.1	-0.1
10	Less Prior Year Productivity Factor on Capital				-0.1	-0.1	-0.2
11	Less Removing Working Capital from Capital Factor			0.0	0.0	0.0	0.0
12	**Total Capital Related Revenue Requirement (including working capital and Productivity)**		**39.1**	**41.1**	**46.9**	**47.5**	**49.6**
13	OM&A (I - X + G + IPD)	E-02-06 *	10.9	11.2	11.6	11.9	12.3
14	**Total Revenue Requirement**		**50.0**	**52.3**	**58.5**	**59.4**	**61.9**
15	Increase in Capital-Related Revenue Requirement			2.0	5.9	0.6	2.1
16	Increase in Capital-Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			4.02%	11.19%	0.96%	3.62%
17	Less Capital-Related Revenue Requirement in I-X+G			2.13%	2.14%	2.19%	2.18%
18	**C Factor**			**1.88%**	**9.05%**	**-1.23%**	**1.44%**

**Exhibit Reference for 2028 OM&A*

Table 6 below summarizes HOSSM's proposed Custom RCI by component that will be used to determine the 2029 to 2032 total revenue requirement.

Table 6 - Custom Revenue Cap Index (RCI) by Component (%) for HOSSM

RCI = I - X + G + IPD_{oma} + C		**2029**	**2030**	**2031**	**2032**
Inflation Factor	I	1.84%	1.84%	1.84%	1.84%
Productivity Factor	X	0.00%	0.00%	0.00%	0.00%
Growth Factor	G	0.89%	0.89%	0.89%	0.89%
Input Price Differential (scaled to OM&A)	IPD_{oma}	0.05%	0.05%	0.05%	0.05%
Capital Factor*	C	1.88%	9.05%	-1.23%	1.44%
Custom Revenue Cap Index	**RCI**	**4.66%**	**11.83%**	**1.55%**	**4.22%**

**Includes Supplemental Stretch on Capital*

Table 7 below outlines the scaling of HOSSM's Input Price Differential calculated to the proportion of total revenue requirement allocated to OM&A, consistent with the approach described for Hydro One Transmission above.

Table 7 - Scaling Input Price Differential to OM&A for HOSSM

		2029	**2030**	**2031**	**2032**
A	**Input Price Differential (IPD)**	**0.24%**	**0.24%**	**0.24%**	**0.24%**
B	Prior Year OM&A ($M)	10.9	11.2	11.6	11.9
C	Prior Year Total Revenue Requirement ($M)	50.0	52.3	58.5	59.4
D = B / C	OM&A as % of Total Revenue Requirement	22%	21%	20%	20%
E = A x D	**Input Price Differential scaled to OM&A (IPD_{oma})**	**0.05%**	**0.05%**	**0.05%**	**0.05%**

Table 8 below outlines the application of the RCI for the years 2029 through 2032 based on a forecast of the OEB's Inflation Factor applicable to electricity transmitters of 1.84%.

Table 8 - HOSSM Revenue Requirement by Year

Year	Formula	Revenue Requirement ($M)
2028	Cost of Service	$50.0
2029	2028 Revenue Requirement x 1.0466	$52.3
2030	2029 Revenue Requirement x 1.1183	$58.5
2031	2030 Revenue Requirement x 1.0155	$59.4
2032	2031 Revenue Requirement x 1.0422	$61.9

**Calculations assume that Inflation Factor remains at 1.84% through term.*

3.0 PROPOSED FRAMEWORK FOR ANNUAL UPDATE APPLICATIONS

Hydro One and HOSSM expect to file annual update applications from 2029-2032. These applications will calculate the revenue requirement for Hydro One Transmission and HOSSM using their respective RCIs to reflect the most up to date Inflation Factor. Hydro One Transmission and HOSSM will also provide revised Uniform Transmission Rate calculations that reflect the revised revenue requirement and OEB-approved billing determinants for the applicable year. If deferral and variance account balances accumulated in subsequent years are material, Hydro One may also seek to dispose of any balances in its annual update applications.

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COMPONENTS OF CUSTOM IR FORMULA – DISTRIBUTION

1.0 HYDRO ONE DISTRIBUTION – RCI COMPONENTS

This Exhibit describes the specific parameters of the Custom Revenue Cap Index (RCI) proposed for Hydro One Distribution. As described in Exhibit A-04-01, the RCI is expressed as follows:

$$RCI = I – X + G + IPD_{oma} + C$$

Where:

- "I" is the Inflation Factor;
- "X" is the Productivity Factor;
- "G" is the Growth Factor;
- "IPD_{oma}" is the Input Price Differential factor, pro-rated to the OM&A portion of the revenue requirement; and
- "C" is Hydro One's Custom Capital Factor.

2.0 INFLATION FACTOR

In its December 2013 Report, "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors" (EB-2010-0379), the OEB established a methodology for determining the annual Inflation Factor (I) to be used in incentive-based rate adjustment mechanisms for electricity distributors.

The Inflation Factor is based on the weighted sum of:

- 70% of the annual percentage change in Canada's GDP-IPI (FDD) as reported by Statistics Canada; and
- 30% of the annual percentage change in the Average Weekly Earnings for workers in Ontario, as reported by Statistics Canada.

Consistent with its prior Custom IR application, Hydro One proposes to use the same Inflation Factor in its RCI.

Hydro One Distribution has used an inflation forecast of 1.96% on a pro-forma basis in its RCI calculation for the years 2029 through 2032. The inflation forecast was prepared by Clearspring Energy Advisors (Clearspring), and is found in their report at Exhibit A-04-01 Attachment 1.

The Inflation Factor will be updated annually over the 2029-2032 period to reflect the OEB issued inflation factor for distributors, applicable to those years.

2.1 PRODUCTIVITY FACTOR

Hydro One engaged Clearspring to undertake a study of the Total Factor Productivity (TFP) trend for the distribution industry in order to recommend the base productivity component of the X-factor, and to undertake an econometric total cost benchmarking study of Hydro One's distribution costs in order to recommend an appropriate stretch factor component of the X-factor. The Clearspring report is provided in Exhibit A-04-01 Attachment 1.

Clearspring recommended a Distribution base productivity factor of -0.31%, calculated as the average of the U.S. distribution industry's 15-year TFP trend of -0.33% and the Ontario distribution industry's 10-year TFP trend of -0.29%.

The Clearspring study found that Hydro One Distribution's total costs are projected to average 25.8% above benchmark over the 2028-2032 Custom IR term. Based on the stretch-factor cohorts established under the OEB's 4GIRM framework, Clearspring recommends a stretch factor of 0.60%.

The recommended base productivity factor and stretch factor combine to produce Hydro One's proposed Distribution X-factor: X = -0.31% + 0.60% = 0.29%. Hydro One applies the 0.29% X-factor cumulatively to both the OM&A and capital-related revenue requirements. Consistent with the approach in previous applications, the X-factor used in the RCI will not be updated annually over the Custom IR term.

2.2 CAPITAL FACTOR

The Custom Capital Factor (C-factor) (line 20 of Table 1 below) is the percentage change in the Total Revenue Requirement attributable to capital investment (depreciation, return on equity, interest and taxes attributable to in-service capital) and Prepaid Cloud Computing Amortization that is not otherwise recovered from customers through the I – X + G adjustment each year of the Custom IR term. Hydro One is proposing to reduce the C-factor by a supplemental stretch factor of 0.15% (the Supplemental Stretch). The C-factor will be updated annually to reflect any changes to the inflation factor. The calculation of the C-factor is set out in Table 1.

The Total Capital Related & Prepaid Cloud Revenue Requirement (line 7 of Table 1) each year, is based on annual rate base. The final Capital Related & Prepaid Cloud Revenue Requirement in lines 1 to 13 of Table 1 will be calculated by Hydro One in conjunction with the Draft Rate Order using OEB-approved values. Consistent with prior OEB decisions, forecast working capital related revenue requirement has been removed from the C-Factor calculation (row 8) and an adjustment is made to fund working capital allowance revenue requirement on the basis of I-X for 2029 through 2032 (row 12). These metrics will not change over the Custom IR term.

The OM&A (line 14 of Table 1) for each year is determined based on the 2028 forecast included in the Application, increased by the Inflation Factor (I), Growth Factor (G), and Input Price Differential ($IPD_{OM\&A}$), and subject to the proposed X-factor, for a total increase of 3.08% per annum.

In addition, in 2031 Hydro One's Peterborough and Orillia rate zones will be integrated with Hydro One Distribution for rate-making purposes. As such, effective 2031 the OM&A costs supporting these rate zones must be incorporated into Hydro One's distribution revenues. To accomplish this, Hydro One proposes a one-time manual increase to OM&A funding of $11.3M in 2031 as shown in line 15 of Table 1, after which the RCI will escalate the combined 2031 amounts to yield 2032 distribution revenue requirement. In respect of determining the Orillia and Peterborough rate zones' capital related revenue requirement,

the average Rate Base shown in line 1 of Table 1 includes the Orillia and Peterborough rate base for 2031 and 2032, as outlined in Exhibit C-01-01.

Table 1 - Summary of Revenue Requirement Components ($M)
for Hydro One Distribution

Line		Reference	2028	2029	2030	2031	2032
1	Average Rate Base	C-01-01	14,434.6	15,795.3	17,135.8	18,957.8	20,712.4
2	Return on Debt	F-01-03	348.0	385.6	422.1	474.8	524.5
3	Return on Equity	F-01-03	591.7	647.5	702.5	777.2	849.1
4	Depreciation & Amortization	E-08-01	707.7	783.5	862.4	882.6	925.7
5	Income Taxes	E-09-02-01	42.7	117.5	157.8	143.4	88.9
6	Prepaid Cloud Computing Amortization	E-08-01	46.0	85.8	102.2	93.2	100.0
7	**Total Capital Related & Prepaid Cloud Revenue Requirement**		1,736.1	2,019.9	2,247.1	2,371.2	2,488.2
8	Less Working Capital Related Revenue Requirement			42.8	44.9	47.4	48.2
9	**Total Capital Related and Prepaid Cloud Revenue Requirement (excluding working capital)**		1,736.1	1,977.1	2,202.2	2,323.8	2,440.0
10	Less Productivity Factor on Capital (0.29% + 0.15%)			-8.7	-9.7	-10.2	-10.7
11	Less Prior Year Productivity Factor on Capital				-8.7	-18.4	-28.6
12	Working Capital Adjustment			-1.2	-2.1	-2.1	-1.6
13	**Total Capital Related and Prepaid Cloud Revenue Requirement (including working capital and Productivity)**		**1,736.1**	**2,010.0**	**2,226.6**	**2,340.5**	**2,447.3**
14	OM&A (I - X + G + IPD)	E-03-01*	958.7	988.2	1,018.7	1,050.0	1,082.4
15	Peterborough & Orillia OM&A					11.3	11.7
16	**Total Revenue Requirement**		**2,694.8**	**2,998.2**	**3,245.3**	**3,401.9**	**3,541.4**
17	Increase in Capital-Related Revenue Requirement			273.9	216.6	113.9	106.8
18	Increase in Capital-Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			10.16%	7.23%	3.51%	3.14%
19	Less Capital-Related Revenue Requirement in I-X+G			1.83%	1.90%	1.95%	1.95%
20	**C Factor**			**8.33%**	**5.32%**	**1.56%**	**1.18%**

**Exhibit Reference for 2028 OM&A*

For purposes of calculating the OM&A amounts in Table 1, the full IPD is applied directly to OM&A. By contrast, when the RCI is applied to the total revenue requirement, the IPD is scaled by the proportion of total revenue requirement attributable to OM&A, as described in Table 3. These approaches produce the same dollar adjustment and ensure that the IPD applies only to OM&A.

The 2028 Total Revenue Requirement of $2,694.8M (line 16 of Table 1) is determined based on a forward test year, cost of service approach and is the rebasing year for this Application.

In 2029, the Capital Related & Prepaid Cloud Revenue Requirement (line 7 of Table 1) increases from $1,736.1M (2028) to $2,019.9M. Hydro One will reduce the Capital Related & Prepaid Cloud Revenue Requirement excluding working capital (line 9 of Table 1) by the approved X-factor and the Supplemental Stretch (line 10 of Table 1). In 2030-2032, Hydro One will also reduce the Capital Related & Prepaid Cloud Revenue Requirement by the cumulative capital-related productivity reductions from prior years (line 11 of Table 1), and Hydro One has reduced the Capital Related & Prepaid Cloud Revenue Requirement to account for to account for the funding of working capital allowance revenue requirement on the basis of I-X indexing (line 12 of Table 1).[1] The change in Total Capital & Prepaid Cloud Related Revenue Requirement (including working capital and Productivity) (line 13 of Table 1) in 2029 versus 2028 is $273.9M (line 17 of Table 1). This difference is equal to 10.16% of the 2028 Total Revenue Requirement of $2,694.8M ($273.9M divided by $2,694.8M).

The 10.16% increase in Total Capital Related & Prepaid Cloud Revenue Requirement is the total increase in revenue requirement arising from the higher 2029 Capital Related & Prepaid Cloud Revenue Requirement (line 13 of Table 1). However, the 10.16% increase must be reduced by the increase in revenue requirement that results from the application of the Inflation, Growth and Productivity Factors (I – X + G) of the RCI applicable to capital. This is done by determining the percentage of the Total Capital Related & Prepaid Cloud

[1] This is consistent with the approach approved by the OEB in EB-2017-0049 and EB-2019-0082.

Revenue Requirement excluding working capital and Productivity (line 13 of Table 1) that is already provided for by the Inflation, Growth and Productivity Factors. In 2029, this equals 1.83% ($1,736.1M x 2.84% / $2,694.8M). The net result of 8.33% (10.16% less 1.83%) is the 2029 Custom C-factor. As noted in Exhibit A-04-01, Hydro One's productivity factors have been applied on a cumulative basis. The cumulative application of the X-factor and Supplemental Stretch results in a significant revenue requirement reduction for customers that grows each year beginning in 2029.

2.3 CUSTOM RCI SUMMARY

Table 2 below summarizes the Custom RCI by component that Hydro One is proposing to use to determine the total revenue requirement for rate-making purposes for 2029 to 2032.

Table 2 - Distribution Custom Revenue Cap Index (RCI) by Component (%)

RCI = I - X + G + IPDoma + C		**2029**	**2030**	**2031**	**2032**
Inflation Factor	I	1.96%	1.96%	1.96%	1.96%
Productivity Factor	X	0.29%	0.29%	0.29%	0.29%
Growth Factor	G	1.17%	1.17%	1.17%	1.17%
Input Price Differential (scaled to OM&A)	IPD_{oma}	0.09%	0.08%	0.08%	0.07%
Capital Factor*	C	8.33%	5.32%	1.56%	1.18%
Custom Revenue Cap Index	**RCI**	**11.26%**	**8.24%**	**4.48%**	**4.10%**

**Includes Supplemental Stretch on Capital*

As discussed in Exhibit A-04-01, for the purpose of applying IPD escalations only to OM&A within the total revenue requirement funding envelope, IPD values must be scaled to reflect the proportion of total revenue requirement allocated to OM&A. Table 3 below demonstrates the scaling of IPD to the OM&A portion of total revenue requirement based on prior year's figures, given the RCI will apply to prior year revenue requirement to yield current year revenue requirement. Hydro One proposes fixing IPD_{oma} values in this Application and does not propose updating these values in subsequent Annual Update applications.

Table 3 - Scaling Input Price Differential to OM&A - Distribution

		2029	2030	2031	2032
A	**Input Price Differential (IPD)**	**0.24%**	**0.24%**	**0.24%**	**0.24%**
B	Prior Year OM&A ($M)	958.7	988.2	1018.7	1061.4
C	Prior Year Total Revenue Requirement ($M)	2694.8	2998.2	3245.3	3401.9
D = B / C	OM&A as % of Total Revenue Requirement	36%	33%	31%	31%
E = A x D	**Input Price Differential scaled to OM&A (IPD_{oma})**	**0.09%**	**0.08%**	**0.08%**	**0.07%**

The Inflation Factor in Table 2 will be updated annually, as described in section 2 above. Hydro One proposes that the X-factor remain unchanged throughout the Custom IR term. The Total Capital Related & Prepaid Cloud Revenue Requirement in line 13 of Table 1 would remain unchanged in subsequent annual update applications, however the 2029 to 2032 C-factors would be updated, for the applicable year, to reflect the OEB's annual inflation factor, in subsequent annual update applications.

Table 4 below summarizes the Total Revenue Requirement that would result from the OEB's approval of Hydro One's Custom IR, as proposed.

Table 4 - Hydro One Distribution Revenue Requirement by Year

Year	Formula	Revenue Requirement ($M)
2028	Cost of Service	$2,694.8
2029	2028 Revenue Requirement x 1.1126	$2,998.2
2030	2029 Revenue Requirement x 1.0824	$3,245.3
2031	2030 Revenue Requirement x 1.0448	$3,401.9
2032	2031 Revenue Requirement x 1.0410	$3,541.4

3.0 PROPOSED FRAMEWORK FOR ANNUAL UPDATE APPLICATIONS

Hydro One expects to file annual update applications from 2029-2032. These applications will calculate the revenue requirement for Hydro One Distribution using the RCI to reflect the most up to date Inflation Factor. Hydro One Distribution will also dispose of Group 1 deferral accounts if appropriate and update Retail Transmission Service Rates.

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DISTRIBUTION ELECTRICITY SERVICE QUALITY REQUIREMENTS

1.0 INTRODUCTION

Hydro One Distribution monitors and reports on service quality indicators as required by the Ontario Energy Board's (OEB) Reporting and Record-keeping Requirements (RRR). The Electricity Service Quality Requirements (ESQRs) included in this Application are set out in Chapter 7 of the Distribution System Code (DSC). Hydro One tracks and internally reports results on ten customer service quality indicators monthly. Reports are provided to the OEB annually in accordance with the DSC.

Hydro One's customer service results and targets are reported for the past five historical years, 2021 to 2025, as required by the OEB in Section 2.2.2.8 of Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications. Over the historical period, Hydro One Distribution met or exceeded all of the OEB customer service indicator targets except Emergency Rural Response in 2021 and 2025 and Rescheduling a Missed Appointment in 2023.

2.0 CUSTOMER SERVICE INDICATORS

Hydro One consistently tracks, analyzes and reports ten customer service indicators monthly as part of its internal performance reporting process. This process identifies areas of concern so that Hydro One's performance can be immediately addressed and brought back in line with OEB requirements.

To ensure continuous improvement, analysis of monthly and annual result trends provides valuable insights that support corporate and program planning, as well as inform management of resources for services.

2.1 DEFINITION OF CUSTOMER SERVICE INDICATORS

The ten customer service indicators are defined below.

2.1.1 APPOINTMENTS

2.1.1.1 APPOINTMENT SCHEDULING

The percentage of appointment scheduling requests that are made within five business days of the day on which all applicable service conditions are satisfied or at a later date agreed upon by the customer and Hydro One. This applies regardless of whether the customer or customer representative's presence is required.

In instances where a customer or a customer representative is required, Hydro One must offer to schedule the appointment during Hydro One's regular hours of operation within a window of time no greater than four hours and must attend the meeting at the appropriate time. This does not apply to appointments that are subject to the requirements in the section on Connection of New Services.

The OEB Minimum Standard for this measure is 90%.

2.1.1.2 APPOINTMENTS MET

The percentage of appointments at a customer's premises or work site met at the appointed time of the customer's choosing (defined as morning or afternoon of a particular date). This indicator includes appointments for disconnects and/or reconnects for maintenance or upgrades, connecting new services, underground cable locates, inspections, meter reading and instructions on prepaid meters. The appointment may be considered to be met even when the customer failed to attend.

The OEB Minimum Standard for this measure is 90%.

2.1.1.3 RESCHEDULING A MISSED APPOINTMENT

In instances when appointments need to be rescheduled, this indicator measures the percentage of instances in which Hydro One has made: (i) an attempt to inform the customer before the scheduled appointment that the appointment is going to be missed; and (ii) an attempt to reschedule the appointment one business day following the initial appointment. This does not apply if the appointment is missed due to the failure of customer or customer representative to attend.

Section 7.5 of the DSC requires that, where an appointment is missed or is going to be missed, distributors must attempt to contact the customer: (a) before the scheduled appointment to inform the customer that the appointment will be missed; and (b) within one business day to reschedule the appointment.

The OEB Minimum Standard for this measure is 100%.

2.1.2 CONNECTION OF NEW SERVICES

2.1.2.1 LOW VOLTAGE CONNECTIONS

The percentage of requests for connection of a new low voltage service (<750 V) that are completed within five business days from the day on which all applicable service conditions are satisfied, or at a later date agreed upon by the customer and Hydro One.

The OEB Minimum Standard for this measure is 90%.

2.1.2.2 HIGH VOLTAGE CONNECTIONS

The percentage of requests for connection of a new high voltage service (≥750 V) that are completed within ten business days from the day on which all applicable service conditions are satisfied, or at a later date agreed upon by the customer and Hydro One. Hydro One does not separately report on this measure due to the complexity of gathering the data. The ≥750 V connections are included with the < 750 V connections which is a more stringent measure. All connections that are not met within five days are analysed to confirm that no connections ≥750 volts failed.

The OEB Minimum Standard for this measure is 90%.

2.1.2.3 EMERGENCY RURAL RESPONSE

The percentage of responses to emergency trouble calls (including fire, ambulance, police) met within 120 minutes for rural utilities. The elapsed time is measured from the call to the arrival of Hydro One qualified service personnel on site.

The OEB Minimum Standard for this measure is 80%.

2.1.3 TELEPHONE

2.1.3.1 TELEPHONE ACCESSIBILITY

The percentage of incoming calls answered by the customer care center within 30 seconds. Time begins the moment the customer chooses to speak to a customer service representative (using the interactive voice recognition system) or from first ring in all other cases.

The OEB Minimum Standard for this measure is 65%.

2.1.3.2 TELEPHONE CALL ABANDON RATE

The percentage of incoming calls abandoned before being answered following the 30 second period outlined in 2.1.4.1 Telephone Accessibility.

The OEB Standard for this measure is 10%.

2.1.4 WRITTEN RESPONSE TO ENQUIRIES

This indicator measures the percentage of responses to requests by a customer for written information relating to their accounts made within the performance standard of ten working days following receipt of the request or, if applicable, ten working days from the date on which any conditions associated with their enquiry have been satisfied. The written response is deemed to be sent on the date it is faxed, mailed or e-mailed by Hydro One,

and when it includes a written acknowledgement of receipt of the qualified enquiry and a specific date in which a complete response will be provided.

2.1.5 RECONNECTION PERFORMANCE STANDARD

The percentage of reconnections of a disconnected customer for non-payment that are completed within two business days after the customer has made full overdue payment or entered into an arrears payment agreement with Hydro One.

The OEB Minimum Standard for this measure is 85%.

3.0 RESULTS

The performance results of the ten Customer Service Performance Indicators from 2021 to 2025 are shown in Table 1 and in Exhibit A-05-03, Attachment 1. The required targets for each measure, as specified by the DSC, are also shown. Hydro One Distribution has met or exceeded all of these indicators with the exception of Emergency Rural Response in 2021 and 2025 and Rescheduling a Missed Appointment in 2023.

Table 1 - Customer Service Indicator

Indicator	OEB Minimum Standard	2021	2022	2023	2024	2025
Appointment Scheduling	90.00%	99.09%	99.99%	100.00%	100.00%	100.00%
Appointments Met[1]	90.00%	100.00%	99.99%	100.00%	100.00%	96.62%
Rescheduling a Missed Appointment	100.00%	100.00%	100.00%	99.01%	100.00%	100.00%
Low Voltage Connections[2]	90.00%	99.98%	99.86%	99.97%	99.94%	99.95%
High Voltage Connections*	90.00%	n/a	n/a	n/a	n/a	n/a
Emergency Rural Response**	80.00%	76.02%	81.85%	85.75%	86.67%	75.62%
Telephone Accessibility[3]	65.00%	70.41%	72.65%	78.24%	78.01%	66.67%
Telephone Call Abandon Rate***	10.00%	4.40%	4.06%	1.38%	1.32%	3.10%
Written Response to Enquires	80.00%	99.92%	97.86%	96.41%	95.50%	96.35%
Reconnection Performance Standard	85.00%	99.54%	99.26%	98.91%	98.67%	98.89%

**High Voltage Connections results are included with Low Voltage results.*
***Emergency Response results include the impact of Force Majeure events.*
****Telephone Call Abandon Rate OEB Minimum Standard of 10.0% should be interpreted as no more than 10.0% of calls.*

[1] Appointments Met is shown in DSP Section 3.5 as Scheduled Appointments Met On Time.
[2] Low Voltage Connections is shown in DSP Section 3.5 as New Residential/Small Business Services Connected on Time.
[3] Telephone Accessibility is show in DSP Section 3.5 as Telephone Calls Answered On Time.

4.0 OEB MINIMUM STANDARD EXCEPTIONS AND RESPONSE ACTIONS

4.1 EMERGENCY RURAL RESPONSE IN 2021 AND 2025

In 2021, Hydro One reported an Emergency Rural Response result of 76.02%, and in 2025 reported a result of 75.62%, against the OEB Minimum Standard of 80%. In 2021, the result was primarily driven by underperformance in the months of September and December, during which multiple severe weather events occurred, including three storms in September and two in December. Ongoing operational challenges associated with the COVID-19 pandemic also continued to affect field execution and response efforts. In 2025, this outcome was primarily driven by underperformance in the months of March and April primarily due to the Generational Ice Storm, and in July and December, during which multiple severe weather events occurred. These events materially impacted field response time and contributed to the overall decline in the annual result.

Hydro One continues to focus on its Distribution Automation and grid modernization initiatives to support reliability and emergency restoration performance. These efforts include the installation of additional Centralized Fault Current Indicators (CFCIs) and remote operable devices that enhance system visibility, improve fault detection, reduce patrol times, and enable faster fault isolation and remote sectionalization. These investments provide operators with greater system visibility and operational flexibility to support more efficient crew deployment, prioritization and field execution during both day-to-day outages and major weather events.

Hydro One has also undertaken several operational initiatives to strengthen storm response capabilities and improve restoration efforts, which are expected to benefit emergency response over time. These initiatives include technology implementation, in-person training and storm exercises, resource management using storm prediction tools, and process improvements. These initiatives support incident management, resource deployment and restoration coordination during weather events, helping to reduce restoration timelines and improve outcomes for customers.

4.2 RESCHEDULING A MISSED APPOINTMENT IN 2023

For 2023, Hydro One reported a result of 99.01% which did not meet the OEB Minimum Standard of 100.00%. Of the 203 appointments requiring rescheduling, 201 were successfully rescheduled prior to the original appointment time and within 24 hours, resulting in the reported outcome. The two instances of non-compliance were primarily attributable to gaps in communication between field staff and scheduling personnel. One instance was associated with a storm-related disruption, while the other was due to the unavailability of required equipment (meter). In response, Hydro One completed a process review and reinforced the importance of adhering to established coordination procedures, including the consistent use of the coordination task to ensure timely communication and scheduling alignment. These corrective actions mitigated recurrence and supported achievement of the OEB performance standard going forward.

HYDRO ONE – CHAPTER 2 APPENDIX 2-G – SERVICE RELIABILITY AND QUALITY INDICATORS

This attachment has been filed separately in MS Excel format.

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ACCOUNTING INFORMATION

1.0 ORGANIZATIONAL STRUCTURE

Hydro One Limited (Hydro One) was incorporated on August 31, 2015, under the *Business Corporations Act* (Ontario). On October 31, 2015, Hydro One Limited acquired all of the shares of Hydro One Inc., thus becoming its parent company. The principal businesses of Hydro One Inc. are the transmission and distribution of electricity to customers within Ontario. These businesses are primarily carried out through Hydro One Networks Inc. (Hydro One Networks, a wholly owned subsidiary of Hydro One Inc.), by its Transmission and Distribution business units.

2.0 ACCOUNTING STANDARD FOR HYDRO ONE NETWORKS

As a wholly-owned subsidiary of Hydro One Inc., the unconsolidated financial statements of Hydro One Networks are prepared and presented in accordance with the same generally accepted accounting principles (GAAP) as its parent company.

Historically, until December 31, 2010, Hydro One Inc. used legacy Canadian GAAP as its basis of accounting. Under Canadian GAAP, there was limited accounting guidance on rate regulated operations. In instances where Canadian GAAP did not have the relevant accounting guidance, the prevailing practice was to refer to United States (US) GAAP, Accounting Standards Update (ASU) 980 - Rate Regulated Operations.

In 2011, a requirement was introduced for Canadian companies to adopt International Financial Reporting Standards (IFRS). However, many Ontario utilities, including Hydro One Networks, were reluctant to adopt IFRS due to the inability to apply regulatory accounting, and because it was expected to result in significant impacts to ratepayers due to differences in the ability to capitalize overheads under IFRS and the need to incur additional costs (such as for modifications to be made to accounting systems). As a result, Hydro One Networks and other utilities approached regulators such as the Ontario Securities Commission (OSC) and the OEB for exemptions from the requirement to adopt

IFRS and permission to instead use US GAAP as their basis of accounting for public filings and for rate setting purposes.

3.0 BASIS OF ACCOUNTING

Hydro One Inc. filed an application with the OSC in 2011 seeking approval to utilize US GAAP as the basis for preparing its financial statements. On July 21, 2011, the OSC issued its decision granting exemptive relief to Hydro One Inc. to allow it to continue reporting its financial statements in accordance with US GAAP. This exemptive relief was to remain in effect until the earlier of: (i) January 1, 2015, and (ii) the date on which Hydro One Inc. ceases to have activities subject to rate regulation.

In connection with its initial public offering in August 2015, Hydro One Limited was also granted exemptive relief by the OSC, as principal securities regulator, on behalf of the securities regulators in each province and territory of Canada allowing Hydro One Limited to prepare its financial statements in accordance with US GAAP following its initial public offering. This exemptive relief was to remain in effect until the earlier of: (i) January 1, 2019, (ii) the first day of Hydro One Limited's financial year that commences after Hydro One Limited ceases to have activities subject to rate regulation; and (iii) the effective date prescribed by the International Accounting Standards Board (IASB) for the mandatory application of a standard within IFRS specific to entities with activities subject to rate regulation (Mandatory Rate-regulated Standard).

In March 2018, Hydro One Limited applied to extend its exemptive relief and was granted such relief by securities regulators in each province and territory of Canada, thereby allowing Hydro One Limited to continue preparing and reporting its financial statements in accordance with US GAAP for a period of time that aligned with the revised expected effective date of a Mandatory Rate-regulated Standard.

In October 2022, Hydro One Limited applied to further extend its exemptive relief and was granted such relief by securities regulators in each province and territory of Canada, thereby allowing Hydro One Limited to continue preparing and reporting its financial

statements in accordance with US GAAP. This exemptive relief was to remain in effect until the earlier of: (i) January 1, 2027; (ii) the first day of Hydro One Limited's financial year that commences after Hydro One Limited ceases to have rate-regulated activities; and (iii) the first day of Hydro One's financial year that commences on or following the later of: (A) the effective date prescribed by the IASB for the mandatory application of a Mandatory Rate-regulated Standard; and (B) two years after the IASB publishes the final version of a Mandatory Rate-regulated Standard.

On May 27, 2026, the IASB published the final version of a Mandatory Rate-regulated Standard, namely IFRS 20, *Regulatory Assets and Liabilities* (IFRS 20). The new standard is effective for periods beginning on or after January 1, 2029.

In August 2026, Hydro One Limited applied to further extend its exemptive relief and was granted such relief by securities regulators in each province and territory of Canada, thereby allowing Hydro One Limited to continue preparing and reporting its financial statements in accordance with US GAAP beyond January 1, 2027. This most recently granted exemptive relief will remain in effect until the earlier of: (i) if Hydro One Limited ceases to have rate-regulated activities, the first day of Hydro One Limited's financial year that commences after Hydro One Limited ceases to have rate-regulated activities; and (ii) January 1, 2031, being the first day of Hydro One Limited's financial year that commences on or following the fourth anniversary of the publication of IFRS 20, being the final version of the Mandatory Rate-regulated Standard

Irrespective of the exemptions noted above, Hydro One Limited and Hydro One Inc. are permitted to prepare and report their financial statements in accordance with US GAAP for securities law purposes by virtue of each of them being a US Securities and Exchange (SEC) issuer within the meaning of National Instrument 52-107 – *Acceptable Accounting Principles and Auditing Standards* (NI 52-107), and will continue to have such permission for as long as they remain an SEC issuer.

On November 23, 2018, Hydro One Holdings Limited (HOHL), an indirect wholly owned subsidiary of Hydro One Limited, filed a US debt short form base shelf prospectus with securities regulatory authorities in Canada and the US (the HOHL US Debt Shelf Prospectus), making Hydro One Limited an SEC issuer (within the meaning of NI 52-107), which enables it to have access to US debt markets. HOHL and Hydro One Limited most recently renewed the HOHL US Debt Shelf Prospectus on November 29, 2024, which allows HOHL to offer debt securities in the US market from time to time, in one or more public offerings, unconditionally guaranteed by Hydro One Limited. Management intends for Hydro One Limited to remain an SEC issuer within the meaning of NI 52-107 for the foreseeable future.

Hydro One Inc. completed a public offering of its Canadian dollar Medium-Term Note (MTN) debt securities in the US in 2013, in connection with which it has debt securities registered in the US and listed on the New York Stock Exchange (NYSE). As a result, Hydro One Inc. is also an SEC issuer (within the meaning of NI 52-107) and by virtue of that fact was permitted to report its financial statements in accordance with US GAAP for as long as it continued to have debt securities registered in the US and listed on the NYSE.

On August 18, 2025, Hydro One Inc. filed a short form base shelf prospectus (HOI US Debt Shelf Prospectus) with securities regulatory authorities in Canada and the US. The HOI US Debt Shelf Prospectus allows Hydro One Inc. to offer, from time to time in one or more public offerings, US debt securities, which also makes it an SEC issuer (within the meaning of NI 52-107), and by virtue of that fact may continue to report its financial statements in accordance with US GAAP. Management intends for Hydro One Inc. to remain an SEC issuer within the meaning of NI 52-107 for the foreseeable future.

On May 26, 2026, Hydro One Inc. issued US$1.0 billion aggregate principal amount of SEC-registered senior unsecured notes under the HOI US Debt Shelf Prospectus. Hydro One expects to access the US bond market on a consistent basis in the future, as further discussed in Exhibit F-01-02.

4.0 BASIS OF RATE SETTING

On November 23, 2011, the OEB issued its Decision with Reasons in EB-2011-0268, granting Hydro One Networks' request to use US GAAP as its accounting standard for regulatory purposes for the Transmission business commencing January 1, 2012. Similarly, on March 23, 2012, the OEB issued its Decision with Reasons in EB-2011-0399, granting the same relief to Hydro One Networks in respect of its Distribution business, with the same commencement date.

In several past rate proceedings, the OEB has considered Hydro One's continued use of US GAAP. In EB-2016-0160, the OEB indicated that it will consider whether it should initiate a generic policy review regarding whether it is appropriate to allow for the continued use of US GAAP for the purpose of determining the capitalization of overhead amounts.[1] In EB 2017-0049, the OEB stated that it expects to review Hydro One's approach to capitalization in its next Distribution application and that, in order to facilitate such review, Hydro One was expected to provide a report that compares its capitalization of common corporate costs with those of other utilities in Ontario, Canada and North America under US GAAP and IFRS.[2] In EB 2019-0082, the OEB stated that:

> Hydro One follows US GAAP for regulatory purposes and therefore follows a US GAAP based capitalization policy. Under US GAAP, Hydro One has the ability to capitalize more in the form of overhead costs than it otherwise would be permitted if it had been ordered to follow the OEB's Modified International Financial Reporting Standards (MIFRS) based capitalization policy, with a corresponding reduction in OM&A.[3]

Furthermore, in its Decision and Order in EB-2019-0082, the OEB stated that in respect of the continued use of US GAAP for regulatory purposes, the issue was to be addressed during EB-2021-0110 as part of the capitalization study previously requested in the Distribution decision. Additionally, the OEB indicated that Hydro One Networks was to

[1] EB-2016-0160, Decision and Order, September 28, 2017, Revised October 11, 2017, p. 81
[2] EB-2017-0049, Decision and Order, March 7, 2019, p. 82
[3] EB-2019-0082, Decision and Order, April 23, 2020, p. 93

provide the revenue requirement impact and risk analysis with the transition from US GAAP to MIFRS.[4]

In response to those prior directions leading up to the 2023-2027 Joint Rate Application (EB-2021-0110), Hydro One engaged PricewaterhouseCoopers LLP (PwC) to undertake two comprehensive studies and perform in-depth analysis for the EB-2021-0110 application regarding:

a) Hydro One's approach to overhead capitalization, benchmarking of overhead capitalization against Canadian and North American peer utilities, and assessing the differences with respect to overhead capitalization between US GAAP and IFRS (the PwC Capitalization Analysis); and
b) The risks, costs, timing and revenue requirement impacts of Hydro One transitioning from US GAAP to IFRS (the PwC IFRS Transition Analysis).

With respect to the PwC Capitalization Analysis, PwC concluded in EB-2021-0110 that Hydro One's proposed method for capitalizing common corporate costs was reasonable and consistent with the principle that any assignment of indirect costs to capital projects should be based on a reasonable causal link. Moreover, PwC concluded that Hydro One's approach to capitalizing common corporate costs was not inconsistent with the principles of US GAAP or applicable regulatory guidance. PwC's report, *Hydro One Capitalization of Common Corporate Costs Review* dated June 17, 2021 (2021 PwC Report on Capitalization of Common Corporate Costs) was filed and subject to review as part of the evidence filed in the EB-2021-0110 proceeding.

With respect to the PwC IFRS Transition Analysis, PwC's analysis in EB-2021-0110 concluded that, for Hydro One to transition to IFRS, the implementation costs would be significant and there would be ongoing maintenance costs incurred. The analysis also concluded that there may not be a significant difference in the overall recognition and measurement of common corporate costs or other costs, assuming that the OEB's views on the nature and types of costs allowed for Hydro One's recovery in revenue requirement

[4] Ibid, p. 95

remain consistent. PwC's report, *Hydro One US GAAP to IFRS Conversion Impact Review* dated June 17, 2021 (2021 PwC Report on IFRS Conversion) was provided as part of the evidence filed in the EB-2021-0110 proceeding.

5.0 APPROACH TO SETTLEMENT COMMITMENT FROM EB-2021-0110

The OEB-approved settlement proposal in EB-2021-0110 included agreement of the parties on Hydro One's continued use of US GAAP for regulatory reporting and rate-setting for the 2023-2027 period. In addition, the approved settlement proposal included the following settlement commitment to be addressed by Hydro One in the current Application:

> As described in section 5, Appendix 'A' of this Settlement Proposal, the Parties agree that:
>
> Subject to the accounting system limitations identified by Hydro One during the proceeding (A-Staff-13, A-Staff-14, A-Staff-15) and the issuance by the IASB of a final IFRS Standard applicable to rate regulated utilities, Hydro One will provide in its next cost-based rate application, on a best efforts basis and without prejudice to its submissions in future applications as to the most appropriate accounting standard to be applied to Hydro One for regulatory purposes, estimated impacts (directional, and ranges where reasonably practical) of an initial transition from USGAAP to IFRS for regulatory purposes as at the beginning of the next rate term, as well as estimated impacts on the annual revenue requirements for the remainder of the rate term. To the extent reasonably possible, the impacts will be broken down based on the areas of potential revenue requirement impacts identified in the PwC US GAAP to IFRS Conversion Impact Review Report (Exhibit A/Tab 6/Schedule 1/Attachment 1/p. 9). Hydro One will also, on a best efforts and without prejudice basis, quantify the incremental costs of transitioning and maintaining IFRS for regulatory purposes.[5]

For continuity in the analysis, Hydro One re-engaged PwC for the current Application to fulfill this settlement commitment.

[5] EB-2021-0110, Decision on Settlement Proposal and Order on Rates, Revenue Requirement and Charge Determinants (November 29, 2022), Schedule A, Settlement Proposal (October 24, 2022), Appendix A - Studies, Reports and Reporting, Item 5, p. 107 of 117.

As indicated above, the settlement commitment from EB-2021-0110 was expressly subject to issuance by the IASB of a final IFRS Standard applicable to rate regulated utilities. As noted earlier, the IASB delayed the issuance of a new standard to May 27, 2026, and previously indicated that the final standard was anticipated to significantly deviate from the exposure draft released in 2021. Therefore, prior to the issuance of the final standard at the end of May, the Company was limited in its ability to assess the estimated impacts of an initial transition from USGAAP to IFRS for regulatory, as well as the annual revenue requirements for the remainder of the rate term.

Following issuance of the final standard, PwC began its assessment based on the finalized requirements. Given the complexities involved, this is a large undertaking, and PwC's assessment could therefore not be completed in time for filing of this Application. It is Hydro One's intention to file PwC's report during the course of this proceeding once it becomes available.

6.0 PROPOSAL FOR CONTINUED USE OF US GAAP

Notwithstanding the analysis above, Hydro One has concluded, for the reasons set out below and in Appendix A to this exhibit, that the continued use of US GAAP remains in the best interests of both ratepayers and the Company.

While the primary benefit of transitioning to IFRS would be that it is a widely used global standard allowing for the possibility of benchmarking against a greater number of rate-regulated utilities in Ontario, this potential benefit would not be realized in Hydro One's circumstances. There are few, if any, Ontario utilities with a customer base, service territory size, and operating practices comparable to Hydro One. From an investor standpoint, comparable companies to Hydro One are predominantly located in the US and file their financial statements under US GAAP.

In the 2021 PwC Report on IFRS Conversion filed in the EB-2021-0110 rate proceeding, PwC confirmed Hydro One's assessment that the implementation costs of converting to IFRS would be significant. This conclusion was based on PwC's experience, as well as its

understanding of Hydro One's technically complex systems, processes, and multiple business units involved in a potential conversion. Additionally, PwC noted that there could be ongoing maintenance costs that would have to be added to revenue requirement in periods following the initial transition. Furthermore, PwC determined that even if Hydro One did transition to IFRS there was not expected to be a significant difference in the overall recognition and measurement of common corporate costs or other costs assuming that the OEB's views on the nature and types of costs allowed for Hydro One's recovery in revenue requirement remain consistent. In consideration of the PwC findings discussed above, Hydro One does not believe that a change in its accounting standard would itself be a reason for the OEB to change its views in this respect.

A change in its accounting standard for regulatory reporting would not be appropriate so long as Hydro One remains an SEC issuer, and particularly in light of the OEB's past decisions approving the use of US GAAP for Transmission since November 23, 2011 (EB-2011-0268) and for Distribution since March 23, 2012 (EB-2011-0399). In those decisions, the OEB found that there was a significant benefit to ratepayers for Hydro One to adopt US GAAP instead of IFRS for regulatory purposes, including avoidance of rate shock associated with additional OM&A costs previously capitalized, and avoided costs from maintaining two sets of books for financial and regulatory purposes.[6] Lastly, Hydro One Inc. remains subject to O. Reg 395/11 under the *Financial Administration Act* requiring it to use US GAAP for financial reporting purposes, and for long as it remains a SEC issuer, both of which apply notwithstanding the exemptive relief granted by OSC.[7]

Given Hydro One's proposal to remain on US GAAP, the only reason that it would transition to IFRS in the foreseeable future would be if it was required to do so by the OEB for regulatory purposes, contrary to its preference to remain on US GAAP. If Hydro One were forced to incur additional costs due to such a requirement being imposed on it, it is Hydro One's view that it would not be appropriate for the utility's shareholders to bear such additional costs. If the OEB was of the view that requiring Hydro One to adopt IFRS was

[6] EB-2021-0110, Interrogatory Response to Staff-14 a) i.
[7] EB-2021-0110, Interrogatory Response to A-Staff-13 b) and c)

in the interests of ratepayers, then it would be Hydro One's view that ratepayers should bear the corresponding costs.[8]

Hydro One therefore maintains its views that the benefits of continuing to use US GAAP for regulatory purposes ensure stability in customer rates, support intergenerational equity as the recovery of incurred costs is matched to the period over which customers benefit from them, and allow for continued benchmarking against historical performance.[9] This avoids the need to maintain two sets of books for external financial reporting and regulatory reporting purposes, which would require significant implementation costs and ongoing maintenance costs.

As indicated above, Hydro One plans to file a new PwC report on US GAAP to IFRS conversion impacts (2026 PwC Report on IFRS Conversion) to address its settlement commitment from EB-2021-0110 during the course of this proceeding, and commits to filing an update to this exhibit once that report is finalized. Please see Appendix A for further details on the conclusions made in PwC's 2021 Report on IFRS Conversion and background included in EB-2021-0110.

7.0 CHANGES TO ACCOUNTING POLICIES

In keeping with good corporate governance, Hydro One reviews and, if appropriate, revises its accounting policies and procedures from time to time. There have been no material changes to accounting policies since EB-2021-0110.

8.0 ACCOUNTING ORDERS

Certain regulatory accounts have been established by the OEB (or requested by Hydro One) subsequent to, and outside of its reviews of, Hydro One's Transmission and Distribution regulatory accounts in EB-2021-0110.

[8] EB-2021-0110, Interrogatory response to A-Staff-14 a) part i
[9] EB-2021-0110, Interrogatory Response to A-Staff-13 c)

Please refer to Exhibit G-01-01, Attachment 1, for details on the accounting orders and other regulatory accounts presented in this Application.

9.0 APPENDIX A

Below is a summary of conclusions from the 2021 PwC Report on IFRS Conversion filed in the EB-2021-0110 proceeding, along with a recap of the IFRS conversion and transition challenges noted by Hydro One in that proceeding.

2021 PwC Report on IFRS Conversion

In the 2021 PwC Report, PwC determined that for Hydro One to transition to IFRS, the implementation costs would be significant and there would be ongoing maintenance costs incurred, but there would not be a significant difference in the overall recognition and measurement of common corporate costs or other costs assuming that the OEB's views on the nature and types of costs allowed for Hydro One's recovery in revenue requirement remain consistent.[10]

In terms of capitalization of indirect overhead costs, the continued use of US GAAP (as articulated in the 2021 PWC Report on IFRS Conversion) explicitly states that Hydro One avoids the risk of rate shock associated with the conversion of rate base into OM&A.[11] This is consistent with the regulatory principles of matching costs with benefits, and establishing rates that provide for intergenerational equity. Specifically, US GAAP standards enable better matching of the costs of getting capital assets to their intended location and ready for their intended use with the benefits that customers receive from those assets as compared to IFRS, which would treat some of these costs as expenses. On the contrary, IFRS is a principles-based standard which entails significant judgement to be applied by preparers of the financial statements, thereby hindering comparability against other utilities. US GAAP standards are rules-based and, as such, they leave very little to the judgement of the preparer of financial information. This results in consistency

[10] EB-2021-0110, Exhibit A-06-01, Attachment 1, PwC, *Hydro One US GAAP to IFRS Conversion Impact Review*, pp. 6-11; Interrogatory Response to A-Staff-13 a)
[11] EB-2021-0110, PwC Report – US GAAP to IFRS: Conversion Impact Review, p. 19

among companies in their accounting treatments and outcomes for similar transactions. If there were any clarity required, Hydro One refers to the principles of US GAAP accounting for guidance.[12]

Conversion to IFRS would introduce challenges, risks, costs and complexity to Hydro One. As indicated in the 2021 PWC Report, the challenges include impacts for financial reporting, management reporting, regulatory reporting, capital planning processes, information systems, organizational changes and internal controls. There would be disruption to the organization in order to upgrade systems and processes to capture the data required to meet the requirements of IFRS on transition and on an ongoing basis. Historical data for certain areas, primarily related to capital assets, may not exist and processes may need to be redesigned to capture the additional information required.[13] A comprehensive list of work streams and key activities that would have to be executed in order for Hydro One to convert from US GAAP to IFRS is detailed in the 2021 PwC Report on IFRS Conversion.[14]

On transition to IFRS, historical capitalized charges would be expected to remain within capital assets. Based on information available at that point in time, it was estimated that there would be material common corporate costs that would be recorded as expenses subject to OEB approval.[15] Notwithstanding that finding, PwC further determined that, if certain accounting processes are amended and updated, specific components of those common corporate costs may ultimately meet the criteria under IFRS for being directly charged to specific capital projects, thereby reducing the impact to revenue requirement. PwC determined that if the OEB maintains the same ratemaking framework and guidance described in the 2007 Handbook, agnostic to the accounting framework, PwC would not expect a significant impact, if any, to future revenue requirements in respect of Common Corporate Costs at Hydro One. As such, despite the significant implementation

[12] EB-2021-0110, Interrogatory Response to A-Staff-14
[13] EB-2021-0110, PwC Report – US GAAP to IFRS: Conversion Impact Review, p. 14
[14] EB-2021-0110, PwC Report – US GAAP to IFRS: Conversion Impact Review, pp. 14 and 15
[15] Once the final standard is issued, PWC will proceed with quantifying the impacts to Hydro One. The updated report will be filed during this proceeding

challenges, risks and costs, and a risk of having to record a significant amount of costs as OM&A rather than as capital upon transition, ultimately PwC found that there may not be a significant difference in the overall recognition and measurement of common corporate costs or other costs assuming that the OEB's views on the nature and types of costs allowed for Hydro One's recovery in revenue requirement remain consistent.[16]

[16] EB-2021-0110, PwC Report – US GAAP to IFRS: Conversion Impact Review, pp. 6 and 11

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HYDRO ONE US GAAP TO IFRS CONVERSION IMPACT REVIEW

(Placeholder for Report)

As discussed in Exhibit A-06-01, Section 5.0, Hydro One has engaged PricewaterhouseCoopers LLP (PwC) to assess the impacts of an initial transition from USGAAP to IFRS. Hydro One intends to file PwC's report during the course of this proceeding once it becomes available.

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HYDRO ONE TRANSMISSION AND DISTRIBUTION FINANCIAL STATEMENTS – HISTORICAL YEARS

This exhibit includes the following historical Financial Statements:

Hydro One Transmission

- Attachment 1: 2023 and 2024 Audited Transmission Financial Statements
- Attachment 2: 2024 and 2025 Audited Transmission Financial Statements

Hydro One Sault Ste. Marie LP (HOSSM)

- Attachment 3: 2023 and 2024 Audited HOSSM Financial Statements
- Attachment 4: 2024 and 2025 Audited HOSSM Financial Statements

Hydro One Distribution

- Attachment 5: 2023 and 2024 Audited Distribution Financial Statements
- Attachment 6: 2024 and 2025 Audited Distribution Financial Statements

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HYDRO ONE NETWORKS INC.

TRANSMISSION BUSINESS

FINANCIAL STATEMENTS

DECEMBER 31, 2024

KPMG LLP
Bay Adelaide Centre
333 Bay Street, Suite 4600
Toronto, ONM 5H 2S5
Canada
Tel 416-777-8500
Fax 416-777-8818

INDEPENDENT AUDITOR'S REPORT

To the Directors of Hydro One Networks Inc.

Opinion

We have audited the financial statements of the Transmission Business (a business of Hydro One Networks Inc.) (the "Entity"), which comprise:

- the carve-out balance sheet as at December 31, 2024;
- the carve-out statement of operations and comprehensive income for the year then ended;
- the carve-out statement of cash flows for the year then ended;
- and notes to the carve-out financial statements, including a summary of significant accounting policies (Hereinafter referred to as the "financial statements").

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements as at and for the year ended December 31, 2024 of the Entity are prepared, in all material respects, in accordance with the financial reporting framework described in Note 2 of these financial statements.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the **"Auditors' Responsibilities for the Audit of the Financial Statements"** section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Emphasis of Matter — Financial Reporting Framework

We draw attention to Note 2 in the financial statements, which describes the applicable financial reporting framework and the purpose of the financial statements.

As a result, the financial statements may not be suitable for another purpose.

Our opinion is not modified in respect of this matter.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation of the financial statements in accordance with the financial reporting framework described in Note 2 in the financial statements; this includes determining that the applicable financial reporting framework is an acceptable basis for the preparation of the financial statements in the circumstances, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
April 23, 2025

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2024 and 2023

Year ended December 31 *(millions of Canadian dollars)*	**2024**	**2023**
Revenues		
Transmission tariff (includes $2,162 million related party revenues; 2023 - $2,107 million) *(Note 23)*	2,145	2,090
Other (includes $83 million related party revenues; 2023 - $57 million) *(Note 23)*	113	92
	2,258	2,182
Costs		
Operation, maintenance and administration *(Note 23)*	560	555
Depreciation, amortization and asset removal costs *(Note 4)*	534	509
	1,094	1,064
Income before financing charges and income tax expense	**1,164**	**1,118**
Financing charges (includes $418 million related party charges; 2023 - $378 million) *(Notes 5, 23)*	373	344
Income before income tax expense	**791**	**774**
Income tax expense *(Note 6)*	97	119
Net income	**694**	**655**
Other comprehensive loss	(1)	(5)
Comprehensive income	**693**	**650**

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
BALANCE SHEETS
As at December 31, 2024 and 2023

As at December 31 *(millions of Canadian dollars)*	**2024**	**2023**
Assets		
Current assets:		
Accounts receivable	71	86
Due from related parties *(Note 23)*	187	162
Other current assets *(Note 7)*	76	46
	334	294
Property, plant and equipment *(Note 8)*	17,095	15,993
Other long-term assets:		
Regulatory assets *(Note 10)*	2,153	2,011
Intangible assets *(Note 9)*	294	276
Other assets *(Note 11)*	42	36
	2,489	2,323
Total assets	**19,918**	**18,610**
Liabilities		
Current liabilities:		
Inter-company demand facility *(Note 23)*	7	462
Long-term debt payable within one year *(Notes 14, 15, 23)*	660	413
Accounts payable and other current liabilities *(Note 12)*	913	552
	1,580	1,427
Long-term liabilities:		
Long-term debt *(Notes 14, 15, 23)*	9,237	8,344
Deferred income tax liabilities *(Note 6)*	2,038	1,899
Regulatory liabilities *(Note 10)*	364	306
Other long-term liabilities *(Note 13)*	718	702
	12,357	11,251
Total liabilities	**13,937**	**12,678**
Contingencies and Commitments *(Notes 25, 26)*		
Subsequent Events *(Note 27)*		
Excess of assets over liabilities *(Notes 16, 21)*	5,981	5,932
Total liabilities and excess of assets over liabilities	**19,918**	**18,610**

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:

Stacey Mowbray
Chair, Audit Committee

David Lebeter
Director

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
STATEMENTS OF CASH FLOWS
For the years ended December 31, 2024 and 2023

Year ended December 31 *(millions of Canadian dollars)*	**2024**	**2023**
Operating activities		
Net income	694	655
Environmental expenditures	(4)	(7)
Adjustments for:		
Depreciation and amortization *(Note 4)*	477	451
Regulatory assets and liabilities	62	(4)
Deferred income tax expense	(18)	32
Other	4	3
Changes in non-cash balances related to operations *(Note 24)*	313	36
Net cash from operating activities	**1,528**	**1,166**
Financing activities		
Long-term debt issued	1,559	1,364
Long-term debt repaid	(413)	(372)
Payments to finance dividends	(441)	(368)
Other	(7)	(3)
Net cash from financing activities	**698**	**621**
Investing activities		
Capital expenditures *(Note 24)*		
Property, plant and equipment	(1,608)	(1,401)
Intangible assets	(38)	(44)
Additions of future use assets	(127)	(55)
Capital contributions received *(Note 24)*	2	5
Other	—	(3)
Net cash used in investing activities	**(1,771)**	**(1,498)**
Net change in inter-company demand facility	455	289
Inter-company demand facility, beginning of year	(462)	(751)
Inter-company demand facility, end of year	**(7)**	**(462)**

See accompanying notes to Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Networks Inc. (Hydro One Networks or the Company) was incorporated on March 4, 1999 under the *Business Corporations Act* (Ontario) and is a wholly owned subsidiary of Hydro One Inc. (Hydro One). The Company owns and operates regulated transmission and distribution businesses. The Company's regulated transmission business (Transmission Business) operates a high-voltage electrical transmission network that represents substantially all of the licensed transmission capacity in Ontario. The Transmission Business is regulated by the Ontario Energy Board (OEB).

Rate Setting

On August 5, 2021 Hydro One Networks filed a custom joint rate application (JRAP) for distribution and transmission revenue requirements for the 2023 to 2027 period. On November 29, 2022, the OEB issued a Decision and Order (JRAP Decision) approving Hydro One Networks' transmission revenue requirement of $1,952 million for 2023, $2,073 million for 2024, $2,168 million for 2025, $2,277 million for 2026 and $2,362 million for 2027. Revenue requirements presented for 2024 to 2027 do not reflect the actual or expected updates resulting from the annual application process with the regulator to reflect OEB inflation factors.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

These Financial Statements are prepared and presented in accordance with the accounting policies summarized below and in Canadian dollars. These policies are consistent with United States (U.S.) generally accepted accounting principles (GAAP).

The purpose of these Financial Statements is to meet Hydro One Networks' obligation to the OEB. As a result, these Financial Statements may not be suitable for another purpose. Consolidated financial statements of Hydro One for the year ended December 31, 2024 have been prepared and are publicly available.

Basis of Preparation

These Financial Statements have been prepared on a carve-out basis to provide the financial position, results of operations and cash flows of the Transmission Business. The Financial Statements are considered by management to be a reasonable representation, prepared on a rational, systematic and consistent basis, of the financial results of the Transmission Business. As a result of this basis of preparation, these Financial Statements may not necessarily be identical to the financial position and results of operations that would have resulted had the Transmission Business historically operated on a stand-alone basis.

The Financial Statements have been constructed primarily through specific identification of assets, liabilities (other than debt), revenues and expenses that relate to the Transmission Business. The Company's long-term debt is allocated based on the respective borrowing requirements of the Company's transmission and distribution businesses. A portion of the Company's shared functions and services costs is allocated to the Transmission Business on a fully allocated-cost basis, consistent with OEB-approved independent studies. Income tax expense has been recorded at effective rates based on income taxes as reported in the statements of operations and comprehensive income as though the Transmission Business was a separate taxpaying entity. These Financial Statements include deferred income taxes and related regulatory balances with respect to the rate-setting treatment of the benefits of the deferred income tax asset resulting from transition from the payments in lieu of tax regime under the *Electricity Act, 1998* (Ontario) to income tax payments under the federal and provincial tax regime which occurred when Hydro One Limited became a public company listed on the Toronto Stock Exchange. Certain other amounts presented in these Financial Statements represent allocations subject to review and approval by the OEB.

Hydro One Networks performed an evaluation of subsequent events through to April 23, 2025, the date these Financial Statements were available to be issued, to determine whether any events or transactions warranted recognition and disclosure in these Financial Statements. See Note 27 – Subsequent Events.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets, regulatory liabilities, post-retirement and post-employment benefits. Actual results may differ significantly from these estimates.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting in accordance with Financial Accounting Standards Board

(FASB) Accounting Standard Codification Topic 980, Regulated Operations within the Transmission Business, giving rise to the recognition of regulatory assets and liabilities. The Transmission Business' regulatory assets represent certain amounts receivable from electricity customers in a future period and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Transmission Business has recorded regulatory liabilities that generally represent amounts that are refundable to electricity customers in future rates. The Transmission Business continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will include its regulatory assets and regulatory liabilities in setting future rates. If, at some future date, the Transmission Business judges that it is no longer probable that the OEB will include a regulatory asset or regulatory liability in setting future rates, the respective carrying amount would be reflected in results of operations, prospectively from the date the Transmission Business' assessment is made.

Revenue Recognition

Transmission revenues predominantly consist of transmission tariffs, which are collected through OEB-approved uniform transmission rates (UTRs) which are applied against the monthly peak demand for electricity across Hydro One's high-voltage network. OEB-approved UTRs are based on an approved revenue requirement that includes a rate of return. The transmission tariffs are designed to recover revenues necessary to support the Company's transmission system with sufficient capacity to accommodate the maximum expected demand which is influenced by weather and economic conditions. Transmission revenues are recognized as electricity is transmitted and delivered to customers.

Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered. Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Trade accounts receivable represent earned revenue for electricity transmitted and delivered to customers and receivable from the Independent Electricity System Operator (IESO). Trade accounts receivable are recorded at the amount reported by the IESO. No allowance for doubtful accounts is recognized with respect to trade accounts receivable as there is no risk of loss associated with such amounts.

For other accounts receivables, the Transmission Business estimates the current lifetime expected credit losses (CECL) by applying internally developed loss rates to all outstanding receivable balances by aging category on an undiscounted basis. Loss rates applied to the other accounts receivable balances are based on historical overdue balances, customer payments and write-offs, which may be further supplemented from time to time to reflect management's best estimate of the loss. Other accounts receivables are written-off against the allowance when they are deemed uncollectible. The allowance for doubtful accounts is affected by changes in volume, prices and economic conditions.

Income Taxes

Income taxes are accounted for using the asset and liability method. Current income tax assets and current income tax liabilities are recognized based on the income taxes refundable or payable on the current and prior year's taxable income. Current and deferred income taxes are computed based on the tax rates and tax laws enacted as at the balance sheet date. Tax benefits associated with income tax positions are recorded only when the more-likely-than-not recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Financial Statements. Management re-evaluates tax positions each period using new information about recognition or measurement as it becomes available.

Deferred Income Taxes

Deferred income tax assets and deferred income tax liabilities are recognized on all temporary differences between the tax bases and carrying amounts of assets and liabilities, including the carryforward of unused tax credits and tax losses to the extent that it is more-likely-than-not that these deductions, credits, and losses can be utilized. Deferred income tax assets and deferred income tax liabilities are measured at the tax rates that are expected to apply in the period when the asset is realized or the liability is settled, based on the tax rates and tax laws that have been enacted as at the balance sheet date.

Deferred income taxes associated with the Transmission business' regulated operations which are considered to be more-likely-than-not to be recovered or refunded in future regulated rates charged to customers are recognized as deferred income tax regulatory assets and deferred income tax regulatory liabilities with an offset to deferred income tax expense.

Investment tax credits are recorded as a reduction of the related expenses or income tax expense in the current or future period to the extent it is more likely than not that the credits can be utilized.

Management reassesses the deferred income tax assets at each balance sheet date and reduces the amount to the extent that it is more likely than not that the deferred income tax asset will not be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more likely than not that the tax benefit will be realized.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, and implicitly, by the regulated businesses of its subsidiaries. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Transmission Business to and from the pooled bank accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.15%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions, and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the balance sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, and information technology. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis.

Property, plant and equipment in service consists of transmission, administration and service, and other communication assets as well as land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, as well as capitalized project development costs associated with deferred capital projects.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, as well as assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, including transformers, circuit breakers and switches.

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.

Other

Communication assets include fibre optic and microwave radio systems, optical ground wire, towers, telephone equipment and associated buildings. Other assets also include easements which include a statutory easement for the use of transmission corridor and related abutting lands pursuant to Part IX.1 of the *Electricity Act, 1998* (Ontario) (Electricity Act), as well as other land rights for occupation.

Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost, which comprises purchased software, direct labour (including employee benefits), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Transmission Business' intangible assets primarily represent major computer applications.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized financing costs are a reduction of financing charges recognized in the statements of operations and comprehensive income. Capitalized financing costs are calculated using the Transmission Business' weighted average effective cost of debt.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation and Amortization

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and amortization rates, as required by the OEB. Any changes arising from such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The most recent review resulted in changes to rates effective January 1, 2023 for the Transmission Business. A summary of average service lives and depreciation and amortization rates as at December 31, 2024 for the various classes of assets is included below:

	Average Service Life	Rate Range	Rate Average
Property, plant and equipment:			
Transmission	57 years	1% - 2%	2 %
Communication	17 years	1% - 11%	5 %
Administration and service	26 years	1% - 20%	4 %
Intangible assets	12 years	8% - 10%	6 %

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation, with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, the Company evaluates whether impairment may exist by estimating future undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

The carrying costs of most of the Transmission Business' long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable.

Management assesses the fair value of such long-lived assets using commonly accepted techniques. Techniques used to determine fair value include, but are not limited to, the use of recent third-party comparable sales for reference and internally developed discounted cash flow analysis. Significant changes in market conditions, changes to the condition of an asset, or a change in management's intent to utilize the asset are generally viewed by management as triggering events to reassess the cash flows related to these long-lived assets. As at December 31, 2024 and 2023, no asset impairment had been recorded.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Transmission Business defers its proportionate share of the relevant Hydro One external transaction costs related to obtaining financing and presents such amounts net of related debt on the balance sheets. Deferred issuance costs are amortized over the contractual life of the related debt on an effective-interest basis and the amortization is included within financing charges in the statements of operations and comprehensive income. Transaction costs for items classified as held-for-trading are expensed immediately.

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Transmission Business considers the carrying amounts of accounts receivable and amounts due from related parties to be reasonable estimates of fair value because of the short time to maturity of these instruments. All financial instrument transactions are recorded at trade date.

The Transmission Business determines the classification of its financial assets and liabilities at the date of initial recognition. The Transmission Business designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with

the Transmission Business' risk management policy disclosed in Note 15 - Fair Value of Financial Instruments and Risk Management.

Derivative Instruments and Hedge Accounting

Hydro One closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedging relationships. Hydro One's derivative instruments, or portions thereof, are mirrored down to Hydro One Networks, and are allocated between the Company's transmission and distribution businesses. The derivative instruments are classified as fair value hedges or undesignated contracts, consistent with Hydro One's derivative instruments classification.

The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value on the balance sheets. For derivative instruments that qualify for hedge accounting, Hydro One may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. Hydro One offsets fair value amounts recognized on its balance sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, any unrealized gain or loss, net of tax, is recorded as a component of accumulated OCI (AOCI) or accumulated OCL (AOCL). Amounts in AOCI or AOCL are reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations and presented in the same line item as the earnings effect of the hedged item. Any gains or losses on the derivative instrument that represent hedge components excluded from the assessment of effectiveness are recognized in the same line item of the statements of operations as the hedged item. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the statements of operations and comprehensive income (loss) in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the statements of operations and comprehensive income (loss). The changes in fair value of the undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and are carried at fair value on the balance sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. Hydro One does not engage in derivative trading or speculative activities and had no embedded derivatives that required bifurcation as at December 31, 2024 or 2023.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where the Company has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. Hydro One also assesses, both at the inception of the hedge and on a quarterly basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of Hydro One's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

Hydro One recognizes the funded status of its defined benefit pension plan (Pension Plan) and its post-retirement and post-employment plans on its consolidated balance sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Defined benefit pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation (PBO) exceeds the fair value of the plan assets. Liabilities are recognized on the consolidated balance sheets for any net underfunded PBO. The net underfunded PBO may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the PBO of the plan, an asset is recognized equal to the net overfunded PBO. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Hydro One recognizes its contributions to the defined contribution pension plan (DC Plan) as pension expense, with a portion being capitalized as part of labour costs included in capital expenditures. The expensed amount is included in operation, maintenance and administration (OM&A) costs in the consolidated statements of operations and comprehensive income.

Defined Benefit Pension

Hydro One has a contributory defined benefit pension plan covering most regular employees of Hydro One and its subsidiaries, including Hydro One Networks. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the pension plan is accounted for as a defined contribution plan and no pension benefit asset or liability is recorded.

Post-retirement and Post-employment Benefits

Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Networks. The benefit obligations of these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Networks. Accordingly, for purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are reflective of earnings allocations of relevant employees to the Company's Transmission Business.

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. For post-retirement benefits, past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or actuarial losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active employees in the plan or over the remaining life expectancy of inactive employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory account, to the extent of the remeasurement adjustment.

The actuarial gains and actuarial losses on post-employment obligations that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory account, to the extent of the remeasurement adjustment.

All post-retirement and post-employment benefit costs are attributed to labour costs and are either charged to results of operations (OM&A costs) or capitalized as part of the cost of property, plant and equipment and intangible assets (applies to the service cost component of benefit cost) and to regulatory assets for all other components of the benefit cost, consistent with their inclusion in OEB-approved rates.

Stock-Based Compensation

Share Grant Plans

The Company measures share grant plans based on fair value of share grants as estimated based on Hydro One Limited's grant date common share price. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. The Company records a regulatory asset equal to the accrued costs of share grant plans recognized in each period. Costs are transferred from the regulatory asset to labour costs at the time the share grants vest and are recovered in rates. Forfeitures are recognized as they occur.

Deferred Share Unit (DSU) Plans

The Company records the liabilities associated with its Directors' and Management DSU Plans at fair value at each reporting date until settlement, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the DSU liability is based on Hydro One Limited's common share closing price at the end of each reporting period.

Society of United Professionals (Society) Restricted Share Unit (RSU) Plan

The Company measures its Society RSU plan based on fair value of share grants as estimated based on Hydro One Limited's grant date common share price. The costs are recognized over the vesting period using the straight-line attribution method. The Company records a regulatory asset equal to the accrued costs of the Society RSU plan recognized in each period. Costs are transferred from the regulatory asset to labour costs at the time the share grants vest and are issued, and are recovered in rates. Forfeitures are recognized as they occur.

Long-term Incentive Plan (LTIP)

The Company measures the awards issued under Hydro One Limited's LTIP, at fair value based on Hydro One Limited grant date common share price. The related compensation expense is recognized over the vesting period on a straight-line basis. Forfeitures are recognized as they occur.

Loss Contingencies

Hydro One and its subsidiaries are involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of the Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Transmission Business records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Transmission Business.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. The Company records a liability for the estimated future expenditures associated with contaminated land assessment and remediation (LAR) and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate that produces an amount at which the environmental liabilities could be settled in an arm's length transaction with a third party. The Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the anticipated amount of future recovery of these environmental expenditures from customers. Hydro One reviews its estimates of future environmental expenditures annually, or more frequently if there are indications that circumstances have changed. Estimate changes are accounted for prospectively.

Asset Retirement Obligations

Asset retirement obligations are recorded for legal obligations associated with the future removal and disposal of long-lived assets. Such obligations may result from the acquisition, construction, development and/or normal use of the asset. Conditional asset retirement obligations are recorded when there is a legal obligation to perform a future asset retirement activity but where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. In such a case, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. This uncertainty is incorporated in the fair value measurement of the obligation.

When recording an asset retirement obligation, the present value of the estimated future expenditures required to complete the asset retirement activity is recorded in the period in which the obligation is incurred, if a reasonable estimate can be made. In general, the present value of the estimated future expenditures is added to the carrying amount of the associated asset and the resulting asset retirement cost is depreciated over the estimated useful life of the asset. The present value is determined with a discount rate that equates to the Company's credit-adjusted risk-free rate. Where an asset is no longer in service when an asset retirement obligation is recorded, the asset retirement cost is recorded in results of operations.

Leases

At the commencement date of a lease, the minimum lease payments are discounted and recognized as a lease obligation. Discount rates used correspond to the Company's incremental borrowing rates. Renewal options are assessed for their likelihood of being exercised and are included in the measurement of the lease obligation when it is reasonably certain they will be exercised. The Company does not recognize leases with a term of less than 12 months. A corresponding Right-of-Use (ROU) asset is recognized at the commencement date of a lease. The ROU asset is measured as the lease obligation adjusted for any lease payments made and/or any lease incentives and initial direct costs incurred. ROU assets are included in other long-term assets, and corresponding lease obligations are included in other current liabilities and other long-term liabilities on the balance sheets.

Subsequent to the commencement date, the lease expense recognized at each reporting period is the total remaining lease payments over the remaining lease term. Lease obligations are measured as the present value of the remaining unpaid lease

payments using the discount rate established at commencement date. The amortization of the ROU assets is calculated as the difference between the lease expense and the accretion of interest, which is calculated using the effective interest method. Lease modifications and impairments are assessed at each reporting period to assess the need for a remeasurement of the lease obligations or ROU assets.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standard Updates (ASUs) issued by the FASB that are applicable to Hydro One Networks:

Recently Adopted Accounting Guidance

Guidance	Date issued	Description	Effective date	Impact on Transmission Business
ASU 2023-07	November 2023	The amendments improve the disclosures about a public entity's reportable segments and address requests from investors for additional, more detailed information about a reportable segment's expenses	Fiscal years beginning after December 15, 2023, and interim periods within fiscal years beginning after December 15, 2024.	No impact upon adoption

Recently Issued Accounting Guidance Not Yet Adopted

Guidance	Date issued	Description	Effective date	Anticipated Impact on Transmission Business
ASU 2023-06	October 2023	The amendments represent changes to clarify or improve disclosure or presentation requirements of a variety of subtopics in the FASB Accounting Standards Codification (Codification). Many of the amendments allow users to more easily compare entities subject to the US Securities and Exchange's (SEC) existing disclosures with those entities that were not previously subject to the SEC's requirements. Also, the amendments align the requirements in the Codification with the SEC's regulations. Applicable to all entities, if by June 30, 2027 the SEC has not removed the applicable requirement from Regulation S-X or Regulation S-K, the pending content of the related amendment will be removed from the Codification and will not become effective for any entity.	Two years subsequent to the date on which the SEC's removal of that related disclosure becomes effective	Under assessment
ASU 2023-09	December 2023	The amendments address investor requests for more transparency about income tax information through improvements to income tax disclosures primarily related to the rate reconciliation and income taxes paid information.	Annual periods beginning after December 15, 2024.	Under assessment
ASU 2024-02	March 2024	The amendments contain modifications to the codification that remove various concept statements which may be extraneous and not required to understand or apply the guidance or references used in prior statements to provide guidance in certain topical areas.	Fiscal years beginning after December 15, 2024.	No impact upon adoption
ASU 2024-03	November 2024	The amendments require public business entities to disclose additional information about specific expense categories in the notes to financial statements at interim and annual reporting periods, which are not generally presented in the current financial statements.	Annual periods beginning after December 15, 2026, and interim periods beginning after December 15, 2027.	Under assessment

4. DEPRECIATION, AMORTIZATION AND ASSET REMOVAL COSTS

Year ended December 31 *(millions of dollars)*	2024	2023
Depreciation of property, plant and equipment	445	420
Amortization of intangible assets	28	24
Amortization of regulatory assets	4	7
Depreciation and amortization	477	451
Asset removal costs	57	58
	534	509

5. FINANCING CHARGES

Year ended December 31 *(millions of dollars)*	2024	2023
Interest on long-term debt *(Note 23)*	410	348
Interest on inter-company demand facility *(Note 23)*	8	30
Interest on regulatory accounts	13	10
Other	12	12
Less: Interest capitalized on construction and development in progress	(70)	(56)
	373	344

6. INCOME TAXES

As a rate regulated utility business, the Transmission Business recovers income taxes from its ratepayers based on estimated current income tax expense in respect of its regulated operations. The amounts of deferred income taxes related to regulated operations which are considered to be more likely-than-not to be recoverable from, or refunded to, ratepayers in future periods are recognized as deferred income tax regulatory assets or deferred income tax regulatory liabilities, with an offset to deferred income tax recovery or deferred income tax expense, respectively. The Transmission Business' income tax expense or income tax recovery for the period includes all current and deferred income tax expenses for the period net of the regulated accounting offset to deferred income tax expense arising from temporary differences to be recoverable from, or refunded to, customers in future rates. Thus, the Transmission Business' income tax expense or income tax recovery differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate.

The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 *(millions of dollars)*	2024	2023
Income before income tax expense	791	774
Income tax expense at statutory rate of 26.5% (2023 - 26.5%)	210	205
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(58)	(78)
Impact of deferred tax asset (DTA) Implementation Decision[1]	—	30
Interest capitalized for accounting but deducted for tax purposes	(18)	(15)
Overheads capitalized for accounting but deducted for tax purposes	(27)	(22)
Pension and post-retirement benefit contributions in excess of expense	(8)	—
Environmental expenditures	(1)	(2)
Other	(3)	(1)
Net temporary differences attributable to regulated business	(115)	(88)
Net permanent differences	2	2
Total income tax expense	97	119
Effective income tax rate	12.3 %	15.4 %

[1] On April 8, 2021, the OEB rendered its DTA Implementation Decision, approving the recovery of the DTA amounts allocated to ratepayers and included in customer rates for the 2017 to 2021 period, plus carrying charges, over a two-year recovery period from July 1, 2021 to June 30, 2023. Pursuant to the DTA Implementation Decision, the impact represents the amounts recovered from ratepayers in respect of tax deductions previously shared with the ratepayers.

The major components of income tax expense and income tax recovery are as follows:

Year ended December 31 *(millions of dollars)*	2024	2023
Current income tax expense	114	87
Deferred income tax (recovery) expense	(17)	32
Total income tax expense	97	119

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and deferred income tax liabilities reflect the future income tax consequences attributable to temporary differences between the tax bases and the financial statement carrying amounts of the assets and liabilities including the carry forward amounts of tax losses and tax credits. Deferred income tax assets and deferred income tax liabilities attributable to the Transmission Business' regulated operations are recognized with a corresponding offset in deferred income tax regulatory assets and deferred income tax liabilities to reflect the anticipated recovery or repayment of these balances in the future electricity rates. As at December 31, 2024 and 2023, deferred income tax assets and deferred income tax liabilities consisted of the following:

As at December 31 *(millions of dollars)*	2024	2023
Deferred income tax assets (liabilities)		
Capital cost allowance in excess of depreciation and amortization	(2,398)	(2,232)
Post-retirement and post-employment benefits expense in excess of cash payments	249	241
Regulatory assets and liabilities	104	88
Environmental expenditures	1	4
Non-capital losses	6	6
Non-depreciable capital property	4	3
Other	—	(6)
	(2,034)	(1,896)
Less: valuation allowance	(4)	(3)
Net deferred income tax liabilities[1]	(2,038)	(1,899)

[1] The net deferred income tax liabilities are presented on the balance sheets as long-term.

7. OTHER CURRENT ASSETS

As at December 31 *(millions of dollars)*	2024	2023
Prepaid expenses and other assets	38	20
Regulatory assets *(Note 10)*	21	8
Materials and supplies	17	18
	76	46

8. PROPERTY, PLANT AND EQUIPMENT

As at December 31, 2024 *(millions of dollars)*	Property, Plant and Equipment[1]	Accumulated Depreciation	Construction in Progress	Total
Transmission	21,260	6,962	1,531	15,829
Administration and service	935	380	48	603
Other	1,733	1,102	32	663
	23,928	8,444	1,611	17,095

[1] Includes future use assets totaling $217 million.

On December 17, 2024, transmission assets related to the Chatham to Lakeshore Transmission Line Project totalling $203 million were transferred from Hydro One Networks to Chatham x Lakeshore Limited Partnership, a subsidiary of Hydro One. See Note 16 - Capital Management.

As at December 31, 2023 *(millions of dollars)*	Property, Plant and Equipment[1]	Accumulated Depreciation	Construction in Progress	Total
Transmission	20,359	6,764	1,123	14,718
Administration and service	916	403	37	550
Other	1,712	1,035	48	725
	22,987	8,202	1,208	15,993

[1] Includes future use assets totaling $183 million.

Financing charges capitalized on property, plant and equipment under construction were $68 million in 2024 (2023 - $54 million).

9. INTANGIBLE ASSETS

As at December 31, 2024 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	584	321	24	287
Other	18	11	—	7
	602	332	24	294

As at December 31, 2023 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	533	310	45	268
Other	18	10	—	8
	551	320	45	276

Financing charges capitalized to intangible assets under development were $2 million in 2024 (2023 - $2 million). The estimated annual amortization expense for intangible assets are as follows: 2025 - $31 million; 2026 - $30 million; 2027 - $30 million; 2028 - $29 million; and 2029 - $26 million.

10. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. The Transmission Business has recorded the following regulatory assets and liabilities:

As at December 31 *(millions of dollars)*	2024	2023
Regulatory assets:		
Deferred income tax regulatory asset	2,131	1,974
Excess export service revenue variance	18	15
Stock-based compensation	10	13
Environmental	4	10
Other	11	7
Total regulatory assets	2,174	2,019
Less: current portion	(21)	(8)
	2,153	2,011
Regulatory liabilities:		
Post-retirement and post-employment benefits	163	174
Earnings sharing mechanism deferral	68	38
External revenue variance	49	34
Asset removal costs cumulative variance	26	23
Capitalized overhead tax variance	23	16
OPEB asymmetrical carrying charge	19	12
Other	16	9
Total regulatory liabilities	364	306
Less: current portion	—	—
	364	306

Deferred Income Tax Regulatory Asset

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. The Transmission Business has recognized regulatory assets that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Transmission Business' income tax expense would have been recognized using the liability method and there would be no regulatory accounts established for income taxes to be recovered through future rates.

Excess Export Service Revenue Variance

The excess export service revenue variance account balance reflects the difference between the Transmission Business' actual export service revenue, and the OEB-approved amounts. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of the Transmission Business' account balance as at December 31, 2020, including accrued interest, over a one-year period ending December 31, 2023. As part of the same decision, the OEB approved the continuance of this

account for the Transmission Business for 2023 to 2027. As part of the OEB's Decision and Order in the Generic Hearing on Uniform Transmission Rates-Related Issues and the Export Transmission Service Rate, the OEB stated that it considered it appropriate for Hydro One Transmission to dispose of the balance on an annual basis. As a result of this decision, the regulatory asset relating to the excess export service revenues has been separately presented from the External Revenue Variance Account. On December 11, 2024, as part of the Decision and Order on 2025 transmission rates, the OEB approved the disposition of the Transmission Business' account balance as at December 31, 2023, including accrued interest, over a one-year period ending December 31, 2025.

Stock-based Compensation

The Transmission Business recognizes costs associated with share grant plans as a regulatory asset as management considers it probable that share grant plans' costs will be recovered in the future through the rate-setting process. Share grant costs are transferred to labour costs at the time they vest and are issued, and are recovered in rates in accordance with recovery of these labour costs.

Environmental

The Transmission Business records a liability for the estimated future expenditures required to remediate environmental contamination. A regulatory asset is recognized to the extent management considers it to be probable environmental expenditures will be recovered in the future through the rate-setting process. For the year ended December 31, 2024, the Transmission Business has recorded an equivalent amount as a regulatory asset. In 2024, the revaluation adjustment decreased the environmental regulatory asset by $2 million (2023 - $8 million) to reflect related changes in the Transmission Business' PCB and LAR environmental liabilities. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudence and the timing of recovery of all of the Transmission Business' actual environmental expenditures.

Post-Retirement and Post-Employment Benefits

In accordance with OEB rate orders, post-retirement and post-employment benefits costs are recovered on an accrual basis. The Transmission Business recognizes the net unfunded or funded status of post-retirement and post-employment obligations on the balance sheets with an incremental offset to the associated regulatory asset or regulatory liability, as the case may be. A regulatory asset or regulatory liability is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered or returned in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to the present value of the actuarially determined benefit obligation at each year end based on an annual actuarial report, with an offset to the associated regulatory asset or regulatory liability, as the case may be, to the extent of the remeasurement adjustment.

Earnings Sharing Mechanism Deferral

In April 2020, the OEB approved the establishment of an earnings sharing mechanism deferral account for the Transmission Business to record over-earnings including tax impacts, if any, realized for any year from 2020 to 2022. Under this mechanism, Hydro One shares 50% of regulated earnings that exceed the OEB-approved regulatory return-on-equity by more than 100 basis points with transmission ratepayers. As part of the JRAP Decision, the account was approved for continuance for the Transmission Business for 2023 to 2027.

External Revenue Variance

The external revenue variance account balance reflects the difference between the Transmission Business' actual external revenues from secondary land use, and the OEB-approved amounts. The account also records the difference between actual net external station maintenance, engineering and construction services revenue, and other external revenue, and the OEB-approved amounts. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of the Transmission Business' account balance as at December 31, 2020, including accrued interest, over a one-year period ending December 31, 2023. As part of the same decision, the OEB approved the continuance of this account for the Transmission Business for 2023 to 2027.

Asset Removal Costs Cumulative Variance

In April 2020, the OEB approved the establishment of an asset removal costs cumulative variance account for the Transmission Business to record the difference between the revenue requirement associated with forecast asset removal costs included in depreciation expense and actual asset removal costs incurred from 2020 to 2022. This account is asymmetrical to the benefit of ratepayers on a cumulative basis for a specified term. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of the Transmission Business' account balance as at December 31, 2020, including accrued interest,

over a one-year period ending December 31, 2023. As part of the same decision, the OEB approved the continuance of this account for the Transmission business for the 2023 to 2027 period.

Capitalized Overhead Tax Variance

As part of the JRAP Decision, the OEB approved the establishment of a capitalized overhead tax variance account to capture the difference between the capitalized overheads deducted in calculating the regulatory tax expense included in rates and the actual capitalized overhead costs deducted in Hydro One's tax returns for the Transmission Business for the 2016 to 2027 period. Variance amounts are recognized at the earlier of (i) when the tax year has been audited by the Canada Revenue Agency or (ii) when the taxation year is statute barred.

OPEB Asymmetrical Carrying Charge

On September 14, 2017, the OEB issued its Report of the Board: *Regulatory Treatment of Pension and OPEB Costs* that allowed rate-regulated utilities to track the difference between their pension and OPEB costs calculated under the accrual method and the cash payment method, effective January 1, 2018, and record the carrying charges associated with the balance on an asymmetrical basis. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of the Transmission Business' account balance as at December 31, 2020, including accrued interest, which was to be returned to ratepayers over a one-year period ending December 31, 2023. As part of the same decision, the OEB approved the continuance and modification of this account for Hydro One Networks' Transmission Business for 2023 to 2027.

11. OTHER LONG-TERM ASSETS

As at December 31 *(millions of dollars)*	**2024**	**2023**
Right-of-Use assets *(Note 20)*	22	23
Cloud Computing Implementation Cost	11	—
Other long-term assets	9	13
	42	36

12. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

As at December 31 *(millions of dollars)*	**2024**	**2023**
Accrued liabilities	588	208
Accounts payable	204	242
Accrued interest *(Note 23)*	109	92
Lease obligations *(Note 20)*	6	5
Derivative liability	3	—
Environmental liabilities *(Note 18)*	3	5
	913	552

13. OTHER LONG-TERM LIABILITIES

As at December 31 *(millions of dollars)*	**2024**	**2023**
Post-retirement and post-employment benefit liability *(Note 17)*	669	647
Lease obligations *(Note 20)*	16	18
Long-term accounts payable and other liabilities	14	12
Derivative liability	2	1
Asset retirement obligations *(Note 19)*	9	9
Long-term inter-company payable *(Note 23)*	7	10
Environmental liabilities *(Note 18)*	1	5
	718	702

14. DEBT

Hydro One issues notes for long-term financing under its Medium-Term Note (MTN) Program. The terms of certain issuances are mirrored down to Hydro One Networks through the issuance of inter-company debt, and are allocated between the Company's transmission and distribution businesses. The following table presents long-term debt allocated to the Transmission Business outstanding as at December 31, 2024 and 2023:

As at December 31 *(millions of dollars)*	**2024**	**2023**
Long-term debt	9,909	8,778
Add: Net unamortized debt premiums	21	6
Add: Realized mark-to-market gain[1]	2	4
Less: Deferred debt issuance costs	(35)	(31)
Less: Long-term debt payable within one year	(660)	(413)
Long-term debt	9,237	8,344

[1] In October 2023, Hydro One entered into a $400 million fixed-to-floating interest-rate swap agreement to convert the $400 million Medium Term Note (MTN) Series 57 notes maturing October 20, 2025, into a variable rate debt. $244 million was allocated to the Transmission Business. This swap was accounted for as a fair value hedge. In December 2023, this swap was terminated with a $6 million payment received on settlement, of which $4 million was allocated to the Transmission Business that is being amortized over the term of the related note.

In 2024, Hydro One issued $2,750 million long-term debt under its MTN Program (2023 - $2,375 million), of which $2,531 million was mirrored down to Hydro One Networks (2023 - $2,375 million), and $1,544 million (2023 - $1,364 million) was allocated to the Transmission Business.

In 2024, Hydro One repaid $700 million (2023 - $600 million) of maturing long-term debt under its MTN Program. Hydro One Networks repaid inter-company debt of $700 million (2023 - $600 million) to Hydro One, of which $413 million (2023 - $372 million) was allocated to the Transmission Business.

Principal and Interest Payments

As at December 31, 2024, future principal repayments, interest payments, and related weighted-average interest rates were as follows:

	Long-Term Debt Principal Repayments *(millions of dollars)*	**Interest Payments** *(millions of dollars)*	**Weighted Average Interest Rate** *(%)*
Year 1	660	438	3.8
Year 2	504	412	3.9
Year 3	—	399	—
Year 4	555	385	5.2
Year 5	636	365	3.7
	2,355	1,999	4.1
Years 6-10	1,927	1,526	4.6
Thereafter	5,627	2,789	4.6
	9,909	6,314	4.5

15. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

The Transmission Business classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One Networks has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest-rate curves and yield curves observable at commonly quoted intervals,

volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

As at December 31, 2024 and 2023, the carrying amounts of accounts receivable, due from related parties, inter-company demand facility, accounts payable, and due to related parties are representative of fair value due to the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The carrying values and fair values of the Transmission Business' long-term debt as at December 31, 2024 and 2023 are as follows:

As at December 31 *(millions of dollars)*	2024 Carrying Value	2024 Fair Value	2023 Carrying Value	2023 Fair Value
Long-term debt, including current portion	9,897	9,879	8,757	8,730

Fair Value Measurements of Derivative Instruments

Hydro One enters into interest-rate swaps agreements with respect to its long-term debt. The terms of certain of these interest-rate swap agreements are mirrored down to Hydro One Networks, and are allocated between the Company's transmission and distribution businesses.

As at December 31, 2024 and 2023, Hydro One had no fair value hedges.

As at December 31, 2024, the value of the Company's derivative instruments was $7 million (2023 - $2 million), of which $5 million was allocated to the Transmission Business (2023 - $1 million).

As at December 31, 2024 and 2023, the Company had no interest-rate swaps classified as undesignated contracts.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities as at December 31, 2024 and 2023 is as follows:

As at December 31, 2024 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Long-term debt, including current portion	9,897	9,879	—	9,879	—
Derivative instruments					
Cash flow hedges, including current portion	5	5	—	5	—
	9,902	9,884	—	9,884	—

As at December 31, 2023 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Long-term debt, including current portion	8,757	8,730	—	8,730	—
Derivative instruments					
Cash flow hedges, including current portion	1	1	—	1	—
	8,758	8,731	—	8,731	—

The fair value of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no transfers between any of the fair value levels during the years ended December 31, 2024 or 2023.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss which results from changes in values, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates, as its regulated return on equity is derived using a formulaic approach that takes anticipated interest rates into account. The Company is not currently exposed to material commodity price risk or material foreign exchange risk.

Hydro One Networks uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. Hydro One Networks also uses derivative financial instruments to manage interest-rate risk. Hydro One's derivative instruments, or portions thereof, are mirrored down to Hydro One Networks, and are allocated between the Company's transmission and distribution businesses. Hydro One Networks may utilize interest-rate swaps designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt, and may also utilize interest-rate derivative instruments, such as cash flow hedges, to manage its exposure to short-term interest rates or to lock in interest-rate levels on forecasted financing.

A hypothetical 100 basis point increase in interest rates associated with variable-rate debt would not have resulted in a significant decrease to the Company's net income for the years ended December 31, 2024 and 2023, respectively.

For derivative instruments that are designated and qualify as cash flow hedges, the unrealized gain or loss, after tax, on the derivative instrument is recorded as OCI or OCL and is reclassified to net income or net loss in the same period during which the hedged transaction affects results of operations. The following table shows the amounts recorded in OCL and reclassified to financing charges for the years ended December 31, 2024 and 2023:

	Hydro One		Transmission Business	
Year ended December 31 *(millions of dollars)*	**2024**	**2023**	**2024**	**2023**
Amounts recorded in OCL				
Before tax loss	1	5	1	1
After tax loss	1	4	1	1
Amounts reclassified to financing charges				
Before tax gain	(4)	(2)	(2)	—
After tax gain	(3)	(2)	(2)	—

The Company estimates that the amount of AOCL, after tax, related to cash flow hedges to be reclassified to results of operations in the next 12 months is approximately $3 million, of which approximately $2 million will be allocated to the Transmission Business. Actual amounts reclassified to results of operations depend on the interest rate in effect until the derivative contracts mature. For all forecasted transactions, as at December 31, 2024, the maximum term over which the Company is hedging exposures to the variability of cash flows is approximately two years.

The Pension Plan manages market risk by diversifying investments in accordance with the Pension Plan's Statement of Investment Policies and Procedures. Interest rate risk arises from the possibility that changes in interest rates will affect the fair value of the Pension Plan's financial instruments. In addition, changes in interest rates can also impact discount rates which impact the valuation of the pension and post-retirement and post-employment liabilities. Currency risk is the risk that the value of the Pension Plan's financial instruments will fluctuate due to changes in foreign currencies relative to the Canadian dollar. Other price risk is the risk that the value of the Pension Plan's investments in equity securities will fluctuate as a result of changes in market prices, other than those arising from interest risk or currency risk. All three factors may contribute to changes in values of the Pension Plan investments. See Note 17 – Pension and Post-Retirement and Post-Employment Benefits for further details.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. As at December 31, 2024 and 2023, there were no significant concentrations of credit risk with respect to any class of financial assets. The Transmission Business' revenue is earned from a broad base of customers. As a result, the Transmission Business did not earn a material amount of revenue from any single customer. As at December 31, 2024 and 2023, there was no material accounts receivable balance due from any single customer.

As at December 31, 2024, the allowance for doubtful accounts reflects the Transmission Business' CECL for all accounts receivable balances, which are based on historical overdue balances, customer payments and write-offs. As at December 31, 2024, approximately 1% (2023 - 13%) of the Transmission Business' net accounts receivable were outstanding for more than 60 days.

Hydro One manages its counterparty credit risk through various techniques including (i) entering into transactions with highly rated counterparties, (ii) limiting total exposure levels with individual counterparties, (iii) entering into master agreements which enable net settlement and the contractual right of offset, and (iv) monitoring the financial condition of counterparties. Hydro One monitors current credit exposure to counterparties on both an individual and an aggregate basis. The Company's counterparty credit risk profile is consistent with Hydro One. The Transmission Business' credit risk for accounts receivable is limited to the carrying amounts on the balance sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The maximum credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts in an asset position at the reporting date. As at December 31, 2024, and 2023, Hydro One's credit exposure for all derivative instruments and applicable payables was with one financial institution with investment grade credit ratings as counterparty.

The Pension Plan manages its counterparty credit risk with respect to bonds by investing in investment-grade corporate and government bonds and with respect to derivative instruments by transacting only with highly rated financial institutions and by ensuring that exposure is diversified across counterparties.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One Networks meets its short-term operating liquidity requirements through the inter-company demand facility with Hydro One and funds from operations. The short-term liquidity available to the Company is expected to be sufficient to fund the Company's operating requirements.

16. CAPITAL MANAGEMENT

The Transmission Business' objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. As at December 31, 2024 and 2023, the Transmission Business' capital structure was as follows:

As at December 31 *(millions of dollars)*	**2024**	**2023**
Long-term debt payable within one year	660	413
Inter-company demand facility	7	462
	667	875
Long-term debt	9,237	8,344
Excess of assets over liabilities	5,981	5,932
Total capital	15,885	15,151

The following table shows the movements in the excess of assets over liabilities for the years ended December 31, 2024 and 2023:

Year ended December 31 *(millions of dollars)*	**2024**	**2023**
Excess of assets over liabilities - beginning	5,932	5,654
Comprehensive income	693	650
Payments to Hydro One to finance dividends	(441)	(368)
Other[1,2]	(203)	(4)
Excess of assets over liabilities - ending	5,981	5,932

[1] The amount represents an allocation to the Other non-regulated Hydro One Networks segment as the underlying transactions do not represent the operations of the regulated Transmission Business. In line with the basis of accounting, these amounts have been excluded from the assets and liabilities of the Transmission Business, resulting in an impact to excess of assets over liabilities.

[2] The 2024 amount includes $203 million related to transmission assets transferred from the Transmission Business to CLLP. See Note 8 - Property, Plant and Equipment.

17. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a Pension Plan, a supplementary pension plan (Supplementary Plan), and post-retirement and post-employment benefit plans (Benefit Plans), and a DC Plan.

Pension Plan and Supplementary Plan

The Pension Plan is a defined benefit contributory plan which covers eligible regular employees of Hydro One and its subsidiaries. The Pension Plan provides benefits based on highest three-year average pensionable earnings up to March 31, 2025. Beginning April 1, 2025, all service for all groups on a go-forward basis will be calculated using the highest five-year average pensionable earnings. For management employees who commenced employment on or after January 1, 2004, and for the Society of United Professionals (Society)-represented staff hired after November 17, 2005, benefits are based on the highest five-year average pensionable earnings for all their service. After retirement, pensions are indexed to inflation. Membership in the Pension Plan was closed to management employees who were not eligible to join the Pension Plan as of September 30, 2015. These employees are eligible to join the DC Plan.

Company and employee contributions to the Pension Plan are based on actuarial reports, including valuations performed at least every three years, and actual or projected levels of pensionable earnings, as applicable. The most recent actuarial valuation was performed effective December 31, 2023 and filed on September 23, 2024. The Transmission Business' total annual cash Pension Plan employer contributions for 2024 were $34 million (2023 - $31 million). The Transmission Business' estimated annual Pension Plan employer contributions for the years 2025, 2026, 2027, 2028, 2029 and 2030 are approximately $36 million, $38 million, $42 million, $46 million, $44 million and $45 million, respectively.

The Supplementary Plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan beyond the limitations imposed by the *Income Tax Act* (Canada). The Supplementary Plan obligation is included with other post-retirement and post-employment benefit obligations on the balance sheets.

As at December 31, 2024, the present value of Hydro One's projected pension benefit obligation was estimated to be $8,686 million (2023 - $8,665 million). The fair value of pension plan assets available for these benefits was $9,333 million (2023 - $8,764 million).

Post-Retirement and Post-Employment Plans

The Company accounts for post-retirement and post-employment costs consistent with their inclusion in OEB-approved rates. During the year ended December 31, 2024, for the Transmission Business, post-retirement and post-employment costs of $50 million (2023 - $49 million) were attributable to labour, of which $29 million (2023 - $33 million) was charged to operations, and $21 million (2023 - $16 million) was capitalized as part of the cost of property, plant and equipment and intangible assets. Benefits paid in 2024 were $33 million (2023 - $23 million).

In the 2020-2022 Transmission Rate Decision, the OEB approved the recovery of the non-service cost component of post-retirement and post-employment benefits as part of operation, maintenance and administration costs for both its transmission and distribution businesses (See Note 10 – Regulatory Assets and Liabilities). These costs were previously capitalized and recovered through rate base. As a result, during the year ended December 31, 2024, for the Transmission Business, additional other post-retirement and post-employment costs of $16 million (2023 - $17 million) attributed to labour were charged to operations.

The Transmission Business presents its post-retirement and post-employment benefit liabilities on its balance sheets as follows:

As at December 31 *(millions of dollars)*	**2024**	**2023**
Accrued liabilities	35	33
Post-retirement and post-employment benefit liability	669	647
Net unfunded status	704	680

DC Plan

Hydro One established a DC Plan effective January 1, 2016. The DC Plan covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One up to an annual contribution limit. There is also a Supplementary Notional Plan that provides members of the DC Plan with employer contributions beyond the limitations imposed by the *Income Tax Act* (Canada) in the form of credits to a notional account. The Transmission Business contributions to the DC Plan for the year ended December 31, 2024 were $2 million (2023 - $2 million).

18. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2024 and 2023:

Year ended December 31, 2024 *(millions of dollars)*	**PCB**	**LAR**	**Total**
Environmental liabilities - beginning	8	2	10
Expenditures	(3)	(1)	(4)
Revaluation adjustment	(2)	—	(2)
Environmental liabilities - ending	3	1	4
Less: current portion	(3)	—	(3)
	—	1	1

Year ended December 31, 2023 *(millions of dollars)*	**PCB**	**LAR**	**Total**
Environmental liabilities - beginning	21	3	24
Interest accretion	1	—	1
Expenditures	(6)	(1)	(7)
Revaluation adjustment	(8)	—	(8)
Environmental liabilities - ending	8	2	10
Less: current portion	(5)	—	(5)
	3	2	5

The following tables show the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the balance sheets after factoring in the discount rate:

As at December 31, 2024 *(millions of dollars)*	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	3	1	4
Less: discounting environmental liabilities to present value	—	—	—
Discounted environmental liabilities	3	1	4

As at December 31, 2023 *(millions of dollars)*	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	8	2	10
Less: discounting environmental liabilities to present value	—	—	—
Discounted environmental liabilities	8	2	10

As at December 31, 2024, the estimated future environmental expenditures were as follows:

(millions of dollars)	
2025	3
2026	—
2027	1
2028	—
2029	—
Thereafter	—
	4

The Company records a liability for the estimated future expenditures for LAR and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred in order to generate future cash flow information. A long-term inflation rate assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 2.0% to 2.3% (2023 - 2.0% to 2.3%) depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Transmission Business' environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, with respect to the PCB environmental liability, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures.

PCBs

The Environment Canada regulations, enacted under the *Canadian Environmental Protection Act, 1999*, govern the management, storage and disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under current regulations, the Transmission Business' PCBs have to be disposed of by the end of 2025, with the exception of specifically exempted equipment. Contaminated equipment will generally be replaced, or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains PCBs in concentrations of less than two parts per million (ppm).

As at December 31, 2024, the Transmission Business' best estimate of the total future expenditures to comply with current PCB regulations was $3 million (2023 - $8 million). These expenditures are expected to be incurred in 2025. As a result of its annual review of environmental liabilities, the Transmission Business recorded a revaluation adjustment in 2024 to decrease the PCB environmental liability by $2 million (2023 - $8 million).

LAR

As at December 31, 2024, the Transmission Business' best estimate of the total future expenditures to complete its LAR program was $1 million (2023 - $2 million). These expenditures are expected to be incurred over the period from 2025 to 2027. As a result of its annual review of environmental liabilities, no material revaluation adjustment was recorded to adjust the LAR environmental liability (2023 - $nil).

19. ASSET RETIREMENT OBLIGATIONS

Hydro One Networks records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities. Asset retirement obligations, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an asset retirement obligation is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the asset retirement obligation, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

Some of the Company's transmission assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its facilities in perpetuity, no asset retirement obligations have been recorded for these assets. If, at some future date, a particular facility is shown not to meet the perpetuity assumption, it will be reviewed to determine whether an estimable asset retirement obligation exists. In such a case, an asset retirement obligation would be recorded at that time.

In determining the amounts to be recorded as asset retirement obligations, the Company estimates the current fair value for completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 1.0% to 3.0% (2023 - 2.0% to 4.0%), depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's Transmission Business' asset retirement obligations represent management's best estimates of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Asset retirement obligations are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively. As a result of its annual review of asset retirement obligations, there was no change to the asset retirement obligations recorded in 2024 (2023 - increase of $1 million).

As at December 31, 2024, Hydro One Networks had recorded asset retirement obligations of $9 million (2023 - $9 million) related to the Transmission Business, primarily consisting of the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities.

20. LEASES

Hydro One has operating lease contracts for buildings used in administrative and service-related functions. These leases have terms between three and six years with renewal options of additional three- to five-year terms at prevailing market rates at the time of extension. All leases include a clause to enable upward revision of the rental charge on an annual basis or on renewal according to prevailing market conditions or pre-established rents. There are no restrictions placed upon Hydro One by entering into these leases. Renewal options are included in the lease term when their exercise is reasonably certain. Other information related to the Transmission Business' operating leases was as follows:

Year ended December 31 *(millions of dollars)*	**2024**	**2023**
Lease expense	7	6
Lease payments made	7	6

As at December 31	**2024**	**2023**
Weighted-average remaining lease term[1] *(years)*	4	5
Weighted-average discount rate	2.9 %	2.6 %

[1] Includes renewal options that are reasonably certain to be exercised.

As at December 31, 2024, future minimum operating lease payments were as follows:

(millions of dollars)	
2025	7
2026	6
2027	5
2028	4
2029	1
Thereafter	1
Total undiscounted minimum lease payments	24
Less: discounting minimum lease payments to present value	(2)
Total discounted minimum lease payments	22

As at December 31, 2023, future minimum operating lease payments were as follows:

(millions of dollars)	
2024	6
2025	5
2026	5
2027	5
2028	2
Thereafter	1
Total undiscounted minimum lease payments	24
Less: discounting minimum lease payments to present value	(1)
Total discounted minimum lease payments	23

Hydro One presents its ROU assets and lease obligations on the balance sheets as follows:

As at December 31 *(millions of dollars)*	**2024**	**2023**
Right-of-Use assets	22	23
Accounts payable and other current liabilities *(Note 12)*	6	5
Other long-term liabilities *(Note 13)*	16	18

21. HYDRO ONE NETWORKS' SHARE CAPITAL

Hydro One Networks is authorized to issue an unlimited number of common and preferred shares. As at December 31, 2024 and 2023, Hydro One Networks had 209,401,290 common shares issued and outstanding and no preferred shares issued and outstanding.

During 2024, Hydro One Networks declared common share dividends in the amount of $753 million (2023 - $692 million) to Hydro One as at December 31, 2024 and 2023, respectively. The amount allocated to the Transmission Business to finance these dividends was $441 million (2023 - $368 million).

22. STOCK-BASED COMPENSATION

The following compensation plans were established by Hydro One Limited, however they represent components of compensation costs of Hydro One and its subsidiaries, including Hydro One Networks, in current and future periods.

Share Grant Plans

Hydro One Limited has two share grant plans (Share Grant Plans), one for the benefit of certain members of the Power Workers' Union (PWU) (PWU Share Grant Plan) and one for the benefit of certain members of the Society (Society Share Grant Plan). Hydro One and Hydro One Limited entered into an intercompany agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with these plans. The agreement requires Hydro One Networks to reimburse Hydro One for the value of shares granted to the Company's eligible employees relating to these plans.

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the PWU annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on April 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. The requisite service period for the PWU Share Grant Plan began on July 3, 2015, which is the date the share grant plan was ratified by the PWU. The number of common shares issued annually to each eligible employee will be

equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the Initial Public Offering (IPO). The aggregate number of Hydro One Limited common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015,1,761,152 Hydro One Limited common shares were granted under the PWU Share Grant Plan relevant to the total stock-based compensation recognized by the Transmission Business.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the Society annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on September 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. Therefore the requisite service period for the Society Share Grant Plan began on September 1, 2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 608,626 Hydro One Limited common shares were granted under the Society Share Grant Plan relevant to the total stock-based compensation recognized by the Transmission Business.

The fair value of the Hydro One Limited 2015 share grants to employees of Hydro One Networks and allocated to the Transmission Business was $49 million. The fair value was estimated based on the grant date Hydro One Limited share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. In 2024, 160,233 common shares of Hydro One Limited were issued under the Share Grant Plans (2023 - 161,987) to eligible employees of Hydro One Networks and allocated to the Transmission Business. Total stock-based compensation recognized by the Transmission Business during 2024 was less than $1 million (2023 - $1 million) and was recorded as a regulatory asset.

A summary of the Transmission Business' share grant activity under the Share Grant Plans during the years ended December 31, 2024 and 2023 is presented below:

Year ended December 31, 2024	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	849,400	$20.50
Granted	516	—
Vested and issued[1]	(160,233)	—
Forfeited	(12,971)	$20.50
Share grants outstanding - ending	676,712	$20.50

[1] In 2024, Hydro One Limited issued common shares from treasury to eligible Hydro One Networks employees in accordance with provisions of the Share Grant Plans. In accordance with the intercompany agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

Year ended December 31, 2023	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	1,031,527	$20.50
Granted	806	—
Vested and issued[1]	(161,987)	—
Forfeited	(20,946)	$20.50
Share grants outstanding - ending	849,400	$20.50

[1] In 2023, Hydro One Limited issued common shares from treasury to eligible Hydro One Networks employees in accordance with provisions of the Share Grant Plans. In accordance with the intercompany agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

Directors' DSU Plan

Under the Directors' DSU Plan, directors can elect to receive credit for their annual cash retainer in a notional account of DSUs in lieu of cash. Hydro One Limited Board of Directors may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled. Each DSU represents a unit with an underlying value equivalent to the value of one common share of Hydro One Limited and is entitled to accrue Hydro One Limited common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One Limited Board of Directors.

During 2024 and 2023, Directors' DSU Plan awards granted by Hydro One Limited that related to Hydro One Network's Transmission Business were as follows:

Year ended December 31 *(number of DSUs)*	2024	2023
DSUs outstanding - beginning	31,538	33,166
Granted	6,597	10,018
Settled	(2,847)	(11,646)
DSUs outstanding - ending	35,288	31,538

For the years ended December 31, 2024 and 2023, the expense related to the Directors' DSU Plan was less than $1 million. As at December 31, 2024, the liability related to Directors' DSUs was $1 million (2023 - $1 million).

Management DSU Plan

Under the Management DSU Plan, eligible executive employees can elect to receive a specified proportion of their annual short-term incentive in a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of Hydro One Limited and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One Limited Board of Directors.

During 2024 and 2023, Management DSU Plan awards granted by Hydro One Limited that related to Hydro One Network's Transmission Business were as follows:

Year ended December 31 *(number of DSUs)*	2024	2023
DSUs outstanding - beginning	27,615	24,309
Granted	4,564	3,896
Paid	(5,502)	(590)
DSUs outstanding - ending	26,677	27,615

To comply with the Accountability Act and the OEB Act, in 2019 Hydro One Limited removed all executive-related compensation from the labour costs of its regulated subsidiaries. During the years ended December 31, 2024 and 2023, no executive-related stock-based compensation was allocated to the regulated businesses of Hydro One Networks.

Employee Share Ownership Plan

In 2015, Hydro One Limited established Employee Share Ownership Plans (ESOP) for certain eligible management and non-represented employees (Management ESOP) and for certain eligible Society-represented staff (Society ESOP). Under the Management ESOP, the eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 50% of their contributions, up to a maximum Company contribution of $25,000 per calendar year. Under the Society ESOP, the eligible Society-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 25% of their contributions, with no maximum Company contribution per calendar year.

In 2024, Hydro One established ESOP for certain eligible PWU represented staff (PWU ESOP). Under the PWU ESOP, the eligible PWU-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One. The Company matches 33% of their contribution, with no maximum Company contribution per calendar year. In 2024, Company contributions made under the ESOP and allocated to the Transmission Business were $2 million (2023 - $1 million).

LTIP

Effective August 31, 2015, the Board of Directors of Hydro One adopted an LTIP. Under the LTIP, long-term incentives were granted to certain executive and management employees of Hydro One and its subsidiaries, and all equity-based awards would either be settled in newly issued shares of Hydro One from treasury or cash, subject to Hydro One's discretion, consistent with the provisions of the plan which also permit the participants to surrender a portion of their awards to satisfy related withholding taxes requirements. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares of Hydro One.

The LTIP provides flexibility to award a range of vehicles, including Performance Share Units (PSUs), RSUs, stock options, share appreciation rights, restricted shares, DSUs, and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance.

PSUs and RSUs

A summary of PSU and RSU awards activity under the LTIP during the years ended December 31, 2024 and 2023 is presented below:

	PSUs		RSUs	
Year ended December 31 *(number of units)*	**2024**	**2023**	**2024**	**2023**
Units outstanding – beginning	33,388	—	75,484	—
Granted	34,171	34,662	62,087	78,642
Forfeited	(1,255)	(1,202)	(5,574)	(3,033)
Settled	(478)	(72)	(1,334)	(125)
Units outstanding – ending	65,826	33,388	130,663	75,484

To comply with the Accountability Act and the OEB Act, in 2019 Hydro One Limited removed all executive-related compensation from the labour costs of its regulated subsidiaries. During the years ended December 31, 2024 and 2023, no executive-related stock-based compensation was allocated to the regulated businesses of Hydro One Networks.

The grant date total fair value of the awards granted during the year ended December 31, 2024 was $4 million (2023 - $4 million). The compensation expense related to the PSU and RSU awards recognized by the Company during 2024 was $4 million (2023 - $1 million). As at December 31, 2024 and 2023, the payable relating to PSU and RSU awards included in due to related parties on the balance sheets was not significant.

Society RSU Plan

As a result of the renewal of the Company's prior collective agreement with members of the Society, the Company provided equity compensation in the form of RSUs to certain eligible members. The equity compensation provides for the purchase of common shares of Hydro One Limited from the open market, effective March 1, 2021 in one equity grant vesting in equal portions over a two-year period. To be eligible, an employee must be an employee of the Company as of July 30, 2021, the date the plan was ratified by the Society; the grant date. The number of common shares issued to each eligible employee will be equal to 1.0% of such eligible employee's salary as at April 1, 2021, divided by $30.80, being the price of the common shares of Hydro One Limited at the grant date. Each RSU is entitled to accrue common share dividend equivalents in the form of additional RSUs at the time dividends are paid, subsequent to declaration by Hydro One's Board of Directors.

A summary of RSU awards activity under the Society RSU Plan during the years ended December 31, 2024 and 2023 is presented below:

Year ended December 31 *(number of RSUs)*	**2024**	**2023**
RSUs outstanding - beginning	—	16,102
Granted	—	—
Vested and issued	—	(14,701)
Settled	—	(1,340)
Forfeited	—	(61)
RSUs outstanding - ending	—	—

23. RELATED PARTY TRANSACTIONS

The Transmission Business is a separately regulated business of Hydro One Networks which is indirectly owned by Hydro One Limited. The Province of Ontario is a shareholder of Hydro One Limited with approximately 47.1% ownership as at December 31, 2024. The IESO, Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), and the OEB, are related parties to Hydro One Networks because they are controlled or significantly influenced by the Ministry of Energy. B2M Limited Partnership (B2M LP), Niagara Reinforcement Limited Partnership (NRLP), and Chatham x Lakeshore Limited Partnership (CLLP) are subsidiaries of Hydro One Networks, Hydro One Sault Ste. Marie LP (HOSSM) is a subsidiary of Hydro One, and Acronym Solutions Inc. (Acronym) is a subsidiary of Hydro One Limited. The Transmission Business also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province. The following is a summary of the Transmission Business' related party transactions during the years ended December 31, 2024 and 2023:

Year ended December 31 *(millions of dollars)*			
Related Party	**Transaction**	**2024**	**2023**
IESO	Revenues for transmission services	2,162	2,107
OPG	Capital contribution received from OPG	3	5
	Costs related to the purchase of services	1	2
	Revenues related to provision of construction and equipment maintenance services	2	2
OEB	OEB fees	6	6
Hydro One	Payments to finance dividends	441	368
	Interest expense on long-term debt	410	348
	Interest expense on inter-company demand facility	8	30
	Stock-based compensation costs	4	2
	Services received - costs expensed	3	—
B2M LP	Revenues for services provided	1	2
NRLP	Revenues for services provided	1	1
CLLP	Transfer of assets	203	—
HOSSM	Revenues for services provided	72	47
Hydro One Networks' Distribution Business	Revenues for services provided	3	2
	Capital contribution received	8	3
Acronym	Services received - costs expensed	23	22
	Revenues for services provided	3	3
Hydro One Limited and its other subsidiaries	Revenues for services provided	1	—
	Services received - costs recovered	5	6

The amounts due to and from related parties as at December 31, 2024 and 2023 are as follows:

As at December 31 *(millions of dollars)*	**2024**	**2023**
Due from related parties	187	162
Long-term inter-company payable	(7)	(10)
Accrued interest	(109)	(92)
Inter-company demand facility	(7)	(462)
Long-term debt, including current portion	(9,897)	(8,757)

24. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 *(millions of dollars)*	2024	2023
Accounts receivable	15	(12)
Due from related parties	(25)	5
Materials and supplies	1	(4)
Other assets	(17)	(7)
Accounts payable	(4)	74
Accrued liabilities	313	(90)
Accrued interest	17	18
Due to related parties	—	1
Long-term accounts payable and other liabilities	2	3
Post-retirement and post-employment benefit liability	11	48
	313	36

Capital Expenditures

The following tables reconcile investments in property, plant and equipment and intangible assets and the amounts presented in the statements of cash flows for the years ended December 31, 2024 and 2023. The reconciling items include net change in accruals, transfers, and capitalized depreciation.

Year ended December 31, 2024 *(millions of dollars)*	Property, Plant and Equipment	Intangible Assets	Total
Capital investments	(1,750)	(39)	(1,789)
Reconciling items	142	1	143
Cash outflow for capital expenditures	(1,608)	(38)	(1,646)

Year ended December 31, 2023 *(millions of dollars)*	Property, Plant and Equipment	Intangible Assets	Total
Capital investments	(1,418)	(45)	(1,463)
Reconciling items	17	1	18
Cash outflow for capital expenditures	(1,401)	(44)	(1,445)

Capital Contributions

Hydro One Networks' Transmission Business enters into contracts governed by the OEB Transmission System Code when a transmission customer requests a new or upgraded transmission connection. The customer is required to make a capital contribution to Hydro One Networks based on the shortfall between the present value of the costs of the connection facility and the present value of revenues. The present value of revenues is based on an estimate of load forecast for the period of the contract with Hydro One Networks. Once the connection facility is commissioned, in accordance with the OEB Transmission System Code, Hydro One Networks will periodically reassess the estimated load forecast which will lead to a decrease, or an increase in the capital contributions from the customer. The increase or decrease in capital contributions is recorded directly to property, plant and equipment in service. In 2024, there were $2 million capital contributions from these assessments (2023 - $2 million).

Supplementary Information

Year ended December 31 *(millions of dollars)*	2024	2023
Net interest paid	393	330
Income taxes paid	94	130

25. CONTINGENCIES

Hydro One Networks is involved in various lawsuits and claims in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Transmission Business' financial position, results of operations or cash flows.

The Company is a wholly owned subsidiary of Hydro One. As such, the assets of the Transmission Business are available to satisfy the debts, contingent liabilities and commitments of both the Company and Hydro One.

26. COMMITMENTS

The Company and Hydro One have numerous commitments. These commitments have not been specifically allocated to the Transmission Business. However, the assets of the Transmission Business are available to satisfy the commitments of both the Company and Hydro One.

27. SUBSEQUENT EVENTS

Payments to Finance Dividends

On February 19, 2025, Hydro One Networks declared a dividend of $187 million. The amount allocated to the Transmission Business to finance this payment was $109 million.

HYDRO ONE NETWORKS INC.

TRANSMISSION BUSINESS

FINANCIAL STATEMENTS

DECEMBER 31, 2025

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INDEPENDENT AUDITOR'S REPORT

To the Directors of Hydro One Networks Inc.

Opinion

We have audited the carve-out financial statements of the Transmission Business (a business of Hydro One Networks Inc.) (the Entity), which comprise:

- the carve-out balance sheet as at December 31, 2025
- the carve-out statement of operations and comprehensive income for the year then ended
- the carve-out statement of cash flows for the year then ended
- and notes to the carve-out financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements as at and for the year ended December 31, 2025 of the Entity are prepared, in all material respects, in accordance with the financial reporting framework described in Note 2 of the financial statements.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the ***"Auditor's Responsibilities for the Audit of the Financial Statements"*** section of our auditor's report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Emphasis of Matter - Financial Reporting Framework

We draw attention to Note 2 to the financial statements which describes the applicable financial reporting framework and the purpose of the financial statements.

KPMG LLP, an Ontario limited liability partnership and member firm of the KPMG global organization of independent member firms affiliated with KPMG International Limited, a private English company limited by guarantee. KPMG Canada provides services to KPMG LLP.

As a result the financial statements may not be suitable for another purpose.

Our opinion is not modified in respect of this matter.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation of the financial statements in accordance with the financial reporting framework described in Note 2 in the financial statements; this includes determining that the applicable financial reporting framework is an acceptable basis for the preparation of the financial statements in the circumstances, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada

April 23, 2026

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2025 and 2024

Year ended December 31 *(millions of Canadian dollars)*	**2025**	**2024**
Revenues		
Transmission tariff (includes $2,271 related party revenues; 2024 - $2,162) *(Note 23)*	2,273	2,145
Other (includes $96 related party revenues; 2024 - $83) *(Note 23)*	124	113
	2,397	2,258
Costs		
Operation, maintenance and administration *(Note 23)*	540	560
Depreciation, amortization and asset removal costs *(Note 4)*	550	534
	1,090	1,094
Income before financing charges and income tax expense	**1,307**	**1,164**
Financing charges (includes $449 related party charges; 2024 - $418) *(Notes 5, 23)*	387	373
Income before income tax expense	**920**	**791**
Income tax expense *(Note 6)*	118	97
Net income	**802**	**694**
Other comprehensive income (loss)	1	(1)
Comprehensive income	**803**	**693**

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
BALANCE SHEETS
As at December 31, 2025 and 2024

As at December 31 *(millions of Canadian dollars)*	**2025**	**2024**
Assets		
Current assets:		
Inter-company demand facility *(Note 23)*	46	—
Accounts receivable	71	71
Due from related parties *(Note 23)*	207	187
Other current assets *(Note 7)*	61	76
	385	334
Property, plant and equipment *(Note 8)*	18,584	17,095
Other long-term assets:		
Regulatory assets *(Note 10)*	2,330	2,153
Intangible assets *(Note 9)*	297	294
Other assets *(Note 11)*	32	42
	2,659	2,489
Total assets	**21,628**	**19,918**
Liabilities		
Current liabilities:		
Inter-company demand facility *(Note 23)*	—	7
Long-term debt payable within one year *(Notes 14, 15, 23)*	504	660
Accounts payable and other current liabilities *(Note 12)*	1,066	913
	1,570	1,580
Long-term liabilities:		
Long-term debt *(Notes 14, 15, 23)*	10,373	9,237
Deferred income tax liabilities *(Note 6)*	2,167	2,038
Regulatory liabilities *(Note 10)*	450	364
Other long-term liabilities *(Note 13)*	744	718
	13,734	12,357
Total liabilities	**15,304**	**13,937**
Contingencies and Commitments *(Notes 25, 26)*		
Subsequent Events *(Note 27)*		
Excess of assets over liabilities *(Notes 16, 21)*	6,324	5,981
Total liabilities and excess of assets over liabilities	**21,628**	**19,918**

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:

Helga Reidel
Chair, Audit Committee

David Lebeter
Director

HYDRO ONE NETWORKS INC.
TRANSMISSION BUSINESS
STATEMENTS OF CASH FLOWS
For the years ended December 31, 2025 and 2024

Year ended December 31 *(millions of Canadian dollars)*	**2025**	**2024**
Operating activities		
Net income	802	694
Environmental expenditures	(1)	(4)
Adjustments for:		
Depreciation and amortization *(Note 4)*	497	477
Regulatory assets and liabilities	173	62
Deferred income tax expense	(42)	(18)
Other	7	4
Changes in non-cash balances related to operations *(Note 24)*	36	313
Net cash from operating activities	**1,472**	**1,528**
Financing activities		
Long-term debt issued	1,646	1,559
Long-term debt repaid	(660)	(413)
Payments to finance dividends	(460)	(441)
Other	(7)	(7)
Net cash from financing activities	**519**	**698**
Investing activities		
Capital expenditures *(Note 24)*		
Property, plant and equipment	(1,836)	(1,608)
Intangible assets	(35)	(38)
Additions of future use assets	(72)	(127)
Capital contributions received *(Note 24)*	3	2
Other	2	—
Net cash used in investing activities	**(1,938)**	**(1,771)**
Net change in inter-company demand facility	53	455
Inter-company demand facility, beginning of year	(7)	(462)
Inter-company demand facility, end of year	**46**	**(7)**

See accompanying notes to Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Networks Inc. (Hydro One Networks or the Company) was incorporated on March 4, 1999 under the *Business Corporations Act* (Ontario) and is a wholly owned subsidiary of Hydro One Inc. (Hydro One). The Company owns and operates regulated transmission and distribution businesses. The Company's regulated transmission business (Transmission Business) operates a transmission system which transmits high-voltage electricity across the province, interconnecting local distribution companies and certain large directly connected industrial customers throughout the Ontario electricity grid. The Transmission Business is regulated by the Ontario Energy Board (OEB).

Rate Setting

On August 5, 2021 Hydro One Networks filed a custom Joint Rate Application (JRAP) for distribution and transmission revenue requirements for the 2023 to 2027 period. On November 29, 2022, the OEB issued a Decision and Order (JRAP Decision) approving Hydro One Networks' transmission revenue requirement of $1,952 million for 2023, $2,073 million for 2024, $2,168 million for 2025, $2,277 million for 2026 and $2,362 million for 2027. Revenue requirements presented for 2024 to 2027 do not reflect the actual or expected updates resulting from the annual application process with the regulator to reflect OEB inflation factors.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

These Financial Statements are prepared and presented in accordance with the accounting policies summarized below and in Canadian dollars. These policies are consistent with United States (U.S.) generally accepted accounting principles (GAAP).

The purpose of these Financial Statements is to meet Hydro One Networks' obligation to the OEB. As a result, these Financial Statements may not be suitable for another purpose. Consolidated financial statements of Hydro One for the year ended December 31, 2025 have been prepared and are publicly available.

Basis of Preparation

These Financial Statements have been prepared on a carve-out basis to provide the financial position, results of operations and cash flows of the Transmission Business. The Financial Statements are considered by management to be a reasonable representation, prepared on a rational, systematic and consistent basis, of the financial results of the Transmission Business. As a result of this basis of preparation, these Financial Statements may not necessarily be identical to the financial position and results of operations that would have resulted had the Transmission Business historically operated on a stand-alone basis.

The Financial Statements have been constructed primarily through specific identification of assets, liabilities (other than debt), revenues and expenses that relate to the Transmission Business. The Company's long-term debt is allocated based on the respective borrowing requirements of the Company's transmission and distribution businesses. A portion of the Company's shared functions and services costs is allocated to the Transmission Business on a fully allocated-cost basis, consistent with OEB-approved independent studies. Income tax expense has been recorded at effective rates based on income taxes as reported in the statements of operations and comprehensive income as though the Transmission Business was a separate taxpaying entity. These Financial Statements include deferred income taxes and related regulatory balances with respect to the rate-setting treatment of the benefits of the deferred income tax asset resulting from transition from the payments in lieu of tax regime under the *Electricity Act, 1998* (Ontario) to income tax payments under the federal and provincial tax regime which occurred when Hydro One Limited became a public company listed on the Toronto Stock Exchange. Certain other amounts presented in these Financial Statements represent allocations subject to review and approval by the OEB.

Hydro One Networks performed an evaluation of subsequent events through to April 23, 2026, the date these Financial Statements were available to be issued, to determine whether any events or transactions warranted recognition and disclosure in these Financial Statements. See Note 27 – Subsequent Events.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets, regulatory liabilities, post-retirement and post-employment benefits. Actual results may differ significantly from these estimates.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company.

Such change in timing involves the application of rate-regulated accounting in accordance with Financial Accounting Standards Board (FASB) Accounting Standard Codification Topic 980, Regulated Operations within the Transmission Business, giving rise to the recognition of regulatory assets and liabilities. The Transmission Business' regulatory assets represent certain amounts receivable from electricity customers in a future period and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Transmission Business has recorded regulatory liabilities that generally represent amounts that are refundable to electricity customers in future rates. The Transmission Business continually assesses the likelihood of settling its regulatory assets and regulatory liabilities and continues to believe that it is probable that the OEB will include them in setting future rates. If, at some future date, the Transmission Business judges that it is no longer probable that the OEB will include a regulatory asset or regulatory liability in setting future rates, the respective carrying amount would be reflected in results of operations, prospectively from the date the Transmission Business' assessment is made.

Revenue Recognition

Transmission revenues predominantly consist of transmission tariffs, which are collected through OEB-approved uniform transmission rates (UTRs) which are applied against the monthly peak demand for electricity across Hydro One's high-voltage network. OEB-approved UTRs are based on an approved revenue requirement that includes a rate of return. The transmission tariffs are designed to recover revenues necessary to support the Company's transmission system with sufficient capacity to accommodate the maximum expected demand which is influenced by weather and economic conditions. Transmission revenues are recognized as electricity is transmitted and delivered to customers.

Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered. Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Trade accounts receivable represent earned revenue for electricity transmitted and delivered to customers and receivable from the Independent Electricity System Operator (IESO). Trade accounts receivable are recorded at the amount reported by the IESO. No allowance for doubtful accounts is recognized with respect to trade accounts receivable as there is no risk of loss associated with such amounts.

For other accounts receivables, the Transmission Business estimates the current lifetime expected credit losses (CECL) by applying internally developed loss rates to all outstanding receivable balances by aging category on an undiscounted basis. Loss rates applied to the other accounts receivable balances are based on historical overdue balances, customer payments and write-offs, which may be further supplemented from time to time to reflect management's best estimate of the loss. Other accounts receivables are written-off against the allowance when they are deemed uncollectible. The allowance for doubtful accounts is affected by changes in volume, prices and economic conditions.

Income Taxes

Income taxes are accounted for using the asset and liability method. Current income tax assets and current income tax liabilities are recognized based on the income taxes refundable or payable on the current year's taxable income. Current and deferred income taxes are computed based on the tax rates and tax laws enacted as at the balance sheet date. Tax benefits associated with income tax positions are recorded only when the more-likely-than-not recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Financial Statements. Management re-evaluates tax positions each period using new information about recognition or measurement as it becomes available.

Deferred Income Taxes

Deferred income tax assets and deferred income tax liabilities are recognized on all temporary differences between the tax bases and carrying amounts of assets and liabilities, including the carryforward of unused tax credits and tax losses to the extent that it is more-likely-than-not that these deductions, credits, and losses can be utilized. Deferred income tax assets and deferred income tax liabilities are measured at the tax rates that are expected to apply in the period when the asset is realized or the liability is settled, based on the tax rates and tax laws that have been enacted as at the balance sheet date.

Deferred income taxes associated with the Transmission business' regulated operations which are considered to be more-likely-than-not to be recovered or refunded in future regulated rates charged to customers are recognized as deferred income tax regulatory assets and deferred income tax regulatory liabilities with an offset to deferred income tax expense.

Investment tax credits are recorded as a reduction of the related expenses or income tax expense in the current or future period to the extent it is more likely than not that the credits can be utilized.

Management reassesses the deferred income tax assets at each balance sheet date and reduces the amount to the extent that it is more likely than not that the deferred income tax asset will not be realized. Previously unrecognized deferred income tax

assets are reassessed at each balance sheet date and are recognized to the extent that it has become more likely than not that the tax benefit will be realized.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, and implicitly, by the regulated businesses of its subsidiaries. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Transmission Business to and from the pooled bank accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.15%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions, and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the balance sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, and information technology. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis.

Property, plant and equipment in service consists of transmission, administration and service, and other communication assets as well as land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, as well as capitalized project development costs associated with deferred capital projects.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, as well as assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, including transformers, circuit breakers and switches.

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.

Other

Communication assets include fibre optic and microwave radio systems, optical ground wire, towers, telephone equipment and associated buildings. Other assets also include easements which include a statutory easement for the use of transmission corridor and related abutting lands pursuant to Part IX.1 of the *Electricity Act, 1998* (Ontario) (Electricity Act), as well as other land rights for occupation.

Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost, which comprises purchased software, direct labour (including employee benefits), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Transmission Business' intangible assets primarily represent major computer applications.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized financing costs are a reduction of financing charges recognized in the statements of operations and comprehensive income. Capitalized financing costs are calculated using the Transmission Business' weighted average effective cost of debt.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation and Amortization

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and amortization rates, as required by the OEB. Any changes arising from such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The most recent review resulted in changes to rates effective January 1, 2023 for the Transmission Business. A summary of average service lives and depreciation and amortization rates as at December 31, 2025 for the various classes of assets is included below:

	Average Service Life	Rate Range	Rate Average
Property, plant and equipment:			
Transmission	57 years	1% - 2%	2 %
Communication	17 years	1% - 11%	5 %
Administration and service	29 years	1% - 20%	5 %
Intangible assets	12 years	8% - 10%	6 %

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation, with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, the Company evaluates whether impairment may exist by estimating future undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

The carrying costs of most of the Transmission Business' long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable.

Management assesses the fair value of such long-lived assets using commonly accepted techniques. Techniques used to determine fair value include, but are not limited to, the use of recent third-party comparable sales for reference and internally developed discounted cash flow analysis. Significant changes in market conditions, changes to the condition of an asset, or a change in management's intent to utilize the asset are generally viewed by management as triggering events to reassess the cash flows related to these long-lived assets. As at December 31, 2025 and 2024, no asset impairment had been recorded.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Transmission Business defers its proportionate share of the relevant Hydro One external transaction costs related to obtaining financing and presents such amounts net of related debt on the balance sheets. Deferred issuance costs are amortized over the contractual life of the related debt on an effective-interest basis and the amortization is included within financing charges in the statements of operations and comprehensive income. Transaction costs for items classified as held-for-trading are expensed immediately.

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Transmission Business considers the carrying amounts of accounts receivable and amounts due from related parties to be reasonable estimates of fair value because of the short time to maturity of these instruments. All financial instrument transactions are recorded at trade date.

The Transmission Business determines the classification of its financial assets and liabilities at the date of initial recognition. The Transmission Business designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with

the Transmission Business' risk management policy disclosed in Note 15 - Fair Value of Financial Instruments and Risk Management.

Derivative Instruments and Hedge Accounting

Hydro One closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedging relationships. Hydro One's derivative instruments, or portions thereof, are mirrored down to Hydro One Networks, and are allocated between the Company's transmission and distribution businesses. The derivative instruments are classified as fair value hedges or undesignated contracts, consistent with Hydro One's derivative instruments classification.

The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value on the balance sheets. For derivative instruments that qualify for hedge accounting, Hydro One may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. Hydro One offsets fair value amounts recognized on its balance sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, any unrealized gain or loss, net of tax, is recorded as a component of accumulated OCI (AOCI) or accumulated OCL (AOCL). Amounts in AOCI or AOCL are reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations and presented in the same line item as the earnings effect of the hedged item. Any gains or losses on the derivative instrument that represent hedge components excluded from the assessment of effectiveness are recognized in the same line item of the statements of operations as the hedged item. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the statements of operations and comprehensive income (loss) in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the statements of operations and comprehensive income (loss). The changes in fair value of the undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and are carried at fair value on the balance sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. Hydro One does not engage in derivative trading or speculative activities and had no embedded derivatives that required bifurcation as at December 31, 2025 or 2024.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where the Company has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. Hydro One also assesses, both at the inception of the hedge and on a quarterly basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of Hydro One's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

Hydro One recognizes the funded status of its defined benefit pension plan (Pension Plan) and its post-retirement and post-employment plans on its consolidated balance sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Defined benefit pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation (PBO) exceeds the fair value of the plan assets. Liabilities are recognized on the consolidated balance sheets for any net underfunded PBO. The net underfunded PBO may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the PBO of the plan, an asset is recognized equal to the net overfunded PBO. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Hydro One recognizes its contributions to the defined contribution pension plan (DC Plan) as pension expense, with a portion being capitalized as part of labour costs included in capital expenditures. The expensed amount is included in operation, maintenance and administration (OM&A) costs in the consolidated statements of operations and comprehensive income.

Defined Benefit Pension

Hydro One has a contributory defined benefit pension plan covering most regular employees of Hydro One and its subsidiaries, including Hydro One Networks. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the pension plan is accounted for as a defined contribution plan and no pension benefit asset or liability is recorded.

Post-retirement and Post-employment Benefits

Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Networks. The benefit obligations of these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Networks. Accordingly, for purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are reflective of earnings allocations of relevant employees to the Company's Transmission Business.

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. For post-retirement benefits, past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or actuarial losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active employees in the plan or over the remaining life expectancy of inactive employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory account, to the extent of the remeasurement adjustment.

The actuarial gains and actuarial losses on post-employment obligations that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory account, to the extent of the remeasurement adjustment.

All post-retirement and post-employment benefit costs are attributed to labour costs and are either charged to results of operations (OM&A costs) or capitalized as part of the cost of property, plant and equipment and intangible assets (applies to the service cost component of benefit cost) and to regulatory assets for all other components of the benefit cost, consistent with their inclusion in OEB-approved rates.

Stock-Based Compensation

Share Grant Plans

The Company measures share grant plans based on fair value of share grants as estimated based on Hydro One Limited's grant date common share price. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. The Company records a regulatory asset equal to the accrued costs of share grant plans recognized in each period. Costs are transferred from the regulatory asset to labour costs at the time the share grants vest and are recovered in rates. Forfeitures are recognized as they occur.

Deferred Share Unit (DSU) Plans

The Company records the liabilities associated with its Directors' and Management DSU Plans at fair value at each reporting date until settlement, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the DSU liability is based on Hydro One Limited's common share closing price at the end of each reporting period.

Long-term Incentive Plan (LTIP)

The Company measures the awards issued under Hydro One Limited's LTIP, at fair value based on Hydro One Limited grant date common share price. The related compensation expense is recognized over the vesting period on a straight-line basis. Forfeitures are recognized as they occur.

Loss Contingencies

Hydro One and its subsidiaries are involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of the Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a

regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Transmission Business records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Transmission Business.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. The Company records a liability for the estimated future expenditures associated with contaminated land assessment and remediation (LAR) and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. To the extent that the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the anticipated amount of future recovery of these environmental expenditures from customers. Hydro One reviews its estimates of future environmental expenditures annually, or more frequently if there are indications that circumstances have changed. Estimate changes are accounted for prospectively.

Asset Retirement Obligations

Asset retirement obligations are recorded for legal obligations associated with the future removal and disposal of long-lived assets. Such obligations may result from the acquisition, construction, development and/or normal use of the asset. Conditional asset retirement obligations are recorded when there is a legal obligation to perform a future asset retirement activity but where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. In such a case, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. This uncertainty is incorporated in the fair value measurement of the obligation.

When recording an asset retirement obligation, the present value of the estimated future expenditures required to complete the asset retirement activity is recorded in the period in which the obligation is incurred, if a reasonable estimate can be made. In general, the present value of the estimated future expenditures is added to the carrying amount of the associated asset and the resulting asset retirement cost is depreciated over the estimated useful life of the asset. The present value is determined with a discount rate that equates to the Company's credit-adjusted risk-free rate. Where an asset is no longer in service when an asset retirement obligation is recorded, the asset retirement cost is recorded in results of operations.

Leases

At the commencement date of a lease, the minimum lease payments are discounted and recognized as a lease obligation. Discount rates used correspond to the Company's incremental borrowing rates. Renewal options are assessed for their likelihood of being exercised and are included in the measurement of the lease obligation when it is reasonably certain they will be exercised. The Company does not recognize leases with a term of less than 12 months. A corresponding Right-of-Use (ROU) asset is recognized at the commencement date of a lease. The ROU asset is measured as the lease obligation adjusted for any lease payments made and/or any lease incentives and initial direct costs incurred. ROU assets are included in other long-term assets, and corresponding lease obligations are included in other current liabilities and other long-term liabilities on the balance sheets.

Subsequent to the commencement date, the lease expense recognized at each reporting period is the total remaining lease payments over the remaining lease term. Lease obligations are measured as the present value of the remaining unpaid lease payments using the discount rate established at commencement date. The amortization of the ROU assets is calculated as the difference between the lease expense and the accretion of interest, which is calculated using the effective interest method. Lease modifications and impairments are assessed at each reporting period to assess the need for a remeasurement of the lease obligations or ROU assets.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standard Updates (ASUs) issued by the FASB that are applicable to Hydro One Networks:

Recently Adopted Accounting Guidance

Guidance	Date issued	Description	Effective date	Impact on Transmission Business
ASU 2024-02	March 2024	The amendments contain modifications to the codification that remove various concept statements which may be extraneous and not required to understand or apply the guidance or references used in prior statements to provide guidance in certain topical areas.	Fiscal years beginning after December 15, 2024.	No impact upon adoption
ASU 2023-09	December 2023	The amendments address investor requests for more transparency about income tax information through improvements to income tax disclosures primarily related to the rate reconciliation and income taxes paid information.	Annual periods beginning after December 15, 2024.	Adoption of the standard does not materially affect Hydro One Networks' income tax disclosures.

Recently Issued Accounting Guidance Not Yet Adopted

Guidance	Date issued	Description	Effective date	Anticipated Impact on Transmission Business
ASU 2023-06	October 2023	The amendments represent changes to clarify or improve disclosure or presentation requirements of a variety of subtopics in the FASB Codification. Many of the amendments allow users to more easily compare entities subject to the U.S. Securities and Exchange's (SEC) existing disclosures with those entities that were not previously subject to the SEC's requirements. Also, the amendments align the requirements in the Codification with the SEC's regulations. Applicable to all entities, if by June 30, 2027 the SEC has not removed the applicable requirement from Regulation S-X or Regulation S-K, the pending content of the related amendment will be removed from the Codification and will not become effective for any entity.	Two years subsequent to the date on which the SEC's removal of that related disclosure becomes effective.	Under assessment
ASU 2024-03	November 2024	The amendments require public business entities to disclose additional information about specific expense categories in the notes to financial statements at interim and annual reporting periods, which are not generally presented in the current financial statements.	Annual periods beginning after December 15, 2026, and interim periods beginning after December 15, 2027.	Under assessment
ASU 2025-03	May 2025	The amendments require entities to apply the guidance for identifying the accounting acquirer in transactions where a business that qualifies as a Variable Interest Entity is acquired through the exchange of equity interests.	Annual and interim periods beginning after December 15, 2026.	No impact upon adoption
ASU 2025-05	July 2025	The amendments allow all entities to use a practical expedient when estimating expected credit losses for current accounts receivable and contract assets under Topic 606, by assuming that current conditions as of the balance sheet date remain unchanged over the asset's life. Additionally, entities other than public business entities that elect this expedient may adopt an accounting policy to consider post–balance sheet date collection activity in their credit loss estimates.	Annual and interim periods beginning after December 15, 2025.	No impact upon adoption
ASU 2025-06	September 2025	The amendments modernize accounting for internal-use software by removing outdated development stage references and introducing a capitalization threshold based on management authorization and project completion probability.	Annual periods beginning after December 15, 2027.	Under assessment

ASU 2025-09	November 2025	The amendments expand hedge-accounting eligibility and better align the guidance with common risk-management practices. Key updates allow grouping forecasted transactions with similar exposure, simplify hedging of choose-your-rate variable-rate debt, and broaden eligibility for hedging nonfinancial components. The guidance modernizes treatment of certain option-based derivatives and resolves mismatches in dual hedge relationships.	Annual and interim periods beginning after December 15, 2026.	Under assessment
ASU 2025-10	December 2025	The amendments establish authoritative GAAP for government grants, setting recognition, measurement, presentation, and disclosure requirements.	Annual and interim periods beginning after December 15, 2028.	Under assessment
ASU 2025-11	December 2025	The amendments clarify interim reporting by establishing a complete list of required GAAP interim disclosures. They introduce a disclosure principle requiring entities to report material events occurring after the annual reporting period. The Update also clarifies types of interim reports and the form and content of interim financial statements. Overall, the changes enhance clarity and consistency without altering existing disclosure requirements.	Interim reporting periods within annual reporting periods beginning after December 15, 2027.	Under assessment
ASU 2025-12	December 2025	The amendments clarify existing guidance, correct errors, and introduce minor improvements to numerous Codification Topics, thereby making the requirements easier for entities to understand and apply.	Annual and interim periods beginning after December 15, 2026.	Under assessment

4. DEPRECIATION, AMORTIZATION AND ASSET REMOVAL COSTS

Year ended December 31 *(millions of dollars)*	**2025**	**2024**
Depreciation of property, plant and equipment	464	445
Amortization of intangible assets	32	28
Amortization of regulatory assets	1	4
Depreciation and amortization	497	477
Asset removal costs	53	57
	550	534

5. FINANCING CHARGES

Year ended December 31 *(millions of dollars)*	**2025**	**2024**
Interest on long-term debt *(Note 23)*	445	410
Interest on regulatory accounts	12	13
Interest on inter-company demand facility *(Note 23)*	4	8
Other	13	12
Less: Interest capitalized on construction and development in progress	(87)	(70)
	387	373

6. INCOME TAXES

As a rate regulated utility business, the Transmission Business recovers income taxes from its ratepayers based on estimated current income tax expense in respect of its regulated operations. The amounts of deferred income taxes related to regulated operations which are considered to be more likely-than-not to be recoverable from, or refunded to, ratepayers in future periods are recognized as deferred income tax regulatory assets or deferred income tax regulatory liabilities, with an offset to deferred income tax recovery or deferred income tax expense, respectively. The Transmission Business' income tax expense or income tax recovery for the period includes all current and deferred income tax expenses for the period net of the regulated accounting offset to deferred income tax expense arising from temporary differences to be recoverable from, or refunded to, customers in future rates. Thus, the Transmission Business' income tax expense or income tax recovery differs from the amount that would have been recorded using the statutory income tax rate. As the Company operates in Ontario, it is subject to the combined Canadian federal and Ontario statutory rates of 26.5%.

The reconciliation between the statutory and the effective tax rates is provided as follows:

	2025		2024	
Year ended December 31 *(millions of dollars)*	*(millions of dollars)*	*(percentage)*	*(millions of dollars)*	*(percentage)*
Income before income tax expense	920		791	
Income tax expense at statutory rate of 26.5% (2024 - 26.5%)	244	26.5 %	210	26.5 %
Increase (decrease) resulting from:				
Net temporary differences recoverable in future rates charged to customers:				
Capital cost allowance in excess of depreciation and amortization	(64)	(7.0)%	(58)	(7.3)%
Overheads capitalized for accounting but deducted for tax purposes	(29)	(3.2)%	(27)	(3.4)%
Interest capitalized for accounting but deducted for tax purposes	(23)	(2.5)%	(18)	(2.3)%
Pension and post-retirement benefit contributions in excess of expense	(6)	(0.7)%	(8)	(1.0)%
Environmental expenditures	—	— %	(1)	(0.1)%
Other	(5)	(0.5)%	(3)	(0.4)%
Net temporary differences attributable to regulated business	(127)	(13.8)%	(115)	(14.5)%
Net permanent differences	1	0.1 %	2	0.3 %
Total income tax expense	118	12.8 %	97	12.3 %

The major components of income tax expense and income tax recovery are as follows:

Year ended December 31 *(millions of dollars)*	2025	2024
Current income tax expense	161	114
Deferred income tax recovery	(43)	(17)
Total income tax expense	118	97

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and deferred income tax liabilities reflect the future income tax consequences attributable to temporary differences between the tax bases and the financial statement carrying amounts of the assets and liabilities including the carry forward amounts of tax losses and tax credits. Deferred income tax assets and deferred income tax liabilities attributable to the Transmission Business' regulated operations are recognized with a corresponding offset in deferred income tax regulatory assets and deferred income tax liabilities to reflect the anticipated recovery or repayment of these balances in the future electricity rates. As at December 31, 2025 and 2024, deferred income tax assets and deferred income tax liabilities consisted of the following:

As at December 31 *(millions of dollars)*	2025	2024
Deferred income tax assets (liabilities)		
Capital cost allowance in excess of depreciation and amortization	(2,576)	(2,398)
Post-retirement and post-employment benefits expense in excess of cash payments	262	249
Regulatory assets and liabilities	146	104
Environmental expenditures	—	1
Non-capital losses	5	6
Non-depreciable capital property	4	4
Other	(4)	—
	(2,163)	(2,034)
Less: valuation allowance	(4)	(4)
Net deferred income tax liabilities[1]	(2,167)	(2,038)

[1] The net deferred income tax liabilities are presented on the balance sheets as long-term.

7. OTHER CURRENT ASSETS

As at December 31 *(millions of dollars)*	2025	2024
Prepaid expenses and other assets	41	38
Materials and supplies	17	17
Regulatory assets *(Note 10)*	3	21
	61	76

8. PROPERTY, PLANT AND EQUIPMENT

As at December 31, 2025 *(millions of dollars)*	Property, Plant and Equipment[1]	Accumulated Depreciation	Construction in Progress	Total
Transmission	22,517	7,278	2,089	17,328
Administration and service	1,000	392	22	630
Other	1,750	1,167	43	626
	25,267	8,837	2,154	18,584

[1] Includes future use assets totaling $208 million.

As at December 31, 2024 *(millions of dollars)*	Property, Plant and Equipment[1]	Accumulated Depreciation	Construction in Progress	Total
Transmission	21,260	6,962	1,531	15,829
Administration and service	935	380	48	603
Other	1,733	1,102	32	663
	23,928	8,444	1,611	17,095

[1] Includes future use assets totaling $217 million.

On December 17, 2024, transmission assets related to the Chatham to Lakeshore Transmission Line Project totalling $203 million were transferred from Hydro One Networks to Chatham x Lakeshore Limited Partnership, a subsidiary of Hydro One. See Note 16 - Capital Management.

Financing charges capitalized on property, plant and equipment under construction were $86 million in 2025 (2024 - $68 million).

9. INTANGIBLE ASSETS

As at December 31, 2025 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	624	351	19	292
Other	18	13	—	5
	642	364	19	297

As at December 31, 2024 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	584	321	24	287
Other	18	11	—	7
	602	332	24	294

Financing charges capitalized to intangible assets under development were $1 million in 2025 (2024 - $2 million). The estimated annual amortization expense for intangible assets are as follows: 2026 - $34 million; 2027 - $34 million; 2028 - $33 million; 2029 - $29 million; and 2030 - $26 million.

10. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. The Transmission Business has recorded the following regulatory assets and liabilities:

As at December 31 *(millions of dollars)*	2025	2024
Regulatory assets:		
Deferred income tax regulatory asset	2,306	2,131
Stock-based compensation	8	10
Incremental cloud computing implementation costs deferral	7	4
Excess export service revenue variance	—	18
Other	12	11
Total regulatory assets	2,333	2,174
Less: current portion	(3)	(21)
	2,330	2,153
Regulatory liabilities:		
Earnings sharing mechanism (ESM) deferral	173	68
Post-retirement and post-employment benefits	147	163
External revenue variance	73	49
Asset removal costs cumulative variance	43	26
Capitalized overhead tax variance	30	23
OPEB asymmetrical carrying charge	27	19
Other	24	16
Total regulatory liabilities	517	364
Less: current portion	(67)	—
	450	364

Deferred Income Tax Regulatory Asset

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. The Transmission Business has recognized regulatory assets that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Transmission Business' income tax expense would have been recognized using the liability method and there would be no regulatory accounts established for income taxes to be recovered through future rates.

Stock-based Compensation

The Transmission Business recognizes costs associated with share grant plans as a regulatory asset as management considers it probable that share grant plans' costs will be recovered in the future through the rate-setting process. Share grant costs are transferred to labour costs at the time they vest and are issued, and are recovered in rates in accordance with recovery of these labour costs.

Incremental Cloud Computing Implementation Costs Deferral

On November 2, 2023, the OEB issued an Accounting Order approving the establishment of a generic sector-wide deferral account, effective December 1, 2023. The account was established to record incremental cloud computing implementation costs.

Excess Export Service Revenue Variance

The excess export service revenue variance account balance reflects the difference between the Transmission Business' actual export service revenue, and the OEB-approved amounts. As part of the OEB's Decision and Order in the Generic Hearing on Uniform Transmission Rates-Related Issues and the Export Transmission Service Rate, the OEB stated that it considered it appropriate for the Transmission Business to dispose of the balance on an annual basis starting with the 2023 final balance until the effective date of the next transmission rebasing. As a result of this decision, the regulatory asset relating to the excess export service revenues was separately presented from the External Revenue Variance Account for the prior year. On December 11, 2024, as part of the Decision and Order on 2025 transmission rates, the OEB approved the disposition of the account balance as at December 31, 2023, including accrued interest, over a one-year period that ended December 31, 2025. The regulatory liability balance as at December 31, 2025 was $1 million.

ESM Deferral

In April 2020, the OEB approved the establishment of an earnings sharing mechanism deferral account for the Transmission Business to record over-earnings including tax impacts, if any, realized for any year from 2020 to 2022. Under this mechanism,

Hydro One shares 50% of regulated earnings that exceed the OEB-approved regulatory return-on-equity by more than 100 basis points with transmission ratepayers. As part of the JRAP Decision received in November 2022, the account was approved for continuance for the Transmission Business for 2023 to 2027. The OEB also approved the disposition of the ESM deferral account balance as at December 31, 2024, including accrued interest, over a one-year period ending December 31, 2026.

Post-Retirement and Post-Employment Benefits

In accordance with OEB rate orders, post-retirement and post-employment benefits costs are recovered on an accrual basis. The Transmission Business recognizes the net unfunded or funded status of post-retirement and post-employment obligations on the balance sheets with an incremental offset to the associated regulatory asset or regulatory liability, as the case may be. A regulatory asset or regulatory liability is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered or returned in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to the present value of the actuarially determined benefit obligation at each year end based on an annual actuarial report, with an offset to the associated regulatory asset or regulatory liability, as the case may be, to the extent of the remeasurement adjustment.

External Revenue Variance

The external revenue variance account balance reflects the difference between the Transmission Business' actual external revenues from secondary land use, and the OEB-approved amounts. The account also records the difference between actual net external station maintenance, engineering and construction services revenue, and other external revenue, and the OEB-approved amounts.

Asset Removal Costs Cumulative Variance

In April 2020, the OEB approved the establishment of an asset removal costs cumulative variance account for the Transmission Business to record the difference between the revenue requirement associated with forecast asset removal costs included in depreciation expense and actual asset removal costs. This account is asymmetrical to the benefit of ratepayers on a cumulative basis. As part of the JRAP Decision received in November 2022, the OEB approved the continuance of this account for the Transmission business for the 2023 to 2027 period.

Capitalized Overhead Tax Variance

As part of the JRAP Decision, the OEB approved the establishment of a capitalized overhead tax variance account to capture the difference between the capitalized overheads deducted in calculating the regulatory tax expense included in rates and the actual capitalized overhead costs deducted in Hydro One's tax returns for the Transmission Business for the 2016 to 2027 period. Variance amounts are recognized at the earlier of (i) when the tax year has been audited by the Canada Revenue Agency or (ii) when the taxation year is statute barred.

OPEB Asymmetrical Carrying Charge

On September 14, 2017, the OEB issued its Report of the Board: *Regulatory Treatment of Pension and OPEB Costs* that allowed rate-regulated utilities to track the difference between their pension and OPEB costs calculated under the accrual method and the cash payment method, effective January 1, 2018, and record the carrying charges associated with the balance on an asymmetrical basis. As part of the JRAP Decision received in November 2022, the OEB approved the modification of this account for the Transmission Business for 2023 to 2027.

11. OTHER LONG-TERM ASSETS

As at December 31 *(millions of dollars)*	**2025**	**2024**
Right-of-Use assets *(Note 20)*	18	22
Cloud Computing Implementation Cost	9	11
Other long-term assets	5	9
	32	42

12. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

As at December 31 *(millions of dollars)*	2025	2024
Accrued liabilities	275	224
Accounts payable	258	204
Unearned revenue	334	364
Accrued interest *(Note 23)*	124	109
Regulatory liabilities *(Note 10)*	67	—
Lease obligations *(Note 20)*	5	6
Derivative liability	3	3
Environmental liabilities *(Note 18)*	—	3
	1,066	913

13. OTHER LONG-TERM LIABILITIES

As at December 31 *(millions of dollars)*	2025	2024
Post-retirement and post-employment benefit liability *(Note 17)*	701	669
Lease obligations *(Note 20)*	13	16
Long-term accounts payable and other liabilities	13	14
Asset retirement obligations *(Note 19)*	10	9
Long-term inter-company payable *(Note 23)*	6	7
Environmental liabilities *(Note 18)*	1	1
Derivative liability	—	2
	744	718

14. DEBT

Hydro One issues notes for long-term financing under its Medium-Term Note (MTN) Program. The terms of certain issuances are mirrored down to Hydro One Networks through the issuance of inter-company debt, and are allocated between the Company's transmission and distribution businesses. The following table presents long-term debt allocated to the Transmission Business outstanding as at December 31, 2025 and 2024:

As at December 31 *(millions of dollars)*	2025	2024
Long-term debt	10,896	9,909
Add: Net unamortized debt premiums	20	21
Add: Realized mark-to-market gain[1]	—	2
Less: Deferred debt issuance costs	(39)	(35)
Less: Long-term debt payable within one year	(504)	(660)
Long-term debt	10,373	9,237

[1] In October 2023, Hydro One entered into a $400 million fixed-to-floating interest-rate swap agreement to convert the $400 million Medium Term Note (MTN) Series 57 notes matured October 20, 2025, into a variable rate debt. $244 million was allocated to the Transmission Business. This swap was accounted for as a fair value hedge. In December 2023, this swap was terminated with a $6 million payment received on settlement, of which $4 million was allocated to the Transmission Business that is being amortized over the term of the related note.

In 2025, Hydro One issued $2,700 million long-term debt under its MTN Program (2024 - $2,750 million), of which $2,700 million (2024 - $2,531 million) was mirrored down to Hydro One Networks, and $1,647 million (2024 - $1,544 million) was allocated to the Transmission Business.

In 2025, Hydro One repaid $1,150 million (2024 - $700 million) of maturing long-term debt under its MTN Program. Hydro One Networks repaid inter-company debt of $1,024 million (2024 - $700 million) to Hydro One, of which $660 million (2024 - $413 million) was allocated to the Transmission Business.

Principal and Interest Payments

As at December 31, 2025, future principal repayments, interest payments, and related weighted-average interest rates were as follows:

	Long-Term Debt Principal Repayments	Interest Payments	Weighted Average Interest Rate
	(millions of dollars)	*(millions of dollars)*	*(%)*
Year 1	504	482	3.1
Year 2	—	473	—
Year 3	555	458	5.2
Year 4	636	439	3.7
Year 5	476	408	5.3
	2,171	2,260	4.3
Years 6-10	3,197	1,710	4.3
Thereafter	5,528	3,024	4.6
	10,896	6,994	4.5

15. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

The Transmission Business classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One Networks has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those, other than quoted market prices included within Level 1, that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest-rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

As at December 31, 2025 and 2024, the carrying amounts of accounts receivable, due from related parties, inter-company demand facility, accounts payable, and due to related parties are representative of fair value due to the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The carrying values and fair values of the Transmission Business' long-term debt as at December 31, 2025 and 2024 are as follows:

As at December 31 *(millions of dollars)*	2025 Carrying Value	2025 Fair Value	2024 Carrying Value	2024 Fair Value
Long-term debt, including current portion	10,877	10,744	9,897	9,879

Fair Value Measurements of Derivative Instruments

Hydro One enters into interest-rate swaps agreements with respect to its long-term debt. The terms of certain of these interest-rate swap agreements are mirrored down to Hydro One Networks, and are allocated between the Company's transmission and distribution businesses.

As at December 31, 2025 and 2024, Hydro One had no fair value hedges.

As at December 31, 2025, the value of the Company's derivative instruments was $4 million (2024 - $7 million), of which $3 million (2024 - $5 million) was allocated to the Transmission Business.

As at December 31, 2025 and 2024, the Company had no interest-rate swaps classified as undesignated contracts.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities as at December 31, 2025 and 2024 is as follows:

As at December 31, 2025 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Long-term debt, including current portion	10,877	10,744	—	10,744	—
Derivative instruments					
Cash flow hedges, including current portion	3	3	—	3	—
	10,880	10,747	—	10,747	—

As at December 31, 2024 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Long-term debt, including current portion	9,897	9,879	—	9,879	—
Derivative instruments					
Cash flow hedges, including current portion	5	5	—	5	—
	9,902	9,884	—	9,884	—

The fair value of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no transfers between any of the fair value levels during the years ended December 31, 2025 or 2024.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss which results from changes in values, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates, as its regulated return on equity is derived using a formulaic approach that takes anticipated interest rates into account. The Company is not currently exposed to material commodity price risk or material foreign exchange risk.

Hydro One Networks uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. Hydro One Networks also uses derivative financial instruments to manage interest-rate risk. Hydro One's derivative instruments, or portions thereof, are mirrored down to Hydro One Networks, and are allocated between the Company's transmission and distribution businesses. Hydro One Networks may utilize interest-rate swaps designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt, and may also utilize interest-rate derivative instruments, such as cash flow hedges, to manage its exposure to short-term interest rates or to lock in interest-rate levels on forecasted financing.

A hypothetical 100 basis point increase in interest rates associated with variable-rate debt would not have resulted in a significant decrease to the Company's net income for the years ended December 31, 2025 and 2024, respectively.

For derivative instruments that are designated and qualify as cash flow hedges, the unrealized gain or loss, after tax, on the derivative instrument is recorded as OCI or OCL and is reclassified to net income or net loss in the same period during which the hedged transaction affects results of operations. The following table shows the amounts recorded in OCL and reclassified to financing charges for the years ended December 31, 2025 and 2024:

	Hydro One		Transmission Business	
Year ended December 31 *(millions of dollars)*	**2025**	**2024**	**2025**	**2024**
Amounts recorded in OCI/OCL				
Before tax loss	2	1	1	1
After tax loss	1	1	1	1
Amounts reclassified to financing charges				
Before tax loss (gain)	4	(4)	2	(2)
After tax loss (gain)	3	(3)	2	(2)

The Company estimates that the amount of AOCL, after tax, related to cash flow hedges to be reclassified to results of operations in the next 12 months is approximately $3 million, of which approximately $2 million will be allocated to the Transmission Business. Actual amounts reclassified to results of operations depend on the interest rate in effect until the derivative contracts mature. For all forecasted transactions, as at December 31, 2025, the maximum term over which the Company is hedging exposures to the variability of cash flows is less than one year.

The Pension Plan manages market risk by diversifying investments in accordance with the Pension Plan's Statement of Investment Policies and Procedures. Interest rate risk arises from the possibility that changes in interest rates will affect the fair value of the Pension Plan's financial instruments. In addition, changes in interest rates can also impact discount rates which impact the valuation of the pension and post-retirement and post-employment liabilities. Currency risk is the risk that the value of the Pension Plan's financial instruments will fluctuate due to changes in foreign currencies relative to the Canadian dollar. Other price risk is the risk that the value of the Pension Plan's investments in equity securities will fluctuate as a result of changes in market prices, other than those arising from interest risk or currency risk. All three factors may contribute to changes in values of the Pension Plan investments. See Note 17 – Pension and Post-Retirement and Post-Employment Benefits for further details.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. As at December 31, 2025 and 2024, there were no significant concentrations of credit risk with respect to any class of financial assets. The Transmission Business' revenue is earned from a broad base of customers. As a result, the Transmission Business did not earn a material amount of revenue from any single customer. As at December 31, 2025 and 2024, there was no material accounts receivable balance due from any single customer.

As at December 31, 2025, the allowance for doubtful accounts reflects the Transmission Business' CECL for all accounts receivable balances, which are based on historical overdue balances, customer payments and write-offs. As at December 31, 2025, approximately 4% (2024 - 1%) of the Transmission Business' net accounts receivable were outstanding for more than 60 days.

Hydro One manages its counterparty credit risk through various techniques including (i) entering into transactions with highly rated counterparties, (ii) limiting total exposure levels with individual counterparties, (iii) entering into master agreements which enable net settlement and the contractual right of offset, and (iv) monitoring the financial condition of counterparties. Hydro One monitors current credit exposure to counterparties on both an individual and an aggregate basis. The Company's counterparty credit risk profile is consistent with Hydro One. The Transmission Business' credit risk for accounts receivable is limited to the carrying amounts on the balance sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The maximum credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts in an asset position at the reporting date. As at December 31, 2025, and 2024, Hydro One's credit exposure for all derivative instruments and applicable payables was with one financial institution with investment grade credit ratings as counterparty.

The Pension Plan manages its counterparty credit risk with respect to bonds by investing in investment-grade corporate and government bonds and with respect to derivative instruments by transacting only with highly rated financial institutions and by ensuring that exposure is diversified across counterparties.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One Networks meets its short-term operating liquidity requirements through the inter-company demand facility with Hydro One and funds from operations. The short-term liquidity available to the Company is expected to be sufficient to fund the Company's operating requirements.

16. CAPITAL MANAGEMENT

The Transmission Business' objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. As at December 31, 2025 and 2024, the Transmission Business' capital structure was as follows:

As at December 31 *(millions of dollars)*	**2025**	**2024**
Long-term debt payable within one year	504	660
Inter-company demand facility	(46)	7
	458	667
Long-term debt	10,373	9,237
Excess of assets over liabilities	6,324	5,981
Total capital	17,155	15,885

The following table shows the movements in the excess of assets over liabilities for the years ended December 31, 2025 and 2024:

Year ended December 31 *(millions of dollars)*	**2025**	**2024**
Excess of assets over liabilities - beginning	5,981	5,932
Comprehensive income	803	693
Payments to Hydro One to finance dividends	(460)	(441)
Other[1]	—	(203)
Excess of assets over liabilities - ending	6,324	5,981

[1]The 2024 amount includes $203 million related to transmission assets transferred from the Transmission Business to CLLP. See Note 8 - Property, Plant and Equipment.

17. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a Pension Plan, a supplementary pension plan (Supplementary Plan), and post-retirement and post-employment benefit plans (Benefit Plans), and a DC Plan.

Pension Plan and Supplementary Plan

The Pension Plan is a defined benefit contributory plan which covers eligible regular employees of Hydro One and its subsidiaries. The Pension Plan provides benefits based on highest three-year average pensionable earnings up to March 31, 2025. Beginning April 1, 2025, all service for all groups on a go-forward basis will be calculated using the highest five-year average pensionable earnings. For management employees who commenced employment on or after January 1, 2004, and for the Society of United Professionals (Society)-represented staff hired after November 17, 2005, benefits are based on the highest five-year average pensionable earnings for all their service. After retirement, pensions are indexed to inflation. Membership in the Pension Plan was closed to management employees who were not eligible to join the Pension Plan as of September 30, 2015. These employees are eligible to join the DC Plan.

Company and employee contributions to the Pension Plan are based on actuarial reports, including valuations performed at least every three years, and actual or projected levels of pensionable earnings, as applicable. The most recent actuarial valuation was performed effective December 31, 2024 and filed on September 23, 2025. The Transmission Business' total annual cash Pension Plan employer contributions for 2025 were $28 million (2024 - $34 million). The Transmission Business' estimated annual Pension Plan employer contributions for the years 2026, 2027, 2028, 2029, and 2030 are approximately $35 million, $40 million, $43 million, $41 million, and $40 million, respectively.

The Supplementary Plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan beyond the limitations imposed by the *Income Tax Act* (Canada). The Supplementary Plan obligation is included with other post-retirement and post-employment benefit obligations on the balance sheets.

As at December 31, 2025, the present value of Hydro One's projected pension benefit obligation was estimated to be $8,907 million (2024 - $8,686 million). The fair value of pension plan assets available for these benefits was $9,517 million (2024 - $9,333 million).

Post-Retirement and Post-Employment Plans

The Company accounts for post-retirement and post-employment costs consistent with their inclusion in OEB-approved rates. During the year ended December 31, 2025, for the Transmission Business, post-retirement and post-employment costs of $52 million (2024 - $50 million) were attributable to labour, of which $33 million (2024 - $29 million) was charged to operations, and $19 million (2024 - $21 million) was capitalized as part of the cost of property, plant and equipment and intangible assets. Benefits paid in 2025 were $32 million (2024 - $33 million).

The Transmission Business presents its post-retirement and post-employment benefit liabilities on its balance sheets as follows:

As at December 31 *(millions of dollars)*	**2025**	**2024**
Accrued liabilities	36	35
Post-retirement and post-employment benefit liability	701	669
Net unfunded status	737	704

DC Plan

Hydro One established a DC Plan effective January 1, 2016. The DC Plan covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One up to an annual contribution limit. There is also a Supplementary Notional Plan that provides members of the DC Plan with employer contributions beyond the limitations imposed by the *Income Tax Act* (Canada) in the form of credits to a notional account. The Transmission Business contributions to the DC Plan for the year ended December 31, 2025 were $2 million (2024 - $2 million).

18. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2025 and 2024:

Year ended December 31, 2025 *(millions of dollars)*	**PCB**	**LAR**	**Total**
Environmental liabilities - beginning	3	1	4
Expenditures	(2)	—	(2)
Revaluation adjustment	(1)	—	(1)
Environmental liabilities - ending	—	1	1
Less: current portion	—	—	—
	—	1	1

Year ended December 31, 2024 *(millions of dollars)*	**PCB**	**LAR**	**Total**
Environmental liabilities - beginning	8	2	10
Expenditures	(3)	(1)	(4)
Revaluation adjustment	(2)	—	(2)
Environmental liabilities - ending	3	1	4
Less: current portion	(3)	—	(3)
	—	1	1

As at December 31, 2025, the estimated future environmental expenditures were as follows:

(millions of dollars)	
2026	—
2027	1
Thereafter	—
	1

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred in order to generate future cash flow information. All factors used in estimating the Transmission Business' environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, with respect to the PCB environmental liability, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures.

PCBs

Environment and Climate Change Canada regulations, enacted under the *Canadian Environmental Protection Act, 1999*, govern the management, storage and disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under previous regulations, the Transmission Business' PCBs were to be disposed of by the end of 2025, with the exception of specifically exempted equipment. On December 31st, 2025, regulations amending the *Canadian*

Environmental Protection Act, 1999 were published in the Canada Gazette, Part II. The amendments include deferring the end-of-use deadline for certain PCB-containing electrical equipment from December 31, 2025 to December 31, 2026. Contaminated equipment will generally be replaced, or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains PCBs in concentrations of less than two parts per million.

As at December 31, 2025, the Transmission Business' best estimate of the total future expenditures to comply with current PCB regulations was $nil (2024 - $3 million). As a result of its annual review of environmental liabilities, the Transmission Business recorded a revaluation adjustment in 2025 to decrease the PCB environmental liability by $1 million (2024 - $2 million).

LAR

As at December 31, 2025, the Transmission Business' best estimate of the total future expenditures to complete its LAR program was $1 million (2024 - $1 million). These expenditures are expected to be incurred over the period from 2026 to 2028. As a result of its annual review of environmental liabilities, the Transmission Business recorded a revaluation adjustment that was less than $1 million to the LAR environmental liability (2024 - $nil).

19. ASSET RETIREMENT OBLIGATIONS

Hydro One Networks records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities. Asset retirement obligations, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an asset retirement obligation is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the asset retirement obligation, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

Some of the Company's transmission assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its facilities in perpetuity, no asset retirement obligations have been recorded for these assets. If, at some future date, a particular facility is shown not to meet the perpetuity assumption, it will be reviewed to determine whether an estimable asset retirement obligation exists. In such a case, an asset retirement obligation would be recorded at that time.

In determining the amounts to be recorded as asset retirement obligations, the Company estimates the current fair value for completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 1.0% to 3.0% (2024 - 1.0% to 3.0%), depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's Transmission Business' asset retirement obligations represent management's best estimates of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Asset retirement obligations are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively. As a result of its annual review of asset retirement obligations, there was an increase of $1 million (2024 - $nil) to the asset retirement obligations recorded in 2025.

As at December 31, 2025, Hydro One Networks had recorded asset retirement obligations of $10 million (2024 - $9 million) related to the Transmission Business, primarily consisting of the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities.

20. LEASES

Hydro One has operating lease contracts for buildings used in administrative and service-related functions. These leases have terms between three and five years with renewal options of additional three- to five-year terms at prevailing market rates at the time of extension. All leases include a clause to enable upward revision of the rental charge on an annual basis or on renewal according to prevailing market conditions or pre-established rents. There are no restrictions placed upon Hydro One by entering into these leases. Renewal options are included in the lease term when their exercise is reasonably certain. Other information related to the Transmission Business' operating leases was as follows:

Year ended December 31 *(millions of dollars)*	**2025**	**2024**
Lease expense	8	7
Lease payments made	8	7

As at December 31	**2025**	**2024**
Weighted-average remaining lease term[1] *(years)*	3	4
Weighted-average discount rate	2.9 %	2.9 %

[1] Includes renewal options that are reasonably certain to be exercised.

As at December 31, 2025, future minimum operating lease payments were as follows:

(millions of dollars)	
2026	6
2027	6
2028	4
2029	2
2030	1
Thereafter	—
Total undiscounted minimum lease payments	19
Less: discounting minimum lease payments to present value	(1)
Total discounted minimum lease payments	18

As at December 31, 2024, future minimum operating lease payments were as follows:

(millions of dollars)	
2025	7
2026	6
2027	5
2028	4
2029	1
Thereafter	1
Total undiscounted minimum lease payments	24
Less: discounting minimum lease payments to present value	(2)
Total discounted minimum lease payments	22

Hydro One presents its ROU assets and lease obligations on the balance sheets as follows:

As at December 31 *(millions of dollars)*	**2025**	**2024**
Right-of-Use assets	18	22
Accounts payable and other current liabilities *(Note 12)*	5	6
Other long-term liabilities *(Note 13)*	13	16

21. HYDRO ONE NETWORKS' SHARE CAPITAL

Hydro One Networks is authorized to issue an unlimited number of common and preferred shares. As at December 31, 2025 and 2024, Hydro One Networks had 209,401,290 common shares issued and outstanding and no preferred shares issued and outstanding.

During 2025, Hydro One Networks declared common share dividends in the amount of $792 million (2024 - $753 million) to Hydro One. The amount allocated to the Transmission Business to finance these dividends was $460 million (2024 - $441 million).

22. STOCK-BASED COMPENSATION

The following compensation plans were established by Hydro One Limited, however they represent components of compensation costs of Hydro One and its subsidiaries, including Hydro One Networks, in current and future periods.

Share Grant Plans

Hydro One Limited has two share grant plans (Share Grant Plans), one for the benefit of certain members of the Power Workers' Union (PWU) (PWU Share Grant Plan) and one for the benefit of certain members of the Society (Society Share Grant Plan). Hydro One and Hydro One Limited entered into an intercompany agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with these plans. The agreement requires Hydro One Networks to reimburse Hydro One for the value of shares granted to the Company's eligible employees relating to these plans.

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the PWU annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on April 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. The requisite service period for the PWU Share Grant Plan began on July 3, 2015, which is the date the share grant plan was ratified by the PWU. The number of common shares issued annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the Initial Public Offering (IPO). The aggregate number of Hydro One Limited common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015,1,761,152 Hydro One Limited common shares were granted under the PWU Share Grant Plan relevant to the total stock-based compensation recognized by the Transmission Business.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the Society annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on September 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. Therefore the requisite service period for the Society Share Grant Plan began on September 1, 2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 608,626 Hydro One Limited common shares were granted under the Society Share Grant Plan relevant to the total stock-based compensation recognized by the Transmission Business.

The fair value of the Hydro One Limited 2015 share grants to employees of Hydro One Networks and allocated to the Transmission Business was $49 million. The fair value was estimated based on the grant date Hydro One Limited share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. In 2025, 138,482 common shares of Hydro One Limited were issued under the Share Grant Plans (2024 - 160,233) to eligible employees of Hydro One Networks and allocated to the Transmission Business. Total stock-based compensation recognized by the Transmission Business during 2025 was $1 million (2024 - less than $1 million) and was recorded as a regulatory asset.

A summary of the Transmission Business' share grant activity under the Share Grant Plans during the years ended December 31, 2025 and 2024 is presented below:

Year ended December 31, 2025	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	676,712	$20.50
Granted	—	—
Vested and issued[1]	(138,482)	—
Forfeited	(19,088)	$20.50
Share grants outstanding - ending	519,142	$20.50

[1] In 2025, Hydro One Limited issued common shares from treasury to eligible Hydro One Networks employees in accordance with provisions of the Share Grant Plans. In accordance with the intercompany agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

Year ended December 31, 2024	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	849,400	$20.50
Granted	516	—
Vested and issued[1]	(160,233)	—
Forfeited	(12,971)	$20.50
Share grants outstanding - ending	676,712	$20.50

[1] In 2024, Hydro One Limited issued common shares from treasury to eligible Hydro One Networks employees in accordance with provisions of the Share Grant Plans. In accordance with the intercompany agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

Directors' DSU Plan

Under the Directors' DSU Plan, directors can elect to receive credit for their annual cash retainer in a notional account of DSUs in lieu of cash. Hydro One Limited Board of Directors may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled. Each DSU represents a unit with an underlying value equivalent to the value of one common share of Hydro One Limited and is entitled to accrue Hydro One Limited common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One Limited Board of Directors.

During 2025 and 2024, Directors' DSU Plan awards granted by Hydro One Limited that related to Hydro One Network's Transmission Business were as follows:

Year ended December 31 *(number of DSUs)*	2025	2024
DSUs outstanding - beginning	35,288	31,538
Granted	6,223	6,597
Settled	(7,715)	(2,847)
DSUs outstanding - ending	33,796	35,288

For the years ended December 31, 2025 and 2024, the expense related to the Directors' DSU Plan was less than $1 million. As at December 31, 2025, the liability related to Directors' DSUs was $2 million (2024 - $1 million).

Management DSU Plan

Under the Management DSU Plan, eligible executive employees can elect to receive a specified proportion of their annual short-term incentive in a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of Hydro One Limited and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One Limited Board of Directors.

During 2025 and 2024, Management DSU Plan awards granted by Hydro One Limited that related to Hydro One Network's Transmission Business were as follows:

Year ended December 31 *(number of DSUs)*	2025	2024
DSUs outstanding - beginning	26,677	27,615
Granted	3,889	4,564
Paid	(1,946)	(5,502)
DSUs outstanding - ending	28,620	26,677

To comply with the Accountability Act and the OEB Act, in 2019 Hydro One Limited removed all executive-related compensation from the labour costs of its regulated subsidiaries. During the years ended December 31, 2025 and 2024, no executive-related stock-based compensation was allocated to the regulated businesses of Hydro One Networks.

Employee Share Ownership Plan

In 2015, Hydro One Limited established Employee Share Ownership Plans (ESOP) for certain eligible management and non-represented employees (Management ESOP) and for certain eligible Society-represented staff (Society ESOP). Under the Management ESOP, the eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 50% of their contributions, up to a maximum Company contribution of $25,000 per calendar year. Under the Society ESOP, the eligible Society-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 25% of their contributions, with no maximum Company contribution per calendar year.

In 2024, Hydro One established ESOP for certain eligible PWU represented staff (PWU ESOP). Under the PWU ESOP, the eligible PWU-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One. The Company matches 33% of their contribution, with no maximum Company contribution per calendar year. In 2025, Company contributions made under the ESOP and allocated to the Transmission Business were $5 million (2024 - $2 million).

LTIP

Effective August 31, 2015, the Board of Directors of Hydro One adopted an LTIP. Under the LTIP, long-term incentives were granted to certain executive and management employees of Hydro One and its subsidiaries, and all equity-based awards would either be settled in newly issued shares of Hydro One from treasury or cash, subject to Hydro One's discretion, consistent with the provisions of the plan which also permit the participants to surrender a portion of their awards to satisfy related withholding taxes requirements. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares of Hydro One.

The LTIP provides flexibility to award a range of vehicles, including Performance Share Units (PSUs), RSUs, stock options, share appreciation rights, restricted shares, DSUs, and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance.

PSUs and RSUs

A summary of PSU and RSU awards activity under the LTIP during the years ended December 31, 2025 and 2024 is presented below:

	PSUs		RSUs	
Year ended December 31 *(number of units)*	2025	2024	2025	2024
Units outstanding – beginning	65,826	33,388	130,663	75,484
Granted	38,356	34,171	61,828	62,087
Forfeited	(14,707)	(1,255)	(22,333)	(5,574)
Settled	(9,247)	(478)	(10,029)	(1,334)
Units outstanding – ending	80,228	65,826	160,129	130,663

To comply with the Accountability Act and the OEB Act, in 2019 Hydro One Limited removed all executive-related compensation from the labour costs of its regulated subsidiaries. During the years ended December 31, 2025 and 2024, no executive-related stock-based compensation was allocated to the regulated businesses of Hydro One Networks.

The grant date total fair value of the awards granted during the year ended December 31, 2025 was $5 million (2024 - $4 million). The compensation expense related to the PSU and RSU awards recognized by the Company during 2025 was $4 million (2024 - $4 million). As at December 31, 2025, the payable relating to PSU awards included in due to related parties on the balance sheets was $1 million (2024 - not significant).

23. RELATED PARTY TRANSACTIONS

The Transmission Business is a separately regulated business of Hydro One Networks which is indirectly owned by Hydro One Limited. The Province of Ontario is a shareholder of Hydro One Limited with approximately 47.1% ownership as at December 31, 2025. The IESO, Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), and the OEB, are related parties to Hydro One Networks because they are controlled or significantly influenced by the Ministry of Energy and Mines. B2M Limited Partnership (B2M LP), Niagara Reinforcement Limited Partnership (NRLP), and Chatham x Lakeshore Limited Partnership (CLLP) are subsidiaries of Hydro One Networks, Hydro One Sault Ste. Marie LP (HOSSM) is a subsidiary of Hydro One, and Acronym Solutions Inc. (Acronym) is a subsidiary of Hydro One Limited. The Transmission Business also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province. The following is a summary of the Transmission Business' related party transactions during the years ended December 31, 2025 and 2024:

Year ended December 31 *(millions of dollars)*			
Related Party	**Transaction**	**2025**	**2024**
IESO	Revenues for transmission services	2,271	2,162
OPG	Capital contribution received from OPG	20	3
	Costs related to the purchase of services	1	1
	Revenues related to provision of construction and equipment maintenance services	2	2
OEB	OEB fees	7	6
Hydro One	Payments to finance dividends	460	441
	Interest expense on long-term debt	445	410
	Interest expense on inter-company demand facility	4	8
	Stock-based compensation costs	5	4
	Services received - costs expensed	4	3
B2M LP	Revenues for services provided	2	1
NRLP	Revenues for services provided	1	1
CLLP	Transfer of assets	—	203
	Revenues for services provided	4	—
HOSSM	Revenues for services provided	79	72
Hydro One Networks' Distribution Business	Revenues for services provided	2	3
	Capital contribution received	6	8
Acronym	Services received - costs expensed	23	23
	Revenues for services provided	6	3
Hydro One Limited and its other subsidiaries	Revenues for services provided	—	1
	Services received - costs recovered	6	5

The amounts due to and from related parties as at December 31, 2025 and 2024 are as follows:

As at December 31 *(millions of dollars)*	**2025**	**2024**
Due from related parties	207	187
Long-term inter-company payable	(6)	(7)
Accrued interest	(124)	(109)
Inter-company demand facility	46	(7)
Long-term debt, including current portion	(10,877)	(9,897)

24. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 *(millions of dollars)*	2025	2024
Accounts receivable	—	15
Due from related parties	(20)	(25)
Materials and supplies	—	1
Other assets	3	(17)
Accounts payable	54	(4)
Accrued liabilities	(2)	191
Unearned revenue	(30)	122
Accrued interest	15	17
Due to related parties	1	—
Long-term accounts payable and other liabilities	(1)	2
Post-retirement and post-employment benefit liability	16	11
	36	313

Capital Expenditures

The following tables reconcile investments in property, plant and equipment and intangible assets and the amounts presented in the statements of cash flows for the years ended December 31, 2025 and 2024. The reconciling items include net change in accruals, transfers, and capitalized depreciation.

Year ended December 31, 2025 *(millions of dollars)*	Property, Plant and Equipment	Intangible Assets	Total
Capital investments	(1,987)	(34)	(2,021)
Reconciling items	151	(1)	150
Cash outflow for capital expenditures	(1,836)	(35)	(1,871)

Year ended December 31, 2024 *(millions of dollars)*	Property, Plant and Equipment	Intangible Assets	Total
Capital investments	(1,750)	(39)	(1,789)
Reconciling items	142	1	143
Cash outflow for capital expenditures	(1,608)	(38)	(1,646)

Capital Contributions

Hydro One Networks' Transmission Business enters into contracts governed by the OEB Transmission System Code when a transmission customer requests a new or upgraded transmission connection. The customer is required to make a capital contribution to Hydro One Networks based on the shortfall between the present value of the costs of the connection facility and the present value of revenues. The present value of revenues is based on an estimate of load forecast for the period of the contract with Hydro One Networks. Once the connection facility is commissioned, in accordance with the OEB Transmission System Code, Hydro One Networks will periodically reassess the estimated load forecast which will lead to a decrease, or an increase in the capital contributions from the customer. The increase or decrease in capital contributions is recorded directly to property, plant and equipment in service. In 2025, there were $3 million capital contributions from these assessments (2024 - $2 million).

Supplementary Information

Year ended December 31 *(millions of dollars)*	2025	2024
Net interest paid	430	393
Income taxes paid	143	94

25. CONTINGENCIES

Hydro One Networks is involved in various lawsuits and claims in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Transmission Business' financial position, results of operations or cash flows.

The Company is a wholly owned subsidiary of Hydro One. As such, the assets of the Transmission Business are available to satisfy the debts, contingent liabilities and commitments of both the Company and Hydro One.

26. COMMITMENTS

The Company and Hydro One have numerous commitments. These commitments have not been specifically allocated to the Transmission Business. However, the assets of the Transmission Business are available to satisfy the commitments of both the Company and Hydro One.

27. SUBSEQUENT EVENTS

Payments to Finance Dividends

On February 12, 2026, Hydro One Networks declared a dividend of $199 million. The amount allocated to the Transmission Business to finance this payment was $115 million.

HYDRO ONE SAULT STE. MARIE LP

FINANCIAL STATEMENTS

DECEMBER 31, 2024

KPMG LLP
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INDEPENDENT AUDITOR'S REPORT

To the Partners of Hydro One Sault Ste. Marie LP.

Opinion

We have audited the financial statements of Hydro One Sault Ste. Marie LP (the Entity), which comprise:

- the statement of financial position as at December 31, 2024;
- the statement of operations and comprehensive income for the year then ended;
- the statement of changes in partners' equity for the year then ended;
- the statement of cash flows for the year then ended;
- and notes to the financial statements, including a summary of material accounting policy information.

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2024, its financial performance and its cash flows for the years then ended in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the ***"Auditor's Responsibilities for the Audit of the Financial Statements"*** section of our auditor's report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

KPMG LLP, an Ontario limited liability partnership and member firm of the KPMG global organization of independent member firms affiliated with KPMG International Limited, a private English company limited by guarantee. KPMG Canada provides services to KPMG LLP.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada

April 28, 2025

HYDRO ONE SAULT STE. MARIE LP
STATEMENTS OF FINANCIAL POSITION
At December 31, 2024 and 2023

December 31 *(thousands of Canadian dollars)*	**2024**	**2023**
Assets		
Current assets:		
Cash	6,138	29,438
Due from related parties *(Note 21)*	3,831	3,740
	9,969	33,178
Long-term assets:		
Property, plant and equipment *(Note 5)*	303,898	246,824
Intangible assets *(Note 6)*	4,297	4,503
Deferred pension asset *(Note 7)*	1,560	1,580
	309,755	252,907
Total assets	**319,724**	**286,085**
Liabilities		
Current liabilities:		
Accounts payable and accrued liabilities *(Note 20)*	456	488
Interest payable on inter-company note payable *(Notes 21)*	250	2,858
Due to related parties *(Note 21)*	36,272	21,444
Inter-company note payable *(Notes 9, 20, 21)*	94,847	94,847
	131,825	119,637
Long-term liabilities:		
Deferred contributions *(Note 10)*	16,504	10,038
	16,504	10,038
Total liabilities	**148,329**	**129,675**
Subsequent Event (Note 22)		
Partners' equity	171,395	156,410
Total liabilities and partners' equity	**319,724**	**286,085**

See accompanying notes to Financial Statements.

On behalf of Hydro One Sault Ste. Marie Inc., in its capacity as general partner of Hydro One Sault Ste. Marie LP:

Joseph Cornacchia
Sole Director

HYDRO ONE SAULT STE. MARIE LP
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2024 and 2023

Year ended December 31 *(thousands of Canadian dollars)*	**2024**	**2023**
Revenues *(Note 13)*	46,851	47,877
Costs		
Operation, maintenance and administration *(Note 14)*	9,400	9,056
Depreciation, amortization and asset removal costs *(Note 16)*	9,624	9,168
	19,024	18,224
Net operating income	**27,827**	**29,653**
Financing charges *(Notes 15)*	356	3,106
Income for the period	**27,471**	**26,547**
Other comprehensive income		
Items that will not be reclassified subsequently to profit or loss:		
Remeasurement of pension asset *(Note 7)*	(43)	66
Total comprehensive income	**27,428**	**26,613**

See accompanying notes to Financial Statements.

HYDRO ONE SAULT STE. MARIE LP
STATEMENTS OF CHANGES IN PARTNERS' EQUITY
For the years ended December 31, 2024 and 2023

Year ended December 31, 2024 *(thousands of Canadian dollars)*	Capital		Accumulated Other Comprehensive Loss	Retained Earnings	Total Partners' Equity
	Hydro One Sault Ste. Marie Holdings LP	Hydro One Sault Ste. Marie Inc.			
January 1, 2024	112,405	11	(426)	44,420	156,410
Net income	—	—	—	27,471	27,471
Distributions paid	—	—	—	(12,443)	(12,443)
Other comprehensive loss *(Note 7)*	—	—	(43)	—	(43)
December 31, 2024	**112,405**	**11**	**(469)**	**59,448**	**171,395**

Year ended December 31, 2023 *(thousands of Canadian dollars)*	Capital		Accumulated Other Comprehensive Loss	Retained Earnings	Total Partners' Equity
	Hydro One Sault Ste. Marie Holdings LP	Hydro One Sault Ste. Marie Inc.			
January 1, 2023	112,405	11	(492)	27,637	139,561
Net income	—	—	—	26,547	26,547
Distributions paid	—	—	—	(9,764)	(9,764)
Other comprehensive income *(Note 7)*	—	—	66	—	66
December 31, 2023	**112,405**	**11**	**(426)**	**44,420**	**156,410**

See accompanying notes to Financial Statements.

HYDRO ONE SAULT STE. MARIE LP
STATEMENTS OF CASH FLOWS
For the years ended December 31, 2024 and 2023

Year ended December 31 *(thousands of Canadian dollars)*	**2024**	**2023**
Operating activities		
Net income	27,471	26,547
Adjustments for:		
Depreciation and amortization *(Note 16)*	9,176	8,864
Other	—	138
Receipt of deferred contributions *(Note 10)*	6,466	833
Net change in non-cash working capital and other *(Note 18)*	(24,211)	23,938
	18,902	**60,320**
Investing activities		
Additions to property, plant and equipment *(Note 5)*	(29,759)	(38,598)
	(29,759)	**(38,598)**
Financing activities		
Inter-company note payable issued *(Note 9)*	—	94,847
Distributions paid *(Note 21)*	(12,443)	(9,764)
Principal repayments on Trans senior bonds	—	(94,847)
	(12,443)	**(9,764)**
Increase (decrease) in cash	(23,300)	11,958
Cash, beginning of year	29,438	17,480
Cash, end of year	**6,138**	**29,438**

See accompanying notes to Financial Statements.

1. GENERAL INFORMATION

Hydro One Sault Ste. Marie LP (the Partnership) was formed on May 17, 2007 and is engaged in the transmission of electricity to the area adjacent to Sault Ste. Marie, Canada and is subject to the regulations of the Ontario Energy Board (OEB). The address of the Partnership's registered office is 483 Bay Street, 8th floor, South Tower, Toronto, Ontario, Canada, M5G 2P5.

Hydro One Sault Ste. Marie Holdings LP is the Limited Partner and holds a 99.99% interest in the Partnership. Hydro One Sault Ste. Marie Inc., the General Partner, holds a 0.01% limited interest in the Partnership and is responsible for management of the Partnership. The Limited Partner is indirectly owned by Hydro One Networks Inc. (Hydro One Networks). Both the General Partner and Hydro One Networks are wholly-owned subsidiaries of Hydro One Inc. (Hydro One), which is wholly-owned by Hydro One Limited.

2. BASIS OF PRESENTATION

Statement of compliance

These financial statements, including comparatives, have been prepared in accordance with International Financial Reporting Standards (IFRS) Accounting Standards as issued by the International Accounting Standards Board (IASB) and in thousands of Canadian dollars. Accounting policies are consistently applied to both years presented, unless otherwise stated.

The financial statements were approved and authorized for issue by those charged with governance of the Partnership on April 28, 2025.

Basis of measurement

The financial statements have been prepared on a going concern assumption using the historical cost basis except where otherwise noted. Historical cost is generally based on the fair value of the consideration given in exchange for assets or settlement of liabilities as at the date the transaction occurs.

Estimates and Judgments

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made with any adjustments being recognized in results of operations in the period they arise.

Impairment

Assets, including property, plant and equipment and intangible assets are reviewed for impairment whenever events or changes in circumstances indicate that their carrying amounts exceed their recoverable amounts. Intangible assets with indefinite useful lives are tested for impairment annually and whenever events or changes in circumstances indicate that their carrying amounts exceed their recoverable amounts. The assessment of fair value often requires estimates and assumptions on items such as approved uniform transmission rates, discount rates, rehabilitation and restoration costs, future capital requirements and future operating performance. Changes in such estimates could impact recoverable values of these assets. Estimates are reviewed annually by management.

Judgment is involved in assessing whether there is any indication that an asset or cash generating unit (CGU) may be impaired. A CGU is the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets. This assessment is made based on the analysis of changes in the market or business environment, and events that have transpired that have impacted the asset or CGU.

Depreciation of property, plant and equipment and intangible assets

Each property, plant and equipment and intangible assets are assessed annually for both its physical life limitations and its economic recoverability. Those assets with a finite life are depreciated on a straight-line basis over a useful life estimated by management. Asset useful lives and residual values are re-evaluated annually.

Pension

Significant estimates and assumptions are made in determining pension benefits as there are numerous factors that will affect the pension obligation. The actuarial determination of the accrued benefit obligation for pension uses the projected unit credit method prorated on service which incorporates management's best estimate of other cost escalation, mortality rates, retirement ages of employees and other actuarial factors. In addition, actuarial determinations used in estimating obligations relating to the defined benefit plans incorporate assumptions using management's best estimates of factors including plan performance and retirement dates of employees.

3. MATERIAL ACCOUNTING POLICIES

The Partnership has consistently applied the following accounting policies to both periods presented in these financial statements:

Financial Instruments

The Partnership recognizes all financial instruments at fair value upon initial recognition and subsequently classifies them into one of the following three measurement categories (i) measured at amortized cost, (ii) fair value through other comprehensive income (FVTOCI) or (iii) fair value through profit and loss (FVTPL). The classification of financial assets is generally based on the business model in which a financial asset is managed and its contractual cash flow characteristics. At December 31, 2024, the Partnership held the following financial instruments: cash, accounts payable and accrued liabilities, due from and to related parties, inter-company note payable. All of these financial instruments are measured and classified at amortized cost.

The Partnership initially recognizes other financial liabilities and loans and receivables on the trade date. The Partnership derecognizes a financial liability when its contractual obligations are discharged, cancelled, or expired.

Other financial liabilities including borrowings are initially measured at fair value net of transaction costs, and subsequently measured at amortized cost using the effective interest method. Subsequent to initial recognition, loans and receivables are measured at amortized cost using the effective interest method, less any impairment losses.

Property, Plant and Equipment

Recognition and Measurement

Property, plant and equipment are measured at cost less accumulated depreciation and any accumulated impairment losses. When significant parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment. The cost of major inspections or overhauls is capitalized and costs relating to the replacement of a major part of property, plant and equipment are recognized in the carrying amount of the asset to which that part relates, if it is probable that the inspection, overhaul or replacement part will generate future economic benefits and its cost can be measured reliably. The carrying amount of previous inspections and overhauls, or the part being replaced is derecognized and any gain or loss is recognized against income. The cost of the day-to-day servicing of property, plant and equipment is recognized in operating and administration or maintenance expense as incurred.

Costs included in the carrying amount of property, plant and equipment include expenditures that are directly attributable to the acquisition or construction of the asset. The cost of self-constructed assets includes: materials, services, direct labour and directly attributable overheads.

Borrowing costs associated with major projects are capitalized during the construction period, if those projects meet the definition of a qualifying asset, meaning those projects that are under construction for a substantial period of time. Capitalization of borrowing costs is suspended during extended periods in which construction development is interrupted. Assets under construction are recorded as work-in-progress until they become available for use.

When property, plant and equipment is disposed of or retired, the related cost, accumulated depreciation and any accumulated impairment losses are eliminated. Any resulting gains or losses are reflected in income in the period the asset is disposed of or retired.

Depreciation

The cost, net of estimated residual values, of an asset classified as property, plant and equipment is depreciated over the estimated useful life of the asset using a straight-line method. The estimated useful lives, residual values and method of depreciation are based on depreciation studies and are reviewed annually for reasonableness. Land is not depreciated. Construction work-in-progress assets are not depreciated until the assets become available for their intended use. A summary of average service lives and depreciation rates for the various classes of assets is included below:

	Average Service Life	Rate Range	Rate Average
Property, plant and equipment			
Transmission	46 years	2% - 3%	3 %
Communication	19 years	5% - 17%	8 %
Administration and service	22 years	4% - 8%	5 %
Intangible assets	28 years	2% - 20%	5 %

Impairment

At each reporting date, the Partnership reviews the carrying amount of its non-financial assets to determine whether there is any indication of impairment. Impairment assessments are conducted at the CGU level. If any such indication exists, the recoverable amount of the CGU is estimated.

The recoverable amount of the CGU is the greater of its value in use and its fair value less costs to sell. Value in use is based on the estimated future cash flows, discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

An impairment loss is recognized in income if the carrying amount of a CGU exceeds its recoverable amount.

Impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. If such indications exist, the Partnership estimates the recoverable amount of that CGU. A reversal of an impairment loss is recognized up to the lesser of the recoverable amount or the carrying amount that would have been determined (net of depreciation charges) had no impairment loss been recognized on the CGU.

Intangible Assets

Acquired intangible assets having finite useful lives are measured at cost less accumulated amortization and any accumulated impairment losses. Intangible assets are capitalized if: (i) It is probable that the asset acquired or developed will generate future economic benefits, (ii) the intangible asset is identifiable, and (iii) the Partnership exerts control over the economic benefit to be derived from the asset. The costs incurred to establish technological feasibility or to maintain existing levels of performance are recognized in operating or maintenance expense as incurred.

The carrying costs of intangible assets include expenditures that are directly attributable to the acquisition or development of the asset. The cost of self-developed assets includes materials, services, direct labour and directly attributable overheads. Borrowing costs associated with major projects (qualifying assets) are capitalized during the development period. Qualifying assets are those projects that are under development for a substantial period of time. Assets under development are recorded as in progress until they become available for use.

Subsequent expenditures are capitalized only when it increases the future economic benefits embodied in the specific asset to which it relates. All other expenditures are recognized against income as incurred.

Amortization is based on the cost of the asset less its residual value and is calculated using the straight-line method over the estimated useful life of the asset from the date the asset is available for use, and is generally recognized against income. The useful lives of intangible assets range from 5 to 49 years. Land rights with indefinite lives are not amortized.

The estimated useful lives, residual values and method of amortization are reviewed annually for reasonableness.

Intangible assets with an indefinite life are tested for impairment on an annual basis.

Employee Future Benefits

As a result of the integration of the Partnership operations into Hydro One Networks, employees of the Partnership were transferred to Hydro One Networks. See Note 7 - Pension and Employee Future Benefits for details.

Pension Plans

The Partnership's net obligation regarding the defined benefit pension plan (HOSSM DB Plan) is calculated separately for each plan by estimating the amount of future benefit that employees have earned in the prior periods, discounting that amount and deducting the fair value of any plan assets.

The calculation of defined benefit obligations is performed annually by a qualified actuary using the projected unit credit method. When the calculation results in a potential asset for the Partnership, the recognized asset is limited to the present value of economic benefits available in the form of any future refunds from the plan or reductions in future contributions to the plan. To calculate the present value of economic benefits, consideration is given to any applicable minimum funding requirements.

Remeasurements of the net defined benefit liability, which comprise actuarial gains and losses, the return on plan assets (excluding interest) and the effect of the asset ceiling (if any, excluding interest), are recognized immediately in other comprehensive income. The Partnership determines the net interest expense (income) on the net defined benefit liability (asset) for the period by applying the discount rate used to measure the defined benefit obligation at the beginning of the annual period to the then-net defined benefit liability (asset), taking into account any changes in the net defined benefit liability (asset) during the period as a result of contributions and benefit payments. Net interest expense and other expenses related to defined benefit plans are recognized against income.

When the benefits of a plan are changed or when a plan is curtailed, the resulting change in benefit that relates to past service or the gain or loss on curtailment is recognized immediately against income. The Partnership recognizes gains and losses on the settlement of a defined benefit plan when the settlement occurs. The gain or loss on curtailment or settlement comprises any resulting change in the fair value of plan assets, any change in the present value of the defined benefit obligation, and any relating actuarial gains or losses and past service costs that had not been previously been recognized.

Obligations for contributions to the defined contribution pension plan (HOSSM DC Plan) are expensed as the related service is provided by the employees.

Revenue

Revenues predominantly consist of transmission tariffs, which are collected through OEB-approved Uniform Transmission Rates (UTRs) which are applied against the monthly peak demand for electricity across the Partnership's high-voltage network. OEB-approved UTRs are based on an approved revenue requirement that includes a rate of return. The transmission tariffs are designed to recover revenues necessary to support the Partnership's transmission system with sufficient capacity to accommodate the maximum expected demand which is influenced by weather and economic conditions. Revenues are recognized as electricity is transmitted and delivered to customers.

Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered. Revenues are recorded net of indirect taxes.

Deferred Contributions

Contributions in aid of construction of property, plant and equipment received from customers where the Partnership has an on-going performance obligation to the customer are presented as deferred contributions when received and subsequently recognized as revenue over the useful lives of the associated assets.

Foreign Currency

Transactions in foreign currencies are translated to the functional currency of the Partnership at exchange rates at the dates of the transactions.

Borrowing Costs

Borrowing costs that are directly attributable to the acquisition, construction or development of a qualifying asset are added to the cost of that asset, until it is available for use. Qualifying assets are those that take a substantial period of time to get ready for their intended use. The Partnership capitalizes borrowing costs by applying its cost of debt. All other borrowing costs are recognized in finance expense in the period in which they are incurred.

4. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present accounting standard updates issued by the International Accounting Standards Board (IASB) that are applicable to the Partnership:

Recently Adopted Accounting Guidance

Guidance	Date issued	Description	Effective date	Anticipated impact
IAS 1	January 2020	The amendment clarifies that the classification of liabilities as current or non-current should be based on contractual arrangements as at the reporting date. The existence of the right to defer payments by at least 12 months would result in the classification as non-current liabilities regardless of the entity's expectation whether they will defer or not.	January 1, 2024	No impact upon adoption
IFRS 16	September 2022	The amendment specifies how a seller-lessee subsequently measures the lease obligation of a sale and leaseback transaction. The amendment is specific to sale and leaseback transactions for which the lease payments include variable payments that do not depend on an index or a rate.	January 1, 2024	No impact upon adoption
IAS 1	October 2022	The amendment clarifies that only covenants with which the Company is required to comply on or before the reporting date affect the classification of a liability as current or non-current. The amendment also defers the effective date of application to January 1, 2024.	January 1, 2024	No impact upon adoption

Recently Issued Accounting Guidance Not Yet Adopted

Guidance	Date issued	Description	Effective date	Anticipated impact
IFRS 18	April 2024	The standard replaces IAS 1 and sets out requirements for the presentation and disclosure of information in general purpose financial statements, including specified total and subtotals within the statement of profit or loss. Early adoption is permitted.	January 1, 2027	Under assessment
IFRS 19	May 2024	The standard specifies the disclosure requirements an eligible subsidiary is permitted to apply instead of the disclosure requirements in other IFRS Accounting Standards. A subsidiary is eligible if: (1) It does not have public accountability; and (2) It has an ultimate or intermediate parent that produces consolidated financial statements available for public use that comply with IFRS Accounting Standards	January 1, 2027	Under assessment
IFRS 1 IFRS 7 IFRS 9 IFRS 10 IAS 7	July 2024	The amendments contained in the "Annual Improvements to IFRS - Volume 11" include clarifications, simplifications, corrections and changes aimed at improving the consistency of several IFRS Accounting Standards. These relate to: - IFRS 1 First-time Adoption of IFRS; - IFRS 7 Financial Instruments: Disclosure; - IFRS 9 Financial Instruments; - IFRS 10 Consolidated financial statements; and - IAS 7 Statement of Cash Flows Early adoption is permitted.	January 1, 2026	Under assessment

5. PROPERTY, PLANT AND EQUIPMENT

(thousands of dollars)	Land	Equipment and Other Assets	Transmission Assets	Work-In-Progress	Total
Cost					
Balance - January 1, 2023	236	13,212	271,097	17,094	301,639
Additions	—	—	—	38,598	38,598
Transfers	—	420	12,184	(12,604)	—
Adjustment	—	—	(72)	—	(72)
Balance - December 31, 2023	236	13,632	283,209	43,088	340,165
Additions	—	—	—	66,044	66,044
Transfers	—		25,065	(25,065)	—
Adjustment	—	2,993	(3,087)	94	—
Balance - December 31, 2024	236	16,625	305,187	84,161	406,209
Accumulated Depreciation					
Balance - January 1, 2023	—	5,808	78,873	—	84,681
Depreciation	—	1,062	7,598	—	8,660
Adjustment	—	—	—		—
Balance - December 31, 2023	—	6,870	86,471	—	93,341
Depreciation	—	1,067	7,903	—	8,970
Adjustment	—	—	—	—	—
Balance - December 31, 2024	—	7,937	94,374	—	102,311
Carrying Amounts					
Balance - December 31, 2023	236	6,762	196,738	43,088	246,824
Balance - December 31, 2024	236	8,688	210,813	84,161	303,898

6. INTANGIBLE ASSETS

As at December 31, 2024 *(thousands of dollars)*	Land	Computer Software	Work-In-Progress	Total
Cost				
Balance - January 1, 2023	4,600	1,908	94	6,602
Adjustment	72			72
Balance - December 31, 2023	4,672	1,908	94	6,674
Adjustment		94	(94)	—
Balance - December 31, 2024	4,672	2,002	—	6,674
Accumulated Amortization				
Balance - January 1, 2023	334	1,633	—	1,967
Amortization	62	142	—	204
Balance - December 31, 2023	396	1,775	—	2,171
Amortization	64	142	—	206
Balance - December 31, 2024	460	1,917	—	2,377
Carrying Amounts				
Balance - December 31, 2023	4,276	133	94	4,503
Balance - December 31, 2024	4,212	85	—	4,297

The Partnership owns land rights and other land easements that are needed as part of the normal business operations. Land rights have been obtained through contractual rights where the transferor has transferred land rights and land easements to specific parcels of land. The Partnership has identified these land rights as intangible assets with having either indefinite useful lives (in instances where contractual rights give access to specific land parcels in perpetuity) or where land rights are over a finite period, amortize over the term of the agreement with the land owner. The Partnership accounts for land rights at cost less depreciation and cumulative impairment losses, if any.

The Partnership has not identified events or changes in circumstances that indicate that the land rights' carrying amounts exceed their recoverable amounts. The Partnership has tested land rights with indefinite useful lives for impairment in accordance with annual impairment tests.

7. PENSION AND EMPLOYEE FUTURE BENEFITS

As a result of the integration of the Partnership operations into Hydro One Networks, employees of the Partnership were transferred to Hydro One Networks. Members of the HOSSM DB Plan ceased to accrue pension benefits under the HOSSM DB Plan as at September 30, 2018 and joined the Hydro One Defined Benefit Pension Plan or the Hydro One Defined Contribution Pension Plan (depending on employment type) effective October 1, 2018. The HOSSM DB Plan was amended to cease benefit accruals as at October 1, 2018 and provide pre-retirement indexation of the accrued benefits for active members while they are with Hydro One Networks.

Effective October 1, 2018, members of the HOSSM DC Plan joined either the Hydro One Defined Contribution or the Hydro One Defined Benefit Pension Plan. The HOSSM DC Plan continues to exist separately. Effective October 1, 2018, no contributions are being made by members or the Partnership to the HOSSM DC Plan.

In 2024, the Partnership contributions to the HOSSM DB Plan was $86 thousand (2023 - $84 thousand). The minimum 2025 Partnership contributions to the HOSSM DB Plan are estimated to be $85 thousand.

The following tables provide information for the HOSSM DB Plan and the Non-Pension Benefit Plans:

Year ended December 31 *(thousands of dollars)*	**2024**	**2023**
	HOSSM DB Plan	**HOSSM DB Plan**
Change in accrued benefit obligation		
Accrued benefit obligation, beginning of year	21,128	19,438
Interest cost	948	960
Benefits paid	(1,458)	(1,363)
Remeasurements:		
Effect of changes in financial assumptions	8	1,165
Effect of experience adjustments	31	928
Accrued benefit obligation, end of year	20,657	21,128
Change in plan assets		
Fair value of plan assets, beginning of year	30,523	27,829
Return on plan assets	1,209	2,729
Employer contributions	86	84
Benefits paid	(1,458)	(1,363)
Administrative expenses	(84)	(142)
Interest income	1,381	1,386
Fair value of plan assets, end of year	31,657	30,523
Changes in asset ceiling	1,263	563
Net benefit asset	1,560	1,580
Total expense recognized in profit and loss		
Net interest income	(72)	(75)
Administrative expenses and taxes	135	135
Total expense recognized in profit and loss	63	60
Actuarial losses/(gain) recognized in statement of comprehensive income		
Effect in changes in financial assumptions	8	1,165
Effect of experience adjustments	31	928
Return on plan assets	(1,260)	(2,722)
Changes in asset ceiling	1,264	563
Total actuarial losses/(gain) recognized in statement of comprehensive income	43	(66)

The following table presents effects of changes in assumptions for the HOSSM DB Plan:

Year ended December 31 *(thousands of dollars)*	**2024**	**2023**
Discount Rate		
Increase by 100 basis points	18,524	18,920
Decrease by 100 basis points	23,248	23,819
Inflation Rate		
Increase by 100 basis points	21,746	21,459
Decrease by 100 basis points	18,604	18,520

The following table presents significant actuarial assumptions for the HOSSM DB Plan:

Year ended December 31	**2024**	**2023**
Weighted-average actuarial assumptions used:		
Discount rate	4.68 %	4.63 %
Inflation rate	2.00 %	2.05 %

The following table presents the HOSSM DB Plan asset allocations:

December 31	**2024**	**2023**
Fixed income	100 %	41 %
Equity	— %	59 %
Total	100 %	100 %

8. TRANS SENIOR BONDS

The Bonds were initially issued in 2023 with a principal amount of $120 million, secured by a charge on the Partnership's transmission real property assets. On June 16, 2023, the Bonds matured and were fully repaid using an inter-company note payable (see Note 9).

Reconciliation of movements of liabilities to cash flows arising from financing activities:

Year ended December 31 *(thousands of dollars)*	**2024**	**2023**
Bonds, including current portion - beginning of year	—	94,709
Add: non-cash amortization of deferred financing costs	—	138
Less: cash outflows for principal repayments	—	(94,847)
Bonds, including current portion - end of year	—	—

9. INTER-COMPANY NOTE PAYABLE

On June 15, 2023, Hydro One issued a promissory note payable of $94,847 thousand to the Partnership at an interest rate of 5.50% per annum, payable on demand. In 2024, the Partnership repaid $nil (2023 -$nil) of the demand promissory note.

10. DEFERRED CONTRIBUTIONS

At December 31, 2024, the Partnership had contributions from customers totalling $16,504 thousand (2023 - $10,038 thousand) in aid of construction of property, plant and equipment. $273 thousand have been recognized as revenue in 2024 (2023- $136 thousand).

11. PARTNERSHIP UNITS

The Partnership is authorized to issue an unlimited number of Class A and Class B partnership units. At December 31, 2024 and 2023, 20,285,007 Class A units and 2 Class B units were issued and outstanding.

12. CONTINGENCIES

Contingencies

The Partnership is from time to time involved in legal proceedings of a nature considered normal to its business. Except as disclosed below, the Partnership believes that none of the litigation in which it is currently involved, or has been involved since the beginning of the most recently completed financial year, individually or in the aggregate, is material to its financial condition or results of operations. The Partnership is not subject to any material regulatory actions.

There are no specified decommissioning costs relating to the Partnership's assets. The Partnership has a comprehensive repair and capital expenditure program to ensure that its transmission lines are maintained to industry standards. Replacement of the assets occurs in accordance with a long term capital plan and would involve typical costs of removal as part of that process. In the circumstance where a portion of a line or other assets were removed completely, there may be some contractual obligations under private or crown easements or other land rights which require the transmission owner to reinstate the land to a certain standard, typically the shape it was prior to the construction of the transmission assets. As well, certain environmental, land use and/or utility legislation, regulations and policy may apply in which the Partnership would have to comply with remediation requirements set by the government. The requirements will typically depend on the specific property characteristics and what criteria the government determines to be appropriate to meet safety and environmental concerns. These asset lives are indeterminate given their nature. As the individual assets or components reach the end of their useful lives, they are retired and replaced. Historically, certain asset components have been replaced a number of times, thus creating a perpetual asset with an indeterminate life. As such, the retirement date for these lines cannot be reasonably estimated and therefore, the fair value of the associated liability cannot be determined at this time. As a result, no liability has been accrued in these financial statements.

13. REVENUE

Year ended December 31 *(thousands of dollars)*	**2024**	**2023**
Transmission services *(Note 20)*	46,026	47,207
Lease income	498	498
Other	327	172
	46,851	47,877

14. OPERATION, MAINTENANCE, AND ADMINISTRATION COSTS

Year ended December 31 *(thousands of dollars)*	**2024**	**2023**
Compensation expenses	2,914	3,526
Contract expenses	1,906	1,934
Maintenance of facilities and real estate	1,733	909
Administration expenses	495	672
Materials	180	171
Other	2,172	1,844
	9,400	9,056

15. FINANCING CHARGES

Year ended December 31 *(thousands of dollars)*	**2024**	**2023**
Interest expense on inter-company note payable	5,217	2,858
Interest expense on Trans senior bonds (Bonds)[1]	—	3,130
Amortization of deferred financing fees on Bonds	—	138
Less: Capitalized interest	(3,479)	(1,196)
Interest income and other expenses	(1,382)	(1,824)
	356	3,106

[1]On June 16, 2023, the Bonds matured and were fully repaid using an inter-company note payable. See Note 9 - Inter-Company Note Payable.

16. DEPRECIATION, AMORTIZATION AND ASSET REMOVAL COSTS

Year ended December 31 *(thousands of dollars)*	**2024**	**2023**
Depreciation of property, plant and equipment	8,970	8,660
Amortization of intangible assets	206	204
Depreciation and amortization	9,176	8,864
Asset removal costs	448	304
	9,624	9,168

17. INCOME TAXES

The Partnership is not a taxable entity for federal and provincial income tax purposes. Accordingly, no current or deferred tax expenses are recognized in the Partnership's financial statements.

18. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 *(thousands of dollars)*	**2024**	**2023**
Due from related parties	(91)	402
Deferred pension asset	(23)	(23)
Accounts payable and accrued liabilities	(32)	(457)
Interest payable on inter-company note payable	(2,608)	2,858
Due to related parties	(21,457)	21,158
	(24,211)	23,938

Supplementary Information

Year ended December 31 *(thousands of dollars)*	**2024**	**2023**
Net interest (received) paid	(1,382)	1,556

19. CAPITAL RISK MANAGEMENT

The Partnership's primary capital management objective is to ensure the sustainability of its capital to support continuing operations, meet its financial obligations, allow for growth opportunities and provide stable distributions to its partners. The Partnership manages its capital to maintain an investment grade credit rating while prudently making use of leverage in order to provide its ultimate parent with enhanced returns. In addition, the Partnership manages its capital to ensure access to incremental borrowings needed to fund new growth initiatives.

The Partnership manages its capital structure in accordance with changes in economic conditions. Generally, capital expenditures, operating activities and contractual obligations are funded with intercompany borrowings. In order to adjust the capital structure, the Partnership may elect to adjust the distribution amount paid to its partners, increase or reduce the equity participation in new and existing operations, adjust the level of capital spending or issue new partnership units.

The Partnership manages its capital in order to maintain a debt to capitalization ratio below 75%. Debt is the total principal balance of Inter-company note payable. Capitalization is calculated as Debt (as defined hereto) and partners' equity (see statements of financial position). At December 31, 2024, the ratio was 36% (2023 - 40%). The table below presents the details of the Partnership's capitalization and the calculation of the ratio:

As at December 31 *(thousands of dollars)*	**2024**	**2023**
Inter-company note payable *(Note 8)*	94,847	94,847
Debt	94,847	94,847
Partners' equity	171,395	156,410
Capitalization	266,242	251,257
Debt to Capitalization	36 %	38 %

There has been no change in the Partnership's approach to managing capital in 2024 or 2023.

20. FINANCIAL INSTRUMENTS

Fair value measurement

The Partnership defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

The carrying amounts for cash, accounts payable and accrued liabilities, due to and from related parties and inter-company note payable approximate fair value due to their short-term nature of these instruments. Due to the use of subjective judgments and uncertainties in the determination of fair values, these values should not be interpreted as being realizable in an immediate settlement of the financial instruments.

Fair value hierarchy

The following provides a description of financial instruments that are measured subsequent to initial recognition at fair value, grouped into Levels 1 to 3 based on the degree to which the fair value is observable:

- Level 1 fair value measurements are those derived from quoted market prices (unadjusted) in active markets for identical assets or liabilities;
- Level 2 fair value measurements are those derived from inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices); and
- Level 3 fair value measurements are those derived from valuation techniques that include inputs for the asset or liability that are not based on observable market data (unobservable inputs).

All financial instruments are classified as level 1.

There were no transfers between any of the levels during the years ended December 31, 2024 or 2023.

Financial risk management

The Partnership has exposure to the following risks from its use of financial instruments: market risk, credit risk and liquidity risk.

The Partnership's management has overall responsibility for the establishment and oversight of the Partnership's risk management framework. Risk management policies are established to identify and analyze the risks faced by the Partnership, to set appropriate risk limits and controls and to monitor risks and ensure adherence to these limits. Risk management policies and systems are reviewed regularly to reflect changes in market conditions and the Partnership's activities. The Partnership, through its training and management standards and procedures, aims to maintain a disciplined and constructive control environment in which all employees understand their roles and obligations. The objectives, policies and processes for managing risk were consistent with those in the prior year.

Market Risk

Market risk is the risk that changes in market prices (interest rates) will affect the Partnership's income or the value of its holdings of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimizing the return.

The Partnership's intercompany note payable is subject to a fixed interest rate of 5.5% per annum. As a result of having fixed-rate debt, fluctuations in interest rate is not expected to materially affect the Partnership's cash flows.

Credit Risk

Credit risk is the risk of financial loss to the Partnership if a counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Partnership's receivables from counterparties. The carrying amount of financial assets represents the maximum credit exposure.

The Partnership actively manages its exposure to credit risk by assessing the ability of counterparties to fulfill their obligations under the related contracts prior to entering into such contracts, and continually monitors these exposures.

The majority of amounts due from related parties are with the Independent Electricity System Operator (IESO). The IESO operates the provincial transmission system, and is a reliable counterparty. The quality of the Partnership's counterparties mitigates the Partnership's exposure to credit risk.

The Partnership is also exposed to credit risk on cash. Credit risk is mitigated by ensuring the majority of the financial assets are placed with a major Canadian financial institution with strong investment-grade ratings by a primary ratings agency. The credit risk of cash has been assessed as low.

Liquidity Risk

Liquidity risk is the risk that the Partnership will encounter difficulty in meeting the obligations associated with its financial liabilities that are settled by delivering cash or another financial asset. The Partnership manages liquidity risk by forecasting cash flows required by operations and anticipating investing and financing activities to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when they are due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Partnership's reputation.

The following table presents a summary of the Partnership's accounts payable and accrued liabilities, interest on inter-company note payable and inter-company note payable:

As at December 31, 2024 *(thousands of dollars)*	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Accounts payable and accrued liabilities	456	456	—	—	—
Interest on inter-company note payable	250	250	—	—	—
Inter-company note payable	94,847	94,847	—	—	—
	95,553	95,553	—	—	—

Going Concern Risk

The remaining principal balance of the inter-company note payable is payable on demand. The Company has insufficient liquidity to fund the repayment of this debt. On April 22, 2024, Hydro One Inc. has confirmed and agreed to not demand repayment of the inter-company note payable from the Partnership.

21. RELATED PARTY TRANSACTIONS AND BALANCES

The Province of Ontario is a shareholder of Hydro One Limited with approximately 47.1% ownership at December 31, 2024. The IESO is a related party to the Partnership because it is controlled or significantly influenced by the Ministry of Energy and Electrification. The Partnership has received services from entities under common control in the normal course of operations. The following is a summary of the Partnership's related party transactions during the years ended December 31, 2024 and 2023:

Year ended December 31 *(thousands of dollars)* Related Party	Transaction	2024	2023
IESO	Revenues for transmission services	46,026	47,207
Hydro One Networks	Services received[1]	72,285	46,889
	Lease income[2]	498	498
Hydro One Inc.	Services received[1]	35	21
	Interest charged on inter-company note payable[3]	5,217	2,858
Hydro One Sault Ste. Marie Holdings LP	Distributions paid	12,443	9,764

[1] Services received include corporate cost allocation, capital project upgrades and transmission system operating services.
[2] On December 7, 2023, Hydro One Networks entered into a one-year lease with the Company to lease land and building. The lease was extended in 2024 until December 31, 2025.
[3] On June 30, 2023, Hydro One Inc. issued a promissory note payable to the Partnership. See Note 9 - Inter-Company Note Payable.

The amounts due to and from related parties at December 31, 2024 and 2023 are as follows:

As at December 31 *(thousands of dollars)*	2024	2023
Due from related parties[1]	3,831	3,740
Interest on inter-company note payable	250	2,858
Due to related parties[1]	36,272	21,444
Inter-company note payable *(Note 8)*	94,847	94,847

[1] The balances payable and receivable for these services are non-interest bearing and unsecured.

22. SUBSEQUENT EVENT

Subsequent to December 31, 2024, the Partnership declared distributions of $3,482 thousand, paid on February 26, 2025.

HYDRO ONE SAULT STE. MARIE LP

FINANCIAL STATEMENTS

DECEMBER 31, 2025

KPMG LLP
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INDEPENDENT AUDITOR'S REPORT

To the Partners of Hydro One Sault Ste. Marie LP

Opinion

We have audited the financial statements of Hydro One Sault Ste. Marie LP (the Entity), which comprise:

- the statement of financial position as at December 31, 2025
- the statement of operations and comprehensive income for the year then ended
- the statement of changes in partners' equity for the year then ended
- the statement of cash flows for the year then ended
- and notes to the financial statements, including a summary of material accounting policy information

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2025, and its financial performance and its cash flows for the year then ended in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the ***"Auditor's Responsibilities for the Audit of the Financial Statements"*** section of our auditor's report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

KPMG LLP, an Ontario limited liability partnership and member firm of the KPMG global organization of independent member firms affiliated with KPMG International Limited, a private English company limited by guarantee. KPMG Canada provides services to KPMG LLP.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada

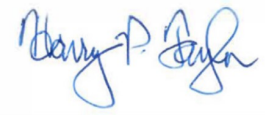
April 15, 2026

HYDRO ONE SAULT STE. MARIE LP
STATEMENTS OF FINANCIAL POSITION
At December 31, 2025 and 2024

December 31 *(thousands of Canadian dollars)*	**2025**	**2024**
Assets		
Current assets:		
Cash	2,434	6,138
Due from related parties *(Note 20)*	4,127	3,831
	6,561	9,969
Long-term assets:		
Property, plant and equipment *(Note 5)*	366,745	303,898
Intangible assets *(Note 6)*	4,180	4,297
Deferred pension asset *(Note 7)*	1,519	1,560
	372,444	309,755
Total assets	**379,005**	**319,724**
Liabilities		
Current liabilities:		
Accounts payable and accrued liabilities *(Note 19)*	492	456
Interest payable on inter-company note payable *(Notes 19, 20)*	250	250
Due to related parties *(Notes 19, 20)*	82,775	36,272
Inter-company note payable *(Notes 8, 19, 20)*	94,847	94,847
	178,364	131,825
Long-term liabilities:		
Deferred contributions *(Note 9)*	16,465	16,504
	16,465	16,504
Total liabilities	**194,829**	**148,329**
Subsequent Event (Note 21)		
Partners' equity	184,176	171,395
Total liabilities and partners' equity	**379,005**	**319,724**

See accompanying notes to Financial Statements.

On behalf of Hydro One Sault Ste. Marie Inc., in its capacity as general partner of Hydro One Sault Ste. Marie LP:



Harry Taylor
Sole Director

HYDRO ONE SAULT STE. MARIE LP
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2025 and 2024

Year ended December 31 *(thousands of Canadian dollars)*	**2025**	**2024**
Revenues *(Note 12)*	49,536	46,851
Costs		
Operation, maintenance and administration *(Note 13)*	9,203	9,400
Depreciation, amortization and asset removal costs *(Note 15)*	11,848	9,624
	21,051	19,024
Net operating income	**28,485**	**27,827**
Financing (income) charges *(Notes 14)*	(264)	356
Income for the period	**28,749**	**27,471**
Other comprehensive income		
Items that will not be reclassified subsequently to profit or loss:		
Remeasurement of pension asset *(Note 7)*	(61)	(43)
Total comprehensive income	**28,688**	**27,428**

See accompanying notes to Financial Statements.

HYDRO ONE SAULT STE. MARIE LP
STATEMENTS OF CHANGES IN PARTNERS' EQUITY
For the years ended December 31, 2025 and 2024

Year ended December 31, 2025 *(thousands of Canadian dollars)*	Capital		Accumulated Other Comprehensive Loss	Retained Earnings	Total Partners' Equity
	Hydro One Sault Ste. Marie Holdings LP	Hydro One Sault Ste. Marie Inc.			
January 1, 2025	112,405	11	(469)	59,448	171,395
Net income	—	—	—	28,749	28,749
Distributions paid	—	—	—	(15,907)	(15,907)
Other comprehensive loss *(Note 7)*	—	—	(61)	—	(61)
December 31, 2025	**112,405**	**11**	**(530)**	**72,290**	**184,176**

Year ended December 31, 2024 *(thousands of Canadian dollars)*	Capital		Accumulated Other Comprehensive Loss	Retained Earnings	Total Partners' Equity
	Hydro One Sault Ste. Marie Holdings LP	Hydro One Sault Ste. Marie Inc.			
January 1, 2024	112,405	11	(426)	44,420	156,410
Net income	—	—	—	27,471	27,471
Distributions paid	—	—	—	(12,443)	(12,443)
Other comprehensive loss *(Note 7)*	—	—	(43)	—	(43)
December 31, 2024	**112,405**	**11**	**(469)**	**59,448**	**171,395**

See accompanying notes to Financial Statements.

HYDRO ONE SAULT STE. MARIE LP
STATEMENTS OF CASH FLOWS
For the years ended December 31, 2025 and 2024

Year ended December 31 *(thousands of Canadian dollars)*	**2025**	**2024**
Operating activities		
Net income	28,749	27,471
Adjustments for:		
Depreciation and amortization *(Note 15)*	9,542	9,176
Receipt of deferred contributions *(Note 9)*	(39)	6,466
Net change in non-cash working capital and other *(Note 17)*	2,847	(24,211)
	41,099	**18,902**
Investing activities		
Additions to property, plant and equipment	(28,896)	(29,759)
	(28,896)	**(29,759)**
Financing activities		
Distributions paid *(Note 20)*	(15,907)	(12,443)
	(15,907)	**(12,443)**
Decrease in cash	(3,704)	(23,300)
Cash, beginning of year	6,138	29,438
Cash, end of year	**2,434**	**6,138**

See accompanying notes to Financial Statements.

1. GENERAL INFORMATION

Hydro One Sault Ste. Marie LP (the Partnership) was formed on May 17, 2007 and is engaged in the transmission of electricity to the area adjacent to Sault Ste. Marie, Canada and is subject to the regulations of the Ontario Energy Board (OEB). The address of the Partnership's registered office is 483 Bay Street, 8th floor, South Tower, Toronto, Ontario, Canada, M5G 2P5.

Hydro One Sault Ste. Marie Holdings LP is the Limited Partner and holds a 99.99% interest in the Partnership. Hydro One Sault Ste. Marie Inc., the General Partner, holds a 0.01% limited interest in the Partnership and is responsible for management of the Partnership. The Limited Partner is indirectly owned by Hydro One Networks Inc. (Hydro One Networks). Both the General Partner and Hydro One Networks are wholly-owned subsidiaries of Hydro One Inc. (Hydro One), which is wholly-owned by Hydro One Limited.

2. BASIS OF PRESENTATION

Statement of compliance

These financial statements, including comparatives, have been prepared in accordance with International Financial Reporting Standards (IFRS) Accounting Standards as issued by the International Accounting Standards Board (IASB) and in thousands of Canadian dollars. Accounting policies are consistently applied to both years presented, unless otherwise stated.

The financial statements were approved and authorized for issue by those charged with governance of the Partnership on April 15, 2026.

Basis of measurement

The financial statements have been prepared on a going concern assumption using the historical cost basis except where otherwise noted. Historical cost is generally based on the fair value of the consideration given in exchange for assets or settlement of liabilities as at the date the transaction occurs.

Estimates and Judgments

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made with any adjustments being recognized in results of operations in the period they arise.

Impairment

Assets, including property, plant and equipment and intangible assets are reviewed for impairment whenever events or changes in circumstances indicate that their carrying amounts exceed their recoverable amounts. Intangible assets with indefinite useful lives are tested for impairment annually and whenever events or changes in circumstances indicate that their carrying amounts exceed their recoverable amounts. The assessment of fair value often requires estimates and assumptions on items such as approved uniform transmission rates, discount rates, rehabilitation and restoration costs, future capital requirements and future operating performance. Changes in such estimates could impact recoverable values of these assets. Estimates are reviewed annually by management.

Judgment is involved in assessing whether there is any indication that an asset or cash generating unit (CGU) may be impaired. A CGU is the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets. This assessment is made based on the analysis of changes in the market or business environment, and events that have transpired that have impacted the asset or CGU.

Depreciation of property, plant and equipment and intangible assets

Each property, plant and equipment and intangible assets are assessed annually for both its physical life limitations and its economic recoverability. Those assets with a finite life are depreciated on a straight-line basis over a useful life estimated by management. Asset useful lives and residual values are re-evaluated annually.

Pension

Significant estimates and assumptions are made in determining pension benefits as there are numerous factors that will affect the pension obligation. The actuarial determination of the accrued benefit obligation for pension uses the projected unit credit method prorated on service which incorporates management's best estimate of other cost escalation, mortality rates, retirement ages of employees and other actuarial factors. In addition, actuarial determinations used in estimating obligations relating to the defined benefit plans incorporate assumptions using management's best estimates of factors including plan performance and retirement dates of employees.

3. MATERIAL ACCOUNTING POLICIES

The Partnership has consistently applied the following accounting policies to both periods presented in these financial statements:

Financial Instruments

The Partnership recognizes all financial instruments at fair value upon initial recognition and subsequently classifies them into one of the following three measurement categories (i) measured at amortized cost, (ii) fair value through other comprehensive income (FVTOCI) or (iii) fair value through profit and loss (FVTPL). The classification of financial assets is generally based on the business model in which a financial asset is managed and its contractual cash flow characteristics. At December 31, 2025, the Partnership held the following financial instruments: cash, accounts payable and accrued liabilities, due from and to related parties, inter-company note payable. All of these financial instruments are measured and classified at amortized cost.

The Partnership initially recognizes other financial liabilities and loans and receivables on the trade date. The Partnership derecognizes a financial liability when its contractual obligations are discharged, cancelled, or expired.

Other financial liabilities including borrowings are initially measured at fair value net of transaction costs, and subsequently measured at amortized cost using the effective interest method. Subsequent to initial recognition, loans and receivables are measured at amortized cost using the effective interest method, less any impairment losses.

Property, Plant and Equipment

Recognition and Measurement

Property, plant and equipment are measured at cost less accumulated depreciation and any accumulated impairment losses. When significant parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment. The cost of major inspections or overhauls is capitalized and costs relating to the replacement of a major part of property, plant and equipment are recognized in the carrying amount of the asset to which that part relates, if it is probable that the inspection, overhaul or replacement part will generate future economic benefits and its cost can be measured reliably. The carrying amount of previous inspections and overhauls, or the part being replaced is derecognized and any gain or loss is recognized against income. The cost of the day-to-day servicing of property, plant and equipment is recognized in operating and administration or maintenance expense as incurred.

Costs included in the carrying amount of property, plant and equipment include expenditures that are directly attributable to the acquisition or construction of the asset. The cost of self-constructed assets includes: materials, services, direct labour and directly attributable overheads.

Borrowing costs associated with major projects are capitalized during the construction period, if those projects meet the definition of a qualifying asset, meaning those projects that are under construction for a substantial period of time. Capitalization of borrowing costs is suspended during extended periods in which construction development is interrupted. Assets under construction are recorded as work-in-progress until they become available for use.

When property, plant and equipment is disposed of or retired, the related cost, accumulated depreciation and any accumulated impairment losses are eliminated. Any resulting gains or losses are reflected in income in the period the asset is disposed of or retired.

Depreciation

The cost, net of estimated residual values, of an asset classified as property, plant and equipment is depreciated over the estimated useful life of the asset using a straight-line method. The estimated useful lives, residual values and method of depreciation are based on depreciation studies and are reviewed annually for reasonableness. Land is not depreciated. Construction work-in-progress assets are not depreciated until the assets become available for their intended use. A summary of average service lives and depreciation rates for the various classes of assets is included below:

	Average Service Life	Rate Range	Rate Average
Property, plant and equipment			
Transmission	47 years	2% - 3%	3 %
Communication	19 years	5% - 17%	7 %
Administration and service	22 years	4% - 8%	5 %
Intangible assets	34 years	2% - 20%	4 %

Impairment

At each reporting date, the Partnership reviews the carrying amount of its non-financial assets to determine whether there is any indication of impairment. Impairment assessments are conducted at the CGU level. If any such indication exists, the recoverable amount of the CGU is estimated.

The recoverable amount of the CGU is the greater of its value in use and its fair value less costs to sell. Value in use is based on the estimated future cash flows, discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

An impairment loss is recognized in income if the carrying amount of a CGU exceeds its recoverable amount.

Impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. If such indications exist, the Partnership estimates the recoverable amount of that CGU. A reversal of an impairment loss is recognized up to the lesser of the recoverable amount or the carrying amount that would have been determined (net of depreciation charges) had no impairment loss been recognized on the CGU.

Intangible Assets

Acquired intangible assets having finite useful lives are measured at cost less accumulated amortization and any accumulated impairment losses. Intangible assets are capitalized if: (i) It is probable that the asset acquired or developed will generate future economic benefits, (ii) the intangible asset is identifiable, and (iii) the Partnership exerts control over the economic benefit to be derived from the asset. The costs incurred to establish technological feasibility or to maintain existing levels of performance are recognized in operating or maintenance expense as incurred.

The carrying costs of intangible assets include expenditures that are directly attributable to the acquisition or development of the asset. The cost of self-developed assets includes materials, services, direct labour and directly attributable overheads. Borrowing costs associated with major projects (qualifying assets) are capitalized during the development period. Qualifying assets are those projects that are under development for a substantial period of time. Assets under development are recorded as in progress until they become available for use.

Subsequent expenditures are capitalized only when it increases the future economic benefits embodied in the specific asset to which it relates. All other expenditures are recognized against income as incurred.

Amortization is based on the cost of the asset less its residual value and is calculated using the straight-line method over the estimated useful life of the asset from the date the asset is available for use, and is generally recognized against income. The useful lives of intangible assets range from 5 to 49 years. Land rights with indefinite lives are not amortized.

The estimated useful lives, residual values and method of amortization are reviewed annually for reasonableness.

Intangible assets with an indefinite life are tested for impairment on an annual basis.

Employee Future Benefits

As a result of the integration of the Partnership operations into Hydro One Networks, employees of the Partnership were transferred to Hydro One Networks. See Note 7 - Pension and Employee Future Benefits for details.

Pension Plans

The Partnership's net obligation regarding the defined benefit pension plan (HOSSM DB Plan) is calculated separately for each plan by estimating the amount of future benefit that employees have earned in the prior periods, discounting that amount and deducting the fair value of any plan assets.

The calculation of defined benefit obligations is performed annually by a qualified actuary using the projected unit credit method. When the calculation results in a potential asset for the Partnership, the recognized asset is limited to the present value of economic benefits available in the form of any future refunds from the plan or reductions in future contributions to the plan. To calculate the present value of economic benefits, consideration is given to any applicable minimum funding requirements.

Remeasurements of the net defined benefit liability, which comprise actuarial gains and losses, the return on plan assets (excluding interest) and the effect of the asset ceiling (if any, excluding interest), are recognized immediately in other comprehensive income. The Partnership determines the net interest expense (income) on the net defined benefit liability (asset) for the period by applying the discount rate used to measure the defined benefit obligation at the beginning of the annual period to the then-net defined benefit liability (asset), taking into account any changes in the net defined benefit liability (asset) during the period as a result of contributions and benefit payments. Net interest expense and other expenses related to defined benefit plans are recognized against income.

When the benefits of a plan are changed or when a plan is curtailed, the resulting change in benefit that relates to past service or the gain or loss on curtailment is recognized immediately against income. The Partnership recognizes gains and losses on the settlement of a defined benefit plan when the settlement occurs. The gain or loss on curtailment or settlement comprises any resulting change in the fair value of plan assets, any change in the present value of the defined benefit obligation, and any relating actuarial gains or losses and past service costs that had not been previously been recognized.

Obligations for contributions to the defined contribution pension plan (HOSSM DC Plan) are expensed as the related service is provided by the employees.

Revenue

Revenues predominantly consist of transmission tariffs, which are collected through OEB-approved Uniform Transmission Rates (UTRs) which are applied against the monthly peak demand for electricity across the Partnership's high-voltage network. OEB-approved UTRs are based on an approved revenue requirement that includes a rate of return. The transmission tariffs are designed to recover revenues necessary to support the Partnership's transmission system with sufficient capacity to accommodate the maximum expected demand which is influenced by weather and economic conditions. Revenues are recognized as electricity is transmitted and delivered to customers.

Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered. Revenues are recorded net of indirect taxes.

Deferred Contributions

Contributions in aid of construction of property, plant and equipment received from customers where the Partnership has an on-going performance obligation to the customer are presented as deferred contributions when received and subsequently recognized as revenue over the useful lives of the associated assets.

Foreign Currency

Transactions in foreign currencies are translated to the functional currency of the Partnership at exchange rates at the dates of the transactions.

Borrowing Costs

Borrowing costs that are directly attributable to the acquisition, construction or development of a qualifying asset are added to the cost of that asset, until it is available for use. Qualifying assets are those that take a substantial period of time to get ready for their intended use. The Partnership capitalizes borrowing costs by applying its cost of debt. All other borrowing costs are recognized in finance expense in the period in which they are incurred.

4. NEW ACCOUNTING PRONOUNCEMENTS

The following table presents accounting standard updates issued by the International Accounting Standards Board (IASB) that are applicable to the Partnership:

Recently Issued Accounting Guidance Not Yet Adopted

Guidance	Date issued	Description	Effective date	Anticipated impact
IFRS 18	April 2024	The standard replaces IAS 1 and sets out requirements for the presentation and disclosure of information in general purpose financial statements, including specified total and subtotals within the statement of profit or loss. Early adoption is permitted.	January 1, 2027	Under assessment
IFRS 19	May 2024	The standard specifies the disclosure requirements an eligible subsidiary is permitted to apply instead of the disclosure requirements in other IFRS Accounting Standards. A subsidiary is eligible if: (1) It does not have public accountability; and (2) It has an ultimate or intermediate parent that produces consolidated financial statements available for public use that comply with IFRS Accounting Standards	January 1, 2027	No impact upon adoption
IFRS 1 IFRS 7 IFRS 9 IFRS 10 IAS 7	July 2024	The amendments contained in the “Annual Improvements to IFRS - Volume 11” include clarifications, simplifications, corrections and changes aimed at improving the consistency of several IFRS Accounting Standards. These relate to: - IFRS 1 First-time Adoption of IFRS; - IFRS 7 Financial Instruments: Disclosure; - IFRS 9 Financial Instruments; - IFRS 10 Consolidated financial statements; and - IAS 7 Statement of Cash Flows Early adoption is permitted.	January 1, 2026	No impact upon adoption

5. PROPERTY, PLANT AND EQUIPMENT

(thousands of dollars)	Land	Equipment and Other Assets	Transmission Assets	Work-In-Progress	Total
Cost					
Balance - January 1, 2024	236	13,632	283,209	43,088	340,165
Additions	—	—	—	66,044	66,044
Transfers	—		25,065	(25,065)	—
Adjustment	—	2,993	(3,087)	94	—
Balance - December 31, 2024	236	16,625	305,187	84,161	406,209
Additions	—	—	—	72,272	72,272
Transfers	—	3,042	59,391	(62,433)	—
Retirements	—	—	(9)	—	(9)
Balance - December 31, 2025	236	19,667	364,569	94,000	478,472
Accumulated Depreciation					
Balance - January 1, 2024	—	6,870	86,471	—	93,341
Depreciation	—	1,067	7,903	—	8,970
Balance - December 31, 2024	—	7,937	94,374	—	102,311
Depreciation	—	1,139	8,286	—	9,425
Retirements	—	—	(9)	—	(9)
Balance - December 31, 2025	—	9,076	102,651	—	111,727
Carrying Amounts					
Balance - December 31, 2024	236	8,688	210,813	84,161	303,898
Balance - December 31, 2025	236	10,591	261,918	94,000	366,745

6. INTANGIBLE ASSETS

(thousands of dollars)	Land	Computer Software	Work-In-Progress	Total
Cost				
Balance - January 1, 2024	4,672	1,908	94	6,674
Adjustment		94	(94)	—
Balance - December 31, 2024	4,672	2,002	—	6,674
Retirements	—	(625)	—	(625)
Balance - December 31, 2025	4,672	1,377	—	6,049
Accumulated Amortization				
Balance - January 1, 2024	396	1,775	—	2,171
Amortization	64	142	—	206
Balance - December 31, 2024	460	1,917	—	2,377
Amortization	58	59	—	117
Retirements	—	(625)	—	(625)
Balance - December 31, 2025	518	1,351	—	1,869
Carrying Amounts				
Balance - December 31, 2024	4,212	85	—	4,297
Balance - December 31, 2025	4,154	26	—	4,180

The Partnership owns land rights and other land easements that are needed as part of the normal business operations. Land rights have been obtained through contractual rights where the transferor has transferred land rights and land easements to specific parcels of land. The Partnership has identified these land rights as intangible assets with having either indefinite useful lives (in instances where contractual rights give access to specific land parcels in perpetuity) or where land rights are over a finite period, amortize over the term of the agreement with the land owner. The Partnership accounts for land rights at cost less depreciation and cumulative impairment losses, if any.

The Partnership has not identified events or changes in circumstances that indicate that the land rights' carrying amounts exceed their recoverable amounts. The Partnership has tested land rights with indefinite useful lives for impairment in accordance with annual impairment tests.

7. PENSION AND EMPLOYEE FUTURE BENEFITS

As a result of the integration of the Partnership operations into Hydro One Networks, employees of the Partnership were transferred to Hydro One Networks. Members of the HOSSM DB Plan ceased to accrue pension benefits under the HOSSM DB Plan as at September 30, 2018 and joined the Hydro One Defined Benefit Pension Plan or the Hydro One Defined Contribution Pension Plan (depending on employment type) effective October 1, 2018. The HOSSM DB Plan was amended to cease benefit accruals as at October 1, 2018 and provide pre-retirement indexation of the accrued benefits for active members while they are with Hydro One Networks.

Effective October 1, 2018, members of the HOSSM DC Plan joined either the Hydro One Defined Contribution or the Hydro One Defined Benefit Pension Plan. The HOSSM DC Plan continues to exist separately. Effective October 1, 2018, no contributions are being made by members or the Partnership to the HOSSM DC Plan.

In 2025, the Partnership contributions to the HOSSM DB Plan was $83 thousand (2024 - $86 thousand). The minimum 2026 Partnership contributions to the HOSSM DB Plan are estimated to be $82 thousand.

The following tables provide information for the HOSSM DB Plan and the Non-Pension Benefit Plans:

Year ended December 31 *(thousands of dollars)*	**2025**	**2024**
	HOSSM DB Plan	**HOSSM DB Plan**
Change in accrued benefit obligation		
Accrued benefit obligation, beginning of year	20,657	21,128
Interest cost	935	948
Benefits paid	(1,371)	(1,458)
Remeasurements:		
Effect of changes in financial assumptions	(507)	8
Effect of experience adjustments	94	31
Accrued benefit obligation, end of year	19,808	20,657
Change in plan assets		
Fair value of plan assets, beginning of year	31,657	30,523
(Loss) return on plan assets	(1,529)	1,209
Employer contributions	83	86
Benefits paid	(1,371)	(1,458)
Administrative expenses	(97)	(84)
Interest income	1,449	1,381
Fair value of plan assets, end of year	30,192	31,657
Changes in asset ceiling	(1,017)	1,263
Net benefit asset	1,519	1,560
Total expense recognized in profit and loss		
Net interest income	(72)	(72)
Administrative expenses and taxes	135	135
Total expense recognized in profit and loss	63	63
Actuarial losses recognized in statement of comprehensive income		
Effect in changes in financial assumptions	(507)	8
Effect of experience adjustments	94	31
Return (loss) on plan assets	1,491	(1,260)
Changes in asset ceiling	(1,017)	1,264
Total actuarial losses recognized in statement of comprehensive income	61	43

The following table presents effects of changes in assumptions for the HOSSM DB Plan:

Year ended December 31 *(thousands of dollars)*	**2025**	**2024**
Discount Rate		
Increase by 100 basis points	17,834	18,524
Decrease by 100 basis points	22,193	23,248
Inflation Rate		
Increase by 100 basis points	21,013	21,746
Decrease by 100 basis points	17,475	18,604

The following table presents significant actuarial assumptions for the HOSSM DB Plan:

Year ended December 31	**2025**	**2024**
Weighted-average actuarial assumptions used:		
Discount rate	4.91 %	4.68 %
Inflation rate	2.00 %	2.00 %

The following table presents the HOSSM DB Plan asset allocations:

December 31	**2025**	**2024**
Fixed income	100 %	100 %
Equity	— %	— %
Total	100 %	100 %

8. INTER-COMPANY NOTE PAYABLE

On June 15, 2023, the Partnership issued a promissory note payable of $94,847 thousand to Hydro One at an interest rate of 5.50% per annum, payable on demand. In 2025, the Partnership repaid $nil (2024 -$nil) of the demand promissory note.

9. DEFERRED CONTRIBUTIONS

At December 31, 2025, the Partnership had contributions from customers totalling $16,465 thousand (2024 - $16,504 thousand) in aid of construction of property, plant and equipment. $279 thousand have been recognized as revenue in 2025 (2024- $273 thousand).

10. PARTNERSHIP UNITS

The Partnership is authorized to issue an unlimited number of Class A and Class B partnership units. At December 31, 2025 and 2024, 20,285,007 Class A units and 2 Class B units were issued and outstanding.

11. CONTINGENCIES

Contingencies

The Partnership is from time to time involved in legal proceedings of a nature considered normal to its business. Except as disclosed below, the Partnership believes that none of the litigation in which it is currently involved, or has been involved since the beginning of the most recently completed financial year, individually or in the aggregate, is material to its financial condition or results of operations. The Partnership is not subject to any material regulatory actions.

There are no specified decommissioning costs relating to the Partnership's assets. The Partnership has a comprehensive repair and capital expenditure program to ensure that its transmission lines are maintained to industry standards. Replacement of the assets occurs in accordance with a long term capital plan and would involve typical costs of removal as part of that process. In the circumstance where a portion of a line or other assets were removed completely, there may be some contractual obligations under private or crown easements or other land rights which require the transmission owner to reinstate the land to a certain standard, typically the shape it was prior to the construction of the transmission assets. As well, certain environmental, land use and/or utility legislation, regulations and policy may apply in which the Partnership would have to comply with remediation requirements set by the government. The requirements will typically depend on the specific property characteristics and what criteria the government determines to be appropriate to meet safety and environmental concerns. These asset lives are indeterminate given their nature. As the individual assets or components reach the end of their useful lives, they are retired and replaced. Historically, certain asset components have been replaced a number of times, thus creating a perpetual asset with an indeterminate life. As such, the retirement date for these lines cannot be reasonably estimated and therefore, the fair value of the associated liability cannot be determined at this time. As a result, no liability has been accrued in these financial statements.

12. REVENUE

Year ended December 31 *(thousands of dollars)*	**2025**	**2024**
Transmission services *(Note 20)*	48,725	46,026
Lease income (*Note 20*)	498	498
Other	313	327
	49,536	46,851

13. OPERATION, MAINTENANCE, AND ADMINISTRATION COSTS

Year ended December 31 *(thousands of dollars)*	**2025**	**2024**
Compensation expenses	3,612	2,914
Contract expenses	1,715	1,906
Corporate costs	900	812
Administration expenses	808	495
Maintenance of facilities and real estate	807	1,733
Materials	163	180
Other	1,198	1,360
	9,203	9,400

14. FINANCING (INCOME) CHARGES

Year ended December 31 *(thousands of dollars)*	**2025**	**2024**
Interest expense on inter-company note payable	5,217	5,217
Less: Capitalized interest	(5,008)	(3,479)
Interest income and other expenses	(473)	(1,382)
	(264)	356

15. DEPRECIATION, AMORTIZATION AND ASSET REMOVAL COSTS

Year ended December 31 *(thousands of dollars)*	**2025**	**2024**
Depreciation of property, plant and equipment	9,425	8,970
Amortization of intangible assets	117	206
Depreciation and amortization	9,542	9,176
Asset removal costs	2,306	448
	11,848	9,624

16. INCOME TAXES

The Partnership is not a taxable entity for federal and provincial income tax purposes. Accordingly, no current or deferred tax expenses are recognized in the Partnership's financial statements.

17. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 *(thousands of dollars)*	**2025**	**2024**
Due from related parties	(296)	(91)
Deferred pension asset	(20)	(23)
Accounts payable and accrued liabilities	36	(32)
Interest payable on inter-company note payable	—	(2,608)
Due to related parties	3,127	(21,457)
	2,847	(24,211)

Supplementary Information

Year ended December 31 *(thousands of dollars)*	**2025**	**2024**
Net interest received	(474)	(1,382)

18. CAPITAL RISK MANAGEMENT

The Partnership's primary capital management objective is to ensure the sustainability of its capital to support continuing operations, meet its financial obligations, allow for growth opportunities and provide stable distributions to its partners. The Partnership manages its capital to maintain an investment grade credit rating while prudently making use of leverage in order to provide its ultimate parent with enhanced returns. In addition, the Partnership manages its capital to ensure access to incremental borrowings needed to fund new growth initiatives.

The Partnership manages its capital structure in accordance with changes in economic conditions. Generally, capital expenditures, operating activities and contractual obligations are funded with intercompany borrowings. In order to adjust the capital structure, the Partnership may elect to adjust the distribution amount paid to its partners, increase or reduce the equity participation in new and existing operations, adjust the level of capital spending or issue new partnership units.

The Partnership manages its capital in order to maintain a debt to capitalization ratio below 75%. Debt is the total principal balance of Inter-company note payable. Capitalization is calculated as Debt (as defined hereto) and partners' equity (see statements of financial position). At December 31, 2025, the ratio was 34% (2024 - 36%). The table below presents the details of the Partnership's capitalization and the calculation of the ratio:

As at December 31 *(thousands of dollars)*	**2025**	**2024**
Inter-company note payable *(Note 8)*	94,847	94,847
Debt	94,847	94,847
Partners' equity	184,176	171,395
Capitalization	279,023	266,242
Debt to Capitalization	34 %	36 %

There has been no change in the Partnership's approach to managing capital in 2025 or 2024.

19. FINANCIAL INSTRUMENTS

Fair value measurement

The Partnership defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

The carrying amounts for cash, accounts payable and accrued liabilities, due to and from related parties and inter-company note payable approximate fair value due to their short-term nature of these instruments. Due to the use of subjective judgments and uncertainties in the determination of fair values, these values should not be interpreted as being realizable in an immediate settlement of the financial instruments.

Fair value hierarchy

The following provides a description of financial instruments that are measured subsequent to initial recognition at fair value, grouped into Levels 1 to 3 based on the degree to which the fair value is observable:

- Level 1 fair value measurements are those derived from quoted market prices (unadjusted) in active markets for identical assets or liabilities;
- Level 2 fair value measurements are those derived from inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices); and
- Level 3 fair value measurements are those derived from valuation techniques that include inputs for the asset or liability that are not based on observable market data (unobservable inputs).

All financial instruments are classified as level 1.

There were no transfers between any of the levels during the years ended December 31, 2025 or 2024.

Financial risk management

The Partnership has exposure to the following risks from its use of financial instruments: market risk, credit risk and liquidity risk.

The Partnership's management has overall responsibility for the establishment and oversight of the Partnership's risk management framework. Risk management policies are established to identify and analyze the risks faced by the Partnership, to set appropriate risk limits and controls and to monitor risks and ensure adherence to these limits. Risk management policies and systems are reviewed regularly to reflect changes in market conditions and the Partnership's activities. The Partnership, through its training and management standards and procedures, aims to maintain a disciplined and constructive control environment in which all employees understand their roles and obligations. The objectives, policies and processes for managing risk were consistent with those in the prior year.

Market Risk

Market risk is the risk that changes in market prices (interest rates) will affect the Partnership's income or the value of its holdings of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimizing the return.

The Partnership's intercompany note payable is subject to a fixed interest rate of 5.5% per annum. As a result of having fixed-rate debt, fluctuations in interest rate is not expected to materially affect the Partnership's cash flows.

Credit Risk

Credit risk is the risk of financial loss to the Partnership if a counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Partnership's receivables from counterparties. The carrying amount of financial assets represents the maximum credit exposure.

The Partnership actively manages its exposure to credit risk by assessing the ability of counterparties to fulfill their obligations under the related contracts prior to entering into such contracts, and continually monitors these exposures.

The majority of amounts due from related parties are with the Independent Electricity System Operator (IESO). The IESO operates the provincial transmission system, and is a reliable counterparty. The quality of the Partnership's counterparties mitigates the Partnership's exposure to credit risk.

The Partnership is also exposed to credit risk on cash. Credit risk is mitigated by ensuring the majority of the financial assets are placed with a major Canadian financial institution with strong investment-grade ratings by a primary ratings agency. The credit risk of cash has been assessed as low.

Liquidity Risk

Liquidity risk is the risk that the Partnership will encounter difficulty in meeting the obligations associated with its financial liabilities that are settled by delivering cash or another financial asset. The Partnership manages liquidity risk by forecasting cash flows required by operations and anticipating investing and financing activities to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when they are due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Partnership's reputation.

The following table presents a summary of the Partnership's accounts payable and accrued liabilities, interest on inter-company note payable, due to related parties and inter-company note payable:

As at December 31, 2025 *(thousands of dollars)*	**Total**	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**
Accounts payable and accrued liabilities	492	492	—	—	—
Interest on inter-company note payable	250	250	—	—	—
Due to related parties	82,775	82,775	—	—	—
Inter-company note payable	94,847	94,847	—	—	—
	178,364	178,364	—	—	—

Going Concern Risk

The remaining principal balance of the inter-company note payable, and inter-company billings is payable on demand. The Company has insufficient liquidity to fund the repayment of the inter-company note payable and inter-company billings. On April 2, 2026, Hydro One Inc. and Hydro One Networks confirmed and agreed to not demand repayment of the inter-company note payable and inter-company billings from the Partnership.

20. RELATED PARTY TRANSACTIONS AND BALANCES

The Province of Ontario is a shareholder of Hydro One Limited with approximately 47.1% ownership at December 31, 2025. The IESO is a related party to the Partnership because it is controlled or significantly influenced by the Ministry of Energy and Mines. The Partnership has received services from entities under common control in the normal course of operations. The following is a summary of the Partnership's related party transactions during the years ended December 31, 2025 and 2024:

Year ended December 31 *(thousands of dollars)*			
Related Party	**Transaction**	**2025**	**2024**
IESO	Revenues for transmission services	48,725	46,026
Hydro One Networks	Services received[1]	78,681	72,285
	Lease income[2]	498	498
Hydro One Inc.	Services received[1]	27	35
	Interest charged on inter-company note payable[3]	5,217	5,217
Hydro One Sault Ste. Marie Holdings LP	Distributions paid	15,907	12,443

[1] Services received include capital project upgrades, transmission system operating services and corporate cost allocation.
[2] On December 7, 2023, Hydro One Networks entered into a one-year lease with the Company to lease land and building. The lease was extended in 2025 until December 31, 2026.
[3] On June 30, 2023, Hydro One Inc. issued a promissory note payable to the Partnership. See Note 8 - Inter-Company Note Payable.

The amounts due to and from related parties at December 31, 2025 and 2024 are as follows:

As at December 31 *(thousands of dollars)*	**2025**	**2024**
Due from related parties[1]	4,127	3,831
Interest on inter-company note payable	250	250
Due to related parties[1]	82,775	36,272
Inter-company note payable *(Note 8)*	94,847	94,847

[1] The balances payable and receivable for these services are non-interest bearing and unsecured.

21. SUBSEQUENT EVENT

Subsequent to December 31, 2025, the Partnership declared distributions of $3,369 thousand, paid on February 25, 2026.

HYDRO ONE NETWORKS INC.

DISTRIBUTION BUSINESS

FINANCIAL STATEMENTS

DECEMBER 31, 2024

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INDEPENDENT AUDITOR'S REPORT

To the Directors of Hydro One Networks Inc.

Opinion

We have audited the financial statements of the Distribution Business (a business of Hydro One Networks Inc.) (the "Entity"), which comprise:

- the carve-out balance sheet as at December 31, 2024;
- the carve-out statement of operations and comprehensive income for the year then ended;
- the carve-out statement of cash flows for the year then ended;
- and notes to the carve-out financial statements, including a summary of significant accounting policies (Hereinafter referred to as the "financial statements").

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements as at and for the year ended December 31, 2024 of the Entity are prepared, in all material respects, in accordance with the financial reporting framework described in Note 2 of these financial statements.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the **"Auditors' Responsibilities for the Audit of the Financial Statements"** section of our auditors' report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Emphasis of Matter — Financial Reporting Framework

We draw attention to Note 2 in the financial statements, which describes the applicable financial reporting framework and the purpose of the financial statements.

As a result, the financial statements may not be suitable for another purpose.

Our opinion is not modified in respect of this matter.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation of the financial statements in accordance with the financial reporting framework described in Note 2 in the financial statements; this includes determining that the applicable financial reporting framework is an acceptable basis for the preparation of the financial statements in the circumstances, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
April 23, 2025

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2024 and 2023

Year ended December 31 *(millions of Canadian dollars)*	**2024**	**2023**
Revenues		
Energy sales	5,682	5,157
Rural rate protection *(Note 24)*	255	250
Other *(Note 24)*	57	43
	5,994	5,450
Costs		
Purchased power (includes $2,696 related party costs; 2023 - $2,311) *(Note 24)*	4,015	3,595
Operation, maintenance and administration *(Note 24)*	689	711
Depreciation, amortization and asset removal costs *(Note 4)*	502	458
	5,206	4,764
Income before financing charges and income tax expense	**788**	**686**
Financing charges (includes $281 million related party charges; 2023 - $247 million) *(Notes 5, 24)*	285	243
Income before income tax expense	**503**	**443**
Income tax expense *(Note 6)*	83	53
Net income	**420**	**390**
Other comprehensive loss	—	(5)
Comprehensive income	**420**	**385**

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
BALANCE SHEETS
As at December 31, 2024 and 2023

As at December 31 *(millions of Canadian dollars)*	**2024**	**2023**
Assets		
Current assets:		
Accounts receivable *(Note 7)*	832	726
Due from related parties *(Note 24)*	115	135
Other current assets *(Note 8)*	82	66
	1,029	927
Property, plant and equipment *(Note 9)*	10,632	9,791
Other long-term assets:		
Regulatory assets *(Note 11)*	1,186	1,094
Intangible assets *(Note 10)*	397	411
Goodwill	217	217
Other assets *(Note 12)*	46	25
	1,846	1,747
Total assets	**13,507**	**12,465**
Liabilities		
Current liabilities:		
Inter-company demand facility *(Note 24)*	301	211
Inter-company demand promissory note *(Notes 15, 17)*	27	29
Long-term debt payable within one year *(Notes 15, 16, 24)*	364	287
Accounts payable and other current liabilities *(Note 13)*	908	886
Due to related parties *(Note 24)*	341	301
	1,941	1,714
Long-term liabilities:		
Long-term debt *(Notes 15, 16, 24)*	6,009	5,380
Deferred income tax liabilities *(Note 6)*	951	870
Regulatory liabilities *(Note 11)*	449	498
Other long-term liabilities *(Note 14)*	931	913
	8,340	7,661
Total liabilities	**10,281**	**9,375**
Contingencies and Commitments *(Notes 26, 27)*		
Subsequent Events *(Note 28)*		
Excess of assets over liabilities *(Notes 17, 22)*	3,226	3,090
Total liabilities and excess of assets over liabilities	**13,507**	**12,465**

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:

Stacey Mowbray
Chair, Audit Committee

David Lebeter
Director

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF CASH FLOWS
For the years ended December 31, 2024 and 2023

Year ended December 31 *(millions of Canadian dollars)*	**2024**	**2023**
Operating activities		
Net income	420	390
Environmental expenditures	(5)	(5)
Adjustments for:		
Depreciation and amortization *(Note 4)*	414	387
Regulatory assets and liabilities	1	50
Deferred income tax expense	8	2
Other	(23)	7
Changes in non-cash balances related to operations *(Note 25)*	(66)	27
Net cash from operating activities	**749**	**858**
Financing activities		
Long-term debt issued	996	1,011
Long-term debt repaid	(287)	(228)
Payments to finance dividends	(284)	(301)
Other	(4)	(2)
Net cash used in financing activities	**421**	**480**
Investing activities		
Capital expenditures *(Note 25)*		
Property, plant and equipment	(1,016)	(893)
Intangible assets	(48)	(86)
Additions of future use assets	(197)	(150)
Capital contributions paid	—	(4)
Other	1	(2)
Net cash used in investing activities	**(1,260)**	**(1,135)**
Net change in inter-company demand facility	(90)	203
Inter-company demand facility, beginning of year	(211)	(414)
Inter-company demand facility, end of year	**(301)**	**(211)**

See accompanying notes to Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Networks Inc. (Hydro One Networks or the Company) was incorporated on March 4, 1999 under the *Business Corporations Act* (Ontario) and is a wholly owned subsidiary of Hydro One Inc. (Hydro One). The Company owns and operates regulated transmission and distribution businesses. The Company's regulated distribution business (Distribution Business) operates a low-voltage electrical distribution network that distributes electricity from the transmission system, or directly from generators, to customers within Ontario. The Distribution Business is regulated by the Ontario Energy Board (OEB).

Rate Setting

On November 29, 2022, the OEB issued its JRAP Decision approving Hydro One Networks' distribution revenue requirement of $1,727 million for 2023, $1,813 million for 2024, $1,886 million for 2025, $1,985 million for 2026 and $2,071 million for 2027. Revenue requirements presented for 2024 to 2027 do not reflect the actual or expected updates resulting from the annual application process with the regulator to reflect the latest OEB inflation factors.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

These Financial Statements are prepared and presented in accordance with the accounting policies summarized below and in Canadian dollars. These policies are consistent with United States (U.S.) generally accepted accounting principles (GAAP).

The purpose of these Financial Statements is to meet Hydro One Networks' obligation to the OEB. As a result, these Financial Statements may not be suitable for another purpose. Consolidated financial statements of Hydro One for the year ended December 31, 2024 have been prepared and are publicly available.

Basis of Preparation

These Financial Statements have been prepared on a carve-out basis to provide the financial position, results of operations and cash flows of the Distribution Business. The Financial Statements are considered by management to be a reasonable representation, prepared on a rational, systematic and consistent basis, of the financial results of the Distribution Business. As a result of this basis of preparation, these Financial Statements may not necessarily be identical to the financial position and results of operations that would have resulted had the Distribution Business historically operated on a stand-alone basis.

The Financial Statements have been constructed primarily through specific identification of assets, liabilities (other than debt), revenues and expenses that relate to the Distribution Business. The Company's long-term debt is allocated based on the respective borrowing requirements of the Company's transmission and distribution businesses. A portion of the Company's shared functions and services costs is allocated to the Distribution Business on a fully allocated-cost basis, consistent with OEB-approved independent studies. Income tax expense has been recorded at effective rates based on income taxes as reported in the statements of operations and comprehensive income as though the Distribution Business was a separate taxpaying entity. These Financial Statements include deferred income taxes and related regulatory balances with respect to the rate-setting treatment of the benefits of the deferred income tax asset resulting from transition from the payments in lieu of tax regime under the *Electricity Act, 1998* (Ontario) to income tax payments under the federal and provincial tax regime which occurred when Hydro One Limited became a public company listed on the Toronto Stock Exchange. Certain other amounts presented in these Financial Statements represent allocations subject to review and approval by the OEB.

Hydro One Networks performed an evaluation of subsequent events through to April 23, 2025, the date these Financial Statements were available to be issued, to determine whether any events or transactions warranted recognition and disclosure in these Financial Statements. See Note 28 – Subsequent Events.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets, regulatory liabilities, post-retirement and post-employment benefits, and unbilled revenues. Actual results may differ significantly from these estimates.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting in accordance with Financial Accounting Standards Board (FASB) Accounting Standard Codification Topic 980, Regulated Operations within the Distribution Business, giving rise to the

recognition of regulatory assets and liabilities. The Distribution Business' regulatory assets represent certain amounts receivable from electricity customers in a future period and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Distribution Business has recorded regulatory liabilities that generally represent amounts that are refundable to electricity customers in future rates. The Distribution Business continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will include its regulatory assets and regulatory liabilities in setting future rates. If, at some future date, the Distribution Business judges that it is no longer probable that the OEB will include a regulatory asset or regulatory liability in setting future rates, the respective carrying amount would be reflected in results of operations, prospectively from the date the Distribution Business assessment is made.

Revenue Recognition

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues. Billed revenues are based on the amount of electricity delivered as measured from customer meters. At the end of each month, the amount of electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes. Distribution revenue also includes an amount relating to rate protection for rural, residential, and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered. Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are recorded at their estimated value, net of allowance for doubtful accounts. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Distribution Business' current lifetime expected credit losses (CECL) for all accounts receivable balances. The Distribution Business estimates the CECL by applying internally developed loss rates to all outstanding receivable balances by aging category on an undiscounted basis. Loss rates applied to the accounts receivable balances are based on historical overdue balances, customer payments and write-offs, which may be further supplemented from time to time to reflect management's best estimate of the loss. Accounts receivable are written-off against the allowance when they are deemed uncollectible. The allowance for doubtful accounts is affected by changes in volume, prices and economic conditions.

Income Taxes

Income taxes are accounted for using the asset and liability method. Current income tax assets and current income tax liabilities are recognized based on the income taxes refundable or payable on the current and prior year's taxable income. Current and deferred income taxes are computed based on the tax rates and tax laws enacted as at the balance sheet date. Tax benefits associated with income tax positions are recorded only when the more-likely-than-not recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Financial Statements. Management re-evaluates tax positions each period using new information about recognition or measurement as it becomes available.

Deferred Income Taxes

Deferred income tax assets and deferred income tax liabilities are recognized on all temporary differences between the tax bases and carrying amounts of assets and liabilities, including the carryforward of unused tax credits and tax losses to the extent that it is more-likely-than-not that these deductions, credits, and losses can be utilized. Deferred income tax assets and deferred income tax liabilities are measured at the tax rates that are expected to apply in the period when the asset is realized or the liability is settled, based on the tax rates and tax laws that have been enacted as at the balance sheet date.

Deferred income taxes associated with the Distribution Business' regulated operations which are considered to be more-likely-than-not to be recovered or refunded in future regulated rates charged to customers are recognized as deferred income tax regulatory assets and deferred income tax regulatory liabilities with an offset to deferred income tax expense.

Investment tax credits are recorded as a reduction of the related expenses or income tax expense in the current or future period to the extent it is more likely than not that the credits can be utilized.

Management reassesses the deferred income tax assets at each balance sheet date and reduces the amount to the extent that it is more likely than not that the deferred income tax asset will not be realized. Previously unrecognized deferred income tax

assets are reassessed at each balance sheet date and are recognized to the extent that it has become more likely than not that the tax benefit will be realized.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, and implicitly, by the regulated businesses of its subsidiaries. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Distribution Business to and from the pooled bank accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.15%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions, and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the balance sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, and information technology. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis.

Property, plant and equipment in service consists of distribution, administration and service, and other communication assets as well as land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, as well as capitalized project development costs associated with deferred capital projects.

Distribution

Distribution assets include assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.

Other

Other assets include fibre optic and microwave radio systems, optical ground wire, towers, telephone equipment and associated buildings. Other assets also include easements which include land rights for occupation.

Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost, which comprises purchased software, direct labour (including employee benefits), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Distribution Business' intangible assets primarily represent major computer applications.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized financing costs are a reduction of financing charges recognized in the statements of operations and comprehensive income. Capitalized financing costs are calculated using the Distribution Business' weighted average effective cost of debt.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation and Amortization

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and amortization rates, as required by the OEB. Any changes arising from such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The most recent review resulted in changes to rates effective January 1, 2023 for the Distribution Business. A summary of average service lives and depreciation and amortization rates as at December 31, 2024 for the various classes of assets is included below:

	Average Service Life	Rate Range	Rate Average
Property, plant and equipment:			
Distribution	49 years	1% - 5%	2 %
Communication	9 years	2% - 11%	9 %
Administration and service	24 years	1% - 20%	5 %
Intangible assets	11 years	8% - 10%	6 %

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation, with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense.

Acquisitions and Goodwill

The Company accounts for business acquisitions using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair value at the date of acquisition. Costs associated with pending acquisitions are expensed as incurred. Goodwill represents the cost of acquired companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is not included in rate base.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. The Company performs a qualitative assessment to determine whether it is more likely than not that the fair value of the applicable reporting unit is greater than its carrying amount, no further testing is required. If the Company determines, as a result of its qualitative assessment, that it is more likely than not that the fair value of the applicable reporting unit is less than its carrying amount, a quantitative goodwill impairment assessment is performed. The quantitative assessment compares the fair value of the applicable reporting unit to its carrying amount, including goodwill. If the fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and as a charge to results of operations.

Based on the assessment performed as at September 30, 2024 and with no significant events since, the Company has concluded that goodwill was not impaired as at December 31, 2024.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, the Company evaluates whether impairment may exist by estimating future undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

The carrying costs of most of the Distribution Business' long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable.

Management assesses the fair value of such long-lived assets using commonly accepted techniques. Techniques used to determine fair value include, but are not limited to, the use of recent third-party comparable sales for reference and internally developed discounted cash flow analysis. Significant changes in market conditions, changes to the condition of an asset, or a change in management's intent to utilize the asset are generally viewed by management as triggering events to reassess the cash flows related to these long-lived assets. As at December 31, 2024 and 2023, no asset impairment had been recorded.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Distribution Business defers its proportionate share of the relevant Hydro One external transaction costs related to obtaining financing and presents such amounts net of related debt on the balance sheets. Deferred issuance costs are amortized over the contractual life of the related debt on an effective-interest

basis and the amortization is included within financing charges in the statements of operations and comprehensive income. Transaction costs for items classified as held-for-trading are expensed immediately.

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Distribution Business considers the carrying amounts of accounts receivable and amounts due from related parties to be reasonable estimates of fair value because of the short time to maturity of these instruments. The Distribution Business estimates the CECL for all accounts receivable balances, which are recognized as adjustments to the allowance for doubtful accounts. Accounts receivable are written-off against the allowance when they are deemed uncollectible. All financial instrument transactions are recorded at trade date.

The Distribution Business determines the classification of its financial assets and liabilities at the date of initial recognition. The Distribution Business designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Distribution Business' risk management policy disclosed in Note 16 - Fair Value of Financial Instruments and Risk Management.

Derivative Instruments and Hedge Accounting

Hydro One closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedging relationships. Hydro One's derivative instruments, or portions thereof, are mirrored down to Hydro One Networks, and are allocated between the Company's transmission and distribution businesses. The derivative instruments are classified as fair value hedges or undesignated contracts, consistent with Hydro One's derivative instruments classification.

The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value on the balance sheets. For derivative instruments that qualify for hedge accounting, Hydro One may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. Hydro One offsets fair value amounts recognized on its balance sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, any unrealized gain or loss, net of tax, is recorded as a component of accumulated OCI (AOCI) or accumulated OCL (AOCL). Amounts in AOCI or AOCL are reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations and presented in the same line item as the earnings effect of the hedged item. Any gains or losses on the derivative instrument that represent hedge components excluded from the assessment of effectiveness are recognized in the same line item of the statements of operations as the hedged item. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the statements of operations and comprehensive income (loss) in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the statements of operations and comprehensive income (loss). The changes in fair value of the undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and are carried at fair value on the balance sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. Hydro One does not engage in derivative trading or speculative activities and had no embedded derivatives that required bifurcation as at December 31, 2024 or 2023.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where the Company has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. Hydro One also assesses, both at the inception of the hedge and on a quarterly basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of Hydro One's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

Hydro One recognizes the funded status of its defined benefit pension plan (Pension Plan) and its post-retirement and post-employment plans on its consolidated balance sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Defined benefit pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation (PBO) exceeds the fair value of the plan assets. Liabilities are recognized on the consolidated balance sheets for any net underfunded PBO. The net underfunded PBO may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the PBO of the plan, an asset is recognized equal to the net overfunded PBO. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Hydro One recognizes its contributions to the defined contribution pension plan (DC Plan) as pension expense, with a portion being capitalized as part of labour costs included in capital expenditures. The expensed amount is included in operation, maintenance and administration (OM&A) costs in the consolidated statements of operations and comprehensive income.

Defined Benefit Pension

Hydro One has a contributory defined benefit pension plan covering most regular employees of Hydro One and its subsidiaries, including Hydro One Networks. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the pension plan is accounted for as a defined contribution plan and no pension benefit asset or liability is recorded.

Post-retirement and Post-employment Benefits

Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Networks. The benefit obligations of these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Networks. Accordingly, for purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are reflective of earnings allocations of relevant employees to the Company's Distribution Business.

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. For post-retirement benefits, past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or actuarial losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active employees in the plan or over the remaining life expectancy of inactive employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory account, to the extent of the remeasurement adjustment.

The actuarial gains and actuarial losses on post-employment obligations that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory account, to the extent of the remeasurement adjustment.

All post-retirement and post-employment benefit costs are attributed to labour costs and are either charged to results of operations (OM&A costs) or capitalized as part of the cost of property, plant and equipment and intangible assets (applies to the service cost component of benefit cost) and to regulatory assets for all other components of the benefit cost, consistent with their inclusion in OEB-approved rates.

Stock-Based Compensation

Share Grant Plans

The Company measures share grant plans based on fair value of share grants as estimated based on Hydro One Limited's grant date common share price. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. The Company records a regulatory asset equal to the accrued costs of share grant plans recognized in each period. Costs are transferred from the regulatory asset to labour costs at the time the share grants vest and are recovered in rates. Forfeitures are recognized as they occur.

Deferred Share Unit (DSU) Plans

The Company records the liabilities associated with its Directors' and Management DSU Plans at fair value at each reporting date until settlement, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the DSU liability is based on Hydro One Limited's common share closing price at the end of each reporting period.

Society of United Professionals (Society) Restricted Share Unit (RSU) Plan

The Company measures its Society RSU plan based on fair value of share grants as estimated based on Hydro One Limited's grant date common share price. The costs are recognized over the vesting period using the straight-line attribution method. The Company records a regulatory asset equal to the accrued costs of the Society RSU plan recognized in each period. Costs are transferred from the regulatory asset to labour costs at the time the share grants vest and are issued and recovered in rates. Forfeitures are recognized as they occur.

Long-term Incentive Plan (LTIP)

The Company measures the awards issued under Hydro One Limited's LTIP, at fair value based on Hydro One Limited grant date common share price. The related compensation expense is recognized over the vesting period on a straight-line basis. Forfeitures are recognized as they occur.

Loss Contingencies

Hydro One and its subsidiaries are involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of the Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Distribution Business records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Distribution Business.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. The Company records a liability for the estimated future expenditures associated with contaminated land assessment and remediation (LAR) and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate that produces an amount at which the environmental liabilities could be settled in an arm's length transaction with a third party. To the extent that the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the anticipated amount of future recovery of these environmental expenditures from customers. Hydro One reviews its estimates of future environmental expenditures annually, or more frequently if there are indications that circumstances have changed. Estimate changes are accounted for prospectively.

Asset Retirement Obligations

Asset retirement obligations are recorded for legal obligations associated with the future removal and disposal of long-lived assets. Such obligations may result from the acquisition, construction, development and/or normal use of the asset. Conditional asset retirement obligations are recorded when there is a legal obligation to perform a future asset retirement activity but where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. In such a case, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. This uncertainty is incorporated in the fair value measurement of the obligation.

When recording an asset retirement obligation, the present value of the estimated future expenditures required to complete the asset retirement activity is recorded in the period in which the obligation is incurred, if a reasonable estimate can be made. In general, the present value of the estimated future expenditures is added to the carrying amount of the associated asset and the resulting asset retirement cost is depreciated over the estimated useful life of the asset. The present value is determined with a discount rate that equates to the Company's credit-adjusted risk-free rate. Where an asset is no longer in service when an asset retirement obligation is recorded, the asset retirement cost is recorded in results of operations.

Leases

At the commencement date of a lease, the minimum lease payments are discounted and recognized as a lease obligation. Discount rates used correspond to the Company's incremental borrowing rates. Renewal options are assessed for their likelihood of being exercised and are included in the measurement of the lease obligation when it is reasonably certain they will be exercised. The Company does not recognize leases with a term of less than 12 months. A corresponding Right-of-Use (ROU) asset is recognized at the commencement date of a lease. The ROU asset is measured as the lease obligation adjusted for any lease payments made and/or any lease incentives and initial direct costs incurred. ROU assets are included in other long-term assets, and corresponding lease obligations are included in other current liabilities and other long-term liabilities on the balance sheets.

Subsequent to the commencement date, the lease expense recognized at each reporting period is the total remaining lease payments over the remaining lease term. Lease obligations are measured as the present value of the remaining unpaid lease payments using the discount rate established at commencement date. The amortization of the ROU assets is calculated as the difference between the lease expense and the accretion of interest, which is calculated using the effective interest method. Lease modifications and impairments are assessed at each reporting period to assess the need for a remeasurement of the lease obligations or ROU assets.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standard Updates (ASUs) issued by the FASB that are applicable to Hydro One Networks:

Recently Adopted Accounting Guidance

Guidance	Date issued	Description	Effective date	Impact on Distribution Business
ASU 2023-07	November 2023	The amendments improve the disclosures about a public entity's reportable segments and address requests from investors for additional, more detailed information about a reportable segment's expenses	Fiscal years beginning after December 15, 2023, and interim periods within fiscal years beginning after December 15, 2024.	No impact upon adoption

Recently Issued Accounting Guidance Not Yet Adopted

Guidance	Date issued	Description	Effective date	Anticipated Impact on Distribution Business
ASU 2023-06	October 2023	The amendments represent changes to clarify or improve disclosure or presentation requirements of a variety of subtopics in the FASB Accounting Standards Codification (Codification). Many of the amendments allow users to more easily compare entities subject to the US Securities and Exchange's (SEC) existing disclosures with those entities that were not previously subject to the SEC's requirements. Also, the amendments align the requirements in the Codification with the SEC's regulations. Applicable to all entities, if by June 30, 2027 the SEC has not removed the applicable requirement from Regulation S-X or Regulation S-K, the pending content of the related amendment will be removed from the Codification and will not become effective for any entity.	Two years subsequent to the date on which the SEC's removal of that related disclosure becomes effective	Under assessment
ASU 2023-09	December 2023	The amendments address investor requests for more transparency about income tax information through improvements to income tax disclosures primarily related to the rate reconciliation and income taxes paid information.	Annual periods beginning after December 15, 2024.	Under assessment
ASU 2024-02	March 2024	The amendments contain modifications to the codification that remove various concept statements which may be extraneous and not required to understand or apply the guidance or references used in prior statements to provide guidance in certain topical areas.	Fiscal years beginning after December 15, 2024.	No impact upon adoption
ASU 2024-03	November 2024	The amendments require public business entities to disclose additional information about specific expense categories in the notes to financial statements at interim and annual reporting periods, which are not generally presented in the current financial statements.	Annual periods beginning after December 15, 2026, and interim periods beginning after December 15, 2027.	Under assessment

4. DEPRECIATION, AMORTIZATION AND ASSET REMOVAL COSTS

Year ended December 31 *(millions of dollars)*	2024	2023
Depreciation of property, plant and equipment	349	321
Amortization of intangible assets	60	61
Amortization of regulatory assets	5	5
Depreciation and amortization	414	387
Asset removal costs	88	71
	502	458

5. FINANCING CHARGES

Year ended December 31 *(millions of dollars)*	2024	2023
Interest on long-term debt *(Note 24)*	261	222
Interest on inter-company demand facility *(Note 24)*	20	25
Interest on regulatory accounts	12	4
Other	7	5
Less: Interest capitalized on construction and development in progress	(15)	(13)
	285	243

6. INCOME TAXES

As a rate regulated utility business, the Distribution Business recovers income taxes from its ratepayers based on estimated current income tax expense in respect of its regulated operations. The amounts of deferred income taxes related to regulated operations which are considered to be more likely-than-not to be recoverable from, or refunded to, ratepayers in future periods are recognized as deferred income tax regulatory assets or deferred income tax regulatory liabilities, with an offset to deferred income tax recovery or deferred income tax expense, respectively. The Distribution Business' income tax expense or income tax recovery for the period includes all current and deferred income tax expenses for the period net of the regulated accounting offset to deferred income tax expense arising from temporary differences to be recoverable from, or refunded to, customers in future rates. Thus, the Distribution Business' income tax expense or income tax recovery differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate.

The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 *(millions of dollars)*	**2024**	**2023**
Income before income tax expense	503	443
Income tax expense at statutory rate of 26.5% (2023 - 26.5%)	133	117
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Impact of DTA Implementation Decision[1]	—	18
Capital cost allowance in excess of depreciation and amortization	(18)	(59)
Overheads capitalized for accounting but deducted for tax purposes	(24)	(19)
Pension and post-retirement benefit contributions in excess of expense	(3)	(1)
Environmental expenditures	(1)	(1)
Interest capitalized for accounting but deducted for tax purposes	(4)	(4)
Other	(2)	1
Net temporary differences attributable to regulated business	(52)	(65)
Net permanent differences	2	1
Total income tax expense	83	53
Effective income tax rate	16.5 %	12.0 %

[1] Pursuant to the DTA Implementation Decision, the impact represents the amounts recovered from ratepayers in respect of tax deductions previously shared with the ratepayers. See Note 11 – Regulatory Assets and Liabilities.

The major components of income tax expense are as follows:

Year ended December 31 *(millions of dollars)*	**2024**	**2023**
Current income tax expense	75	50
Deferred income tax expense	8	3
Total income tax expense	83	53

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and deferred income tax liabilities reflect the future income tax consequences attributable to temporary differences between the tax bases and the financial statement carrying amounts of the assets and liabilities including the carry forward amounts of tax losses and tax credits. Deferred income tax assets and deferred income tax liabilities attributable to the Distribution Business' regulated operations are recognized with a corresponding offset in deferred income tax regulatory assets and deferred income tax liabilities to reflect the anticipated recovery or repayment of these balances in the future electricity rates. As at December 31, 2024 and 2023, deferred income tax assets and deferred income tax liabilities consisted of the following:

As at December 31 *(millions of dollars)*	**2024**	**2023**
Deferred income tax assets (liabilities)		
Capital cost allowance in excess of depreciation and amortization	(1,391)	(1,306)
Post-retirement and post-employment benefits expense in excess of cash payments	325	317
Regulatory assets and liabilities	126	121
Goodwill	(19)	(19)
Environmental expenditures	1	3
Non-capital losses	4	4
Other	3	10
Net deferred income tax liabilities[1]	(951)	(870)

[1] The net deferred income tax liabilities are presented on the balance sheets as long-term.

7. ACCOUNTS RECEIVABLE

As at December 31 *(millions of dollars)*	**2024**	**2023**
Accounts receivable – billed	403	361
Accounts receivable – unbilled	489	421
Accounts receivable, gross	892	782
Allowance for doubtful accounts	(60)	(56)
Accounts receivable, net	832	726

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2024 and 2023:

Year ended December 31 *(millions of dollars)*	**2024**	**2023**
Allowance for doubtful accounts – beginning	(56)	(61)
Write-offs	18	18
Additions to allowance for doubtful accounts	(22)	(13)
Allowance for doubtful accounts – ending	(60)	(56)

8. OTHER CURRENT ASSETS

As at December 31 *(millions of dollars)*	**2024**	**2023**
Prepaid expenses and other assets	46	21
Regulatory assets *(Note 11)*	28	32
Materials and supplies	8	13
	82	66

9. PROPERTY, PLANT AND EQUIPMENT

As at December 31, 2024 *(millions of dollars)*	Property, Plant and Equipment[1]	Accumulated Depreciation	Construction in Progress	Total
Distribution	14,229	4,784	308	9,753
Administration and service	1,426	677	86	835
Other	228	184	—	44
	15,883	5,645	394	10,632

[1] Includes future use assets totalling $326 million.

As at December 31, 2023 *(millions of dollars)*	Property, Plant and Equipment[1]	Accumulated Depreciation	Construction in Progress	Total
Distribution	13,406	4,567	202	9,041
Administration and service	1,399	718	43	724
Other	211	185	—	26
	15,016	5,470	245	9,791

[1] Includes future use assets totalling $229 million.

Financing charges capitalized on property, plant and equipment under construction in 2024 were $13 million (2023 - $9 million).

10. INTANGIBLE ASSETS

As at December 31, 2024 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	891	550	28	369
Other	77	53	4	28
	968	603	32	397

As at December 31, 2023 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	852	503	36	385
Other	73	47	—	26
	925	550	36	411

Financing charges capitalized to intangible assets under development were $2 million in 2024 (2023 - $4 million). The estimated annual amortization expense for intangible assets are as follows: 2025 - $61 million; 2026 - $57 million; 2027 - $54 million; 2028 - $49 million; and 2029 - $41 million.

11. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. The Distribution Business has recorded the following regulatory assets and liabilities:

As at December 31 *(millions of dollars)*	2024	2023
Regulatory assets:		
Deferred income tax regulatory asset	1,018	940
Post-retirement and post-employment benefits - non-service cost	71	92
Broadband deferral	48	37
Getting Ontario Connected Act variance	24	9
Stock-based compensation	13	15
Environmental	2	7
Other	38	26
Total regulatory assets	1,214	1,126
Less: current portion	(28)	(32)
	1,186	1,094

Regulatory liabilities:		
Post-retirement and post-employment benefits	210	221
Retail settlement variance account (RSVA)	157	84
Earnings sharing mechanism deferral	68	61
Distribution rate riders	45	99
Tax rule changes variance	32	31
Capitalized overhead tax variance	15	10
OPEB Asymmetrical Carrying Charge	14	8
Pension cost differential	14	7
Other	26	29
Total regulatory liabilities	581	550
Less: current portion	(132)	(52)
	449	498

Deferred Income Tax Regulatory Asset

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. The Distribution Business has recognized regulatory assets that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Distribution Business' income tax expense would have been recognized using the liability method and there would be no regulatory accounts established for income taxes to be recovered through future rates.

Post-Retirement and Post-Employment Benefits - Non-Service Cost

The Distribution Business has recorded a regulatory asset relating to the future recovery of its post-retirement and post-employment benefits other than service costs. The regulatory asset includes the applicable tax impact to reflect taxes payable. Prior to adoption of ASU 2017-07 in 2018, these amounts were capitalized to property, plant and equipment and intangible assets. In 2018 and 2019, the OEB approved the regulatory asset for Hydro One Networks' transmission business and distribution business, respectively. As part of Hydro One Networks' 2020 to 2022 Transmission Decision, the OEB concluded that the non-service cost component of Hydro One's OPEB costs shall be recognized as OM&A for both its transmission and distribution businesses. Furthermore, the Distribution Business continued to record the non-service cost component of OPEBs in this account until the end of 2022. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of the Distribution Business' account balance as at December 31, 2020, including accrued interest, which is being recovered from ratepayers over a three-year period ending December 31, 2025.

Broadband Deferral

The Distribution Business recognizes the incremental costs and incremental revenues attributable to carrying out activities pertaining to designated broadband projects as defined under the *Building Broadband Faster Act* (Ontario) in this generic deferral account.

Getting Ontario Connected Act Variance

On October 31, 2023, the OEB issued its Decision and Order approving the establishment of a generic sector-wide variance account, effective April 1, 2023. The account was established to record incremental costs of locating underground infrastructure resulting from the implementation of Provincial legislation: Bill 93, *Getting Ontario Connected Act, 2022*.

Stock-based Compensation

The Distribution Business recognizes costs associated with share grant plans as a regulatory asset as management considers it probable that share grant plans' costs will be recovered in the future through the rate-setting process. Share grant costs are transferred to labour costs at the time they vest and are issued, and are recovered in rates in accordance with recovery of these labour costs.

Environmental

The Distribution Business records a liability for the estimated future expenditures required to remediate environmental contamination. A regulatory asset is recognized to the extent management considers it to be probable that environmental expenditures will be recovered in the future through the rate-setting process. For the year ended December 31, 2024, the Distribution Business has recorded a portion of the liability as a regulatory asset. In 2024, the revaluation adjustment decreased the environmental regulatory asset by less than $1 million (2023 - $2 million) to reflect changes in the recoverable portion of the Distribution Business' PCB and LAR environmental liabilities. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the

discretion to examine and assess the prudence and the timing of recovery of all of the Distribution Business' actual environmental expenditures.

Post-Retirement and Post-Employment Benefits

In accordance with OEB rate orders, post-retirement and post-employment benefits costs are recovered on an accrual basis. The Distribution Business recognizes the net unfunded or funded status of post-retirement and post-employment obligations on the consolidated balance sheets with an incremental offset to the associated regulatory asset or regulatory liability, as the case may be. A regulatory asset or regulatory liability is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered or returned in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to the present value of the actuarially determined benefit obligation at each year end based on an annual actuarial report, with an offset to the associated regulatory asset or regulatory liability, as the case may be, to the extent of the remeasurement adjustment.

RSVA

The Distribution Business has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. The RSVA account tracks the difference between the cost of power purchased from the IESO and the cost of power recovered from ratepayers. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of the Distribution Business' account balance as at December 31, 2020, including accrued interest, over a three-year period ending December 31, 2025. In December 2024, as part of the Decision and Order on 2025 distribution rates, the OEB approved the disposition of certain RSVA balances as at December 31, 2023, including accrued interest, over a one-year period ending December 31, 2025 on an interim basis.

Earnings Sharing Mechanism Deferral

In March 2019, the OEB approved the establishment of an earnings sharing mechanism deferral account for the Distribution Business to record over-earnings including tax impacts, if any, realized for any year from 2018 to 2022. Under this mechanism, Hydro One shares 50% of regulated earnings that exceed the OEB-approved regulatory return-on-equity by more than 100 basis points with distribution ratepayers. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of the Distribution Business' account balance as at December 31, 2020, including accrued interest, over a three-year period ending December 31, 2025. As part of the same decision, the account was approved for continuance for the Distribution Business for 2023 to 2027.

Distribution Rate Riders

As part of the JRAP Decision, the OEB approved the disposition of certain deferral and variance account balances as at December 31, 2020, including accrued interest. These approved balances, including those for RSVA, tax rule changes variance, pension cost differential, and ESM were accumulated in distribution rate riders which makes up the majority of this balance. The amounts are being disposed of over a three-year period ending December 31, 2025.

Tax Rule Changes Variance

The 2019 federal and Ontario budgets (Budgets) provided certain time-limited investment incentives permitting the Distribution Business to deduct accelerated capital cost allowance of up to three times the first-year rate for capital investments acquired after November 20, 2018 and placed in-service before January 1, 2028 (Accelerated Depreciation). Following the enactment of the Budget measures in the second quarter of 2019, the OEB directed all Ontario regulated utilities including the Distribution Business to track the full revenue impact of the tax benefits related to the Accelerated Depreciation rules to ratepayers. The tax benefit to be returned to ratepayers in the future gave rise to a regulatory liability and resulted in a decrease in revenues as current rates do not include the benefit of the Accelerated Depreciation; therefore, the revenue subject to refund cannot be recognized. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of the Distribution Business' account balance as at December 31, 2020, including accrued interest, which is being returned to ratepayers over a three-year period ending December 31, 2025.

Capitalized Overhead Tax Variance

As part of the JRAP Decision, the OEB approved the establishment of a capitalized overhead tax variance account to capture the difference between the capitalized overheads deducted in calculating the regulatory tax expense included in rates and the actual capitalized overhead costs deducted in Hydro One's tax returns for the Distribution Business for the 2016 to 2027 period. Variance amounts are recognized at the earlier of (i) when the tax year has been audited by the Canada Revenue Agency or (ii) when the taxation year is statute barred.

OPEB Asymmetrical Carrying Charge Variance Account

On September 14, 2017, the OEB issued its Report of the Board: *Regulatory Treatment of Pension and OPEB Costs* that allowed rate-regulated utilities to track the difference between their pension and OPEB costs calculated under the accrual method and the cash payment method, effective January 1, 2018, and record the carrying charges associated with the balance

on an asymmetrical basis. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of Distribution Business' account balances as at December 31, 2020, including accrued interest, which is being returned to ratepayers over a three-year period ending December 31, 2023. As part of the same decision, the OEB approved the continuance and modification of this account for Hydro One Networks' Distribution business for 2023 to 2027.

Pension Cost Differential

Variances between the OM&A pension cost recognized and the cost embedded in rates as part of the rate-setting process for the Distribution Business are recognized as a regulatory asset or regulatory liability, as the case may be. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of the Distribution Business' account balance as at December 31, 2020, including accrued interest, which is being returned to ratepayers over a three-year period ending December 31, 2025. As part of the same decision, the account was approved for continuance for the Distribution Business for 2023 to 2027.

12. OTHER LONG-TERM ASSETS

As at December 31 *(millions of dollars)*	**2024**	**2023**
Cloud Computing Implementation Cost	24	—
Right-of-Use assets *(Note 21)*	21	24
Other long-term assets	1	1
	46	25

13. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

As at December 31 *(millions of dollars)*	**2024**	**2023**
Accrued liabilities	574	666
Regulatory liabilities *(Note 11)*	132	52
Accounts payable	121	74
Accrued interest *(Note 24)*	69	59
Lease obligations *(Note 21)*	6	6
Environmental liabilities *(Note 19)*	4	29
Derivative liability	2	—
	908	886

14. OTHER LONG-TERM LIABILITIES

As at December 31 *(millions of dollars)*	**2024**	**2023**
Post-retirement and post-employment benefit liability *(Note 18)*	880	857
Lease obligations *(Note 21)*	15	18
Long-term accounts payable and other liabilities	14	12
Long-term inter-company payable *(Note 24)*	10	11
Asset retirement obligations *(Note 20)*	10	10
Derivative liability	1	1
Environmental liabilities *(Note 19)*	1	4
	931	913

15. DEBT

Hydro One issues notes for long-term financing under its Medium-Term Note (MTN) Program. The terms of certain issuances are mirrored down to Hydro One Networks through the issuance of inter-company debt, and are allocated between the Company's transmission and distribution businesses. The following table presents long-term debt allocated to the Distribution Business outstanding as at December 31, 2024 and 2023:

As at December 31 *(millions of dollars)*	**2024**	**2023**
Long-term debt[1]	6,379	5,679
Add: Net unamortized debt premiums	16	7
Add: Realized mark-to-market gain[2]	1	1
Less: Deferred debt issuance costs	(23)	(20)
Less: Long-term debt payable within one year	(364)	(287)
Long-term debt	6,009	5,380

[1] Certain prior year amounts have been reclassified for consistency with the current year presentation. An adjustment has been made within debts to reclassify changes in long-term debt to inter-company demand note. This reclassification had no effect on the reported results of operations or balance sheet.

[2] In October 2023, Hydro One entered into $400 million fixed-to-floating interest-rate swap agreement to convert the $400 million Medium Term Note (MTN) Series 57 notes maturing October 20, 2025, into a variable rate debt. $156 million was allocated to the Distribution Business. This swap was accounted for as a fair value hedge. In December 2023, this swap was terminated with a $6 million payment received on settlement, of which $1 million was allocated to the Distribution business that is being amortized over the term of the related note.

In 2024, Hydro One issued $2,750 million long-term debt under its MTN Program (2023 - $2,375 million), of which $2,531 million was mirrored down to Hydro One Networks, and $987 million was allocated to the Distribution Business.

In 2024, Hydro One repaid $700 million (2023 - $600 million) of maturing long-term debt under its MTN Program. Hydro One Networks repaid inter-company debt of $700 million (2023 - $600 million) to Hydro One, of which $287 million (2023 - $228 million) was allocated to the Distribution Business.

Principal and Interest Payments

As at December 31, 2024, future principal repayments, interest payments, and related weighted-average interest rates were as follows:

	Long-Term Debt Principal Repayments *(millions of dollars)*	**Interest Payments** *(millions of dollars)*	**Weighted-Average Interest Rate** *(%)*
Year 1	364	280	4.1
Year 2	411	262	3.7
Year 3	—	253	—
Year 4	195	247	5.2
Year 5	464	239	3.7
	1,434	1,281	4.0
Years 6-10	1,339	994	4.6
Thereafter	3,606	1,867	4.6
	6,379	4,142	4.4

Inter-company Demand Loan

On June 1, 2021, Hydro One Networks issued a $29 million non-interest bearing demand promissory note to Orillia Power Distribution Corporate in exchange for the assets of Orillia Power. In 2024, the note was reduced by $2 million through an offset of the inter-company demand facility (2023 - $nil). As at December 31, 2024, $27 million of the promissory note was outstanding (2023 - $29 million). During the years ended December 31, 2024 and 2023, no promissory notes were issued.

16. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

The Distribution Business classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One Networks has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest-rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

As at December 31, 2024 and 2023, the carrying amounts of accounts receivable, due from related parties, inter-company demand facility, inter-company demand note, accounts payable, and due to related parties are representative of fair value due to the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The carrying values and fair values of the Distribution Business' long-term debt as at December 31, 2024 and 2023 are as follows:

As at December 31 *(millions of dollars)*	2024 Carrying Value	2024 Fair Value	2023 Carrying Value	2023 Fair Value
Long-term debt, including current portion	6,373	6,335	5,667	5,623

Fair Value Measurements of Derivative Instruments

Hydro One enters into interest-rate swaps agreements with respect to its long-term debt. The terms of certain of these interest-rate swap agreements are mirrored down to Hydro One Networks, and are allocated between the Company's transmission and distribution businesses.

As at December 31, 2024 and 2023, Hydro One had no fair value hedges.

As at December 31, 2024, the value of the Company's derivative instruments was $7 million (2023 - $2 million), of which $3 million was allocated to the Distribution Business.

As at December 31, 2024 and 2023, the Company had no interest-rate swaps classified as undesignated contracts.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities as at December 31, 2024 and 2023 is as follows:

As at December 31, 2024 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Long-term debt, including current portion *(Note 15)*	6,373	6,335	—	6,335	—
Derivative instruments					
Cash flow hedges, including current portion	3	3	—	3	—
	6,376	6,338	—	6,338	—

As at December 31, 2023 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Long-term debt, including current portion	5,667	5,623	—	5,623	—
Derivative instruments					
Cash flow hedges, including current portion	1	1	—	1	—
	5,668	5,624	—	5,624	—

The fair value of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no transfers between any of the fair value levels during the years ended December 31, 2024 or 2023.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss which results from changes in values, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates, as its regulated return on equity is derived using a formulaic approach that takes anticipated interest rates into account. The Company is not currently exposed to material commodity price risk or material foreign exchange risk.

Hydro One Networks uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. Hydro One Networks also uses derivative financial instruments to manage interest-rate risk. Hydro One's derivative instruments, or portions thereof, are mirrored down to Hydro One Networks, and are allocated between the Company's transmission and distribution businesses. Hydro One Networks may utilize interest-rate swaps designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt, and may also utilize interest-rate derivative instruments, such as cash flow hedges, to manage its exposure to short-term interest rates or to lock in interest-rate levels on forecasted financing.

A hypothetical 100 basis point increase in interest rates associated with variable-rate debt would not have resulted in a significant decrease to the Company's net income for the years ended December 31, 2024 and 2023, respectively.

For derivative instruments that are designated and qualify as cash flow hedges, the unrealized gain or loss, after tax, on the derivative instrument is recorded as OCI or OCL and is reclassified to net income or net loss in the same period during which the hedged transaction affects results of operations. The following table shows the amounts recorded in OCL and reclassified to financing charges for the years ended December 31, 2024 and 2023:

	Hydro One		Distribution Business	
Year ended December 31 *(millions of dollars)*	**2024**	**2023**	**2024**	**2023**
Amounts recorded in OCL				
Before tax loss	1	5	—	1
After tax loss	1	4	—	1
Amounts reclassified to financing charges				
Before tax gain	(4)	(2)	(1)	—
After tax gain	(3)	(2)	(1)	—

The Company estimates that the amount of AOCL, after tax, related to cash flow hedges to be reclassified to results of operations in the next 12 months is approximately $3 million, of which approximately $1 million will be allocated to the Distribution Business. Actual amounts reclassified to results of operations depend on the interest rate in effect until the derivative contracts mature. For all forecasted transactions, as at December 31, 2024, the maximum term over which the Company is hedging exposures to the variability of cash flows is approximately two years.

The Pension Plan manages market risk by diversifying investments in accordance with the Pension Plan's Statement of Investment Policies and Procedures. Interest rate risk arises from the possibility that changes in interest rates will affect the fair value of the Pension Plan's financial instruments. In addition, changes in interest rates can also impact discount rates which impact the valuation of the pension and post-retirement and post-employment liabilities. Currency risk is the risk that the value of the Pension Plan's financial instruments will fluctuate due to changes in foreign currencies relative to the Canadian dollar. Other price risk is the risk that the value of the Pension Plan's investments in equity securities will fluctuate as a result of changes in market prices, other than those arising from interest risk or currency risk. All three factors may contribute to changes in values of the Pension Plan investments. See Note 18 – Pension and Post-Retirement and Post-Employment Benefits for further details.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. As at December 31, 2024 and 2023, there were no significant concentrations of credit risk with respect to any class of financial assets. The Distribution Business' revenue is earned from a broad base of customers. As a result, the Distribution Business did not earn a material amount of revenue from any single customer. As at December 31, 2024 and 2023, there was no material accounts receivable balance due from any single customer.

As at December 31, 2024, the Distribution Business' allowance for doubtful accounts was $60 million (2023 - $56 million). The allowance for doubtful accounts reflects the Company's CECL for all accounts receivable balances, which are based on historical overdue balances, customer payments and write-offs. As at December 31, 2024, approximately 7% (2023 - 4%) of the Distribution Business' net accounts receivable were outstanding for more than 60 days.

Hydro One manages its counterparty credit risk through various techniques including (i) entering into transactions with highly rated counterparties, (ii) limiting total exposure levels with individual counterparties, (iii) entering into master agreements which enable net settlement and the contractual right of offset, and (iv) monitoring the financial condition of counterparties. Hydro One

monitors current credit exposure to counterparties on both an individual and an aggregate basis. The Company's counterparty credit risk profile is consistent with Hydro One. The Distribution Business' credit risk for accounts receivable is limited to the carrying amounts on the balance sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The maximum credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts in an asset position at the reporting date. As at December 31, 2024 and 2023, Hydro One's credit exposure for all derivative instruments and applicable payables was with one financial institution with investment grade credit ratings as counterparty.

The Pension Plan manages its counterparty credit risk with respect to bonds by investing in investment-grade corporate and government bonds and with respect to derivative instruments by transacting only with highly rated financial institutions and by ensuring that exposure is diversified across counterparties.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One Networks meets its short-term operating liquidity requirements through the inter-company demand facility with Hydro One and funds from operations. The short-term liquidity available to the Company is expected to be sufficient to fund the Company's operating requirements.

17. CAPITAL MANAGEMENT

The Distribution Business' objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. As at December 31, 2024 and 2023, the Distribution Business' capital structure was as follows:

As at December 31 *(millions of dollars)*	**2024**	**2023**
Long-term debt payable within one year *(Note 15)*	364	287
Inter-company demand promissory note	27	29
Inter-company demand facility	301	211
	692	527
Long-term debt *(Note 15)*	6,009	5,380
Excess of assets over liabilities	3,226	3,090
Total capital	9,927	8,997

The following table shows the movements in the excess of assets over liabilities for the years ended December 31, 2024 and 2023:

Year ended December 31 *(millions of dollars)*	**2024**	**2023**
Excess of assets over liabilities - beginning	3,090	3,010
Comprehensive income	420	385
Payments to Hydro One to finance dividends	(284)	(301)
Other[1]	—	(4)
Excess of assets over liabilities - ending	3,226	3,090

[1] The amount represents an allocation to the Other non-regulated Hydro One Networks segment as the underlying transactions do not represent the operations of the regulated Distribution Business. In line with the basis of accounting, these amounts have been excluded from the assets and liabilities of the Distribution Business, resulting in an impact to excess of assets over liabilities.

18. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a Pension Plan, a supplementary pension plan (Supplementary Plan), and post-retirement and post-employment benefit plans (Benefit Plans), and a DC Plan.

Pension Plan and Supplementary Plan

The Pension Plan is a defined benefit contributory plan which covers eligible regular employees of Hydro One and its subsidiaries. The Pension Plan provides benefits based on highest three-year average pensionable earnings up to March 31, 2025. Beginning April 1, 2025, all service for all groups on a go-forward basis will be calculated using the highest five-year average pensionable earnings. For management employees who commenced employment on or after January 1, 2004, and for the Society of United Professionals (Society)-represented staff hired after November 17, 2005, benefits are based on the highest five-year average pensionable earnings for all their service. After retirement, pensions are indexed to inflation. Membership in the Pension Plan was closed to management employees who were not eligible to join the Pension Plan as of September 30, 2015. These employees are eligible to join the DC Plan.

Company and employee contributions to the Pension Plan are based on actuarial reports, including valuations performed at least every three years, and actual or projected levels of pensionable earnings, as applicable. The most recent actuarial valuation was performed effective December 31, 2023 and filed on September 23, 2024. The Distribution Business' total annual cash Pension Plan employer contributions for 2024 were $39 million (2023 - $36 million). The Distribution Business' estimated annual Pension Plan employer contributions for the years 2025, 2026, 2027, 2028, 2029 and 2030 are approximately $40 million, $39 million, $39 million, $38 million, $43 million and $44 million, respectively.

The Supplementary Plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan beyond the limitations imposed by the *Income Tax Act* (Canada). The Supplementary Plan obligation is included with other post-retirement and post-employment benefit obligations on the balance sheets.

As at December 31, 2024, the present value of Hydro One's projected pension benefit obligation was estimated to be $8,686 million (2023 - $8,665 million). The fair value of pension plan assets available for these benefits was $9,333 million (2023 - $8,764 million).

Post-Retirement and Post-Employment Plans

The Company accounts for post-retirement and post-employment costs consistent with their inclusion in OEB-approved rates. During the year ended December 31, 2024, for the Distribution Business, $59 million (2023 - $61 million) were attributable to labour, of which $41 million (2023 - $42 million) was charge to operations, and $18 million (2023 - $19 million) was capitalized as part of the cost of property, plant and equipment and intangible assets. Benefits paid in 2024 were $38 million (2023 - $27 million).

In the 2020-2022 Transmission Rate Decision, the OEB approved the recovery of the non-service cost component of post-retirement and post-employment benefits as part of operation, maintenance and administration costs for both its transmission and distribution businesses (See Note 11 – Regulatory Assets and Liabilities). These costs were previously capitalized and recovered through rate base. As a result, during the year ended December 31, 2024, additional other post-retirement and post-employment costs of $15 million (2023 - $19 million) attributed to labour were charged to operations.

The Distribution Business presents its post-retirement and post-employment benefit liabilities on its balance sheets as follows:

As at December 31 *(millions of dollars)*	**2024**	**2023**
Accrued liabilities	39	37
Post-retirement and post-employment benefit liability	880	857
Net unfunded status	919	894

DC Plan

Hydro One established a DC Plan effective January 1, 2016. The DC Plan covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One up to an annual contribution limit. There is also a Supplementary Notional Plan that provides members of the DC Plan with employer contributions beyond the limitations imposed by the *Income Tax Act* (Canada) in the form of credits to a notional account. The Distribution Business contributions to the DC Plan for the year ended December 31, 2024 were $2 million (2023 - $2 million).

19. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2024 and 2023:

Year ended December 31, 2024 *(millions of dollars)*	**PCB**	**LAR**	**Total**
Environmental liabilities - beginning	31	2	33
Expenditures	(31)	—	(31)
Revaluation adjustment	3	—	3
Environmental liabilities - ending	3	2	5
Less: current portion	(3)	(1)	(4)
	—	1	1

Year ended December 31, 2023 *(millions of dollars)*	**PCB**	**LAR**	**Total**
Environmental liabilities - beginning	28	4	32
Expenditures	(22)	(1)	(23)
Revaluation adjustment	25	(1)	24
Environmental liabilities - ending	31	2	33
Less: current portion	(28)	(1)	(29)
	3	1	4

The following tables show the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the balance sheets after factoring in the discount rate:

As at December 31, 2024 *(millions of dollars)*	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	3	2	5
Less: discounting environmental liabilities to present value	—	—	—
Discounted environmental liabilities	3	2	5

As at December 31, 2023 *(millions of dollars)*	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	31	3	34
Less: discounting environmental liabilities to present value	—	(1)	(1)
Discounted environmental liabilities	31	2	33

As at December 31, 2024, the estimated future environmental expenditures were as follows:

(millions of dollars)	
2025	4
2026	1
2027	—
2028	—
2029	—
Thereafter	—
	5

Hydro One records a liability for the estimated future expenditures for LAR and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred in order to generate future cash flow information. A long-term inflation rate assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 2.0% to 6.3% (2023 - 2.0% to 6.3%) depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, with respect to the PCB environmental liability, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures.

PCBs

The Environment Canada regulations, enacted under the *Canadian Environmental Protection Act, 1999*, govern the management, storage and disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under current regulations, the Distribution Business' PCBs have to be disposed of by the end of 2025, with the exception of specifically exempted equipment. Contaminated equipment will generally be replaced, or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains PCBs in concentrations of less than two parts per million (ppm).

As at December 31, 2024, the Distribution Business' best estimate of the total estimated future expenditures to comply with current PCB regulations was $3 million (2023 - $31 million). These expenditures are expected to be incurred in 2025. As a result

of its annual review of environmental liabilities, the Distribution Business recorded a revaluation adjustment in 2024 to increase the PCB environmental liability by $3 million (2023 - $25 million).

LAR

As at December 31, 2024, the Distribution Business' best estimate of the total estimated future expenditures to complete its LAR program was $2 million (2023 - $3 million). These expenditures are expected to be incurred over the period from 2025 to 2028. As a result of its annual review of environmental liabilities, the Distribution Business did not record a revaluation adjustment in 2024 to the LAR environmental liability (2023 - decrease by $1 million).

20. ASSET RETIREMENT OBLIGATIONS

Hydro One Networks records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities. Asset retirement obligations, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an asset retirement obligation is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the asset retirement obligation, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

Some of the Company's distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its facilities in perpetuity, no asset retirement obligations have been recorded for these assets. If, at some future date, a particular facility is shown not to meet the perpetuity assumption, it will be reviewed to determine whether an estimable asset retirement obligation exists. In such a case, an asset retirement obligation would be recorded at that time.

In determining the amounts to be recorded as asset retirement obligations, the Company estimates the current fair value for completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 1.0% to 3.0% (2023 - 2.0% to 4.0%), depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's Distribution Business' asset retirement obligations represent management's best estimates of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Asset retirement obligations are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively. As a result of its annual review of asset retirement obligations, there was no change to the asset retirement obligations recorded in 2024 (2023 - increase of $1 million).

As at December 31, 2024, Hydro One Networks had recorded asset retirement obligations of $10 million (2023 - $10 million) related to the Distribution Business, primarily consisting of the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities.

21. LEASES

Hydro One has operating lease contracts for buildings used in administrative and service-related functions. These leases have terms between three and six years with renewal options of additional three- to five-year terms at prevailing market rates at the time of extension. All leases include a clause to enable upward revision of the rental charge on an annual basis or on renewal according to prevailing market conditions or pre-established rents. There are no restrictions placed upon Hydro One by entering into these leases. Renewal options are included in the lease term when their exercise is reasonably certain. Other information related to the Distribution Business' operating leases was as follows:

Year ended December 31 *(millions of dollars)*	**2024**	**2023**
Lease expense	6	6
Lease payments made	5	6

As at December 31	**2024**	**2023**
Weighted-average remaining lease term[1] *(years)*	4	5
Weighted-average discount rate	2.9 %	2.6 %

[1] Includes renewal options that are reasonably certain to be exercised.

As at December 31, 2024, future minimum operating lease payments were as follows:

(millions of dollars)	
2025	6
2026	6
2027	5
2028	3
2029	1
Thereafter	1
Total undiscounted minimum lease payments	22
Less: discounting minimum lease payments to present value	(1)
Total discounted minimum lease payments	21

As at December 31, 2023, future minimum operating lease payments were as follows:

(millions of dollars)	
2024	6
2025	6
2026	5
2027	4
2028	3
Thereafter	2
Total undiscounted minimum lease payments	26
Less: discounting minimum lease payments to present value	(2)
Total discounted minimum lease payments	24

Hydro One presents its ROU assets and lease obligations on the balance sheets as follows:

As at December 31 *(millions of dollars)*	**2024**	**2023**
Other long-term assets *(Note 12)*	21	24
Accounts payable and other current liabilities *(Note 13)*	6	6
Other long-term liabilities *(Note 14)*	15	18

22. HYDRO ONE NETWORKS' SHARE CAPITAL

Hydro One Networks is authorized to issue an unlimited number of common and preferred shares. As at December 31, 2024 and 2023, Hydro One Networks had 209,401,290 common shares issued and outstanding and no preferred shares issued and outstanding.

During 2024, Hydro One Networks declared common share dividends in the amount of $753 million (2023 - $692 million) to Hydro One as at December 31, 2024 and 2023, respectively. The amount allocated to the Distribution Business to finance these dividends was $284 million (2023 - $301 million).

23. STOCK-BASED COMPENSATION

The following compensation plans were established by Hydro One Limited, however they represent components of compensation costs of Hydro One and its subsidiaries, including Hydro One Networks, in current and future periods.

Share Grant Plans

Hydro One Limited has two share grant plans (Share Grant Plans), one for the benefit of certain members of the Power Workers' Union (PWU) (PWU Share Grant Plan) and one for the benefit of certain members of the Society (Society Share Grant Plan). Hydro One and Hydro One Limited entered into an intercompany agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with these plans. The agreement requires Hydro One Networks to reimburse Hydro One for the value of shares granted to the Company's eligible employees relating to these plans.

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the PWU annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on April 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. The requisite service period for the PWU Share Grant Plan began on July 3, 2015, which is the date the share grant plan was ratified by the PWU. The number of common shares issued annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the Initial Public Offering (IPO). The aggregate number of Hydro One Limited common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 2,152,519 Hydro One Limited common shares were granted under the PWU Share Grant Plan relevant to the total stock-based compensation recognized by the Distribution Business.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the Society annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on September 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. Therefore the requisite service period for the Society Share Grant Plan began on September 1, 2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 743,877 Hydro One Limited common shares were granted under the Society Share Grant Plan relevant to the total stock-based compensation recognized by the Distribution Business.

The fair value of the Hydro One Limited 2015 share grants to employees of Hydro One Networks and allocated to the Distribution Business was $59 million. The fair value was estimated based on the grant date Hydro One Limited share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. In 2024, 178,884 common shares of Hydro One Limited were issued under the Share Grant Plans (2023 - 190,236) to eligible employees of Hydro One Networks and allocated to the Distribution Business. Total stock-based compensation recognized by the Distribution Business during 2024 was $2 million (2023 - $2 million) and was recorded as a regulatory asset.

A summary of the Distribution Business' share grant activity under the Share Grant Plans during the years ended December 31, 2024 and 2023 is presented below:

Year ended December 31, 2024	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	882,358	$20.50
Granted	576	—
Vested and issued[1]	(178,884)	—
Forfeited	(14,481)	$20.50
Share grants outstanding - ending	689,569	$20.50

[1] In 2024, Hydro One Limited issued common shares from treasury to eligible Hydro One Networks employees in accordance with provisions of the Share Grant Plans. In accordance with the intercompany agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

Year ended December 31, 2023	Share Grants (number of common shares)	Weighted-Average Price
Share grants outstanding - beginning	1,096,245	$20.50
Granted	947	—
Vested and issued[1]	(190,236)	—
Forfeited	(24,598)	$20.50
Share grants outstanding - ending	882,358	$20.50

[1] In 2023, Hydro One Limited issued common shares from treasury to eligible Hydro One Networks employees in accordance with provisions of the Share Grant Plans. In accordance with the intercompany agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

Directors' DSU Plan

Under the Directors' DSU Plan, directors can elect to receive credit for their annual cash retainer in a notional account of DSUs in lieu of cash. Hydro One Limited Board of Directors may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled. Each DSU represents a unit with an underlying value equivalent to the value of one common share of Hydro One Limited and is entitled to accrue Hydro One Limited common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One Limited Board of Directors.

During 2024 and 2023, Directors' DSU Plan awards granted by Hydro One Limited that related to the Distribution Business were as follows:

Year ended December 31 *(number of DSUs)*	2024	2023
DSUs outstanding - beginning	27,328	29,226
Granted	8,190	11,691
Settled	(3,535)	(13,589)
DSUs outstanding - ending	31,983	27,328

For the years ended December 31, 2024 and 2023, the expense related to the Directors' DSU Plan was less than $1 million. As at December 31, 2024, the liability related to Directors' DSUs was $2 million (2023 - $1 million).

Management DSU Plan

Under the Management DSU Plan, eligible executive employees can elect to receive a specified proportion of their annual short-term incentive in a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of Hydro One Limited and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One Limited Board of Directors.

During 2024 and 2023, Management DSU Plan awards granted by Hydro One Limited that related to Hydro One Network's Distribution Business were as follows:

Year ended December 31 *(number of DSUs)*	2024	2023
DSUs outstanding - beginning	23,487	20,823
Granted	4,248	3,139
Paid	(6,655)	(475)
DSUs outstanding - ending	21,080	23,487

To comply with the Accountability Act and the OEB Act, in 2019 Hydro One Limited removed all executive-related compensation from the labour costs of its regulated subsidiaries. During the years ended December 31, 2024 and 2023, no executive-related stock-based compensation was allocated to the regulated businesses of Hydro One Networks.

Employee Share Ownership Plan

In 2015, Hydro One Limited established Employee Share Ownership Plans (ESOP) for certain eligible management and non-represented employees (Management ESOP) and for certain eligible Society-represented staff (Society ESOP). Under the Management ESOP, the eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 50% of their contributions, up to a maximum Company contribution of $25,000 per calendar year. Under the Society ESOP, the eligible Society-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 25% of their contributions, with no maximum Company contribution per calendar year.

In 2024, Hydro One established ESOP for certain eligible PWU represented staff (PWU ESOP). Under the PWU ESOP, the eligible PWU-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One. The Company matches 33% of their contribution, with no maximum Company contribution per calendar year.

In 2024, Company contributions made under the ESOP and allocated to the Distribution Business were $3 million (2023 - $1 million).

LTIP

Effective August 31, 2015, the Board of Directors of Hydro One adopted an LTIP. Under the LTIP, long-term incentives were granted to certain executive and management employees of Hydro One and its subsidiaries, and all equity-based awards would either be settled in newly issued shares of Hydro One from treasury or cash, subject to Hydro One's discretion, consistent with the provisions of the plan which also permit the participants to surrender a portion of their awards to satisfy related withholding taxes requirements. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares of Hydro One.

The LTIP provides flexibility to award a range of vehicles, including Performance Share Units (PSUs), RSUs, stock options, share appreciation rights, restricted shares, DSUs, and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance.

PSUs and RSUs

A summary of PSU and RSU awards activity under the LTIP during the years ended December 31, 2024 and 2023 is presented below:

	PSUs		RSUs	
Year ended December 31 *(number of units)*	**2024**	**2023**	**2024**	**2023**
Units outstanding – beginning	30,999	—	75,658	—
Granted	35,018	32,183	63,947	78,578
Forfeited	(3,125)	(1,102)	(8,634)	(2,786)
Settled	(1,126)	(82)	(1,087)	(134)
Units outstanding – ending	61,766	30,999	129,884	75,658

To comply with the Accountability Act and the OEB Act, in 2019 Hydro One Limited removed all executive-related compensation from the labour costs of its regulated subsidiaries. During the years ended December 31, 2024 and 2023, no executive-related stock-based compensation was allocated to the regulated businesses of Hydro One Networks.

The grant date total fair value of the awards granted during the year ended December 31, 2024 was $4 million (2023 - $4 million). The compensation expense related to the PSU and RSU awards recognized by the Company during 2024 was $3 million (2023 - $1 million). As at December 31, 2024 and 2023, the payable relating to PSU and RSU awards included in due to related parties on the balance sheets was not significant.

Society RSU Plan

As a result of the renewal of the Company's prior collective agreement with members of the Society, the Company provided equity compensation in the form of RSUs to certain eligible members. The equity compensation provides for the purchase of common shares of Hydro One Limited from the open market, effective March 1, 2021 in one equity grant vesting in equal portions over a two-year period. To be eligible, an employee must be an employee of the Company as of July 30, 2021, the date the plan was ratified by the Society; the grant date. The number of common shares issued to each eligible employee will be equal to 1.0% of such eligible employee's salary as at April 1, 2021, divided by $30.80, being the price of the common shares of Hydro One Limited at the grant date. Each RSU is entitled to accrue common share dividend equivalents in the form of additional RSUs at the time dividends are paid, subsequent to declaration by Hydro One's Board of Directors.

A summary of RSU awards activity under the Society RSU Plan during the years ended December 31, 2024 and 2023 is presented below:

Year ended December 31 *(number of RSUs)*	**2024**	**2023**
RSUs outstanding - beginning	—	18,156
Granted	—	—
Vested and issued	—	(16,577)
Settled	—	(1,511)
Forfeited	—	(68)
RSUs outstanding - ending	—	—

24. RELATED PARTY TRANSACTIONS

The Distribution Business is a separately regulated business of Hydro One Networks which is indirectly owned by Hydro One Limited. The Province of Ontario is a shareholder of Hydro One Limited with approximately 47.1% ownership as at December 31, 2024. The Ministry of Infrastructure (MOI) is a related party to Hydro One because it is controlled by the Province. The IESO, Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), and the OEB, are related parties to Hydro One Networks because they are controlled or significantly influenced by the Ministry of Energy. Acronym Solutions Inc. (Acronym) and Hydro One Broadband Solutions Inc, (HOBSI) are subsidiaries of Hydro One Limited. The Distribution Business also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province. The following is a summary of the Distribution Business' related party transactions during the years ended December 31, 2024 and 2023:

Year ended December 31 *(millions of dollars)*			
Related Party	**Transaction**	**2024**	**2023**
MOI	Broadband subsidy[1]	43	—
IESO	Power purchased	2,677	2,294
	Amounts related to electricity rebates	1,164	893
	Distribution revenues related to rural rate protection	255	250
	Funding received related to Conservation and Demand Management programs	1	3
OPG	Power purchased	18	16
	Revenues related to supply of electricity	5	5
OEFC	Power purchased from power contracts administered by the OEFC	1	1
OEB	OEB fees	6	6
Hydro One	Payments to finance dividends	284	301
	Interest expense on long-term debt	261	222
	Interest expense on inter-company demand facility	20	25
	Stock-based compensation costs	5	3
	Services received - costs expensed	3	—
Hydro One Networks' Transmission Business	Services received - costs expensed	3	2
	Capital contributions made	8	3
Acronym	Services received - costs expensed	10	11
Hydro One Limited and its other subsidiaries	Revenues for services provided	2	3
	Services received - costs recovered	5	6
	Decrease in capital contributions from HOBSI	—	(1)

[1] On October 31, 2024, the Ministry of Infrastructure announced that it has developed a program to deliver up to $400 million in subsidies to internet service providers (ISPs) for work associated with designated broadband projects. The program is intended to enable ISPs to successfully and safely attach their material and equipment to the Company's poles to bring connectivity to rural communities as part of a designated broadband project as defined under *Building Broadband Faster Act (Ontario)*. A portion of these subsidies is used to reimburse Hydro One Networks on behalf of ISPs for their share of enablement costs incurred to facilitate the program to date.

The amounts due to and from related parties as at December 31, 2024 and 2023 are as follows:

As at December 31 *(millions of dollars)*	**2024**	**2023**
Due from related parties	115	135
Long-term inter-company payable	(10)	(11)
Accrued interest	(69)	(59)
Due to related parties	(341)	(301)
Inter-company demand promissory note *(Note 15)*	(27)	(29)
Inter-company demand facility	(301)	(211)
Long-term debt, including current portion *(Note 15)*	(6,373)	(5,667)

25. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 *(millions of dollars)*	2024	2023
Accounts receivable	(106)	(47)
Due from related parties	20	(34)
Materials and supplies	5	(7)
Other assets	(40)	—
Accounts payable	93	(46)
Accrued liabilities	(124)	75
Accrued interest	10	13
Due to related parties	41	31
Long-term accounts payable and other liabilities	2	2
Post-retirement and post-employment benefit liability	33	40
	(66)	27

Capital Expenditures

The following tables reconcile investments in property, plant and equipment and intangible assets and the amounts presented in the statements of cash flows for the years ended December 31, 2024 and 2023. The reconciling items include net change in accruals, transfers, and capitalized depreciation.

Year ended December 31, 2024 *(millions of dollars)*	Property, Plant and Equipment	Intangible Assets	Total
Capital investments	(1,121)	(54)	(1,175)
Reconciling items	105	6	111
Cash outflow for capital expenditures	(1,016)	(48)	(1,064)

Year ended December 31, 2023 *(millions of dollars)*	Property, Plant and Equipment	Intangible Assets	Total
Capital investments	(925)	(82)	(1,007)
Reconciling items	32	(4)	28
Cash outflow for capital expenditures	(893)	(86)	(979)

Supplementary Information

Year ended December 31 *(millions of dollars)*	2024	2023
Net interest paid	251	209
Income taxes paid	61	115

26. CONTINGENCIES

Hydro One Networks is involved in various lawsuits and claims in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Distribution Business' financial position, results of operations or cash flows.

The Company is a wholly owned subsidiary of Hydro One. As such, the assets of the Distribution Business are available to satisfy the debts, contingent liabilities and commitments of both the Company and Hydro One.

27. COMMITMENTS

The Company and Hydro One have numerous commitments. These commitments have not been specifically allocated to the Distribution Business. However, the assets of the Distribution Business are available to satisfy the commitments of both the Company and Hydro One.

28. SUBSEQUENT EVENTS

Payments to Finance Dividends

On February 19, 2025, Hydro One Networks declared a dividend of $187 million. The amount allocated to the Distribution Business to finance this payment was $71 million.

HYDRO ONE NETWORKS INC.

DISTRIBUTION BUSINESS

FINANCIAL STATEMENTS

DECEMBER 31, 2025

KPMG LLP
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Canada
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INDEPENDENT AUDITOR'S REPORT

To the Directors of Hydro One Networks Inc.

Opinion

We have audited the carve-out financial statements of the Distribution Business (a business of Hydro One Networks Inc.) (the Entity), which comprise:

- the carve-out balance sheet as at December 31, 2025
- the carve-out statement of operations and comprehensive income for the year then ended
- the carve-out statement of cash flows for the year then ended
- and notes to the carve-out financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements as at and for the year ended December 31, 2025 of the Entity are prepared, in all material respects, in accordance with the financial reporting framework described in Note 2 of the financial statements.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the ***"Auditor's Responsibilities for the Audit of the Financial Statements"*** section of our auditor's report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Emphasis of Matter - Financial Reporting Framework

We draw attention to Note 2 to the financial statements which describes the applicable financial reporting framework and the purpose of the financial statements.

KPMG LLP, an Ontario limited liability partnership and member firm of the KPMG global organization of independent member firms affiliated with KPMG International Limited, a private English company limited by guarantee. KPMG Canada provides services to KPMG LLP.

As a result the financial statements may not be suitable for another purpose.

Our opinion is not modified in respect of this matter.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation of the financial statements in accordance with the financial reporting framework described in Note 2 in the financial statements; this includes determining that the applicable financial reporting framework is an acceptable basis for the preparation of the financial statements in the circumstances, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Entity's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada

April 23, 2026

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2025 and 2024

Year ended December 31 *(millions of Canadian dollars)*	**2025**	**2024**
Revenues		
Energy sales	6,049	5,682
Rural rate protection *(Note 24)*	256	255
Other *(Note 24)*	62	57
	6,367	5,994
Costs		
Purchased power (includes $3,024 related party costs; 2024 - $2,696) *(Note 24)*	4,341	4,015
Operation, maintenance and administration *(Note 24)*	638	689
Depreciation, amortization and asset removal costs *(Note 4)*	525	502
	5,504	5,206
Income before financing charges and income tax expense	**863**	**788**
Financing charges (includes $300 related party charges; 2024 - $281) *(Notes 5, 24)*	304	285
Income before income tax expense	**559**	**503**
Income tax expense *(Note 6)*	87	83
Net income	**472**	**420**
Other comprehensive income	1	—
Comprehensive income	**473**	**420**

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
BALANCE SHEETS
As at December 31, 2025 and 2024

As at December 31 *(millions of Canadian dollars)*	**2025**	**2024**
Assets		
Current assets:		
Accounts receivable *(Note 7)*	991	832
Due from related parties *(Note 24)*	178	115
Other current assets *(Note 8)*	52	82
	1,221	1,029
Property, plant and equipment *(Note 9)*	11,416	10,632
Other long-term assets:		
Regulatory assets *(Note 11)*	1,362	1,186
Intangible assets *(Note 10)*	384	397
Goodwill	217	217
Other assets *(Note 12)*	51	46
	2,014	1,846
Total assets	**14,651**	**13,507**
Liabilities		
Current liabilities:		
Inter-company demand facility *(Note 24)*	185	301
Inter-company demand promissory note *(Notes 15, 17)*	27	27
Long-term debt payable within one year *(Notes 15, 16, 24)*	411	364
Accounts payable and other current liabilities *(Note 13)*	974	908
Due to related parties *(Note 24)*	478	341
	2,075	1,941
Long-term liabilities:		
Long-term debt *(Notes 15, 16, 24)*	6,646	6,009
Deferred income tax liabilities *(Note 6)*	1,030	951
Regulatory liabilities *(Note 11)*	535	449
Other long-term liabilities *(Note 14)*	965	931
	9,176	8,340
Total liabilities	**11,251**	**10,281**
Contingencies and Commitments *(Notes 26, 27)*		
Subsequent Events *(Note 28)*		
Excess of assets over liabilities *(Notes 17, 22)*	3,400	3,226
Total liabilities and excess of assets over liabilities	**14,651**	**13,507**

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:

Helga Reidel
Chair, Audit Committee

David Lebeter
Director

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF CASH FLOWS
For the years ended December 31, 2025 and 2024

Year ended December 31 *(millions of Canadian dollars)*	**2025**	**2024**
Operating activities		
Net income	472	420
Environmental expenditures	—	(5)
Adjustments for:		
Depreciation and amortization *(Note 4)*	438	414
Regulatory assets and liabilities	43	1
Deferred income tax expense	(4)	8
Other	2	(23)
Changes in non-cash balances related to operations *(Note 25)*	(9)	(66)
Net cash from operating activities	**942**	**749**
Financing activities		
Long-term debt issued	1,052	996
Long-term debt repaid	(364)	(287)
Payments to finance dividends	(299)	(284)
Other	(5)	(4)
Net cash used in financing activities	**384**	**421**
Investing activities		
Capital expenditures *(Note 25)*		
Property, plant and equipment	(1,025)	(1,016)
Intangible assets	(50)	(48)
Additions of future use assets	(139)	(197)
Other	4	1
Net cash used in investing activities	**(1,210)**	**(1,260)**
Net change in inter-company demand facility	116	(90)
Inter-company demand facility, beginning of year	(301)	(211)
Inter-company demand facility, end of year	**(185)**	**(301)**

See accompanying notes to Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Networks Inc. (Hydro One Networks or the Company) was incorporated on March 4, 1999 under the *Business Corporations Act* (Ontario) and is a wholly owned subsidiary of Hydro One Inc. (Hydro One). The Company owns and operates regulated transmission and distribution businesses. The Company's regulated distribution business (Distribution Business) operates a low-voltage electrical distribution network that distributes electricity from the transmission system, or directly from generators, to customers within Ontario. The Distribution Business is regulated by the Ontario Energy Board (OEB).

Rate Setting

On November 29, 2022, the OEB issued its JRAP Decision approving Hydro One Networks' distribution revenue requirement of $1,727 million for 2023, $1,813 million for 2024, $1,886 million for 2025, $1,985 million for 2026 and $2,071 million for 2027. Revenue requirements presented for 2024 to 2027 do not reflect the actual or expected updates resulting from the annual application process with the regulator to reflect the latest OEB inflation factors.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

These Financial Statements are prepared and presented in accordance with the accounting policies summarized below and in Canadian dollars. These policies are consistent with United States (U.S.) generally accepted accounting principles (GAAP).

The purpose of these Financial Statements is to meet Hydro One Networks' obligation to the OEB. As a result, these Financial Statements may not be suitable for another purpose. Consolidated financial statements of Hydro One for the year ended December 31, 2025 have been prepared and are publicly available.

Basis of Preparation

These Financial Statements have been prepared on a carve-out basis to provide the financial position, results of operations and cash flows of the Distribution Business. The Financial Statements are considered by management to be a reasonable representation, prepared on a rational, systematic and consistent basis, of the financial results of the Distribution Business. As a result of this basis of preparation, these Financial Statements may not necessarily be identical to the financial position and results of operations that would have resulted had the Distribution Business historically operated on a stand-alone basis.

The Financial Statements have been constructed primarily through specific identification of assets, liabilities (other than debt), revenues and expenses that relate to the Distribution Business. The Company's long-term debt is allocated based on the respective borrowing requirements of the Company's transmission and distribution businesses. A portion of the Company's shared functions and services costs is allocated to the Distribution Business on a fully allocated-cost basis, consistent with OEB-approved independent studies. Income tax expense has been recorded at effective rates based on income taxes as reported in the statements of operations and comprehensive income as though the Distribution Business was a separate taxpaying entity. These Financial Statements include deferred income taxes and related regulatory balances with respect to the rate-setting treatment of the benefits of the deferred income tax asset resulting from transition from the payments in lieu of tax regime under the *Electricity Act, 1998* (Ontario) to income tax payments under the federal and provincial tax regime which occurred when Hydro One Limited became a public company listed on the Toronto Stock Exchange. Certain other amounts presented in these Financial Statements represent allocations subject to review and approval by the OEB.

Hydro One Networks performed an evaluation of subsequent events through to April 23, 2026, the date these Financial Statements were available to be issued, to determine whether any events or transactions warranted recognition and disclosure in these Financial Statements. See Note 28 – Subsequent Events.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets, regulatory liabilities, post-retirement and post-employment benefits, and unbilled revenues. Actual results may differ significantly from these estimates.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting in accordance with Financial Accounting Standards Board (FASB) Accounting Standard Codification Topic 980, Regulated Operations within the Distribution Business, giving rise to the

recognition of regulatory assets and liabilities. The Distribution Business' regulatory assets represent certain amounts receivable from electricity customers in a future period and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Distribution Business has recorded regulatory liabilities that generally represent amounts that are refundable to electricity customers in future rates. The Distribution Business continually assesses the likelihood of settling its regulatory assets and regulatory liabilities and continues to believe that it is probable that the OEB will include them in setting future rates. If, at some future date, the Distribution Business judges that it is no longer probable that the OEB will include a regulatory asset or regulatory liability in setting future rates, the respective carrying amount would be reflected in results of operations, prospectively from the date the Distribution Business assessment is made.

Revenue Recognition

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues. Billed revenues are based on the amount of electricity delivered as measured from customer meters. At the end of each month, the amount of electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption and changes in the composition of customer classes. Distribution revenue also includes an amount relating to rate protection for rural, residential, and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered. Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are recorded at their estimated value, net of allowance for doubtful accounts. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Distribution Business' current lifetime expected credit losses (CECL) for all accounts receivable balances. The Distribution Business estimates the CECL by applying internally developed loss rates to all outstanding receivable balances by aging category on an undiscounted basis. Loss rates applied to the accounts receivable balances are based on historical overdue balances, customer payments and write-offs, which may be further supplemented from time to time to reflect management's best estimate of the loss. Accounts receivable are written-off against the allowance when they are deemed uncollectible. The allowance for doubtful accounts is affected by changes in volume, prices and economic conditions.

Income Taxes

Income taxes are accounted for using the asset and liability method. Current income tax assets and current income tax liabilities are recognized based on the income taxes refundable or payable on the current year's taxable income. Current and deferred income taxes are computed based on the tax rates and tax laws enacted as at the balance sheet date. Tax benefits associated with income tax positions are recorded only when the more-likely-than-not recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Financial Statements. Management re-evaluates tax positions each period using new information about recognition or measurement as it becomes available.

Deferred Income Taxes

Deferred income tax assets and deferred income tax liabilities are recognized on all temporary differences between the tax bases and carrying amounts of assets and liabilities, including the carryforward of unused tax credits and tax losses to the extent that it is more-likely-than-not that these deductions, credits, and losses can be utilized. Deferred income tax assets and deferred income tax liabilities are measured at the tax rates that are expected to apply in the period when the asset is realized or the liability is settled, based on the tax rates and tax laws that have been enacted as at the balance sheet date.

Deferred income taxes associated with the Distribution Business' regulated operations which are considered to be more-likely-than-not to be recovered or refunded in future regulated rates charged to customers are recognized as deferred income tax regulatory assets and deferred income tax regulatory liabilities with an offset to deferred income tax expense.

Investment tax credits are recorded as a reduction of the related expenses or income tax expense in the current or future period to the extent it is more likely than not that the credits can be utilized.

Management reassesses the deferred income tax assets at each balance sheet date and reduces the amount to the extent that it is more likely than not that the deferred income tax asset will not be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more likely than not that the tax benefit will be realized.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, and implicitly, by the regulated businesses of its subsidiaries. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Distribution Business to and from the pooled bank accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.15%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions, and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the balance sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, and information technology. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis.

Property, plant and equipment in service consists of distribution, administration and service, and other communication assets as well as land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, as well as capitalized project development costs associated with deferred capital projects.

Distribution

Distribution assets include assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.

Other

Other assets include fibre optic and microwave radio systems, optical ground wire, towers, telephone equipment and associated buildings. Other assets also include easements which include land rights for occupation.

Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost, which comprises purchased software, direct labour (including employee benefits), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Distribution Business' intangible assets primarily represent major computer applications.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized financing costs are a reduction of financing charges recognized in the statements of operations and comprehensive income. Capitalized financing costs are calculated using the Distribution Business' weighted average effective cost of debt.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation and Amortization

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and amortization rates, as required by the OEB. Any changes arising from such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The most recent review resulted in changes to rates effective January 1, 2023 for the Distribution Business. A summary of average service lives and depreciation and amortization rates as at December 31, 2025 for the various classes of assets is included below:

	Average Service Life	Rate Range	Rate Average
Property, plant and equipment:			
Distribution	48 years	1% - 5%	2 %
Communication	10 years	2% - 11%	9 %
Administration and service	27 years	1% - 20%	5 %
Intangible assets	11 years	8% - 10%	6 %

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation, with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense.

Acquisitions and Goodwill

The Company accounts for business acquisitions using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair value at the date of acquisition. Costs associated with pending acquisitions are expensed as incurred. Goodwill represents the cost of acquired companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is not included in rate base.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. The Company performs a qualitative assessment to determine whether it is more likely than not that the fair value of the applicable reporting unit is greater than its carrying amount, no further testing is required. If the Company determines, as a result of its qualitative assessment, that it is more likely than not that the fair value of the applicable reporting unit is less than its carrying amount, a quantitative goodwill impairment assessment is performed. The quantitative assessment compares the fair value of the applicable reporting unit to its carrying amount, including goodwill. If the fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and as a charge to results of operations.

Based on the assessment performed as at September 30, 2025 and with no significant events since, the Company has concluded that goodwill was not impaired as at December 31, 2025.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, the Company evaluates whether impairment may exist by estimating future undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

The carrying costs of most of the Distribution Business' long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable.

Management assesses the fair value of such long-lived assets using commonly accepted techniques. Techniques used to determine fair value include, but are not limited to, the use of recent third-party comparable sales for reference and internally developed discounted cash flow analysis. Significant changes in market conditions, changes to the condition of an asset, or a change in management's intent to utilize the asset are generally viewed by management as triggering events to reassess the cash flows related to these long-lived assets. As at December 31, 2025 and 2024, no asset impairment had been recorded.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Distribution Business defers its proportionate share of the relevant Hydro One external transaction costs related to obtaining financing and presents such amounts net of related debt on the balance sheets. Deferred issuance costs are amortized over the contractual life of the related debt on an effective-interest

basis and the amortization is included within financing charges in the statements of operations and comprehensive income. Transaction costs for items classified as held-for-trading are expensed immediately.

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Distribution Business considers the carrying amounts of accounts receivable and amounts due from related parties to be reasonable estimates of fair value because of the short time to maturity of these instruments. The Distribution Business estimates the CECL for all accounts receivable balances, which are recognized as adjustments to the allowance for doubtful accounts. Accounts receivable are written-off against the allowance when they are deemed uncollectible. All financial instrument transactions are recorded at trade date.

The Distribution Business determines the classification of its financial assets and liabilities at the date of initial recognition. The Distribution Business designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Distribution Business' risk management policy disclosed in Note 16 - Fair Value of Financial Instruments and Risk Management.

Derivative Instruments and Hedge Accounting

Hydro One closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedging relationships. Hydro One's derivative instruments, or portions thereof, are mirrored down to Hydro One Networks, and are allocated between the Company's transmission and distribution businesses. The derivative instruments are classified as fair value hedges or undesignated contracts, consistent with Hydro One's derivative instruments classification.

The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value on the balance sheets. For derivative instruments that qualify for hedge accounting, Hydro One may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. Hydro One offsets fair value amounts recognized on its balance sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, any unrealized gain or loss, net of tax, is recorded as a component of accumulated OCI (AOCI) or accumulated OCL (AOCL). Amounts in AOCI or AOCL are reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations and presented in the same line item as the earnings effect of the hedged item. Any gains or losses on the derivative instrument that represent hedge components excluded from the assessment of effectiveness are recognized in the same line item of the statements of operations as the hedged item. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the statements of operations and comprehensive income (loss) in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the statements of operations and comprehensive income (loss). The changes in fair value of the undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and are carried at fair value on the balance sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. Hydro One does not engage in derivative trading or speculative activities and had no embedded derivatives that required bifurcation as at December 31, 2025 or 2024.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where the Company has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. Hydro One also assesses, both at the inception of the hedge and on a quarterly basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of Hydro One's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

Hydro One recognizes the funded status of its defined benefit pension plan (Pension Plan) and its post-retirement and post-employment plans on its consolidated balance sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Defined benefit pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation (PBO) exceeds the fair value of the plan assets. Liabilities are recognized on the consolidated balance sheets for any net underfunded PBO. The net underfunded PBO may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the PBO of the plan, an asset is recognized equal to the net overfunded PBO. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Hydro One recognizes its contributions to the defined contribution pension plan (DC Plan) as pension expense, with a portion being capitalized as part of labour costs included in capital expenditures. The expensed amount is included in operation, maintenance and administration (OM&A) costs in the consolidated statements of operations and comprehensive income.

Defined Benefit Pension

Hydro One has a contributory defined benefit pension plan covering most regular employees of Hydro One and its subsidiaries, including Hydro One Networks. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the pension plan is accounted for as a defined contribution plan and no pension benefit asset or liability is recorded.

Post-retirement and Post-employment Benefits

Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Networks. The benefit obligations of these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Networks. Accordingly, for purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are reflective of earnings allocations of relevant employees to the Company's Distribution Business.

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. For post-retirement benefits, past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or actuarial losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active employees in the plan or over the remaining life expectancy of inactive employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory account, to the extent of the remeasurement adjustment.

The actuarial gains and actuarial losses on post-employment obligations that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory account, to the extent of the remeasurement adjustment.

All post-retirement and post-employment benefit costs are attributed to labour costs and are either charged to results of operations (OM&A costs) or capitalized as part of the cost of property, plant and equipment and intangible assets (applies to the service cost component of benefit cost) and to regulatory assets for all other components of the benefit cost, consistent with their inclusion in OEB-approved rates.

Stock-Based Compensation

Share Grant Plans

The Company measures share grant plans based on fair value of share grants as estimated based on Hydro One Limited's grant date common share price. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. The Company records a regulatory asset equal to the accrued costs of share grant plans recognized in each period. Costs are transferred from the regulatory asset to labour costs at the time the share grants vest and are recovered in rates. Forfeitures are recognized as they occur.

Deferred Share Unit (DSU) Plans

The Company records the liabilities associated with its Directors' and Management DSU Plans at fair value at each reporting date until settlement, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the DSU liability is based on Hydro One Limited's common share closing price at the end of each reporting period.

Long-term Incentive Plan (LTIP)

The Company measures the awards issued under Hydro One Limited's LTIP, at fair value based on Hydro One Limited grant date common share price. The related compensation expense is recognized over the vesting period on a straight-line basis. Forfeitures are recognized as they occur.

Loss Contingencies

Hydro One and its subsidiaries are involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of the Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Distribution Business records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Distribution Business.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. The Company records a liability for the estimated future expenditures associated with contaminated land assessment and remediation (LAR) and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. To the extent that the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the anticipated amount of future recovery of these environmental expenditures from customers. Hydro One reviews its estimates of future environmental expenditures annually, or more frequently if there are indications that circumstances have changed. Estimate changes are accounted for prospectively.

Asset Retirement Obligations

Asset retirement obligations are recorded for legal obligations associated with the future removal and disposal of long-lived assets. Such obligations may result from the acquisition, construction, development and/or normal use of the asset. Conditional asset retirement obligations are recorded when there is a legal obligation to perform a future asset retirement activity but where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. In such a case, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. This uncertainty is incorporated in the fair value measurement of the obligation.

When recording an asset retirement obligation, the present value of the estimated future expenditures required to complete the asset retirement activity is recorded in the period in which the obligation is incurred, if a reasonable estimate can be made. In general, the present value of the estimated future expenditures is added to the carrying amount of the associated asset and the resulting asset retirement cost is depreciated over the estimated useful life of the asset. The present value is determined with a discount rate that equates to the Company's credit-adjusted risk-free rate. Where an asset is no longer in service when an asset retirement obligation is recorded, the asset retirement cost is recorded in results of operations.

Leases

At the commencement date of a lease, the minimum lease payments are discounted and recognized as a lease obligation. Discount rates used correspond to the Company's incremental borrowing rates. Renewal options are assessed for their likelihood of being exercised and are included in the measurement of the lease obligation when it is reasonably certain they will be exercised. The Company does not recognize leases with a term of less than 12 months. A corresponding Right-of-Use (ROU) asset is recognized at the commencement date of a lease. The ROU asset is measured as the lease obligation adjusted for any lease payments made and/or any lease incentives and initial direct costs incurred. ROU assets are included in other long-term assets, and corresponding lease obligations are included in other current liabilities and other long-term liabilities on the balance sheets.

Subsequent to the commencement date, the lease expense recognized at each reporting period is the total remaining lease payments over the remaining lease term. Lease obligations are measured as the present value of the remaining unpaid lease payments using the discount rate established at commencement date. The amortization of the ROU assets is calculated as the difference between the lease expense and the accretion of interest, which is calculated using the effective interest method. Lease modifications and impairments are assessed at each reporting period to assess the need for a remeasurement of the lease obligations or ROU assets.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standard Updates (ASUs) issued by the FASB that are applicable to Hydro One Networks:

Recently Adopted Accounting Guidance

Guidance	Date issued	Description	Effective date	Impact on Distribution Business
ASU 2024-02	March 2024	The amendments contain modifications to the codification that remove various concept statements which may be extraneous and not required to understand or apply the guidance or references used in prior statements to provide guidance in certain topical areas.	Fiscal years beginning after December 15, 2024.	No impact upon adoption
ASU 2023-09	December 2023	The amendments address investor requests for more transparency about income tax information through improvements to income tax disclosures primarily related to the rate reconciliation and income taxes paid information.	Annual periods beginning after December 15, 2024.	Adoption of the standard does not materially affect Hydro One Networks' income tax disclosures.

Recently Issued Accounting Guidance Not Yet Adopted

Guidance	Date issued	Description	Effective date	Anticipated Impact on Distribution Business
ASU 2023-06	October 2023	The amendments represent changes to clarify or improve disclosure or presentation requirements of a variety of subtopics in the FASB Codification. Many of the amendments allow users to more easily compare entities subject to the U.S. Securities and Exchange's (SEC) existing disclosures with those entities that were not previously subject to the SEC's requirements. Also, the amendments align the requirements in the Codification with the SEC's regulations. Applicable to all entities, if by June 30, 2027 the SEC has not removed the applicable requirement from Regulation S-X or Regulation S-K, the pending content of the related amendment will be removed from the Codification and will not become effective for any entity.	Two years subsequent to the date on which the SEC's removal of that related disclosure becomes effective.	Under assessment
ASU 2024-03	November 2024	The amendments require public business entities to disclose additional information about specific expense categories in the notes to financial statements at interim and annual reporting periods, which are not generally presented in the current financial statements.	Annual periods beginning after December 15, 2026, and interim periods beginning after December 15, 2027.	Under assessment
ASU 2025-03	May 2025	The amendments require entities to apply the guidance for identifying the accounting acquirer in transactions where a business that qualifies as a Variable Interest Entity is acquired through the exchange of equity interests.	Annual and interim periods beginning after December 15, 2026.	No impact upon adoption
ASU 2025-05	July 2025	The amendments allow all entities to use a practical expedient when estimating expected credit losses for current accounts receivable and contract assets under Topic 606, by assuming that current conditions as of the balance sheet date remain unchanged over the asset's life. Additionally, entities other than public business entities that elect this expedient may adopt an accounting policy to consider post–balance sheet date collection activity in their credit loss estimates.	Annual and interim periods beginning after December 15, 2025.	No impact upon adoption

ASU 2025-06	September 2025	The amendments modernize accounting for internal-use software by removing outdated development stage references and introducing a capitalization threshold based on management authorization and project completion probability.	Annual periods beginning after December 15, 2027.	Under assessment
ASU 2025-09	November 2025	The amendments expand hedge-accounting eligibility and better align the guidance with common risk-management practices. Key updates allow grouping forecasted transactions with similar exposure, simplify hedging of choose-your-rate variable-rate debt, and broaden eligibility for hedging nonfinancial components. The guidance modernizes treatment of certain option-based derivatives and resolves mismatches in dual hedge relationships.	Annual and interim periods beginning after December 15, 2026.	Under assessment
ASU 2025-10	December 2025	The amendments establish authoritative GAAP for government grants, setting recognition, measurement, presentation, and disclosure requirements.	Annual and interim periods beginning after December 15, 2028.	Under assessment
ASU 2025-11	December 2025	The amendments clarify interim reporting by establishing a complete list of required GAAP interim disclosures. They introduce a disclosure principle requiring entities to report material events occurring after the annual reporting period. The Update also clarifies types of interim reports and the form and content of interim financial statements. Overall, the changes enhance clarity and consistency without altering existing disclosure requirements.	Interim reporting periods within annual reporting periods beginning after December 15, 2027.	Under assessment
ASU 2025-12	December 2025	The amendments clarify existing guidance, correct errors, and introduce minor improvements to numerous Codification Topics, thereby making the requirements easier for entities to understand and apply.	Annual and interim periods beginning after December 15, 2026.	Under assessment

4. DEPRECIATION, AMORTIZATION AND ASSET REMOVAL COSTS

Year ended December 31 *(millions of dollars)*	**2025**	**2024**
Depreciation of property, plant and equipment	375	349
Amortization of intangible assets	63	60
Amortization of regulatory assets	—	5
Depreciation and amortization	438	414
Asset removal costs	87	88
	525	502

5. FINANCING CHARGES

Year ended December 31 *(millions of dollars)*	**2025**	**2024**
Interest on long-term debt *(Note 24)*	284	261
Interest on inter-company demand facility *(Note 24)*	16	20
Interest on regulatory accounts	11	12
Other	10	7
Less: Interest capitalized on construction and development in progress	(17)	(15)
	304	285

6. INCOME TAXES

As a rate regulated utility business, the Distribution Business recovers income taxes from its ratepayers based on estimated current income tax expense in respect of its regulated operations. The amounts of deferred income taxes related to regulated operations which are considered to be more likely-than-not to be recoverable from, or refunded to, ratepayers in future periods are recognized as deferred income tax regulatory assets or deferred income tax regulatory liabilities, with an offset to deferred income tax recovery or deferred income tax expense, respectively. The Distribution Business' income tax expense or income tax recovery for the period includes all current and deferred income tax expenses for the period net of the regulated accounting offset to deferred income tax expense arising from temporary differences to be recoverable from, or refunded to, customers in future rates. Thus, the Distribution Business' income tax expense or income tax recovery differs from the amount that would have been recorded using the statutory income tax rate. As the Company operates in Ontario, it is subject to the combined Canadian federal and Ontario statutory rates of 26.5%.

The reconciliation between the statutory and the effective tax rates is provided as follows:

	2025		2024	
Year ended December 31 *(millions of dollars)*	*(millions of dollars)*	*(percentage)*	*(millions of dollars)*	*(percentage)*
Income before income tax expense	559		503	
Income tax expense at statutory rate of 26.5% (2024 - 26.5%)	148	26.5 %	133	26.5 %
Increase (decrease) resulting from:				
Net temporary differences recoverable in future rates charged to customers:				
Capital cost allowance in excess of depreciation and amortization	(34)	(6.1)%	(18)	(3.6)%
Overheads capitalized for accounting but deducted for tax purposes	(24)	(4.3)%	(24)	(4.8)%
Interest capitalized for accounting but deducted for tax purposes	(4)	(0.7)%	(4)	(0.8)%
Pension and post-retirement benefit contributions in excess of expense	1	0.2 %	(3)	(0.6)%
Environmental expenditures	—	— %	(1)	(0.2)%
Other	1	0.2 %	(2)	(0.4)%
Net temporary differences attributable to regulated business	(60)	(10.7)%	(52)	(10.3)%
Net permanent differences	(1)	(0.2)%	2	0.4 %
Total income tax expense	87	15.6 %	83	16.5 %

The major components of income tax expense are as follows:

Year ended December 31 *(millions of dollars)*	2025	2024
Current income tax expense	92	75
Deferred income tax (recovery) expense	(5)	8
Total income tax expense	87	83

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and deferred income tax liabilities reflect the future income tax consequences attributable to temporary differences between the tax bases and the financial statement carrying amounts of the assets and liabilities including the carry forward amounts of tax losses and tax credits. Deferred income tax assets and deferred income tax liabilities attributable to the Distribution Business' regulated operations are recognized with a corresponding offset in deferred income tax regulatory assets and deferred income tax liabilities to reflect the anticipated recovery or repayment of these balances in the future electricity rates. As at December 31, 2025 and 2024, deferred income tax assets and deferred income tax liabilities consisted of the following:

As at December 31 *(millions of dollars)*	2025	2024
Deferred income tax assets (liabilities)		
Capital cost allowance in excess of depreciation and amortization	(1,487)	(1,391)
Post-retirement and post-employment benefits expense in excess of cash payments	343	325
Regulatory assets and liabilities	139	126
Goodwill	(19)	(19)
Environmental expenditures	—	1
Non-capital losses	3	4
Other	(9)	3
Net deferred income tax liabilities[1]	(1,030)	(951)

[1] The net deferred income tax liabilities are presented on the balance sheets as long-term.

7. ACCOUNTS RECEIVABLE

As at December 31 *(millions of dollars)*	2025	2024
Accounts receivable – billed	436	403
Accounts receivable – unbilled	610	489
Accounts receivable, gross	1,046	892
Allowance for doubtful accounts	(55)	(60)
Accounts receivable, net	991	832

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2025 and 2024:

Year ended December 31 *(millions of dollars)*	2025	2024
Allowance for doubtful accounts – beginning	(60)	(56)
Write-offs	23	18
Additions to allowance for doubtful accounts	(18)	(22)
Allowance for doubtful accounts – ending	(55)	(60)

8. OTHER CURRENT ASSETS

As at December 31 *(millions of dollars)*	2025	2024
Prepaid expenses and other assets	42	46
Materials and supplies	9	8
Regulatory assets *(Note 11)*	1	28
	52	82

9. PROPERTY, PLANT AND EQUIPMENT

As at December 31, 2025 *(millions of dollars)*	Property, Plant and Equipment[1]	Accumulated Depreciation	Construction in Progress	Total
Distribution	15,227	5,018	289	10,498
Administration and service	1,555	702	24	877
Other	241	200	—	41
	17,023	5,920	313	11,416

[1] Includes future use assets totalling $322 million.

As at December 31, 2024 *(millions of dollars)*	Property, Plant and Equipment[1]	Accumulated Depreciation	Construction in Progress	Total
Distribution	14,229	4,784	308	9,753
Administration and service	1,426	677	86	835
Other	228	184	—	44
	15,883	5,645	394	10,632

[1] Includes future use assets totalling $326 million.

Financing charges capitalized on property, plant and equipment under construction in 2025 were $15 million (2024 - $13 million).

10. INTANGIBLE ASSETS

As at December 31, 2025 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	955	607	10	358
Other	76	59	9	26
	1,031	666	19	384

As at December 31, 2024 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	891	550	28	369
Other	77	53	4	28
	968	603	32	397

Financing charges capitalized to intangible assets under development were $2 million in 2025 (2024 - $2 million). The estimated annual amortization expense for intangible assets are as follows: 2026 - $63 million; 2027 - $60 million; 2028 - $55 million; 2029 - $47 million; and 2030 - $41 million.

11. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. The Distribution Business has recorded the following regulatory assets and liabilities:

As at December 31 *(millions of dollars)*	2025	2024
Regulatory assets:		
Deferred income tax regulatory asset	1,115	1,018
Broadband deferral	73	48
Post-retirement and post-employment benefits - non-service cost	48	71
Getting Ontario Connected Act variance	39	24
Distribution rate riders	26	—
Incremental cloud computing implementation costs deferral	13	6
Stock-based compensation	10	13
Other	39	34
Total regulatory assets	1,363	1,214
Less: current portion	(1)	(28)
	1,362	1,186
Regulatory liabilities:		
Retail settlement variance account (RSVA)	242	157
Post-retirement and post-employment benefits	187	210
Earnings sharing mechanism (ESM) deferral	124	68
Tax rule changes variance	33	32
Advanced Metering Infrastructure (AMI) 2.0 variance	29	7
OPEB Asymmetrical Carrying Charge	22	14
Capitalized overhead tax variance	20	15
Pension cost differential	16	14
Distribution rate riders	—	45
Other	19	19
Total regulatory liabilities	692	581
Less: current portion	(157)	(132)
	535	449

Deferred Income Tax Regulatory Asset

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. The Distribution Business has recognized regulatory assets that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Distribution Business' income tax expense would have been recognized using the liability method and there would be no regulatory accounts established for income taxes to be recovered through future rates.

Broadband Deferral

The Distribution Business recognizes the incremental costs and incremental revenues attributable to carrying out activities pertaining to designated broadband projects as defined under the *Building Broadband Faster Act* (Ontario) in this generic deferral account.

Post-Retirement and Post-Employment Benefits - Non-Service Cost

The Distribution Business has recorded a regulatory asset relating to the future recovery of its post-retirement and post-employment benefits other than service costs. The regulatory asset includes the applicable tax impact to reflect taxes payable. Prior to adoption of ASU 2017-07 in 2018, these amounts were capitalized to property, plant and equipment and intangible assets. In 2018 and 2019, the OEB approved the regulatory asset for Hydro One Networks' transmission business and distribution business, respectively. As part of Hydro One Networks' 2020 to 2022 Transmission Decision, the OEB concluded that the non-service cost component of Hydro One's OPEB costs shall be recognized as OM&A for both its transmission and distribution businesses. Furthermore, the Distribution Business continued to record the non-service cost component of OPEBs in this account until the end of 2022. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of the Distribution Business' account balance as at December 31, 2020, including accrued interest, which were recovered from ratepayers over a three-year period that ended December 31, 2025.

Getting Ontario Connected Act Variance

On October 31, 2023, the OEB issued its Decision and Order approving the establishment of a generic sector-wide variance account, effective April 1, 2023. The account was established to record incremental costs of locating underground infrastructure resulting from the implementation of Provincial legislation: Bill 93, *Getting Ontario Connected Act, 2022*.

Distribution Rate Riders

As part of the JRAP Decision, the OEB approved the disposition of certain deferral and variance account balances as at December 31, 2020, including accrued interest, which were accumulated in distribution rate riders. The amounts were disposed of over a three-year period that ended December 31, 2025. The balance in the account is mostly comprised of excess returns to be collected from ratepayers in a future rate application.

Incremental Cloud Computing Implementation Costs Deferral

On November 2, 2023, the OEB issued an Accounting Order approving the establishment of a generic sector-wide deferral account, effective December 1, 2023. The account was established to record incremental cloud computing implementation costs.

Stock-based Compensation

The Distribution Business recognizes costs associated with share grant plans as a regulatory asset as management considers it probable that share grant plans' costs will be recovered in the future through the rate-setting process. Share grant costs are transferred to labour costs at the time they vest and are issued, and are recovered in rates in accordance with recovery of these labour costs.

RSVA

The Distribution Business has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. The RSVA account tracks the difference between the cost of power purchased from the IESO and the cost of power recovered from ratepayers. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of the Distribution Business' account balance as at December 31, 2020, including accrued interest, over a three-year period that ended December 31, 2025. In December 2024, as part of the Decision and Order on 2025 distribution rates, the OEB approved, on an interim basis, the disposition of certain RSVA balances as at December 31, 2023, including accrued interest, over a one-year period that ended December 31, 2025. This disposition became final upon receipt of the Decision and Order on 2026 distribution rates, issued in December 2025. The OEB also approved disposition of certain RSVA balances as at December 31, 2024, including accrued interest, over a one-year period ending December 31, 2026 on both an interim and final basis.

Post-Retirement and Post-Employment Benefits

In accordance with OEB rate orders, post-retirement and post-employment benefits costs are recovered on an accrual basis. The Distribution Business recognizes the net unfunded or funded status of post-retirement and post-employment obligations on the consolidated balance sheets with an incremental offset to the associated regulatory asset or regulatory liability, as the case may be. A regulatory asset or regulatory liability is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered or returned in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to the present value of the actuarially determined benefit obligation at each year end based on an annual actuarial report, with an offset to the associated regulatory asset or regulatory liability, as the case may be, to the extent of the remeasurement adjustment.

ESM Deferral

In March 2019, the OEB approved the establishment of an earnings sharing mechanism deferral account for the Distribution Business to record over-earnings including tax impacts. Under this mechanism, Hydro One shares 50% of regulated earnings that exceed the OEB-approved regulatory return-on-equity by more than 100 basis points with distribution ratepayers. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of the Distribution Business' account balance as at December 31, 2020, including accrued interest, over a three-year period that ended December 31, 2025. As part of the same decision, the account was approved for continuance for the Distribution Business for 2023 to 2027. The OEB also approved the disposition of the ESM account balances as at December 31, 2024 in Hydro One Networks' distribution business 2026 rates application on a final basis, including accrued interest, over a one-year period ending December 31, 2026.

Tax Rule Changes Variance

The 2019 federal and Ontario budgets (Budgets) provided certain time-limited investment incentives permitting the Distribution Business to deduct accelerated capital cost allowance of up to three times the first-year rate for capital investments acquired after November 20, 2018 and placed in-service before January 1, 2028 (Accelerated Depreciation). Following the enactment of the Budget measures in the second quarter of 2019, the OEB directed all Ontario regulated utilities including the Distribution Business to track the full revenue impact of the tax benefits related to the Accelerated Depreciation rules to ratepayers. The tax benefit to be returned to ratepayers in the future gave rise to a regulatory liability and resulted in a decrease in revenues as current rates do not include the benefit of the Accelerated Depreciation; therefore, the revenue subject to refund cannot be recognized. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of the Distribution Business' account balance as at December 31, 2020, including accrued interest, which were returned to ratepayers over a three-year period that ended December 31, 2025.

AMI 2.0 Variance

As part of the JRAP Decision, the OEB approved the establishment of the AMI 2.0 variance account. The account records the difference in revenue requirement impact including tax, if any, between the planned in-service additions included in the forecasted costs of the AMI 2.0 program over the 2023-2027 period and the actual in-service additions achieved as part of the AMI 2.0 program over the 2023-2027 period. The account is asymmetrical to the benefit of ratepayers.

OPEB Asymmetrical Carrying Charge Variance Account

On September 14, 2017, the OEB issued its Report of the Board: *Regulatory Treatment of Pension and OPEB Costs* that allowed rate-regulated utilities to track the difference between their pension and OPEB costs calculated under the accrual method and the cash payment method, effective January 1, 2018, and record the carrying charges associated with the balance on an asymmetrical basis. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of Distribution Business' account balances as at December 31, 2020, including accrued interest, which were returned to ratepayers over a three-year period that ended December 31, 2025. As part of the same decision, the OEB approved the modification of this account for Hydro One Networks' Distribution business for 2023 to 2027.

Capitalized Overhead Tax Variance

As part of the JRAP Decision, the OEB approved the establishment of a capitalized overhead tax variance account to capture the difference between the capitalized overheads deducted in calculating the regulatory tax expense included in rates and the actual capitalized overhead costs deducted in Hydro One's tax returns for the Distribution Business for the 2016 to 2027 period. Variance amounts are recognized at the earlier of (i) when the tax year has been audited by the Canada Revenue Agency or (ii) when the taxation year is statute barred.

Pension Cost Differential

Variances between the OM&A pension cost recognized and the cost embedded in rates as part of the rate-setting process for the Distribution Business are recognized as a regulatory asset or regulatory liability, as the case may be. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of the Distribution Business' account balance as at December 31, 2020, including accrued interest, which were returned to ratepayers over a three-year period that ended December 31, 2025.

12. OTHER LONG-TERM ASSETS

As at December 31 *(millions of dollars)*	**2025**	**2024**
Cloud Computing Implementation Cost	34	24
Right-of-Use assets *(Note 21)*	16	21
Other long-term assets	1	1
	51	46

13. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

As at December 31 *(millions of dollars)*	**2025**	**2024**
Accrued liabilities	637	574
Regulatory liabilities *(Note 11)*	157	132
Accounts payable	91	121
Accrued interest *(Note 24)*	79	69
Lease obligations *(Note 21)*	6	6
Environmental liabilities *(Note 19)*	2	4
Derivative liability	2	2
	974	908

14. OTHER LONG-TERM LIABILITIES

As at December 31 *(millions of dollars)*	**2025**	**2024**
Post-retirement and post-employment benefit liability *(Note 18)*	926	880
Asset retirement obligations *(Note 20)*	12	10
Lease obligations *(Note 21)*	10	15
Long-term accounts payable and other liabilities	9	14
Long-term inter-company payable *(Note 24)*	8	10
Derivative liability	—	1
Environmental liabilities *(Note 19)*	—	1
	965	931

15. DEBT

Hydro One issues notes for long-term financing under its Medium-Term Note (MTN) Program. The terms of certain issuances are mirrored down to Hydro One Networks through the issuance of inter-company debt, and are allocated between the Company's transmission and distribution businesses. The following table presents long-term debt allocated to the Distribution Business outstanding as at December 31, 2025 and 2024:

As at December 31 *(millions of dollars)*	**2025**	**2024**
Long-term debt	7,068	6,379
Add: Net unamortized debt premiums	14	16
Add: Realized mark-to-market gain[1]	—	1
Less: Deferred debt issuance costs	(25)	(23)
Less: Long-term debt payable within one year	(411)	(364)
Long-term debt	6,646	6,009

[1] In October 2023, Hydro One entered into $400 million fixed-to-floating interest-rate swap agreement to convert the $400 million Medium Term Note (MTN) Series 57 notes matured October 20, 2025, into a variable rate debt. $156 million was allocated to the Distribution Business. This swap was accounted for as a fair value hedge. In December 2023, this swap was terminated with a $6 million payment received on settlement, of which $1 million was allocated to the Distribution business that is being amortized over the term of the related note.

In 2025, Hydro One issued $2,700 million long-term debt under its MTN Program (2024 - $2,750 million), of which $2,700 million (2024 - $2,531 million) was mirrored down to Hydro One Networks, and $1,053 million (2024 - $987 million) was allocated to the Distribution Business.

In 2025, Hydro One repaid $1,150 million (2024 - $700 million) of maturing long-term debt under its MTN Program. Hydro One Networks repaid inter-company debt of $1,024 million (2024 - $700 million) to Hydro One, of which $364 million (2024 - $287 million) was allocated to the Distribution Business.

Principal and Interest Payments

As at December 31, 2025, future principal repayments, interest payments, and related weighted-average interest rates were as follows:

	Long-Term Debt Principal Repayments	Interest Payments	Weighted-Average Interest Rate
	(millions of dollars)	*(millions of dollars)*	*(%)*
Year 1	411	307	3.1
Year 2	—	300	—
Year 3	195	295	5.2
Year 4	464	286	3.7
Year 5	198	267	5.5
	1,268	1,455	4.0
Years 6-10	2,257	1,105	4.4
Thereafter	3,543	2,018	4.6
	7,068	4,578	4.4

Inter-company Demand Loan

On June 1, 2021, Hydro One Networks issued a $29 million non-interest bearing demand promissory note to Orillia Power Distribution Corporate in exchange for the assets of Orillia Power. In 2024, the note was reduced by $2 million through an offset of the inter-company demand facility. As at December 31, 2025 and 2024, $27 million of the promissory note was outstanding. During the years ended December 31, 2025 and 2024, no promissory notes were issued.

16. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

The Distribution Business classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One Networks has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those, other than quoted market prices included within Level 1, that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest-rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

As at December 31, 2025 and 2024, the carrying amounts of accounts receivable, due from related parties, inter-company demand facility, inter-company demand note, accounts payable, and due to related parties are representative of fair value due to the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The carrying values and fair values of the Distribution Business' long-term debt as at December 31, 2025 and 2024 are as follows:

As at December 31 *(millions of dollars)*	2025 Carrying Value	2025 Fair Value	2024 Carrying Value	2024 Fair Value
Long-term debt, including current portion	7,057	6,942	6,373	6,335

Fair Value Measurements of Derivative Instruments

Hydro One enters into interest-rate swaps agreements with respect to its long-term debt. The terms of certain of these interest-rate swap agreements are mirrored down to Hydro One Networks, and are allocated between the Company's transmission and distribution businesses.

As at December 31, 2025 and 2024, Hydro One had no fair value hedges.

As at December 31, 2025, the value of the Company's derivative instruments was $4 million (2024 - $7 million), of which $2 million (2024 - $3 million) was allocated to the Distribution Business.

As at December 31, 2025 and 2024, the Company had no interest-rate swaps classified as undesignated contracts.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities as at December 31, 2025 and 2024 is as follows:

As at December 31, 2025 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Long-term debt, including current portion *(Note 15)*	7,057	6,942	—	6,942	—
Derivative instruments					
Cash flow hedges, including current portion	2	2	—	2	—
	7,059	6,944	—	6,944	—

As at December 31, 2024 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Long-term debt, including current portion	6,373	6,335	—	6,335	—
Derivative instruments					
Cash flow hedges, including current portion	3	3	—	3	—
	6,376	6,338	—	6,338	—

The fair value of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no transfers between any of the fair value levels during the years ended December 31, 2025 or 2024.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss which results from changes in values, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates, as its regulated return on equity is derived using a formulaic approach that takes anticipated interest rates into account. The Company is not currently exposed to material commodity price risk or material foreign exchange risk.

Hydro One Networks uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. Hydro One Networks also uses derivative financial instruments to manage interest-rate risk. Hydro One's derivative instruments, or portions thereof, are mirrored down to Hydro One Networks, and are allocated between the Company's transmission and distribution businesses. Hydro One Networks may utilize interest-rate swaps designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt, and may also utilize interest-rate derivative instruments, such as cash flow hedges, to manage its exposure to short-term interest rates or to lock in interest-rate levels on forecasted financing.

A hypothetical 100 basis point increase in interest rates associated with variable-rate debt would not have resulted in a significant decrease to the Company's net income for the years ended December 31, 2025 and 2024, respectively.

For derivative instruments that are designated and qualify as cash flow hedges, the unrealized gain or loss, after tax, on the derivative instrument is recorded as OCI or OCL and is reclassified to net income or net loss in the same period during which the hedged transaction affects results of operations. The following table shows the amounts recorded in OCL and reclassified to financing charges for the years ended December 31, 2025 and 2024:

	Hydro One		Distribution Business	
Year ended December 31 *(millions of dollars)*	**2025**	**2024**	**2025**	**2024**
Amounts recorded in OCI/OCL				
Before tax loss	2	1	1	—
After tax loss	1	1	—	—
Amounts reclassified to financing charges				
Before tax loss (gain)	4	(4)	2	(1)
After tax loss (gain)	3	(3)	1	(1)

The Company estimates that the amount of AOCL, after tax, related to cash flow hedges to be reclassified to results of operations in the next 12 months is approximately $3 million, of which approximately $1 million will be allocated to the Distribution Business. Actual amounts reclassified to results of operations depend on the interest rate in effect until the derivative contracts mature. For all forecasted transactions, as at December 31, 2025, the maximum term over which the Company is hedging exposures to the variability of cash flows is less than one year.

The Pension Plan manages market risk by diversifying investments in accordance with the Pension Plan's Statement of Investment Policies and Procedures. Interest rate risk arises from the possibility that changes in interest rates will affect the fair value of the Pension Plan's financial instruments. In addition, changes in interest rates can also impact discount rates which impact the valuation of the pension and post-retirement and post-employment liabilities. Currency risk is the risk that the value of the Pension Plan's financial instruments will fluctuate due to changes in foreign currencies relative to the Canadian dollar. Other price risk is the risk that the value of the Pension Plan's investments in equity securities will fluctuate as a result of changes in market prices, other than those arising from interest risk or currency risk. All three factors may contribute to changes in values of the Pension Plan investments. See Note 18 – Pension and Post-Retirement and Post-Employment Benefits for further details.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. As at December 31, 2025 and 2024, there were no significant concentrations of credit risk with respect to any class of financial assets. The Distribution Business' revenue is earned from a broad base of customers. As a result, the Distribution Business did not earn a material amount of revenue from any single customer. As at December 31, 2025 and 2024, there was no material accounts receivable balance due from any single customer.

As at December 31, 2025, the Distribution Business' allowance for doubtful accounts was $55 million (2024 - $60 million). The allowance for doubtful accounts reflects the Company's CECL for all accounts receivable balances, which are based on historical overdue balances, customer payments and write-offs. As at December 31, 2025, approximately 7% (2024 - 7%) of the Distribution Business' net accounts receivable were outstanding for more than 60 days.

Hydro One manages its counterparty credit risk through various techniques including (i) entering into transactions with highly rated counterparties, (ii) limiting total exposure levels with individual counterparties, (iii) entering into master agreements which enable net settlement and the contractual right of offset, and (iv) monitoring the financial condition of counterparties. Hydro One monitors current credit exposure to counterparties on both an individual and an aggregate basis. The Company's counterparty credit risk profile is consistent with Hydro One. The Distribution Business' credit risk for accounts receivable is limited to the carrying amounts on the balance sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The maximum credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts in an asset position at the reporting date. As at December 31, 2025 and 2024, Hydro One's credit exposure for all derivative instruments and applicable payables was with one financial institution with investment grade credit ratings as counterparty.

The Pension Plan manages its counterparty credit risk with respect to bonds by investing in investment-grade corporate and government bonds and with respect to derivative instruments by transacting only with highly rated financial institutions and by ensuring that exposure is diversified across counterparties.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One Networks meets its short-term operating liquidity requirements through the inter-company demand facility with Hydro One and funds from operations. The short-term liquidity available to the Company is expected to be sufficient to fund the Company's operating requirements.

17. CAPITAL MANAGEMENT

The Distribution Business' objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. As at December 31, 2025 and 2024, the Distribution Business' capital structure was as follows:

As at December 31 *(millions of dollars)*	**2025**	**2024**
Long-term debt payable within one year *(Note 15)*	411	364
Inter-company demand promissory note	27	27
Inter-company demand facility	185	301
	623	692
Long-term debt *(Note 15)*	6,646	6,009
Excess of assets over liabilities	3,400	3,226
Total capital	10,669	9,927

The following table shows the movements in the excess of assets over liabilities for the years ended December 31, 2025 and 2024:

Year ended December 31 *(millions of dollars)*	**2025**	**2024**
Excess of assets over liabilities - beginning	3,226	3,090
Comprehensive income	473	420
Payments to Hydro One to finance dividends	(299)	(284)
Excess of assets over liabilities - ending	3,400	3,226

18. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a Pension Plan, a supplementary pension plan (Supplementary Plan), and post-retirement and post-employment benefit plans (Benefit Plans), and a DC Plan.

Pension Plan and Supplementary Plan

The Pension Plan is a defined benefit contributory plan which covers eligible regular employees of Hydro One and its subsidiaries. The Pension Plan provides benefits based on highest three-year average pensionable earnings up to March 31, 2025. Beginning April 1, 2025, all service for all groups on a go-forward basis will be calculated using the highest five-year average pensionable earnings. For management employees who commenced employment on or after January 1, 2004, and for the Society of United Professionals (Society)-represented staff hired after November 17, 2005, benefits are based on the highest five-year average pensionable earnings for all their service. After retirement, pensions are indexed to inflation. Membership in the Pension Plan was closed to management employees who were not eligible to join the Pension Plan as of September 30, 2015. These employees are eligible to join the DC Plan.

Company and employee contributions to the Pension Plan are based on actuarial reports, including valuations performed at least every three years, and actual or projected levels of pensionable earnings, as applicable. The most recent actuarial valuation was performed effective December 31, 2024 and filed on September 23, 2025. The Distribution Business' total annual cash Pension Plan employer contributions for 2025 were $38 million (2024 - $39 million). The Distribution Business' estimated annual Pension Plan employer contributions for the years 2026, 2027, 2028, 2029, and 2030 are approximately $33 million, $31 million, $31 million, $37 million, and $43 million, respectively.

The Supplementary Plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan beyond the limitations imposed by the *Income Tax Act* (Canada). The Supplementary Plan obligation is included with other post-retirement and post-employment benefit obligations on the balance sheets.

As at December 31, 2025, the present value of Hydro One's projected pension benefit obligation was estimated to be $8,907 million (2024 - $8,686 million). The fair value of pension plan assets available for these benefits was $9,517 million (2024 - $9,333 million).

Post-Retirement and Post-Employment Plans

The Company accounts for post-retirement and post-employment costs consistent with their inclusion in OEB-approved rates. During the year ended December 31, 2025, for the Distribution Business, $72 million (2024 - $59 million) were attributable to labour, of which $50 million (2024 - $41 million) was charge to operations, and $22 million (2024 - $18 million) was capitalized as part of the cost of property, plant and equipment and intangible assets. Benefits paid in 2025 were $41 million (2024 - $38 million).

The Distribution Business presents its post-retirement and post-employment benefit liabilities on its balance sheets as follows:

As at December 31 *(millions of dollars)*	**2025**	**2024**
Accrued liabilities	40	39
Post-retirement and post-employment benefit liability	926	880
Net unfunded status	966	919

DC Plan

Hydro One established a DC Plan effective January 1, 2016. The DC Plan covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One up to an annual contribution limit. There is also a Supplementary Notional Plan that provides members of the DC Plan with employer contributions beyond the limitations imposed by the *Income Tax Act* (Canada) in the form of credits to a notional account. The Distribution Business contributions to the DC Plan for the year ended December 31, 2025 were $3 million (2024 - $2 million).

19. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2025 and 2024:

Year ended December 31, 2025 *(millions of dollars)*	**PCB**	**LAR**	**Total**
Environmental liabilities - beginning	3	2	5
Expenditures	(2)	(1)	(3)
Revaluation adjustment	—	—	—
Environmental liabilities - ending	1	1	2
Less: current portion	(1)	(1)	(2)
	—	—	—

Year ended December 31, 2024 *(millions of dollars)*	**PCB**	**LAR**	**Total**
Environmental liabilities - beginning	31	2	33
Expenditures	(31)	—	(31)
Revaluation adjustment	3	—	3
Environmental liabilities - ending	3	2	5
Less: current portion	(3)	(1)	(4)
	—	1	1

As at December 31, 2025, the estimated future environmental expenditures were as follows:

(millions of dollars)	
2026	2
Thereafter	—
	2

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred in order to generate future cash flow information. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, with respect to the PCB environmental liability, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures.

PCBs

Environment and Climate Change Canada regulations, enacted under the *Canadian Environmental Protection Act, 1999*, govern the management, storage and disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under previous regulations, the Distribution Business' PCBs were to be disposed of by the end of 2025, with the exception of specifically exempted equipment. On December 31st, 2025, regulations amending the *Canadian Environmental Protection Act, 1999* were published in the Canada Gazette, Part II. The amendments include deferring the end-of-use deadline for certain PCB-containing electrical equipment from December 31, 2025 to December 31, 2026. Contaminated equipment will generally be replaced, or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains PCBs in concentrations of less than two parts per million.

As at December 31, 2025, the Distribution Business' best estimate of the total future expenditures to comply with current PCB regulations was $1 million (2024 - $3 million). These expenditures are expected to be incurred in 2026. As a result of its annual review of environmental liabilities, the Distribution Business recorded a revaluation adjustment that was less than $1 million in 2025 to the PCB environmental liability (2024 - increase of $3 million).

LAR

As at December 31, 2025, the Distribution Business' best estimate of the total estimated future expenditures to complete its LAR program was $1 million (2024 - $2 million). These expenditures are expected to be incurred over the period from 2026 to 2027. As a result of its annual review of environmental liabilities, the Distribution Business recorded a revaluation adjustment that was less than $1 million in 2025 to the LAR environmental liability (2024 - $nil).

20. ASSET RETIREMENT OBLIGATIONS

Hydro One Networks records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities. Asset retirement obligations, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an asset retirement obligation is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the asset retirement obligation, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

Some of the Company's distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its facilities in perpetuity, no asset retirement obligations have been recorded for these assets. If, at some future date, a particular facility is shown not to meet the perpetuity assumption, it will be reviewed to determine whether an estimable asset retirement obligation exists. In such a case, an asset retirement obligation would be recorded at that time.

In determining the amounts to be recorded as asset retirement obligations, the Company estimates the current fair value for completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 1.0% to 3.0% (2024 - 1.0% to 3.0%), depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's Distribution Business' asset retirement obligations represent management's best estimates of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Asset retirement obligations are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively. As a result of its annual review of asset retirement obligations, there was an increase of $2 million to the asset retirement obligations recorded in 2025 (2024 - $nil).

As at December 31, 2025, Hydro One Networks had recorded asset retirement obligations of $12 million (2024 - $10 million) related to the Distribution Business, primarily consisting of the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities.

21. LEASES

Hydro One has operating lease contracts for buildings used in administrative and service-related functions. These leases have terms between three and five years with renewal options of additional three- to five-year terms at prevailing market rates at the time of extension. All leases include a clause to enable upward revision of the rental charge on an annual basis or on renewal according to prevailing market conditions or pre-established rents. There are no restrictions placed upon Hydro One by entering into these leases. Renewal options are included in the lease term when their exercise is reasonably certain. Other information related to the Distribution Business' operating leases was as follows:

Year ended December 31 *(millions of dollars)*	**2025**	**2024**
Lease expense	6	6
Lease payments made	6	5

As at December 31	**2025**	**2024**
Weighted-average remaining lease term[1] *(years)*	3	4
Weighted-average discount rate	2.9 %	2.9 %

[1] Includes renewal options that are reasonably certain to be exercised.

As at December 31, 2025, future minimum operating lease payments were as follows:

(millions of dollars)	
2026	6
2027	5
2028	3
2029	1
2030	1
Thereafter	1
Total undiscounted minimum lease payments	17
Less: discounting minimum lease payments to present value	(1)
Total discounted minimum lease payments	16

As at December 31, 2024, future minimum operating lease payments were as follows:

(millions of dollars)	
2025	6
2026	6
2027	5
2028	3
2029	1
Thereafter	1
Total undiscounted minimum lease payments	22
Less: discounting minimum lease payments to present value	(1)
Total discounted minimum lease payments	21

Hydro One presents its ROU assets and lease obligations on the balance sheets as follows:

As at December 31 *(millions of dollars)*	**2025**	**2024**
Other long-term assets *(Note 12)*	16	21
Accounts payable and other current liabilities *(Note 13)*	6	6
Other long-term liabilities *(Note 14)*	10	15

22. HYDRO ONE NETWORKS' SHARE CAPITAL

Hydro One Networks is authorized to issue an unlimited number of common and preferred shares. As at December 31, 2025 and 2024, Hydro One Networks had 209,401,290 common shares issued and outstanding and no preferred shares issued and outstanding.

During 2025, Hydro One Networks declared common share dividends in the amount of $792 million (2024 - $753 million) to Hydro One. The amount allocated to the Distribution Business to finance these dividends was $299 million (2024 - $284 million).

23. STOCK-BASED COMPENSATION

The following compensation plans were established by Hydro One Limited, however they represent components of compensation costs of Hydro One and its subsidiaries, including Hydro One Networks, in current and future periods.

Share Grant Plans

Hydro One Limited has two share grant plans (Share Grant Plans), one for the benefit of certain members of the Power Workers' Union (PWU) (PWU Share Grant Plan) and one for the benefit of certain members of the Society (Society Share Grant Plan). Hydro One and Hydro One Limited entered into an intercompany agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with these plans. The agreement requires Hydro One Networks to reimburse Hydro One for the value of shares granted to the Company's eligible employees relating to these plans.

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the PWU annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on April 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. The requisite service period for the PWU Share Grant Plan began on July 3, 2015, which is the date the share grant plan was ratified by the PWU. The number of common shares issued annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the Initial Public Offering (IPO). The aggregate number of Hydro One Limited common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 2,152,519 Hydro One Limited common shares were granted under the PWU Share Grant Plan relevant to the total stock-based compensation recognized by the Distribution Business.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the Society annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on September 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. Therefore the requisite service period for the Society Share Grant Plan began on September 1, 2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 743,877 Hydro One Limited common shares were granted under the Society Share Grant Plan relevant to the total stock-based compensation recognized by the Distribution Business.

The fair value of the Hydro One Limited 2015 share grants to employees of Hydro One Networks and allocated to the Distribution Business was $59 million. The fair value was estimated based on the grant date Hydro One Limited share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. In 2025, 187,818 common shares of Hydro One Limited were issued under the Share Grant Plans (2024 - 178,884) to eligible employees of Hydro One Networks and allocated to the Distribution Business. Total stock-based compensation recognized by the Distribution Business during 2025 was less than $1 million (2024 - $2 million) and was recorded as a regulatory asset.

A summary of the Distribution Business' share grant activity under the Share Grant Plans during the years ended December 31, 2025 and 2024 is presented below:

Year ended December 31, 2025	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	689,569	$20.50
Vested and issued[1]	(187,818)	—
Forfeited	(25,889)	$20.50
Share grants outstanding - ending	475,862	$20.50

[1] In 2025, Hydro One Limited issued common shares from treasury to eligible Hydro One Networks employees in accordance with provisions of the Share Grant Plans. In accordance with the intercompany agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

Year ended December 31, 2024	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	882,358	$20.50
Granted	576	—
Vested and issued[1]	(178,884)	—
Forfeited	(14,481)	$20.50
Share grants outstanding - ending	689,569	$20.50

[1] In 2024, Hydro One Limited issued common shares from treasury to eligible Hydro One Networks employees in accordance with provisions of the Share Grant Plans. In accordance with the intercompany agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.

Directors' DSU Plan

Under the Directors' DSU Plan, directors can elect to receive credit for their annual cash retainer in a notional account of DSUs in lieu of cash. Hydro One Limited Board of Directors may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled. Each DSU represents a unit with an underlying value equivalent to the value of one common share of Hydro One Limited and is entitled to accrue Hydro One Limited common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One Limited Board of Directors.

During 2025 and 2024, Directors' DSU Plan awards granted by Hydro One Limited that related to the Distribution Business were as follows:

Year ended December 31 *(number of DSUs)*	2025	2024
DSUs outstanding - beginning	31,983	27,328
Granted	7,728	8,190
Settled	(9,579)	(3,535)
DSUs outstanding - ending	30,132	31,983

For the years ended December 31, 2025 and 2024, the expense related to the Directors' DSU Plan was less than $1 million. As at December 31, 2025, the liability related to Directors' DSUs was $2 million (2024 - $2 million).

Management DSU Plan

Under the Management DSU Plan, eligible executive employees can elect to receive a specified proportion of their annual short-term incentive in a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of Hydro One Limited and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One Limited Board of Directors.

During 2025 and 2024, Management DSU Plan awards granted by Hydro One Limited that related to Hydro One Network's Distribution Business were as follows:

Year ended December 31 *(number of DSUs)*	2025	2024
DSUs outstanding - beginning	21,080	23,487
Granted	3,862	4,248
Paid	(2,172)	(6,655)
DSUs outstanding - ending	22,770	21,080

To comply with the Accountability Act and the OEB Act, in 2019 Hydro One Limited removed all executive-related compensation from the labour costs of its regulated subsidiaries. During the years ended December 31, 2025 and 2024, no executive-related stock-based compensation was allocated to the regulated businesses of Hydro One Networks.

Employee Share Ownership Plan

In 2015, Hydro One Limited established Employee Share Ownership Plans (ESOP) for certain eligible management and non-represented employees (Management ESOP) and for certain eligible Society-represented staff (Society ESOP). Under the Management ESOP, the eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 50% of their contributions, up to a maximum Company contribution of $25,000 per calendar year. Under the Society ESOP, the eligible Society-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 25% of their contributions, with no maximum Company contribution per calendar year.

In 2024, Hydro One established ESOP for certain eligible PWU represented staff (PWU ESOP). Under the PWU ESOP, the eligible PWU-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One. The Company matches 33% of their contribution, with no maximum Company contribution per calendar year.

In 2025, Company contributions made under the ESOP and allocated to the Distribution Business were $4 million (2024 - $3 million).

LTIP

Effective August 31, 2015, the Board of Directors of Hydro One adopted an LTIP. Under the LTIP, long-term incentives were granted to certain executive and management employees of Hydro One and its subsidiaries, and all equity-based awards would either be settled in newly issued shares of Hydro One from treasury or cash, subject to Hydro One's discretion, consistent with the provisions of the plan which also permit the participants to surrender a portion of their awards to satisfy related withholding taxes requirements. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares of Hydro One.

The LTIP provides flexibility to award a range of vehicles, including Performance Share Units (PSUs), RSUs, stock options, share appreciation rights, restricted shares, DSUs, and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance.

PSUs and RSUs

A summary of PSU and RSU awards activity under the LTIP during the years ended December 31, 2025 and 2024 is presented below:

	PSUs		RSUs	
Year ended December 31 *(number of units)*	**2025**	**2024**	**2025**	**2024**
Units outstanding – beginning	61,766	30,999	129,884	75,658
Granted	37,084	35,018	64,223	63,947
Forfeited	(13,085)	(3,125)	(20,675)	(8,634)
Settled	(7,630)	(1,126)	(10,464)	(1,087)
Units outstanding – ending	78,135	61,766	162,968	129,884

To comply with the Accountability Act and the OEB Act, in 2019 Hydro One Limited removed all executive-related compensation from the labour costs of its regulated subsidiaries. During the years ended December 31, 2025 and 2024, no executive-related stock-based compensation was allocated to the regulated businesses of Hydro One Networks.

The grant date total fair value of the awards granted during the year ended December 31, 2025 was $5 million (2024 - $4 million). The compensation expense related to the PSU and RSU awards recognized by the Company during 2025 was $4 million (2024 - $3 million). As at December 31, 2025, the payable relating to PSU awards included in due to related parties on the balance sheets was $2 million (2024 - not significant).

24. RELATED PARTY TRANSACTIONS

The Distribution Business is a separately regulated business of Hydro One Networks which is indirectly owned by Hydro One Limited. The Province of Ontario is a shareholder of Hydro One Limited with approximately 47.1% ownership as at December 31, 2025. The Ministry of Energy and Mines (Ministry) and the Ministry of Infrastructure (MOI) are related parties to Hydro One because they are controlled by the Province. The IESO, Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), and the OEB, are related parties to Hydro One Networks because they are controlled or significantly influenced by the Ministry. Acronym Solutions Inc. (Acronym) is a subsidiary of Hydro One Limited. The Distribution Business also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province. The following is a summary of the Distribution Business' related party transactions during the years ended December 31, 2025 and 2024:

Year ended December 31 *(millions of dollars)*			
Related Party	**Transaction**	**2025**	**2024**
Ministry	Broadband subsidy[1]	27	—
MOI	Broadband subsidy[1]	19	43
IESO	Power purchased	2,999	2,677
	Amounts related to electricity rebates	1,104	1,164
	Distribution revenues related to rural rate protection	256	255
	Funding received related to Conservation and Demand Management programs	—	1
OPG	Power purchased	23	18
	Revenues related to supply of electricity	8	5
OEFC	Power purchased from power contracts administered by the OEFC	2	1
OEB	OEB fees	7	6
Hydro One	Payments to finance dividends	299	284
	Interest expense on long-term debt	284	261
	Interest expense on inter-company demand facility	16	20
	Stock-based compensation costs	4	5
	Services received - costs expensed	3	3
Hydro One Networks' Transmission Business	Services received - costs expensed	2	3
	Capital contributions made	6	8
Acronym	Services received - costs expensed	8	10
Hydro One Limited and its other subsidiaries	Revenues for services provided	2	2
	Services received - costs recovered	5	5

[1] On October 31, 2024, the MOI announced that it has developed a program to deliver up to $400 million in subsidies to internet service providers (ISPs) for work associated with designated broadband projects. The program is intended to enable ISPs to successfully and safely attach their material and equipment to the Company's poles to bring connectivity to rural communities as part of a designated broadband project as defined under *Building Broadband Faster Act (Ontario)*. A portion of these subsidies is used to reimburse Hydro One Networks on behalf of ISPs for their share of enablement costs incurred to facilitate the program to date. During 2025, Ministry replaced MOI in making broadband subsidy payments to Hydro One.

The amounts due to and from related parties as at December 31, 2025 and 2024 are as follows:

As at December 31 *(millions of dollars)*	**2025**	**2024**
Due from related parties	178	115
Long-term inter-company payable	(8)	(10)
Accrued interest	(79)	(69)
Due to related parties	(478)	(341)
Inter-company demand promissory note *(Note 15)*	(27)	(27)
Inter-company demand facility	(185)	(301)
Long-term debt, including current portion *(Note 15)*	(7,057)	(6,373)

25. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 *(millions of dollars)*	2025	2024
Accounts receivable	(159)	(106)
Due from related parties	(63)	20
Materials and supplies	(1)	5
Other assets	(6)	(40)
Accounts payable	(30)	93
Accrued liabilities	61	(124)
Accrued interest	10	10
Due to related parties	138	41
Long-term accounts payable and other liabilities	(5)	2
Post-retirement and post-employment benefit liability	46	33
	(9)	(66)

Capital Expenditures

The following tables reconcile investments in property, plant and equipment and intangible assets and the amounts presented in the statements of cash flows for the years ended December 31, 2025 and 2024. The reconciling items include net change in accruals, transfers, and capitalized depreciation.

Year ended December 31, 2025 *(millions of dollars)*	Property, Plant and Equipment	Intangible Assets	Total
Capital investments	(1,191)	(48)	(1,239)
Reconciling items	166	(2)	164
Cash outflow for capital expenditures	(1,025)	(50)	(1,075)

Year ended December 31, 2024 *(millions of dollars)*	Property, Plant and Equipment	Intangible Assets	Total
Capital investments	(1,121)	(54)	(1,175)
Reconciling items	105	6	111
Cash outflow for capital expenditures	(1,016)	(48)	(1,064)

Supplementary Information

Year ended December 31 *(millions of dollars)*	2025	2024
Net interest paid	274	251
Income taxes paid	91	61

26. CONTINGENCIES

Hydro One Networks is involved in various lawsuits and claims in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Distribution Business' financial position, results of operations or cash flows.

The Company is a wholly owned subsidiary of Hydro One. As such, the assets of the Distribution Business are available to satisfy the debts, contingent liabilities and commitments of both the Company and Hydro One.

27. COMMITMENTS

The Company and Hydro One have numerous commitments. These commitments have not been specifically allocated to the Distribution Business. However, the assets of the Distribution Business are available to satisfy the commitments of both the Company and Hydro One.

28. SUBSEQUENT EVENTS

Payments to Finance Dividends

On February 12, 2026, Hydro One Networks declared a dividend of $199 million. The amount allocated to the Distribution Business to finance this payment was $75 million.

RECONCILIATION OF REGULATORY FINANCIAL RESULTS WITH AUDITED FINANCIAL STATEMENTS (2025)

Hydro One Transmission

$M	Total per Exhibit A-06-02-02	Adjustments	Regulated Results
	(a)	(b)	(c)
REVENUE			
Transmission Tariff	2,273	25	2,298
Other	124		124
COSTS			
Operation, maintenance, and administration	540	(79)	461
Depreciation, amortization, and asset removal costs	550		550
Income before financing charges and income tax expense	**1,307**		**1,411**
Financing charges	387	35	422
Income tax expense (recovery)	118	44	162
NET INCOME	**802**		**827**

Certain adjustments are required to reconcile from the audited financial statements to regulated net income. These adjustments are consistent with those presented in the RRR 3.1.4 Regulated ROE Template for Electricity Transmitters. The accounting treatment of any non-utility business has segregated activities from rate regulated activities.

Witness: Anthony Nava

Hydro One Sault Ste. Marie LP (HOSSM)

$M	Total per Exhibit A-06-02-04	Adjustments	Regulated Results
	(a)	(b)	(c)
REVENUE			
Transmission Tariff	49	4	53
Other	1		1
COSTS			
Operation, maintenance, and administration	9		9
Depreciation, amortization, and asset removal costs	12		12
Income before financing charges and income tax expense	**29**		**33**
Financing charges	0	10	10
Income tax expense (recovery)	0	5	5
NET INCOME	**29**		**18**

Certain adjustments are required to reconcile from the audited financial statements to regulated net income. These adjustments are consistent with those presented in the RRR 3.1.4 ROE Template for Electricity Transmitters. The accounting treatment of any non-utility business has segregated activities from rate regulated activities.

Hydro One Distribution

$M	Total per Exhibit A-06-02-06	Adjustments	Utility Income
REVENUE			
Energy sales	6,049	48	6,097
Rural rate protection	256		256
Other	62		62
COSTS			
Purchased power	4,341		4,341
Operation, maintenance & administration	638	2	640
Depreciation, amortization and asset removal costs	525		525
Income before financing charges & income tax expense	**863**		**909**
Financing charges	304	(16)	288
Income before income taxes			
Income tax expense (recovery)	87	25	112
NET INCOME	**472**		**509**

Certain adjustments are required to reconcile from the audited financial statements to regulated net income. These adjustments are consistent with those presented in the RRR 2.1.5.6 Regulated ROE Filing Guide for Electricity Distributors. The accounting treatment of any non-utility business has segregated activities from rate regulated activities.

1 This page has been left blank intentionally.

2025 ANNUAL REPORT AND ANNUAL INFORMATION FORM

Included in this exhibit are the following Hydro One Limited Reports:

- Attachment 1: 2025 Annual Report, including MD&A
- Annual Information Form (2025-HOL-AIF.pdf)

1 This page has been left blank intentionally.

Connecting power and possibility

2025 Annual Report

hydro One

Corporate profile

Hydro One Limited (TSX: H)

Hydro One Limited, through its wholly-owned subsidiaries, is Ontario's largest electricity transmission and distribution provider with 1.5 million valued customers, $39.7 billion in assets as at December 31, 2025, and annual revenues in 2025 of $9 billion.

Our team of 9,600 skilled and dedicated employees proudly build and maintain a safe and reliable electricity system which is essential to supporting strong and successful communities. In 2025, Hydro One invested $3.4 billion in its transmission and distribution networks, and supported the economy through buying $3.0 billion of goods and services.

We are committed to the communities where we live and work through community investment, sustainability and diversity initiatives.

Hydro One Limited's common shares are listed on the TSX and certain of Hydro One Inc.'s medium term notes are listed on the NYSE. Additional information can be accessed at www.HydroOne.com, www.sedarplus.com or www.sec.gov.

This report contains forward-looking information within the meaning of applicable Canadian securities laws that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate, and includes beliefs and assumptions made by the management of Hydro One. Such information includes, but is not limited to, statements relating to: the Company's strategies and priorities for the future, including anticipated outcomes and impacts; the Company's commitment to communities; the Company's commitment to a culture of safety, including Hydro One's progress towards the goal of zero life-altering/life-threatening injuries and fatalities; Hydro One's investment plans for our transmission and distribution systems to improve reliability and provide growth capacity to the electricity networks, including the St. Clair Transmission Line and the transmission line between Bowmanville and the Greater Toronto Area, and the impact of such transmission lines; the Company's continued investment in the 50/50 equity partnership model with the First Nations; the Company's various development and construction projects and the expected outcome and economic opportunities from such projects; the Company's advancement of sustainability targets and evolvement of sustainability strategy; timing and payment of upcoming dividends; the Company's intentions to keep borrowing costs low; and the Company's collaborative relationships and relationship agreements with Indigenous communities. Words such as "expect" and "will" are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. Some of the factors that could cause actual results or outcomes to differ materially from the results expressed, implied or forecasted by such forward-looking information, including some of the assumptions used in making such statements, are discussed more fully in Hydro One Limited's and Hydro One Inc.'s filings with the securities regulatory authorities in Canada, which are available on SEDAR+ at www.sedarplus.com. We do not intend, and we disclaim any obligation, to update any forward-looking statements, except as required by law.

All figures in this document are approximate figures that are rounded to the nearest decimal place.

A message from our

President and CEO

As I write this letter, I reflect on Hydro One's strong performance in 2025 and the momentum we are carrying forward into 2026. Ontario's demand for electricity is growing, bringing with it the need for a more resilient and reliable electricity grid.

David Lebeter
President and Chief Executive Officer

Hydro One continues to play a central role in meeting this challenge – building, maintaining and operating a transmission and distribution system to meet our customers' needs today and tomorrow. Our strategy reflects this responsibility, with Customers, Partners, Solutions and Growth as its pillars. Together these pillars guide how we are *Connecting Power and Possibility* for people, businesses and communities across the province.

Safety first

Safety remains the foundation of our operations and the defining measure of our success. In 2025, our relentless focus on safety delivered strong results, including 20 months with no High Energy Serious Injury or Fatality incidents and a very low recordable injury rate – putting Hydro One in the top safety quartile amongst our peers. Knowing this journey is ongoing, we refreshed our Health and Safety Plan, incorporating frontline insight and aligning it with industry best practices. I am confident that we are on the right path towards our goal of ZERO life-altering/life-threatening injuries and fatalities.

Resilience and response

Through our actions, we demonstrated to customers that they can count on Hydro One during extreme weather events and outages, especially when they need us most. On March 28, 2025, a generational ice storm swept across Ontario, affecting more than 620,000, or about 42 per cent of our customers. Our teams responded immediately. More than 4,800 employees, supported by 30 local distribution companies and utility partners from New Brunswick, Nova Scotia and Quebec, mobilized to restore power. This extraordinary response reflects the skill, dedication and teamwork that defines Hydro One at its best.

In December, when winter storms struck again, our crews once more stepped up, shortening or canceling their own family time to restore power as quickly as possible and minimize any impacts on the holiday season.

To further aid the recovery efforts from the March ice storm, Hydro One established the Ice Storm 2025 Recovery Grant, offering up to $10,000 to Indigenous communities and municipalities that were impacted by the storm.

Powering growth

In 2025, we advanced our work in support of the government's Integrated Energy Plan, which sets out a unified, long-term strategy to ensure the province has affordable, reliable, secure, and clean energy to support economic growth through 2050.

We broke ground on the St. Clair Transmission Line, a $472 million project to be delivered with First Nation partners that will add about 450 megawatts of power in southwest Ontario and support EV battery manufacturing and agriculture in the region.

In addition to the existing transmission lines in our portfolio, we were designated to develop a new 500 kV transmission line running from Bowmanville to the Greater Toronto Area. With 14 transmission lines in various stages of development or construction, we are poised to deliver significant growth in critical infrastructure, driving economic opportunity and prosperity across the province. We are doing this in collaboration with Indigenous partners and communities and with the support of our Canadian suppliers. In 2025, over 90 per cent of purchases were with Canadian companies.

Sustainability

As strong as 2025 was, maintaining a strong foundation is critical so we can continue delivering results for our customers and shareholders. All 14 of the transmission lines awarded to Hydro One will be built with First Nations through our 50/50 Equity Partnership Model. At the same time, we continue to strengthen local economic development by prioritizing Canadian suppliers. In 2025, more than 90 per cent of our annual spend went to companies based in Ontario or elsewhere in Canada.

We also continue to advance on our sustainability targets, and in 2025, for the fourth year in a row, our Indigenous procurement spend exceeded our target of achieving at least five per cent by 2026. As we construct, maintain and operate the electric system we are conscious of our carbon footprint. As of the end of 2025, 57 per cent of sedans and SUVs are now electric or hybrid. Transitioning our fleet, combined with our focus on our own energy efficiency and SF6 gas management, keeps us on track to achieve a 30 per cent reduction in operations greenhouse gas emissions by 2030.

An engaged workforce is essential to our strong long-term performance, and this came to life through our 2025 Power to Give campaign, where employees raised a record $2 million and contributed more than 5,200 volunteer hours to support communities and causes across Ontario.

In 2026 we will evolve our sustainability strategy to focus on the areas that provide the greatest value for our business and the communities we serve, without losing focus on the sustainability priorities embedded in our corporate strategy.

Financial strength

Our strong performance is underpinned by a strong balance sheet. At the end of 2025, our Funds from Operations to Debt (FFO/Debt) ratio was 14.2, allowing us to continue reinvesting in the business and keep borrowing costs low, without issuing equity. Recognizing that every dollar we spend comes from our customers, we significantly expanded our productivity program, generating $254 million in savings. These disciplined efforts contributed to a compelling total shareholder return of 27 per cent for the year, driven by a rising share price and a six per cent increase in our quarterly dividend to 33.31 cents per share in May. We also shared $166 million with customers through our earnings sharing mechanism, ultimately reducing future rate increases.

Hydro One is leading Ontario into an electrified future that promises a better and brighter future for generations to come. I am proud of what we have achieved together and confident in what lies ahead. Thank you to our employees for their dedication and for the trust of our customers, partners and shareholders. Together, we are connecting power and possibility.

Sincerely,
David

Financial report

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The following Management's Discussion and Analysis (MD&A) of the financial condition and results of operations should be read together with the consolidated financial statements and accompanying notes thereto of Hydro One Limited (Hydro One or the Company) for the year ended December 31, 2025 (together, the Consolidated Financial Statements). The Consolidated Financial Statements have been prepared in accordance with United States (U.S.) generally accepted accounting principles (GAAP).

The Company has prepared this MD&A in accordance with National Instrument 51-102 - Continuous Disclosure Obligations of the Canadian Securities Administrators. Under the U.S./Canada Multijurisdictional Disclosure System, the Company is permitted to prepare this MD&A in accordance with the disclosure requirements of Canadian securities laws and regulations, which can vary from those of the U.S. This MD&A provides information as at and for the year ended December 31, 2025, based on information available to management as of February 12, 2026.

Included in this MD&A are certain specified financial measures and financial ratios that are not recognized by U.S. GAAP but that are used by management to evaluate the performance of the Company and its businesses. Since these specified financial measures and financial ratios may not have a standardized meaning within U.S. GAAP, results may not be comparable to similar financial measures and financial ratios presented by other entities. These measures and ratios should not be considered in isolation nor as a substitute for analysis of the Company's financial information reported under U.S. GAAP. See "Non-GAAP Financial Measures" for a discussion of these non-GAAP financial measures and a reconciliation of such measures to the most directly comparable U.S. GAAP measure.

All financial information in this MD&A is presented in Canadian dollars, unless otherwise indicated.

CONSOLIDATED FINANCIAL HIGHLIGHTS AND STATISTICS

Year ended December 31 *(millions of dollars, except as otherwise noted)*	**2025**	**2024**	**Change**
Revenues	9,041	8,484	6.6%
Purchased power	4,486	4,143	8.3%
Revenues, net of purchased power[1]	4,555	4,341	4.9%
Operation, maintenance and administration (OM&A) costs	1,206	1,308	(7.8%)
Depreciation, amortization and asset removal costs	1,111	1,066	4.2%
Financing charges	679	621	9.3%
Income tax expense	219	181	21.0%
Net income attributable to common shareholders of Hydro One	**1,339**	**1,156**	**15.8%**
Basic earnings per common share (EPS)	$2.23	$1.93	15.5%
Diluted EPS	$2.23	$1.92	16.1%
Net cash from operating activities	2,695	2,534	6.4%
Funds from operations (FFO)[1]	2,630	2,275	15.6%
Annualized FFO to Net Debt[1]	14.2 %	13.4 %	0.8%
Capital investments	3,366	3,063	9.9%
Assets placed in-service	2,901	2,463	17.8%
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	21,398	20,659	3.6%
Distribution: Electricity distributed to Hydro One customers *(GWh)*	33,294	31,523	5.6%

As at December 31	**2025**	**2024**
Net Debt to capitalization ratio[1]	59.5%	58.4%

[1] See section "Non-GAAP Financial Measures".

OVERVIEW

Through its wholly-owned subsidiary Hydro One Inc., Hydro One is Ontario's largest electricity transmission and distribution utility. Hydro One owns and operates substantially all of Ontario's electricity transmission network and is the largest electricity distributor in Ontario by number of customers. The Company's regulated transmission and distribution operations are owned by Hydro One Inc. Hydro One delivers electricity safely and reliably to approximately 1.5 million customers across the province, and to large industrial customers and municipal utilities. Through its subsidiaries, Hydro One Inc. owns and operates approximately 30,000 circuit kilometres of high-voltage transmission lines and approximately 126,000 circuit kilometres of primary low-voltage distribution lines. Hydro One has three segments: (i) transmission; (ii) distribution; and (iii) other.

For the years ended December 31, 2025 and 2024, Hydro One's segments accounted for the Company's total revenues, as follows:

Year ended December 31	2025	2024
Transmission	27 %	27 %
Distribution	72 %	72 %
Other	1 %	1 %

When adjusted for the recovery of purchased power costs, Hydro One's segments accounted for the Company's total revenues, net of purchased power,[1] for the years ended December 31, 2025 and 2024 as follows:

Year ended December 31	2025	2024
Transmission	53 %	52 %
Distribution	46 %	47 %
Other	1 %	1 %

As at December 31, 2025 and 2024, Hydro One's segments accounted for the Company's total assets as follows:

As at December 31	2025	2024
Transmission	60 %	59 %
Distribution	38 %	38 %
Other	2 %	3 %

Transmission Segment

Hydro One's transmission business consists of owning and operating the Company's transmission system, which accounts for approximately 91% (2024 - 90%) of Ontario's transmission capacity based on the network component of the revenue requirement[2] approved by the Ontario Energy Board (OEB).[3] As at December 31, 2025, the Company's transmission business consists of the transmission system operated by Hydro One Inc.'s rate-regulated subsidiaries, Hydro One Networks Inc. (Hydro One Networks), Hydro One Sault Ste. Marie LP (HOSSM), and an approximate 80% (2024 - 100%) interest in Chatham x Lakeshore Limited Partnership (CLLP), an approximate 66% interest in B2M Limited Partnership (B2M LP) and an approximate 55% interest in Niagara Reinforcement Limited Partnership (NRLP). The Company's approximately 80% interest in CLLP was reduced to approximately 70% in January 2026 and 50% in February 2026. The transmission segment also includes Hydro One Networks' approximate 48% minority interest in the East-West Tie Limited Partnership (EWT LP) (see section "Other Developments - EWT LP"). The Company's transmission business is rate-regulated and earns revenues mainly by charging transmission rates that are approved by the OEB.

For the year ended December 31	2025	2024
Electricity transmitted[1] *(MWh)*	145,587,496	140,417,171
Rate base *(millions of dollars)*	17,256	16,335
Capital investments *(millions of dollars)*	2,097	1,860
Assets placed in-service *(millions of dollars)*	1,543	1,431

[1] Electricity transmitted represents total electricity transmitted in Ontario by all transmitters.

As at December 31	2025	2024
Transmission lines spanning the province *(circuit-kilometres)*	30,479	29,935

[1] See section "Non-GAAP Financial Measures".
[2] The network component of the revenue requirement is Hydro One's portion of the transmission revenue requirement attributed to assets that are used for the common benefit of all Hydro One and non-Hydro One customers in the province.
[3] Hydro One owns and operates approximately 94% of the transmission system in Ontario based on the total OEB approved revenue requirement.

Distribution Segment

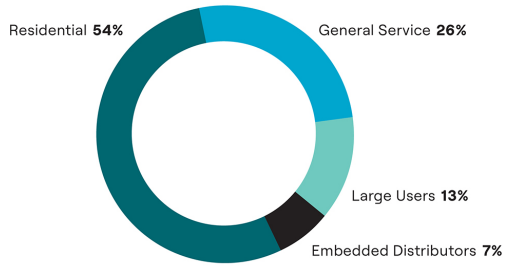
Hydro One's distribution business is the largest in Ontario and consists of the distribution systems operated by Hydro One Inc.'s rate-regulated subsidiaries, Hydro One Networks and Hydro One Remote Communities Inc. (Hydro One Remotes). The Company's distribution business earns revenues mainly by charging distribution rates that are approved by the OEB, as well as amounts to recover the cost of purchased power.

For the year ended December 31	2025	2024
Electricity distributed to Hydro One customers *(GWh)*	33,294	31,523
Electricity distributed through Hydro One lines *(GWh)*[1]	43,283	41,445
Rate base *(millions of dollars)*	10,788	10,184
Capital investments *(millions of dollars)*	1,252	1,185
Assets placed in-service *(millions of dollars)*	1,338	1,017

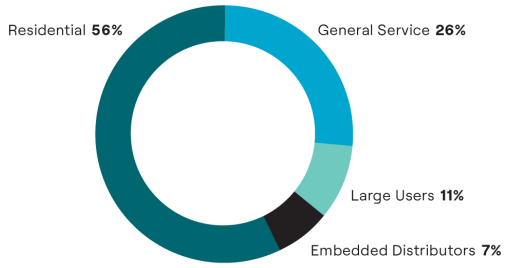
[1] Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the Independent Electricity System Operator (IESO).

As at December 31	2025	2024
Distribution lines spanning the province *(circuit-kilometres)*	126,179	125,533
Distribution customers *(number of customers)*	1,520,883	1,514,690

2025 Distribution Revenues



2024 Distribution Revenues



Other Segment

Hydro One's other segment consists principally of its telecommunications business, which provides telecommunications support for the Company's transmission and distribution businesses, as well as certain corporate activities.

The telecommunication business is carried out by Hydro One's wholly-owned subsidiary, Acronym Solutions Inc. (Acronym). In addition to supporting Hydro One's regulated business segments, Acronym offers a comprehensive suite of Information and Communications Technology solutions within a number of categories (including: Internet & Network, Security, Voice & Collaboration, Cloud and Managed Information Technology (IT)) that extend beyond its fibre optic network, in a competitive commercial market. Acronym is not regulated by the OEB, however Acronym is registered with the Canadian Radio-television and Telecommunications Commission as a non-dominant, facilities-based carrier, providing broadband telecommunications services in Ontario with connections to Montreal, Quebec; Buffalo, New York; and Detroit, Michigan.

Hydro One's other segment also includes the deferred tax asset (DTA) which arose from the revaluation of the tax bases of Hydro One's assets to fair market value when the Company transitioned from the provincial payments in lieu of tax regime to the federal tax regime at the time of the Company's initial public offering in 2015. As the DTA is not required to be shared with ratepayers, the Company considers it to not be part of the regulated transmission and distribution segment assets, and it is included in the other segment. Furthermore, Hydro One's other segment also includes Aux Energy Inc., a wholly-owned subsidiary that provides energy solutions to commercial and industrial clients, and Ontario Charging Network LP, a wholly-owned subsidiary (2024 - a joint venture) that owns and operates electric vehicle fast charging stations across Ontario under the Ivy Charging Network brand, as well as certain corporate activities, and is not rate-regulated.

PRIMARY FACTORS AFFECTING RESULTS OF OPERATIONS

Transmission Revenues

Transmission revenues primarily consist of regulated transmission rates approved by the OEB which are charged based on the monthly peak electricity demand across Hydro One's high-voltage network. Transmission rates are designed to generate revenues necessary to construct, upgrade, extend and support a transmission system with sufficient capacity to accommodate maximum forecasted demand and a regulated return on the Company's investment. Peak electricity demand is primarily influenced by weather and economic conditions. Transmission revenues also include export revenues associated with transmitting electricity to markets outside of Ontario as well as ancillary revenues associated with providing maintenance services to power generators and from third-party land use.

Distribution Revenues

Distribution revenues primarily consist of regulated distribution rates approved by the OEB, as well as the recovery of purchased power costs. Distribution rates are designed to generate revenues necessary to construct and support the local distribution system with sufficient capacity to accommodate existing and new customer demand and a regulated return on the Company's investment. Accordingly, distribution revenues are influenced by distribution rates, the cost of purchased power, and the amount of electricity the Company distributes. Distribution revenues also include ancillary distribution service revenues, such as fees related to the joint use of Hydro One's distribution poles by the telecommunications and cable television industries, as well as miscellaneous revenues such as charges for late payments.

Purchased Power Costs

Purchased power costs are incurred by the distribution business and represent the cost of the electricity purchased by the Company for delivery to customers within Hydro One's distribution service territory. These costs are comprised of: (i) the wholesale commodity cost of energy; (ii) the Global Adjustment, which is the difference between the guaranteed price and the money the generators earn in the wholesale marketplace; and (iii) the wholesale market service and transmission charges levied by the IESO. Hydro One passes on the cost of electricity that it delivers to its customers, and is therefore not exposed to wholesale electricity commodity price risk.

OM&A

OM&A costs are incurred to support the operation and maintenance of the transmission and distribution systems, and include other costs such as property taxes related to transmission and distribution stations and buildings, and the operation of IT systems. Transmission OM&A costs are required to sustain the Company's high-voltage transmission stations, lines, and rights-of-way, and include preventive and corrective maintenance costs related to power equipment, overhead transmission lines, transmission station sites, and forestry control to maintain safe distances between line spans and trees. Distribution OM&A costs are required to maintain the Company's low-voltage distribution system to provide safe and reliable electricity to the Company's residential, small business, commercial, and industrial customers across the province. These include costs related to distribution line clearing and forestry control to reduce power outages caused by trees, line maintenance and repair, land assessment and remediation, as well as issuing timely and accurate bills and responding to customer inquiries.

Hydro One manages its costs through ongoing efficiency and productivity initiatives, while continuing to complete planned work programs associated with the development and maintenance of its transmission and distribution networks.

Depreciation, Amortization and Asset Removal Costs

Depreciation and amortization costs relate primarily to the depreciation of the Company's property, plant and equipment, and amortization of certain intangible assets and regulatory assets. Asset removal costs consist of costs incurred to remove property, plant and equipment where no asset retirement obligations have been recorded on the balance sheet.

Financing Charges

Financing charges relate to the Company's financing activities and include interest expense on the Company's long-term debt and short-term borrowings, as well as gains and losses on interest rate swap agreements, foreign exchange or other similar contracts, net of interest earned on short-term investments. A portion of financing charges incurred by the Company is capitalized to the cost of property, plant and equipment associated with the periods during which such assets are under construction before being placed in-service.

RESULTS OF OPERATIONS

Net Income

Net income attributable to common shareholders of Hydro One for the year ended December 31, 2025 of $1,339 million is $183 million, or 15.8%, higher than the prior year. Significant influences on the change in net income attributable to common shareholders of Hydro One included:

- higher revenues, net of purchased power,[4] resulting from an increase in transmission and distribution revenues due to OEB-approved 2025 rates, as well as higher average monthly peak demand and energy consumption, partially offset by regulatory adjustments including higher earnings sharing in the current period; and
- lower OM&A costs primarily resulting from lower work program expenditures and lower corporate support costs; partially offset by
- higher depreciation, amortization and asset removal costs primarily due to the growth in capital assets as the Company continues to place new assets in-service;
- higher financing charges primarily due to an increase in outstanding long-term debt, partially offset by higher capitalized interest; and
- higher income tax expense, primarily resulting from higher pre-tax earnings, partially offset by higher deductible timing differences.

EPS

EPS was $2.23 for the year ended December 31, 2025, compared to EPS of $1.93 in 2024. The 15.5% increase in EPS was primarily driven by higher earnings year-over-year, as discussed above.

Revenues

Year ended December 31 *(millions of dollars, except as otherwise noted)*	**2025**	**2024**	**Change**
Transmission	2,429	2,269	7.1%
Distribution	6,557	6,175	6.2%
Other	55	40	37.5%
Total revenues	9,041	8,484	6.6%
Transmission	2,429	2,269	7.1%
Distribution revenues, net of purchased power[1]	2,071	2,032	1.9%
Other	55	40	37.5%
Total revenues, net of purchased power[1]	4,555	4,341	4.9%
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	21,398	20,659	3.6%
Distribution: Electricity distributed to Hydro One customers *(GWh)*	33,294	31,523	5.6%

[1] See section "Non-GAAP Financial Measures".

Transmission Revenues

Transmission revenues increased by 7.1% compared to the year ended December 31, 2024, primarily due to:

- higher average monthly peak demand;
- higher revenues resulting from OEB-approved 2025 rates; and
- CLLP revenues following the in servicing of the transmission line in the fourth quarter of 2024; partially offset by
- regulatory adjustments in the period, including a higher earnings sharing accrual.

Distribution Revenues

Distribution revenues increased by 6.2% compared to the year ended December 31, 2024, primarily due to:

- higher purchased power costs, which are fully recovered from ratepayers and thus net income neutral;
- higher revenues resulting from OEB-approved 2025 rates; and
- higher energy consumption; partially offset by
- regulatory adjustments in the period, including a higher earnings sharing accrual; and
- net income neutral items, including lower revenue of Hydro One Remotes, which is offset in OM&A.

Distribution revenues, net of purchased power,[4] increased by 1.9% compared to the same period in the prior year largely due to the factors noted above.

[4] See section "Non-GAAP Financial Measures".

OM&A Costs

Year ended December 31 *(millions of dollars)*	2025	2024	Change
Transmission	447	475	(5.9%)
Distribution	661	721	(8.3%)
Other	98	112	(12.5%)
	1,206	1,308	(7.8%)

Transmission OM&A Costs

Transmission OM&A costs were 5.9% lower than the year ended December 31, 2024, primarily due to:

- severance costs in the prior year;
- lower work program expenditures, including vegetation management and lines maintenance; and
- lower corporate support costs; partially offset by
- higher property taxes; and
- higher asset write-offs.

Distribution OM&A Costs

Distribution OM&A costs were 8.3% lower than the year ended December 31, 2024, primarily due to:

- severance costs in the prior year;
- lower work program expenditures, including environmental and vegetation management;
- lower fuel costs of Hydro One Remotes, which are fully recovered through revenue and therefore net income neutral; and
- lower bad debt expense; partially offset by
- higher asset write-offs.

Other OM&A Costs

Other OM&A costs were 12.5% lower than the year ended December 31, 2024, including lower costs in Acronym primarily due to higher third party service costs in the prior year.

Depreciation, Amortization and Asset Removal Costs

Depreciation, amortization and asset removal costs increased by $45 million, or 4.2%, for the year ended December 31, 2025. This increase was primarily due to growth in capital assets as the Company continues to place new assets in-service, consistent with its ongoing capital investment program.

Financing Charges

Financing charges increased by $58 million, or 9.3%, for the year ended December 31, 2025, primarily due to an increase in outstanding long-term debt, partially offset by higher capitalized interest.

Income Tax Expense

Income taxes are accounted for using the asset and liability method. Current income taxes are recorded based on the income taxes expected to be paid in respect of the current and prior years' taxable income. Deferred income tax assets and liabilities are recognized for the future tax consequences attributable to temporary differences between the financial statement carrying amounts and the respective tax basis of assets and liabilities including carryforward unused tax losses and credits.

As prescribed by the regulators, the Company recovers income taxes in revenues from ratepayers based on an estimate of current income tax expense in respect of regulated operations. The amounts of deferred income taxes related to regulated operations, which are considered to be more likely-than-not of recovery from, or refund to, ratepayers in future periods are recognized as deferred income tax regulatory assets or liabilities, with an offset to deferred income tax expense. Therefore, the consolidated income tax expense or recovery for the current period is based on the total current and deferred income tax expense or recovery, net of the regulatory accounting offset to deferred income tax expense arising from temporary differences recoverable from or refundable to customers in the future.

Income tax expense was $219 million for the year ended December 31, 2025, compared to $181 million in 2024. The $38 million increase in income tax expense for the year ended December 31, 2025 was primarily attributable to:

- higher pre-tax earnings, partially offset by
- higher deductible timing differences compared to the prior year.

The Company realized an effective tax rate (ETR) of approximately 14.0% for the year ended December 31, 2025 compared to approximately 13.4% realized in 2024. The increase of 0.6% was primarily attributable to the factors noted above.

SHARE CAPITAL

The common shares of Hydro One are publicly traded on the Toronto Stock Exchange (TSX) under the trading symbol "H". Hydro One is authorized to issue an unlimited number of common shares. The amount and timing of any dividends payable by Hydro One is at the discretion of Hydro One's Board of Directors (Board) and is established on the basis of Hydro One's results of operations, maintenance of its deemed regulatory capital structure, the Company's financial condition and forecast cash requirements, the satisfaction of solvency tests imposed by corporate laws for the declaration and payment of dividends, and other factors that the Board may consider relevant. As at February 12, 2026, Hydro One had 599,781,811 issued and outstanding common shares.

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. As at February 12, 2026, the Company had no preferred shares issued and outstanding.

The number of additional common shares of Hydro One that would be issued if all outstanding awards under the share grant plans and the Long-term Incentive Plan (LTIP) were vested and exercised as at February 12, 2026 was 1,424,325.

Common Share Dividends

In 2025, the Company declared and paid cash dividends to common shareholders as follows:

Date Declared	Record Date	Payment Date	Amount per Share	Total Amount *(millions of dollars)*
February 19, 2025	March 12, 2025	March 31, 2025	$0.3142	188
May 7, 2025	June 11, 2025	June 30, 2025	$0.3331	200
August 12, 2025	September 10, 2025	September 29, 2025	$0.3331	200
November 12, 2025	December 10, 2025	December 31, 2025	$0.3331	200
				788

Following the conclusion of the fourth quarter of 2025, the Company declared a cash dividend to common shareholders as follows:

Date Declared	Record Date	Payment Date	Amount per Share	Total Amount *(millions of dollars)*
February 12, 2026	March 11, 2026	March 31, 2026	$0.3331	$200

SELECTED ANNUAL FINANCIAL STATISTICS

Year ended December 31 *(millions of dollars, except per share amounts)*	2025	2024	2023
Revenues	9,041	8,484	7,844
Net income attributable to common shareholders of Hydro One	1,339	1,156	1,085
Basic EPS	$2.23	$1.93	$1.81
Diluted EPS	$2.23	$1.92	$1.81
Dividends per common share declared	$1.31	$1.24	$1.17
As at December 31 *(millions of dollars)*	**2025**	**2024**	**2023**
Total assets	39,671	36,682	32,852
Total non-current financial liabilities[1]	18,138	16,393	14,750

[1] Total non-current financial liabilities include long-term debt, long-term lease obligations, derivative liabilities, and long-term accounts payable and accruals.

Net Income - 2024 compared to 2023

Net income attributable to common shareholders of Hydro One for the year ended December 31, 2024 of $1,156 million was $71 million, or 6.5%, higher than the prior year. Significant influences on the change in net income attributable to common shareholders included:

- higher revenues, net of purchased power,[5] resulting from an increase in transmission and distribution revenues due to OEB-approved 2024 rates, differences in regulatory adjustments recorded in each respective period, and higher energy consumption; and
- lower OM&A costs primarily resulting from lower work program expenditures; partially offset by
- higher depreciation, amortization and asset removal costs primarily due to the growth in capital assets as the Company continues to place new assets in-service;
- higher financing charges primarily due to higher interest on long-term debt as well as higher long-term debt, partially offset by a lower average volume of short-term notes outstanding and a higher capitalized interest; and
- higher income tax expense, adjusted for net income neutral items, primarily due to lower deductible timing differences higher pre-tax earnings.

[5] See section "Non-GAAP Financial Measures"

While net income neutral, year-to-date results were also impacted by the cessation of the OEB-approved recovery of DTA amounts previously shared with ratepayers (DTA Recovery Amounts) on June 30, 2023, which resulted in a decrease in revenue, net of purchased power[6] in 2024 that has been offset by lower income tax expense.

EPS - 2024 compared to 2023

EPS was $1.93 for the year ended December 31, 2024, compared to EPS of $1.81 in 2023. The increase in EPS was primarily driven by the impact of higher earnings year-over-year, as discussed above.

QUARTERLY RESULTS OF OPERATIONS

Quarter ended *(millions of dollars, except EPS and ratio)*	Dec 31, 2025	Sep 30, 2025	Jun 30, 2025	Mar 31, 2025	Dec 31, 2024	Sep 30, 2024	Jun 30, 2024	Mar 31, 2024
Revenues	2,268	2,299	2,066	2,408	2,095	2,192	2,031	2,166
Purchased power	1,287	1,080	899	1,220	1,060	1,047	940	1,096
Revenues, net of purchased power[1]	981	1,219	1,167	1,188	1,035	1,145	1,091	1,070
Net income attributable to common shareholders	233	421	327	358	200	371	292	293
Basic EPS	$0.39	$0.70	$0.54	$0.60	$0.33	$0.62	$0.49	$0.49
Diluted EPS	$0.39	$0.70	$0.54	$0.60	$0.33	$0.62	$0.49	$0.49
Earnings coverage ratio[1]	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8

[1] See section "Non-GAAP Financial Measures".

Variations in revenues and net income attributable to common shareholders over the quarters are primarily due to the impact of seasonal weather conditions on customer demand and market pricing, as well as timing of regulatory decisions.

CAPITAL INVESTMENTS

The Company makes capital investments to maintain the safety, reliability and integrity of its transmission and distribution system assets and to provide for the ongoing growth and modernization required to meet the expanding and evolving needs of its customers and the electricity market. This is achieved through a combination of sustaining capital investments, which are required to support the continued operation of Hydro One's existing assets, and development capital investments, which involve additions to both existing assets and large-scale projects such as new transmission lines and transmission stations.

Assets Placed In-Service

The following table presents Hydro One's assets placed in-service during the years ended December 31, 2025 and 2024:

Year ended December 31 *(millions of dollars)*	2025	2024	Change
Transmission	1,543	1,431	7.8%
Distribution	1,338	1,017	31.6%
Other	20	15	33.3%
Total assets placed in-service	2,901	2,463	17.8%

Transmission Assets Placed In-Service

Transmission assets placed in-service increased by $112 million, or 7.8%, during the year ended December 31, 2025, compared to the year ended December 31, 2024, primarily due to:

- timing of assets placed in-service for station refurbishments and replacements, including the Bruce A Transmission Station;
- investments placed in-service in Sault Ste. Marie for the Sault #3 Circuit;
- investments placed in-service for customer connection projects; and
- investments placed in-service at the Orillia Distribution Warehouse; partially offset by
- investments placed in-service for the Chatham to Lakeshore Transmission Line;
- lower volume of line refurbishments and wood pole replacements; and
- investment placed in-service for the Network Management System.

[6] See section "Non-GAAP Financial Measures"

Distribution Assets Placed In-Service

Distribution assets placed in-service increased by $321 million, or 31.6%, during the year ended December 31, 2025, compared to the year ended December 31, 2024, primarily due to:

- higher volume of storm-related asset replacements;
- assets placed in-service for the Advanced Metering Infrastructure (AMI) 2.0 system;
- investments placed in-service for the Orillia Distribution Warehouse and the Orillia Operation Centre;
- investments placed in-service for Ontario's broadband initiative; and
- timing of assets placed in-service for system capability reinforcement projects; partially offset by
- lower volume of wood pole replacements and line refurbishments;
- timing of investments placed in-service for IT initiatives; and
- assets placed in-service for the Orleans Operation Centre in the prior year.

Capital Investments

The following table presents Hydro One's capital investments during the years ended December 31, 2025 and 2024:

Year ended December 31 *(millions of dollars)*	**2025**	**2024**	**Change**
Transmission			
Sustaining	1,146	1,284	(10.7%)
Development	864	467	85.0%
Other	87	109	(20.2%)
	2,097	1,860	12.7%
Distribution			
Sustaining	688	561	22.6%
Development	463	513	(9.7%)
Other	101	111	(9.0%)
	1,252	1,185	5.7%
Other	17	18	(5.6%)
Total capital investments	3,366	3,063	9.9%

Total 2025 capital investments of $3,366 million for the year ended December 31, 2025, were $176 million lower than the previously disclosed expected amount of $3,542 million, primarily due to timing and project schedule shifts of capital investments for transmission station refurbishments and equipment replacements.

Transmission Capital Investments

Transmission capital investments increased by $237 million, or 12.7%, during the year ended December 31, 2025 compared to the year ended December 31, 2024, primarily due to:

- investments in the Waasigan Transmission Line Project;
- investments in the St. Clair Transmission Line Project; and
- higher spend on customer connections; partially offset by
- lower volume of station refurbishments and equipment replacements;
- lower volume of line refurbishments and wood pole replacements; and
- investments in the Orillia Distribution Warehouse.

Distribution Capital Investments

Distribution capital investments increased by $67 million, or 5.7%, in the year ended December 31, 2025 compared to the year ended December 31, 2024, primarily due to:

- higher spend on storm-related asset replacements;
- investments in Ontario's broadband initiative; and
- investments in the AMI 2.0 system; partially offset by
- lower volume of wood pole replacements;
- lower spend on system capability reinforcement projects;
- investments in the Orillia Distribution Warehouse, Orillia Operation Centre and Orleans Operation Centre;
- lower spend on IT initiatives;
- lower volume of work on customer connections; and
- lower volume of polychlorinated biphenyl (PCB) transformer replacements.

Major Transmission Capital Investment Projects

The following table summarizes the status of significant transmission projects as at December 31, 2025:

Project Name	Location	Type	Anticipated In-Service Date	Estimated Cost[1]	Capital Cost To Date
Development Projects:			*(year)*	*(millions of dollars)*	
Centennial Transmission Station[2]	Southwestern Ontario	New transmission station and connection	2026	229	185
Waasigan Transmission Line[3]	Thunder Bay-Atikokan-Dryden Northwestern Ontario	New transmission line and station expansion	2027	1,200	539
Holt Transmission Station	Bowmanville Central Ontario	New transmission station and connection	2027	137	28
St. Clair Transmission Line[4]	Southwestern Ontario	New transmission line and station expansion	2027	472	247
Keith Intertie Upgrade	Windsor Southwestern Ontario	Transmission station upgrade	2028	109	9
Welland Thorold Power Line[5]	Niagara Southern Ontario	New transmission line and station expansion	2029	311	20
Longwood to Lakeshore Transmission Line[6]	Southwestern Ontario	New transmission line and station expansion	TBD	TBD	46
Durham Kawartha Power Line[7,8]	Eastern Ontario	New transmission line and station expansion	TBD	TBD	24
Northeast Power Line[7,8]	Northeastern Ontario	New transmission line and station expansion	TBD	TBD	23
North Shore Link[7,8]	Northeastern Ontario	New transmission line and station expansion	TBD	TBD	20
Wawa Timmins Power Line[7,8]	Northeastern Ontario	New transmission line and station expansion	TBD	TBD	8
Second Longwood to Lakeshore Transmission Line[6]	Southwestern Ontario	New transmission line and station expansion	TBD	TBD	2
Windsor to Lakeshore Transmission Line[6]	Southwestern Ontario	New transmission line and station expansion	TBD	TBD	2
Bowmanville to Parkway Transmission Line[9]	Southern Ontario	New transmission line and station expansion	TBD	TBD	—
Wellington to Preston Transmission Line[10]	Southwestern Ontario	New transmission line and new transmission station	TBD	TBD	—
Greenstone Transmission Line	Northwestern Ontario	New transmission line and station expansion	TBD	TBD	—
Sudbury to Barrie Transmission Line[11]	Northern-Central Ontario	New transmission line and station expansion	TBD	TBD	—
Sustainment Projects:					
Middleport Transmission Station Circuit Breaker Replacement	Middleport Southwestern Ontario	Station sustainment	2026	184	171
Lennox Transmission Station Circuit Breaker Replacement	Napanee Southeastern Ontario	Station sustainment	2026	152	152
Esplanade x Terauley Underground Cable Replacement	Toronto Southern Ontario	Line sustainment	2026	117	96
Bridgman Transmission Station Refurbishment	Toronto Southern Ontario	Station sustainment	2026	108	93
Bruce A Transmission Station Switchyard Replacement	Tiverton Southwestern Ontario	Station sustainment	2027	555	421
Otto Holden Transmission Station Refurbishment	Mattawa Northeast Ontario	Station sustainment	2028	128	72
Merivale Transmission Station Replacement and Upgrades[12]	Ottawa Eastern Ontario	Station sustainment and upgrade	2029	271	178
Synchronous Optical Network Telecommunication Replacement	Ontario	Telecommunication sustainment	2029	137	16
Essa Transmission Station Circuit Breaker Replacement	Barrie Central Ontario	Station sustainment	2030	116	7

[1] Estimated costs are presented gross of any potential contribution from external parties.
[2] This Project is part of a two-phase project, which includes the construction of a transmission station and a transmission line to meet the needs of, and is anticipated to be largely funded by, an industrial customer. Phase 1 of the Centennial Transmission Station Project includes a new transmission station in St. Thomas and an approximately 2 km, 230 kV double-circuit transmission line between the new transmission station and an existing transmission station in the city. This phase of the project is anticipated to be in service by the end of 2026. Scope and timing of the second phase, an approximately 20 km, 230 kV double-circuit transmission line from London to St. Thomas, is currently under review.
[3] The Waasigan Transmission Line Project includes construction of new transmission lines as well as station enhancements to support energization of the new lines. The estimated cost relates to the development and construction phases of the project and the anticipated in-service date reflects anticipated completion in 2027. The first phase of the project is anticipated to be in-serviced in 2026.
[4] The St. Clair Transmission Line Project includes the line and associated facilities.
[5] The IESO has recommended a target in-service date of 2029 for the Welland Thorold Power Line.
[6] The capital cost to date relates to costs incurred in the development phase of the project. The scope and timing of these Southwestern Ontario transmission reinforcement projects are currently under review. The IESO has recommended a target in-service date by 2032 for the Windsor to Lakeshore Transmission Line.
[7] The capital cost to date relates to costs incurred in the development phase of the project. The scope and timing of these Northeastern and Eastern Ontario transmission reinforcements are currently under review. The Wawa Timmins Power Line was previously referred to as the Wawa to Porcupine Transmission Line.
[8] The IESO has recommended a target in-service date of 2030 for the Wawa Timmins Power Line, and of 2029 for the Northeast Power Line, North Shore Link, and the Durham Kawartha Power Line.
[9] The Bowmanville to Parkway Transmission Line was previously referred to as the Bowmanville to Greater Toronto Area Transmission Line.
[10] The IESO has recommended a target in-service date of 2031 for the Wellington to Preston Transmission Line and the Wellington Transmission Station in the Township of Puslinch. (See Section "Other Developments - Wellington to Preston Line Project")
[11] Pertains to the First Sudbury to Barrie Transmission Line. The scope and timing of the line is currently under review. The IESO has recommended a target in-service date by 2032.
[12] The coordinated project includes both an asset replacement and station expansion. The anticipated in-service dates are between 2026 to 2029.

Future Capital Investments

The Company estimates future capital investments based on management's expectations of the amount of capital expenditures that will be required to provide transmission and distribution services that are efficient, reliable, and provide value for customers, consistent with the OEB's Renewed Regulatory Framework. The Company includes projects when there is a high degree of confidence that the project will go forward and when there is a thorough estimate of the expected expenditures.

The forecast below does not include offsets associated with the impact of restoration costs associated with a severe storm that began on March 28, 2025 causing significant damage to system infrastructure and outages to customers in the central and eastern regions of the province, with restoration efforts continuing into the second quarter. On April 29, 2025, the Company notified the OEB that it intended to submit a Z-Factor application to seek recovery of costs incurred for this storm. On August 28, 2025, the Company submitted the Z-Factor application. The application seeks recovery of approximately $225 million in storm-related costs, including capital and asset removal costs. The forecast is expected to be updated pending the outcome of that application. The decision regarding the Z-factor application is anticipated to be issued by the OEB in early 2026.

The following tables summarize Hydro One's annual projected capital investments for 2026 to 2027 by business segment and by category:

By business segment: *(millions of dollars)*	2026	2027
Transmission[1]	2,116	1,892
Distribution	1,093	918
Other	39	32
Total capital investments[2]	3,248	2,842

By category: *(millions of dollars)*	2026	2027
Sustainment	1,426	1,064
Development[1]	1,657	1,626
Other[3]	165	152
Total capital investments[2]	3,248	2,842

[1] Figures include investments in certain development projects of Hydro One Networks not included in the investment plan approved by the OEB in the Joint Rate Application (JRAP) decision.

[2] Since the first quarter of 2022, the Minister of Energy and Electrification (formerly the Minister of Energy) (Minister) has directed the OEB to amend Hydro One Networks' transmission licence to require it to develop and seek approvals for eleven priority transmission lines in Ontario. The future capital investments presented do not include capital expenditures, nor development costs, associated with the following three priority Southwestern Ontario transmission line projects: Longwood to Lakeshore Transmission Line, Second Longwood to Lakeshore Transmission Line, and Windsor to Lakeshore Transmission Line; nor the following four priority Northeastern and Eastern Ontario transmission line projects: North Shore Link, Northeast Power Line, Durham Kawartha Power Line, and Wawa Timmins Power Line (see section "Other Developments - Supporting Critical Transmission Infrastructure in Northeastern and Eastern Ontario"); nor the Bowmanville to Parkway, Greenstone and Barrie to Sudbury Transmission Lines (see section "Affordable Energy Act, 2024 and Ontario Integrated Energy Plan"). Hydro One is currently evaluating the scope and timing of these ten lines.

[3] "Other" capital expenditures include investments in fleet, real estate, IT, and operations technology and related functions.

SUMMARY OF SOURCES AND USES OF CASH

Hydro One's primary sources of cash flows are funds generated from operations, capital market debt issuances and bank credit facilities that are used to satisfy Hydro One's capital resource requirements, including the Company's capital expenditures, servicing and repayment of debt, and dividend payments.

Year ended December 31 *(millions of dollars)*	2025	2024
Net cash from operating activities	2,695	2,534
Net cash from financing activities	652	1,233
Net cash used in investing activities	(3,514)	(3,130)
Net change in cash and cash equivalents	(167)	637

Net cash from operating activities

Net cash from operating activities increased by $161 million for the year ended December 31, 2025 compared to the same period in 2024. The increase was impacted by various factors, including the following:

- higher pre-tax earnings; and
- changes in regulatory account balances; partially offset by
- changes in net working capital deficiency primarily attributable to lower unearned revenue related to capital contributions, timing differences in the settlement of receivables, higher receivables from the IESO driven by a higher Ontario Electricity Rebate, partially offset by higher cost of power payable to the IESO due to higher purchased volumes.

Net cash from financing activities

Net cash from financing activities decreased by $581 million for the year ended December 31, 2025, compared to the same period of 2024. This decrease was impacted by various factors, including the following:

Uses of cash

- the Company repaid $6,170 million of short-term notes in 2025, compared to $2,890 million repaid in 2024.
- the Company repaid $1,150 million of long-term debt in 2025, compared to $700 million repaid in 2024.
- the Company paid common share dividends of $788 million in 2025, compared to dividends of $743 million paid in 2024.

Sources of cash

- the Company received proceeds of $6,070 million from the issuance of short-term notes in 2025, compared to $2,810 million received in 2024.
- the Company issued $2,698 million of long-term debt in 2025, compared to $2,781 million of long-term debt issued in 2024.

Net cash used in investing activities

Net cash used in investing activities for the year ended December 31, 2025 was $384 million higher than the same period of 2024 as a result of the investment in EWT LP (see section "Other Developments - EWT LP"), and higher capital investments. See section "Capital Investments" for comparability of capital investments made by the Company during the year ended December 31, 2025 compared to the prior year.

LIQUIDITY AND FINANCING STRATEGY

Short-term liquidity is provided through FFO,[7] Hydro One Inc.'s commercial paper program, and the Company's consolidated bank credit facilities. Under the commercial paper program, Hydro One Inc. is authorized to issue up to $2,300 million in short-term notes with a term to maturity of up to 365 days.

As at December 31, 2025, Hydro One Inc. had $100 million in commercial paper borrowings outstanding, compared to $200 million outstanding at December 31, 2024. The Company also has committed, unsecured, and revolving credit facilities (Operating Credit Facilities) with a total available balance of $3,300 million as at December 31, 2025. The Operating Credit Facilities include a pricing adjustment which can increase or decrease Hydro One's cost of borrowing based on its performance on certain sustainability performance measures, which are related to Hydro One's sustainability goals. On June 1, 2025, Hydro One extended the maturity date of the Operating Credit Facilities from 2029 to 2030. No amounts were drawn on the Operating Credit Facilities as at December 31, 2025 or 2024. The Company may use the Operating Credit Facilities for working capital and general corporate purposes. The short-term liquidity under the commercial paper program, the Operating Credit Facilities, available cash on hand and anticipated levels of FFO[7] are expected to be sufficient to fund the Company's operating requirements.

As at December 31, 2025, the Company had long-term debt outstanding in the principal amount of $19,045 million, which included $425 million of long-term debt issued by Hydro One and $18,620 million of long-term debt issued by Hydro One Inc. The majority of long-term debt issued by Hydro One Inc. has been issued under its Medium-Term Note (MTN) Program, as further described below. The Company's total long-term debt consists of notes and debentures that mature between 2026 and 2064, and as at December 31, 2025 had a weighted-average term to maturity of approximately 13.7 years (December 31, 2024 - 13.7 years) and a weighted-average coupon rate of 4.2% (December 31, 2024 - 4.2%).

In February 2024, Hydro One Inc. filed a short form base shelf prospectus in connection with its MTN Program, which expires in March 2026. A new MTN Program prospectus is expected to be filed in the first quarter of 2026.

On August 19, 2024, Hydro One filed a short form base shelf prospectus (Universal Base Shelf Prospectus) with securities regulatory authorities in Canada. The Universal Base Shelf Prospectus allows Hydro One to offer, from time to time in one or more public offerings, debt, equity or other securities, or any combination thereof, during the 25-month period ending in September 2026. As at December 31, 2025, no securities have been issued under the Universal Base Shelf Prospectus.

On November 29, 2024, Hydro One Holdings Limited (HOHL) filed a short form base shelf prospectus (HOHL U.S. Debt Shelf Prospectus) with securities regulatory authorities in Ontario and the U.S., that expires in December 2026. The HOHL U.S. Debt Shelf Prospectus allows HOHL to offer, from time to time in one or more public offerings, debt securities, unconditionally guaranteed by Hydro One. As at December 31, 2025, no securities have been issued under the HOHL U.S. Debt Shelf Prospectus.

[7] See section "Non-GAAP Financial Measures".

On August 18, 2025, Hydro One Inc. filed a short form base shelf prospectus (HOI U.S. Debt Shelf Prospectus) with securities regulatory authorities in Ontario and the U.S. The HOI U.S. Debt Shelf Prospectus allows Hydro One Inc. to offer, from time to time in one or more public offerings, U.S. debt securities, during the 25-month period ending on September 18, 2027. As at December 31, 2025, no securities have been issued under the HOI U.S. Debt Shelf Prospectus.

Compliance

As at December 31, 2025, the Company was in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

Credit Ratings

Various ratings organizations review the Company's and Hydro One Inc.'s debt ratings from time to time. These rating organizations may take various actions, positive or negative. The Company cannot predict what actions rating agencies may take in the future. The failure to maintain the Company's current credit ratings could adversely affect the Company's financial condition and results of operations, and a downgrade in the Company's credit ratings could restrict the Company's ability to access debt capital markets and increase the Company's cost of debt.

As at December 31, 2025, Hydro One's long-term debt ratings were as follows:

Rating Agency	Long-term Debt Rating
DBRS Limited	A
S&P Global Ratings	A-

As at December 31, 2025, Hydro One Inc.'s long-term and short-term debt ratings were as follows:

Rating Agency	Short-term Debt Rating	Long-term Debt Rating
DBRS Limited	R-1 (low)	A (high)
Moody's Ratings	Prime-2	A3
S&P Global Ratings	A-1 (Mid)	A

Effect of Interest Rates

The Company is exposed to fluctuations of interest rates as its regulated return on equity (ROE) is derived using a formulaic approach that takes into account changes in benchmark interest rates for Government of Canada debt and the A-rated utility corporate bond yield spread. The Company issues debt from time to time to refinance maturing debt and for general corporate purposes. The Company is therefore exposed to fluctuations in interest rates in relation to such issuances of debt. See section "Risk Management and Risk Factors - Risks Relating to Hydro One's Business - Market, Financial Instrument and Credit Risk" for more details.

Pension Plan

In 2025, Hydro One made cash contributions of $68 million to its pension plan, compared to cash contributions of $75 million in 2024. The Company also incurred $124 million of net periodic benefit credit, compared to $57 million of net periodic benefit credit incurred in 2024.

In September 2025, Hydro One filed a triennial actuarial valuation of its pension plan as at December 31, 2024 which is effective for 2025 to 2027. Based on this valuation, Hydro One estimates that total Company pension contributions for 2026, 2027, 2028, 2029 and 2030 are approximately $70 million, $73 million, $77 million, $81 million, and $85 million, respectively. Future minimum contributions beyond 2027 will be updated following the actuarial funding valuation as of December 31, 2027, which is expected to be filed by no later than September 30, 2028. Should Hydro One elect to file a valuation earlier than required, contributions for 2027 would also be updated, as applicable.

The Company's pension benefits obligation is impacted by various assumptions and estimates, such as the discount rate, rate of return on plan assets, rate of cost of living increase and mortality assumptions. A full discussion of the significant assumptions and estimates can be found in the section "Critical Accounting Estimates - Employee Future Benefits".

OTHER OBLIGATIONS

Off-Balance Sheet Arrangements

There are no off-balance sheet arrangements that have, or are reasonably likely to have, a material current or future effect on the Company's financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of Hydro One's debt and other major contractual obligations and commercial commitments:

As at December 31, 2025 *(millions of dollars)*	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Contractual obligations *(due by year)*					
Long-term debt - principal repayments	19,045	925	1,175	1,900	15,045
Long-term debt - interest payments	11,444	792	1,526	1,399	7,727
Short-term notes payable	100	100	—	—	—
Pension contributions[1]	386	70	150	166	—
Outsourcing and other agreements	147	48	80	2	17
Environmental and asset retirement obligations	104	10	8	17	69
Lease obligations	45	16	24	4	1
Total contractual obligations	31,271	1,961	2,963	3,488	22,859
Other commercial commitments *(by year of expiry)*					
Operating Credit Facilities	3,300	—	—	3,300	—
Letters of credit[2]	191	191	—	—	—
Guarantees[3]	540	540	—	—	—
Total other commercial commitments	4,031	731	—	3,300	—

[1] Contributions to the Hydro One Pension Plan are based on actuarial reports, including valuations performed at least every three years, and actual or projected levels of pensionable earnings, as applicable. The most recent actuarial valuation was performed effective December 31, 2024 and filed on September 23, 2025.
[2] Letters of credit consist of $166 million letters of credit related to retirement compensation arrangements, an $18 million letter of credit provided to the IESO for prudential support, and $7 million in letters of credit for various operating purposes.
[3] Guarantees consist of $475 million prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries, as well as $60 million of guarantees provided by Hydro One to ONroute relating to OCN LP (OCN Guarantee) and $5 million relating to Aux Energy Inc.

REGULATION

The following table summarizes the key elements and status of Hydro One's electricity rate applications:

Application	Year	Rate Base Approved/ Proposed *(millions of dollars)*	Base Revenue Requirement Approved/Proposed *(millions of dollars)*	Status
Transmission:				
Hydro One Networks[1]	2025	16,271	2,168	Approved in November 2022
	2026	17,148	2,277	Approved in November 2022
	2027	17,940	2,362	Approved in November 2022
B2M LP	2025	455	38	Approved in November 2024
	2026	447	38	Approved in October 2025[2]
	2027	440	39	Approved in October 2025[2]
	2028	433	39	Approved in October 2025[2]
	2029	426	37	Approved in October 2025[2]
HOSSM[3]	2017-2026	218	41	Approved in January 2016
CLLP	2025	201	17	Approved in November 2024
	2026	209	17	Approved in December 2025[2]
	2027	206	16	Approved in December 2025[2]
	2028	204	16	Approved in December 2025[2]
	2029	201	16	Approved in December 2025[2]
NRLP	2025	110	9	Approved in November 2024
	2026	108	9	Approved in October 2025[2]
	2027	107	9	Approved in October 2025[2]
	2028	105	9	Approved in October 2025[2]
	2029	104	9	Approved in October 2025[2]
Distribution:				
Hydro One Networks[1]	2025	10,573	1,886	Approved in November 2022
	2026	11,153	1,985	Approved in November 2022
	2027	11,656	2,071	Approved in November 2022
Hydro One Remotes[4]	2023-2027	58	128	Approved in March 2023

[1] Revenue requirements for 2025 to 2027 do not include the impacts of updates filed with the regulator per the annual application process to reflect the latest OEB inflation factors.
[2] Under the agreed-upon revenue requirement framework, there is no longer a requirement for these LPs to file annual update applications with the OEB throughout the rate term, except for the one-time update in 2025.
[3] HOSSM is under a 10-year deferred rebasing period for years 2017-2026, as approved in the OEB Mergers, Amalgamations, Acquisitions and Divestitures decision dated October 13, 2016. Revenue requirement since 2019 have been subject to an approved revenue cap escalator index.
[4] Revenue requirements for 2025 to 2027 will be updated per the annual application process with the regulator to reflect latest OEB inflation factors. Rate increases for Hydro One Remotes are effective May 1st of each year.

The following table summarizes the status of Hydro One's Leave to Construct Applications with the OEB for significant transmission projects as at December 31, 2025:

Application	Status
Welland Thorold Power Line Project	Filed in November 2025[1]
Waasigan Transmission Line Project	Approved in April 2024[1]
St. Clair Transmission Line Project	Approved in December 2024[2]

[1] See section "Major Transmission Capital Investment Projects" and "Other Developments - Welland Thorold Power Line". Under Hydro One's equity partnership model, First Nations communities would have an opportunity to acquire a 50% equity stake in the transmission line component of the project.
[2] See section "Major Transmission Capital Investment Projects" and "Other Developments - Supporting Critical Infrastructure in Southwestern Ontario." Under Hydro One's equity partnership model, First Nations communities would have an opportunity to acquire a 50% equity stake in the transmission line component of the project.

OEB Cost of Capital Policy Review

On March 6, 2024, the OEB commenced a hearing on its own motion to consider the methodology for determining the values of the cost of capital parameters and deemed capital structure to be used in the rate-setting process, as well as the methodology for determining the OEB's prescribed interest rates and matters related to the Incremental Cloud Computing Implementation Costs deferral account, including what type of interest rate, if any, should apply to the account. On March 27, 2025, the OEB issued its Decision and Order, issuing new cost of capital parameters and confirming that the new cost of capital parameters will take effect at a utility's next rebasing rate application. The OEB's approach for deemed capital structure remained unchanged at 40% equity and 60% debt, for transmission and distribution electricity utilities. The OEB also concluded that the prescribed interest rate for deferral and variance accounts will continue to apply to the Incremental Cloud Computing Implementation Costs deferral account, and that each utility, in its next rebasing rate application, can propose the treatment of any future cloud solutions during the rate term, which could include a new cloud solution deferral account. If no proposal is made during that rebasing rate application, the account will be closed.

Extended Horizons Variance Account

On March 20, 2025, the OEB established a generic deferral and variance account, effective November 18, 2024. This variance account allows rate-regulated electricity distributors to record the incremental revenue requirement impacts resulting from reductions in the forecasted customer capital contributions embedded in distribution rates related to the OEB's amendments to the Distribution System Code in December 2024, which extend the connection horizon and revenue horizon for certain customer connections. As at December 31, 2025, the balance in the account is immaterial.

B2M LP

On May 23, 2024, Hydro One Networks, on behalf of B2M LP, submitted B2M LP's five-year Transmission Revenue Requirement Application for the 2025 to 2029 period. On November 21, 2024, the OEB issued a Decision and Order approving B2M LP's five-year revenue requirement application, which includes a 2025 base revenue requirement of $38 million. Under the agreed-upon revenue requirement framework, there is no longer a requirement for B2M LP to file annual update applications with the OEB throughout the rate term, except for a one-time update in 2025, which the OEB approved in October 2025, setting the revenue requirements for 2026-2029.

NRLP

On May 23, 2024, Hydro One Networks, on behalf of NRLP, submitted NRLP's five-year Transmission Revenue Requirement Application for the 2025 to 2029 period. On November 21, 2024, the OEB issued a Decision and Order approving NRLP's revenue requirement application, which includes a 2025 base revenue requirement of $9 million. Under the agreed-upon revenue requirement framework, there is no longer a requirement for NRLP to file annual update applications with the OEB throughout the rate term, except for a one-time update in 2025, which the OEB approved in October 2025, setting the revenue requirements for 2026-2029.

CLLP

On July 12, 2024, Hydro One Networks, on behalf of CLLP, submitted CLLP's five-year Transmission Revenue Requirement Application for the 2025 to 2029 period. On December 17, 2024, the OEB issued a Decision and Order approving CLLP's revenue requirement application, which includes a 2025 base revenue requirement of $17 million, effective January 1, 2025. Under the agreed-upon revenue requirement framework, there is no longer a requirement for CLLP to file annual update applications with the OEB throughout the rate term, except for a one-time update in 2025, which the OEB approved in December 2025, setting the revenue requirements for 2026-2029.

Building Broadband Faster Act, 2021

In March 2021, the Province of Ontario (Province) introduced Bill 257, Supporting Broadband and Infrastructure Expansion Act, 2021, to create a new act entitled the Building Broadband Faster Act, 2021 (BBFA) that is aimed at supporting the timely deployment of broadband infrastructure within unserved and underserved rural Ontario communities. Bill 257 received Royal Assent on April 12, 2021. Bill 257 amended the *Ontario Energy Board Act, 1998* (OEBA) to provide the Province with regulation-making authority regarding the development of, access to, or use of electricity infrastructure for non-electricity purposes. The BBFA Guideline and two regulations informing the legislative changes were also published in 2021, with a third regulation on annual wireline attachment rate for telecommunications carriers issued in December 2021. The most recent Order and Decision from the OEB adjusts the annual wireline attachment rate to $39.14 per attacher per pole, effective January 1, 2025.

In March 2022, the Province introduced Bill 93 (Getting Ontario Connected Act, 2022). Bill 93 received Royal Assent on April 14, 2022. Bill 93 amends the BBFA to ensure that organizations that own underground utility infrastructure near a designated high-speed internet project provide timely access to their infrastructure data, which would allow internet service providers to quickly start work on laying down underground high-speed internet infrastructure.

A regulation regarding electricity infrastructure and designated broadband projects under the OEBA (O.Reg. 410/22) came into force on April 21, 2022. On July 7, 2022, the OEB established a deferral account for rate-regulated distributors to record incremental costs associated with carrying out activities pertaining to designated broadband projects. In September 2022, the

Company launched its choice-based operating model to provide internet service providers with choices on how to access the Company's infrastructure in order to effectively execute designated broadband projects. On March 28, 2023, the Province amended the OEBA (O.Reg. 410/22) with respect to performance timelines associated with designated broadband projects.

On August 14, 2023, the third edition of the BBFA Guideline was issued with amendments providing additional guidance to support the implementation of legislative and regulatory requirements, including a framework to support cost sharing for pole attachments and make-ready work.

The Company has developed and adapted an appropriate management framework that meets the government's objectives, including arrangements to sustain the Company's revenues and recovery of reasonable associated costs.

On October 31, 2024, the Ministry of Infrastructure (MOI) announced that it has developed a program to deliver up to $400 million in subsidies to internet service providers (ISPs) for work associated with designated broadband projects. The program is intended to enable ISPs to successfully and safely attach their material and equipment to the Company's poles to bring connectivity to rural communities as part of a designated broadband project. A portion of the subsidies will be used to reimburse Hydro One Networks on behalf of ISPs for their share of enablement costs incurred to facilitate the program to date (see section "Related Party Transactions").

On November 1, 2025, the Province amended a regulation made under the OEBA (O.Reg. 410/22), implementing a monthly capacity target of poles ready for deployment and extending the performance timelines associated with the designated broadband projects. Hydro One Networks must complete its share of the work before July 1, 2028.

Affordable Energy Act, 2024 and Ontario Integrated Energy Plan

In January 2024, the Electrification and Energy Transition Panel, an advisory body to the Province, released its report outlining a roadmap for Ontario's transition to a clean energy economy. In October 2024, the Province released its vision for Ontario's energy sector, Ontario's Affordable Energy Future, outlining key objectives to meet growing electricity demand in Ontario. This vision was intended to help guide the Province's first integrated energy plan (IEP), among other initiatives. In support, Bill 214, Affordable Energy Act, 2024, was introduced and subsequently received Royal Assent on December 4, 2024. The Affordable Energy Act, 2024 amended various statutes, including the *Electricity Act, 1998* (Ontario) (Electricity Act) and the OEBA, providing a legislative framework to replace the Province's long-term energy plans (including the 2017 Long-Term Energy Plan), with integrated energy plans. Whereas the focus of the long-term energy plan had been primarily on the electricity system, the integrated energy plan is intended to address all sources of energy. The amendments effected by the Affordable Energy Act, 2024 also allow the Minister, subject to the approval of the Lieutenant Governor in Council, to issue directives to the IESO and OEB setting out implementation requirements relating to the integrated energy plan. From October to December 2024, the Ministry of Energy and Mines (Ministry) (formerly the Ministry of Energy and Electrification) ran a consultation requesting feedback to assist the Province in developing its first plan.

The changes made by the Affordable Energy Act, 2024 to the OEBA, among other things, also provide the Province with the ability to make regulations specifying amendments to the Distribution System Code and the Transmission System Code in relation to certain cost allocation and cost recovery matters relating to the construction, expansion or reinforcement of distribution systems or transmission systems, or of connections to those systems. The changes made by the Affordable Energy Act, 2024 also allow regulations to be made exempting persons or things from provisions of the Distribution System Code and the Transmission System Code relating to cost allocation or cost recovery, as well as alternative provisions that apply instead.

On June 12, 2025, the Ontario government released its first IEP, *Energy for Generations*, which aims to leverage electricity, natural gas, hydrogen, storage and other energy sources to provide Ontario with affordable, secure, reliable and clean energy to power growth and jobs across the province. The IEP establishes a planning horizon out to 2050, including the acceleration of the development of transmission infrastructure and the modernization of the distribution grid. As part of the IEP, the government announced the advancement of several transmission projects, including the following:

- Barrie to Sudbury Transmission Line, a new single circuit 500 kV line between Essa Transformer Station (TS) and Hanmer TS, including any associated station facilities with a target in-service date of 2032, as well as early development work on a second 500 kV line;
- Orangeville to Barrie Reconductoring Project, which involves the reconductoring of Hydro One's existing 230kV transmission lines between Orangeville TS (Orangeville) and Essa TS (Barrie), with a target in-service date of 2027;
- Bowmanville to Parkway Transmission Line (formerly known as Bowmanville to Greater Toronto Area (GTA) Transmission Line), a new double-circuit 500 kV line from Bowmanville Switching Station (SS) to an existing 500 kV station in the GTA with a target in-service in the early 2030s;
- Windsor to Lakeshore Transmission Line, a 230 kV transmission line from Lauzon Transformer Station (Windsor) to Lakeshore Transformer Station (Lakeshore) with a target in-service date of 2032; and
- Greenstone Transmission Line, a new 230 kV transmission line between Longlac TS (Geraldton) to Nipigon Generation Station and connecting into the East-West Tie near Nipigon Bay, and associated station facilities, with a target in-service in 2032.

On June 16, 2025, the Ministry announced a series of proposals to take certain actions to facilitate the timely development of several transmission projects to further the objectives outlined in the IEP.

The Ministry proposed, subject to required approvals, to declare the five transmission projects as priority projects. The second Barrie to Sudbury Transmission Line was not proposed to be declared priority at the time.

The Ministry also proposed to bring forward Orders in Council (to be recommended by the Minister of Energy and Mines (Minister)) and companion directive, that would, if approved, direct the OEB to amend Hydro One Networks' transmitter licence to require it to undertake development work and seek all necessary approvals to construct the Barrie to Sudbury Transmission Line, the Bowmanville to Parkway Transmission Line and the Greenstone Transmission Line, and to undertake development work on the second Barrie to Sudbury Transmission Line. The Minister had previously, on March 31, 2022, directed the OEB to amend Hydro One Networks' licence to require it to develop and seek approvals for the Windsor to Lakeshore Transmission Line. The Orangeville to Barrie Reconductoring Project does not require designation because this project relates to existing Hydro One Networks transmission infrastructure. The consultation period for the proposals was announced on June 16, 2025, and closed on August 15, 2025.

On November 21, 2025, the Minister notified the OEB that the Orangeville to Barrie Reconductoring Project, the Windsor to Lakeshore Transmission Line and the Bowmanville to Parkway Transmission Line were declared priority projects and issued a directive to the OEB to amend Hydro One Networks' transmission license to require it to develop and seek approvals for the Bowmanville to Parkway Transmission Line. On November 25, 2025, further to the Minister's Directive, the OEB amended Hydro One Networks' electricity transmission licence to allow it to develop and seek approvals for this project in accordance with the recommendations of the IESO.

On January 28, 2026, the Minister notified the OEB that the Greenstone Transmission Line was declared a priority project, and issued a directive to the OEB to amend Hydro One Networks' transmission license, to require it to develop and seek approvals for this project. On January 29, 2026, further to the Minister's Directive, the OEB amended Hydro One Networks' electricity transmission license to allow it to develop and seek approvals for this project in accordance with the recommendations of the IESO.

On February 6, 2026, the Minister notified the OEB that the first Barrie to Sudbury Transmission Line was declared a priority project, and issued a directive to the OEB to amend Hydro One Networks' transmission license to require it to develop and seek approvals for both Barrie to Sudbury Transmission Lines, and to undertake development work on the second Barrie to Sudbury Transmission Line. On February 10, 2026, further to the Minister's Directive, the OEB amended Hydro One Networks' electricity transmission licence to allow it to develop and seek approvals for the project in accordance with the recommendations of the IESO.

The IEP also addressed the need for additional transmission capacity in the Red Lake Area in Northwestern Ontario. In August 2025, the IESO released the *Northwest Region Integrated Regional Resource Plan Addendum* (Addendum). The Addendum recommends the urgent development of the Red Lake Transmission Line, a one double-circuit 230 kV transmission line that will run from Dryden TS to Ear Falls TS, and another double-circuit 230-kV transmission line that will run from Ear Falls TS to Red Lake SS, along with associated station facilities, to meet growing capacity needs after 2028. Hydro One will work with the IESO to identify the earliest achievable in-service date for the project. On October 29, 2025, the Ministry announced a proposal to bring forward an Order in Council (to be recommended by the Minister) to declare the project as priority and a companion directive, that would, if approved, direct the OEB to amend Hydro One Networks' transmitter licence to require it to undertake development work and seek all necessary approvals to construct the project. The consultation period for the proposal closed on December 13, 2025.

On July 31, 2025, the IESO announced the launch of the Transmitter Selection Framework (TSF) Registry. Registration enables transmitters to participate in future competitive IESO transmission procurements. Hydro One Networks intends to submit an application to be included in the TSF Registry.

OTHER DEVELOPMENTS

EWT LP

On March 4, 2025, Hydro One Networks completed the acquisition of an approximate 48% interest in the EWT LP for approximately $261 million in cash, including closing adjustments. The partnership owns the East-West Tie Line, a 450-kilometre, 230-kV double-circuit transmission line spanning between Wawa and Thunder Bay, along the north shore of Lake Superior.

Northern Ontario Voltage Study

In December 2023, the IESO published its Northern Ontario Voltage Study Report (Bulk System Reactive Requirements in Northern Ontario) (the Study), which recommended installation of reactive compensation devices at several stations in Northern Ontario to address both current and future system conditions that are expected once new Northern transmission lines are in-service. This study includes projects being developed by Hydro One, including: the East-West Tie Station Expansion, the Waasigan Transmission Line Project, the Northeast Power Line (previously referred to as the Hanmer to Mississagi Line), and the North Shore Link (previously referred to as Mississagi to Third Line Line).

In March 2024, the Company received a letter from the IESO recommending Hydro One proceed with the implementation of the reactive devices, in line with the timelines identified by the IESO. The Company has reviewed and assessed the results of the Study and recommendation from the IESO and has incorporated them into the associated projects so as to meet the timelines identified by the IESO.

Supporting Critical Transmission Infrastructure in Southwestern Ontario

St. Clair Transmission Line Project

In March 2022, the Province issued an Order in Council with a directive from the Minister (formerly the Minister of Energy) to the OEB, requiring Hydro One Networks to develop and seek approvals for the St. Clair Transmission Line Project, a 230 kV line from Lambton Transmission Station to Chatham Switching Station. In response to the directive, the OEB amended Hydro One Networks' transmission license in April 2022 to develop and seek approval for the St. Clair Transmission Line Project. On May 28, 2024, Hydro One Networks filed a leave-to-construct application seeking OEB approval of the project. The total project is expected to cost approximately $472 million, with $335 million attributable to transmission line work and $137 million attributable to station costs. On December 10, 2024, the OEB issued its Decision and Order granting leave to construct as requested in the application, with standard conditions of approval.

On September 9, 2025, Hydro One commenced the construction of the St. Clair Transmission Line Project, which is expected to be in service by 2027.

Supporting Critical Transmission Infrastructure in Northeastern and Eastern Ontario

On July 10, 2023, the Ministry announced a proposal to take certain actions to facilitate the timely development of three transmission projects across Northeastern and Eastern Ontario: North Shore Link, Northeast Power Line, and Durham Kawartha Power Line. On October 23, 2023, the Minister (formerly the Minister of Energy) directed the OEB to amend Hydro One Networks' licence to require it to develop and seek approvals for these three priority transmission line projects. On November 14, 2023, further to the Minister's Directive, the OEB amended Hydro One Networks' electricity transmission licence to require it to develop and seek approvals for these projects in accordance with the recommendations of the IESO.

On August 1, 2024, the Ministry announced a proposal to declare the Wawa Timmins Power Line (formerly Wawa to Porcupine line) as a priority project and designate Hydro One Networks, as the transmitter. These actions are intended to facilitate the timely development of a new 230 kV, 260 km transmission line in Northeastern Ontario from the Wawa Transformer Station (south of Wawa) to the Porcupine Transformer Station (Timmins area). Based on IESO forecasts, the government has identified a targeted in-service date of 2030; planned development work will inform the final construction schedule. The proposal was open for a 45 day consultation period ending September 15, 2024. On November 28, 2024, the Minister directed the OEB to amend Hydro One Networks' transmission license to require it to develop and seek approvals for this project. On December 23, 2024, further to the Minister's Directive, the OEB amended Hydro One Networks' electricity transmission licence to allow it to develop and seek approvals for this project in accordance with the recommendations of the IESO.

Wellington to Preston Line Project

As part of its integrated regional resource plan process for the Kitchener-Waterloo-Cambridge-Guelph Region, on September 29, 2025 the IESO, in conjunction with a technical working group (working group), issued a letter to Hydro One Networks with respect to an urgent need for certain transmission infrastructure. As part of the letter, the IESO identified the following two investments for Hydro One to complete:

- Development and initiating construction of a new 500/230 kV autotransformer station in Puslinch, with a target in-service date of 2031; and
- Development and initiating construction of a new 230 kV transmission line from Puslinch to Preston TS, with a target in-service date of 2031.

The IESO and the working group recommend that Hydro One proceed immediately with development of these projects, including pursuing the required environmental and regulatory approvals.

Welland Thorold Power Line

The IESO's 2022 integrated regional resource plan (IRRP) for the Niagara region identified growing electricity demand in the Welland area. To support this projected increase, the IRRP recommended enhancing transmission capacity through the development of a new transmission line. This need was subsequently reaffirmed in the 2023 Regional Infrastructure Plan. On November 17, 2025, Hydro One Networks filed a leave-to-construct application seeking OEB's approval for the Welland to Thorold Power Line, a new double-circuit 230-kilovolt transmission line between Abitibi Consolidated Junction, within an existing Hydro One transmission corridor in Thorold and Crowland TS in Welland. In addition to the line work, Hydro One will also expand Crowland TS. See section "Major Transmission Capital Investment Projects" for additional information.

Bill 2, Protect Ontario Through Free Trade Within Canada Act, Bill 5, Protect Ontario by Unleashing our Economy Act, and Bill 40, Protect Ontario by Securing Affordable Energy for Generations Act

On April 16, 2025, the Ontario Government introduced Bill 2, *Protect Ontario Through Free Trade Within Canada Act*, 2025. The legislation enables the province to, among other things, enter into mutual recognition agreements with other provinces to remove internal trade barriers in the movement of goods, services, and labour.

On April 17, 2025, the Ontario Government introduced Bill 5, the *Protect Ontario by Unleashing our Economy Act*, which aims to streamline the permitting and authorization process for certain projects, including major infrastructure, including through proposed changes to the environmental permitting process in Ontario.

On June 3, 2025, the Ontario Government introduced Bill 40, *Protect Ontario by Securing Affordable Energy for Generations Act*, 2025. The legislation enables the establishment of variance accounts for foreign equipment restrictions and introduces regulation-making authority with regards to data centre connections in Ontario.

Bill 2 and Bill 5 received Royal Assent on June 5, 2025. Bill 40 received Royal Assent on December 11, 2025. The Company is assessing the potential impacts of this legislation and associated regulations on Hydro One.

Sustainability Report

The Hydro One 2024 Sustainability Report entitled "A Better and Brighter Future For All" is available on the Company's website at www.hydroone.com/sustainability.

The 2024 Sustainability Report highlights the alignment of sustainability with Hydro One's refreshed corporate strategy to enable the Company to continue to deliver for its customers and all Ontarians. The report discloses the Company's performance across a range of environmental, social and governance (ESG) measures from January 1, 2024 to December 31, 2024.

HYDRO ONE BOARD OF DIRECTORS AND EXECUTIVE OFFICERS

Board of Directors

Effective March 24, 2025, Timothy Hodgson, then chair of the Board, commenced an unpaid leave of absence to pursue candidacy in the federal election. The board appointed Susan Wolburgh Jenah as Interim Chair on the same date.

On April 28, 2025, Mr. Hodgson formally resigned from the Board. Subsequently, the Board appointed Melissa Sonberg as chair of the Board, with the appointment taking effect on June 4, 2025.

Director Cherie Brant did not stand for re-election at the Annual and Special Meeting of Shareholders on June 24, 2025.

Effective August 14, 2025, the Board appointed Michael W. Rencheck as a director.

Executive Officers

Effective February 18, 2025, Gillian Whitebread joined Hydro One as Executive Vice President (EVP), Head of Human Resources. On the same day, Megan Telford's title became EVP, Strategy and Energy Transition.

Effective July 21, 2025, Megan Telford was appointed as Chief Operating Officer, and Lisa Pearson was appointed as EVP, Corporate Affairs.

Effective August 25, 2025, David Lebeter commenced a temporary compassionate care leave. The Board selected Harry Taylor to become the Interim President and Chief Executive Officer (CEO). Harry Taylor continued to serve as EVP, Chief Financial and Regulatory Officer during the interim period. David Lebeter returned from leave on November 12, 2025.

HYDRO ONE WORK FORCE

As at December 31, 2025, Hydro One had a skilled and flexible work force of approximately 7,200 (2024 - 7,300) regular employees and 1,900 (2024 - 2,100) non-regular employees province-wide, comprising a mix of skilled trades, engineering, professional, managerial and executive personnel. Hydro One's regular employees are supplemented primarily by accessing a large external labour force available through arrangements with the Company's trade unions for contingent workers, sometimes referred to as "hiring halls", and also by access to contract personnel. The hiring halls offer Hydro One the ability to flexibly use highly trained and appropriately skilled workers on a project-by-project and seasonal basis.

The following table sets out the number of Hydro One employees as at December 31, 2025:

	Regular Employees	Non-Regular Employees	Total
Power Workers' Union (PWU)[1]	4,201	626	4,827
Society of United Professionals (Society)	2,020	29	2,049
Canadian Union of Skilled Workers (CUSW) and construction building trade unions	—	1,270	1,270
Total employees represented by unions	6,221	1,925	8,146
Management and non-represented employees	930	22	952
Total employees[2]	7,151	1,947	9,098

[1] Includes 510 non-regular "hiring hall" employees covered by the PWU agreement.
[2] The average number of Hydro One employees in 2025 was approximately 9,600, consisting of approximately 7,200 regular employees and approximately 2,400 non-regular employees.

Collective Agreements

On May 4, 2025, Hydro One Inc. reached tentative renewal agreements with the PWU for both its main collective agreement and its Customer Service Operations (CSO) collective agreement which merges the two agreements into one. On June 2, 2025, the agreement was ratified by the PWU-represented employees for a term from October 1, 2025, to March 31, 2028.

Hydro One Inc.'s collective agreement with the Society expired on September 30, 2025. On January 13, 2026, Hydro One and the Society announced that a settlement for a renewal collective agreement had been reached. On January 30, 2026, the Society-represented employees ratified the collective agreement, with a term of October 1, 2025 to March 31, 2028.

The construction building trade unions have collective agreements with the Electrical Power Systems Construction Association (EPSCA). EPSCA is an employers' association of which Hydro One is a member. All 20 of the EPSCA construction collective agreements, which bind Hydro One, expired on April 30, 2025. EPSCA negotiated five-year renewal agreements, covering the period from May 1, 2025 to April 30, 2030, for all 20 collective agreements.

Stock-based Compensation

The Company granted Deferred Share Units (DSUs) and LTIP awards, consisting of Performance Share Units (PSUs) and Restricted Share Units (RSUs) to Directors and Management. As at December 31, 2025 and 2024, the following LTIP and other awards were outstanding:

As at December 31 *(number of units)*	2025	2024
PSUs	399,181	286,554
RSUs	391,623	322,925
Management DSUs	80,404	85,690
Director DSUs	102,256	107,296

NON-GAAP FINANCIAL MEASURES

Hydro One uses a number of non-GAAP financial measures to assess its performance. The Company presents FFO or "funds from operations" to reflect a measure of the Company's cash flow; revenues, net of purchased power, to reflect the impact of revenue on net income; and net debt to reflect a measure of the Company's financial leverage.

Hydro One also uses financial ratios that are non-GAAP ratios such as the net debt to capitalization ratio and annualized FFO to net debt ratio to reflect a measure of the Company's financial leverage, and the earnings coverage ratio to reflect a measure of liquidity.

FFO

FFO is defined as net cash from operating activities, adjusted for changes in non-cash balances related to operations and distributions to noncontrolling interest. Management believes that FFO is helpful as a supplemental measure of the Company's operating cash flows as it excludes timing-related fluctuations in non-cash operating working capital and cash flows not attributable to common shareholders. As such, management believes that FFO provides a consistent measure of the cash generating performance of the Company's assets.

The following table provides a reconciliation of reported GAAP results to non-GAAP results on a consolidated basis.

Quarter ended *(millions of dollars)*	Dec 31, 2025	Sep 30, 2025	Jun 30, 2025	Mar 31, 2025	Dec 31, 2024	Sep 30, 2024	Jun 30, 2024	Mar 31, 2024
Net cash from operating activities	867	713	605	510	703	623	746	462
Changes in non-cash balances related to operations	(214)	(31)	14	178	(190)	18	(221)	144
Distributions to noncontrolling interest	(1)	(4)	(2)	(5)	(2)	(2)	(2)	(4)
FFO	652	678	617	683	511	639	523	602

Twelve months ended *(millions of dollars)*	Dec 31, 2025	Dec 31, 2024
FFO	**2,630**	**2,275**

Revenues, Net of Purchased Power

Revenues, net of purchased power, is defined as revenues less the cost of purchased power; distribution revenues, net of purchased power, is defined as distribution revenues less the cost of purchased power. These measures are used internally by management to assess the impacts of revenue on net income and are considered useful because they exclude the cost of power that is fully recovered through revenues and therefore net income neutral.

The following tables provide a reconciliation of reported GAAP revenues to non-GAAP revenues, net of purchased power, on a consolidated basis.

Quarter ended *(millions of dollars)*	Dec 31, 2025	Sep 30, 2025	Jun 30, 2025	Mar 31, 2025	Dec 31, 2024	Sep 30, 2024	Jun 30, 2024	Mar 31, 2024
Revenues	2,268	2,299	2,066	2,408	2,095	2,192	2,031	2,166
Less: Purchased power	1,287	1,080	899	1,220	1,060	1,047	940	1,096
Revenues, net of purchased power	981	1,219	1,167	1,188	1,035	1,145	1,091	1,070

Quarter ended *(millions of dollars)*	Dec 31, 2025	Sep 30, 2025	Jun 30, 2025	Mar 31, 2025	Dec 31, 2024	Sep 30, 2024	Jun 30, 2024	Mar 31, 2024
Distribution revenues	1,757	1,605	1,434	1,761	1,583	1,551	1,436	1,605
Less: Purchased power	1,287	1,080	899	1,220	1,060	1,047	940	1,096
Distribution revenues, net of purchased power	470	525	535	541	523	504	496	509

Year ended December 31 *(millions of dollars)*	2025	2024
Revenues	9,041	8,484
Less: Purchased power	4,486	4,143
Revenues, net of purchased power	4,555	4,341

Year ended December 31 *(millions of dollars)*	2025	2024
Distribution revenues	6,557	6,175
Less: Purchased power	4,486	4,143
Distribution revenues, net of purchased power	2,071	2,032

Net Debt

The Company uses net debt as an alternative measure of outstanding debt. Management considers net debt as an important measure in assessing the financial leverage of the Company. Net debt is used by management to assess the Company's overall debt position and financial leverage.

The following table provides a reconciliation of net debt as reported in the Company's Consolidated Financial Statements.

Year ended December 31 *(millions of dollars)*	2025	2024
Short-term notes payable	100	200
Less: cash and cash equivalents	(549)	(716)
Long-term debt (current portion)	925	1,150
Long-term debt (long-term portion)	18,092	16,329
Net Debt	**18,568**	**16,963**

Net Debt to Capitalization Ratio

The Company believes that the net debt to capitalization ratio is an important non-GAAP ratio as a measure of the Company's financial leverage. Net debt to capitalization ratio has been calculated as net debt, as described above, divided by net debt plus total shareholders' equity, but excluding any amounts related to noncontrolling interest. Management believes that the net debt to capitalization ratio is helpful as a measure of the proportion of debt in the Company's capital structure.

Year ended December 31 *(millions of dollars)*	2025	2024
Net debt (A)	**18,568**	**16,963**
Shareholders' equity (excluding noncontrolling interest)	12,648	12,089
Net debt plus shareholders' equity (B)	**31,216**	**29,052**
Net Debt-to-capitalization ratio (A/B)	**59.5 %**	**58.4 %**

Annualized FFO to Net Debt

Management believes that the annualized FFO to net debt ratio is helpful as a measure of the Company's financial leverage. Annualized FFO to net debt ratio has been calculated as FFO (see section "Non-GAAP Financial Measures - FFO") on a rolling twelve-month period divided by net debt at the period end date (see section "Non-GAAP Financial Measures – Net Debt"). Management believes the annualized FFO to net debt ratio is helpful as a measure of the company's ability to pay off its debt using the Company's net operating income.

The following table provides a reconciliation of reported GAAP results to non-GAAP results on a consolidated basis.

Twelve months and period ended *(millions of dollars)*	Dec 31, 2025	Sep 30, 2025	Jun 30, 2025	Mar 31, 2025	Dec 31, 2024	Sep 30, 2024	Jun 30, 2024	Mar 31, 2024
Annualized FFO (A)	2,630	2,489	2,450	2,356	2,275	2,238	2,221	2,256
Net Debt (B)	18,568	18,346	18,030	17,615	16,963	16,679	16,308	16,016
Annualized FFO to Net Debt (A/B)	**14.2 %**	**13.6 %**	**13.6 %**	**13.4 %**	**13.4 %**	**13.4 %**	**13.6 %**	**14.1 %**

Earnings Coverage Ratio

Earnings coverage ratio is defined as earnings before income taxes, financing charges and equity income attributable to shareholders, divided by the sum of financing charges and capitalized interest, and is calculated on a rolling twelve-month basis. The Company believes that the earnings coverage ratio is an important non-GAAP measure in the management of its liquidity.

Quarter ended *(millions of dollars)*	Dec 31, 2025	Sep 30, 2025	Jun 30, 2025	Mar 31, 2025	Dec 31, 2024	Sep 30, 2024	Jun 30, 2024	Mar 31, 2024
Net income attributable to common shareholders	233	421	327	358	200	371	292	293
Income tax expense	30	60	61	68	17	56	57	51
Financing charges	175	172	169	163	158	158	157	148
Equity income	3	6	—	—	—	—	—	—
Earnings before income taxes, financing charges and equity income attributable to common shareholders	435	647	557	589	375	585	506	492

Twelve months ended *(millions of dollars)*	Dec 31, 2025	Dec 31, 2024
Earnings before income taxes, financing charges and equity income attributable to common shareholders (A)	**2,228**	**1,958**

Quarter ended *(millions of dollars)*	Dec 31, 2025	Sep 30, 2025	Jun 30, 2025	Mar 31, 2025	Dec 31, 2024	Sep 30, 2024	Jun 30, 2024	Mar 31, 2024
Financing charges	175	172	169	163	158	158	157	148
Capitalized interest	29	30	27	24	24	24	22	19
Financing charges and capitalized interest	204	202	196	187	182	182	179	167

Twelve months ended *(millions of dollars)*	Dec 31, 2025	Dec 31, 2024
Financing charges and capitalized interest (B)	**789**	**710**
Earnings coverage ratio = A/B	**2.8**	**2.8**

RELATED PARTY TRANSACTIONS

The Province is a shareholder of Hydro One with approximately 47.1% ownership as at December 31, 2025. The Ministry and MOI are related parties to Hydro One because they are controlled by the Province. The IESO, Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), and the OEB are related parties to Hydro One because they are controlled or significantly influenced by the Ministry. Hydro One also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province. The following is a summary of the Company's related party transactions during the years ended December 31, 2025 and 2024:

Year ended December 31 *(millions of dollars)*

Related Party	Transaction	2025	2024
Province	Dividends paid	370	350
Ministry	Broadband subsidy[1]	27	—
MOI	Broadband subsidy[1]	19	43
IESO	Power purchased	3,011	2,686
	Revenues for transmission services	2,388	2,252
	Amounts related to electricity rebates	1,110	1,170
	Distribution revenues related to rural rate protection	256	255
	Distribution revenues related to Wataynikaneyap Power LP	133	119
	Distribution revenues related to supply of electricity to remote northern communities	50	48
	Funding received related to Conservation and Demand Management programs	—	1
OPG	Power purchased	23	18
	Transmission revenues related to provision of services and supply of electricity	2	2
	Distribution revenues related to provision of services and supply of electricity	8	5
	Other revenues related to provision of services and supply of electricity	2	1
	Capital contribution received from OPG	20	3
	Costs related to the purchase of services	2	1
OEFC	Power purchased from power contracts administered by the OEFC	2	1
OEB	OEB fees	14	12

[1] See section "Building Broadband Faster Act, 2021", During 2025, Ministry replaced MOI in making broadband subsidy payments to Hydro One.

RISK MANAGEMENT AND RISK FACTORS

Hydro One is subject to numerous risks and uncertainties. Critical to Hydro One's success is the identification, management and, to the extent possible, mitigation of these risks. Hydro One's Enterprise Risk Management (ERM) program assists decision-makers throughout the organization with the management of key business risks, including new and emerging risks and opportunities.

The material risks relating to Hydro One and its business that the Company believes would be the most likely to influence an investor's decision to purchase Hydro One's securities are set out in the risk factors below. These risks, if they materialize, could have a materially adverse effect on the Company or its business, financial condition, or results of operations. This list is not a comprehensive list of all the risks to the Company, and the actual effect of any of the risks cited below could be materially different from what is described below. Additionally, other risks may arise or risks currently not considered material may become material in the future.

Risks Relating to Hydro One's Business

Regulatory Risks and Risks Relating to Hydro One's Revenues

Risks Relating to Actual Performance Against Forecasts

The Company's ability to recover the actual costs of providing service and earn the allowed ROE depends on the Company achieving its forecasts established and approved in the rate-setting process. Actual costs could exceed the approved forecasts if, for example, the Company incurs operations, maintenance, administration, capital and financing costs above those included in the Company's approved revenue requirement. The inability to recover any significant difference between forecast and actual expenses and to obtain associated regulatory approvals to recover the difference could materially adversely affect the Company's financial condition and results of operations.

Further, the OEB approves the Company's transmission and distribution rates based on projected electricity load and consumption levels, among other factors. If actual load or consumption materially falls below projected levels, the Company's revenue, net income and cash flows for either, or both, of these businesses could be materially adversely affected.

The Company's current revenue requirements for its transmission and distribution businesses are based on cost and other assumptions, including inflation, that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in the Company's costs.

The Company is subject to risk of revenue loss from other factors, such as economic trends and conditions, changes in service territory, and weather conditions that influence the demand for electricity. The Company's overall operating results may fluctuate substantially on a seasonal and year-to-year basis based on these trends and weather conditions. For instance, a cooler than normal summer or warmer than normal winter can be expected to reduce demand for electricity below that forecast by the Company, causing a decrease in the Company's revenues, net income and cash flows as compared to the same period of the previous year.

The Company's load could also be negatively affected by successful conservation and demand management programs whose results exceed forecasted expectations.

Risks Relating to Non-Rate Applications to the OEB

In addition to the matters described in the "Risks Relating to Obtaining Rate Orders" subsection below, the Company is also subject to the risk that it will not obtain, or will not obtain in a timely manner, required regulatory approvals for other matters, such as leave to construct applications, applications for mergers, acquisitions, amalgamations and divestitures, and environmental approvals. Appeals of OEB decisions and/or the need to obtain required occupation rights may result in significant delays, which could also lead to increased costs and project delays.

Decisions to acquire or divest other regulated businesses licensed by the OEB are subject to OEB approval. Accordingly, there is the risk that such matters may not be approved, or that unfavourable conditions will be imposed by the OEB.

Hydro One may face increased competition with other transmitters for opportunities to build new, large-scale transmission facilities in Ontario. The Company is subject to the risk that it will not be selected to build new transmission in Ontario, which could impair growth, disrupt operations and/or development, or have other adverse impacts.

Risks Relating to Rate-Setting Models for Transmission and Distribution

The OEB approves and periodically changes the rate-setting models and methodology for the transmission and distribution businesses. Changes to the application type, filing requirements, rate-setting model or methodology, or revenue requirement determination may have a material negative impact on Hydro One's revenue and net income. For example, the OEB may in the future decide to reduce the allowed ROE for either of these businesses, modify the formula or methodology it uses to determine the ROE, or reduce the weighting of the equity component of the deemed capital structure. Any such reduction could reduce the net income of the Company. Similarly, the OEB may in the future consider other utility remuneration models, and any such change could affect Hydro One's revenue and net income. If the OEB was to significantly change the formula for calculating ROE or the deemed regulatory capital structure, this could result in a material adverse impact to the financial condition of the Company.

The OEB's Custom Incentive Rate-setting model requires that the term of a custom rate application be for multi-year periods. There are risks associated with forecasting key inputs such as revenues, operating expenses and capital over such a long period. For instance, if unanticipated capital expenditures arise that were not contemplated in the Company's most recent rate decision, the Company may be required to incur costs that may not be recoverable until a future period or not recoverable at all in future rates. This could have a material adverse effect on the Company.

When rates are set for a multi-year period, including under a Custom Incentive Rate application, the OEB expects there to be no further rate applications for annual updates within the multi-year period, unless it is consistent with OEB approved funding mechanisms or there are exceptional circumstances, with the exception of the clearance of established deferral and variance accounts. For example, the OEB does not expect to address annual rate applications for updates for cost of capital (including ROE), working capital allowance or sales volumes. If there were an increase in interest rates over the period of a rate decision and no corresponding changes were permitted to the Company's revenue requirement (including cost of capital parameters), then the result could be a decrease in the Company's financial performance. See also "Market, Financial Instrument and Credit Risk".

To the extent that the OEB approves an in-service variance account for the transmission and/or distribution businesses, and should the Company fail to meet the threshold levels of in-service capital, the OEB may reclaim a corresponding portion of the Company's revenues.

Risks Relating to Capital Expenditures

In order to be recoverable in rates, capital expenditures require the approval of the OEB. There can be no assurance that all capital expenditures, including any imposed by or resulting from government or regulatory bodies, incurred by Hydro One will be approved by the OEB. For example, capital cost overruns including those due to economic trends and conditions including inflation; the potential imposition of duties, tariffs or trade restrictions; unexpected capital expenditures in maintaining or improving the Company's assets; unexpected costs as a result of proposed legislation, including that relating to the expansion of broadband service in Canada; may not be recoverable in transmission or distribution rates. To the extent possible, Hydro One aims to mitigate this risk by ensuring expenditures are reasonable and prudent, and also by seeking from the regulator clear policy direction on cost responsibility, and by obtaining pre-approval of the need for capital expenditures.

Any regulatory decision by the OEB to disallow or limit the recovery of any capital expenditures would lead to a lower-than-expected approved revenue requirement or rate base, potential asset impairment or charges to the Company's results of operations, any of which could have a material adverse effect on the Company.

Risks Relating to Obtaining Rate Orders

The Company is subject to the risk that the OEB will not approve the Company's transmission and distribution revenue requirements requested in outstanding or future applications for rates. Rate applications for revenue requirements are subject to the OEB's review process, usually involving participation from intervenors and a public hearing process. There can be no assurance that resulting decisions or rate orders issued by the OEB will permit Hydro One to recover all costs actually incurred, including the costs of debt and income taxes, or to earn a particular ROE. A failure to obtain acceptable rate orders, or approvals of appropriate returns on equity and the ability to recover in rates costs actually incurred, may materially adversely affect: Hydro One's transmission and distribution businesses, the undertaking or timing of capital expenditures, ratings assigned by credit rating agencies, the cost and issuance of long-term debt, and other matters, any of which may in turn have a material adverse effect on the Company. In addition, there is no assurance that the Company will receive regulatory decisions in a timely manner and, therefore, the Company may incur costs before having an approved revenue requirement and cash flows could be impacted. The Company is also subject to the risk that the OEB could change the regulatory treatment of certain costs which may affect the Company's accounting treatment of and ability to recover such costs.

Risk of Recoverability of Total Compensation Costs

Hydro One manages all of its total compensation costs, including pension and other post-employment and post-retirement benefits (OPEBs), subject to restrictions and requirements imposed by the collective bargaining process and legislative requirements. Any element of total compensation costs which is disallowed in whole or part by the OEB and therefore not recoverable from customers in rates could result in costs which could be material and could decrease net income, which could have a material adverse effect on the Company. The *OEB Act* prohibits Hydro One from recovering specified executive compensation costs in its rates.

The Company provides OPEBs to qualifying employees. Hydro One currently maintains the accrual accounting method with respect to OPEBs. If the OEB directed Hydro One to transition to a different accounting method for OPEBs or otherwise adjusted the basis of recovery for OPEB costs, this could result in income volatility, due to an inability of the Company to book the difference between the accrual and cash as a regulatory asset, and the Company might not be able to recover some costs. A determination that some of the Company's post-employment and post-retirement benefit costs are not recoverable could have a material adverse effect on the Company.

Risks Relating to Government Action

The Province is, and is likely to remain, the largest shareholder in Hydro One Limited. The Province may be in a position of conflict from time to time as a result of being an investor in Hydro One Limited and also being a government actor setting broad policy objectives in the electricity industry. Government actions may not be in the interests of the Company or investors.

Governments may pass legislation or issue regulations at any time, including legislation or regulation impacting Hydro One, which could have potential material adverse effects on Hydro One and its business. Such government actions may include, but are not limited to, legislation, regulation, directives or shareholder action intended to reduce electricity rates, place constraints on compensation, or affect the governance of Hydro One. Such government actions could adversely affect the Company's financial condition and results of operations, as well as public opinion and the Company's reputation. Government action may also hinder Hydro One's ability to pursue its strategy and/or objectives.

The Province has in the past passed legislation to place limits on executive compensation at Hydro One and there is no guarantee they may not do so in the future. Potential involvement by the Province in the Company's executive compensation practices may inhibit the Company's ability to attract and retain qualified executive talent, which may also impact the Company's performance, strategy and/or objectives. The failure to attract and retain qualified executives could have a material adverse effect on the Company.

Government action may also impact the Company's credit ratings as the Company's credit ratings reflect, in part, the rating agencies' assessment of government involvement in the business of Hydro One. The Company cannot predict what actions rating agencies may take in the future, positive or negative, including in response to government action or inaction relating to or impacting Hydro One. The failure to maintain the Company's current credit ratings could adversely affect the Company's financial condition and results of operations, and a downgrade in the Company's credit ratings could restrict the Company's ability to access debt capital markets and increase the Company's cost of debt.

Indigenous Claims Risk

Some of the Company's current and proposed transmission and distribution assets are or may be located on reserve (as defined in the *Indian Act* (Canada)) (Reserve) lands, or lands over which Indigenous people have Aboriginal, treaty, or other legal rights or claims. Some Indigenous leaders, communities, and their members have made assertions related to sovereignty and jurisdiction over Reserve lands and traditional territories (land traditionally occupied or used by a First Nation, Métis or Inuit

group) and can assert their claims through the courts, tribunals, or direct action. These claims, and/or the settlement or resolution of these claims could have a material adverse effect on the Company or otherwise materially adversely impact the Company's operations, including the development of current and future projects.

The Company's operations and activities may give rise to the Crown having a duty to consult and potentially accommodate Indigenous communities. Procedural aspects of the Crown's duty to consult may be delegated to the Company by the Province or the federal government. A perceived failure by the Crown to sufficiently consult an Indigenous community, including communities with a traditional governance model not recognized under the *Indian Act* (Canada), or a perceived failure by the Company in relation to delegated consultation obligations, could result in legal challenges against the Crown and/or the Company, including judicial review or injunction proceedings, or could potentially result in direct action against the Company by a community or its citizens. If this occurs, it could disrupt or delay the Company's operations and activities, including current and future projects, and have a material adverse effect on the Company.

Risk from Transfer of Assets Located on Reserves

The transfer orders by which the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to assets located on Reserves. The transfer of title to these assets did not occur because authorizations originally granted by the federal government for the construction and operation of these assets on Reserves could not be transferred without required consent. In several cases, the authorizations had either expired or had never been issued.

Currently, OEFC holds legal title to these assets and it is expected that the Company will manage them until it has obtained permits to complete the title transfer. To occupy Reserves, the Company must have valid permits as required by the *Indian Act* (Canada). For each permit, the Company may need to negotiate (an) agreement(s) with the First Nation, OEFC and any members of the First Nation who have occupancy rights. Any such agreement(s) include provisions whereby the First Nation consents to the issuance of a permit. For transmission assets, the Company must negotiate terms of payment. It is difficult to predict the aggregate amount that the Company may have to pay to obtain the required agreements from First Nations. If the Company cannot reach satisfactory agreements with the relevant First Nation to obtain federal permits, or is unable to obtain the actual federal permits for any other reason, it may have to relocate these assets to other locations and restore the lands at a cost that could be substantial. In a limited number of cases, it may be necessary to abandon a line and replace it with diesel generation facilities. In either case, the costs relating to these assets could have a material adverse effect on the Company if the costs are not recoverable in future rate orders.

Compliance with Laws and Regulations

Hydro One must comply with numerous laws and regulations affecting its business, including requirements relating to transmission and distribution companies, environmental laws, employment laws and health and safety laws. The failure of the Company to comply with these laws could have a material adverse effect on the Company's business. See also "Environment Risk" and "Health and Safety Risk".

For example, Hydro One's licensed transmission and distribution businesses are required to comply with the terms of their licences, with codes and rules issued by the OEB, and with other regulatory requirements. In Ontario, the Market Rules issued by the IESO require the Company to, among other things, comply with applicable reliability standards established by the North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council, Inc. (NPCC). The costs associated with compliance with these reliability standards are expected to be recovered through rates, but there can be no assurance that the OEB will approve the recovery of all of such costs. Failure to obtain such approvals could have a material adverse effect on the Company.

There is the risk that new legislation, regulations, requirements or policies will be introduced in the future or that regulatory bodies may change or modify the regulations or rules that apply to the Company. These may reduce Hydro One's revenue, or may require Hydro One to incur additional costs, which may or may not be recovered in future transmission and distribution rates.

Risk of Natural and Other Unexpected Occurrences

The Company's facilities are exposed to the effects of severe weather conditions, natural disasters, man-made events including, but not limited to, cyber and physical terrorist type attacks, events which originate from third-party connected systems, and any other potentially catastrophic events. The Company's facilities may not withstand occurrences of these types in all circumstances.

The Company could also be subject to claims for damages from events which may be proximately connected with the Company's assets (for example, wildfires), claims for damages caused by its failure to transmit or distribute electricity, costs related to ensuring its continued ability to transmit or distribute electricity or costs related to information or cyber security.

The Company does not have insurance for damage to its transmission and distribution wires, poles and towers located outside its transmission and distribution stations resulting from these or other events. Where insurance is available for the Company's other assets and for damage claims and cyber security claims, such insurance coverage may have deductibles, limits and/or

exclusions that may still expose the Company to material losses. Losses from lost revenues and repair costs could be substantial, especially for many of the Company's facilities that are located in remote areas.

In the event that the Company is unable to recover such costs, this could have a material adverse effect on the Company.

Risk Associated with IT, Operational Technology (OT) Infrastructure, and Data Security

The Company's ability to operate effectively in the Ontario electricity market is, in part, dependent upon it developing, modernizing, maintaining and managing complex IT and OT systems which are employed to operate and monitor its transmission and distribution facilities, financial and billing systems and other business systems. The Company's increasing reliance on information systems and expanding data networks, as well as growing volume and complexity of data, increases its vulnerability, and exposure to information security threats. The Company's transmission business is required to comply with various rules and standards for transmission reliability, including mandatory standards established by the NERC and the NPCC. These include standards relating to cyber-security and OT, which only apply to certain of the Company's assets (generally being those whose failure could impact the functioning of the bulk electricity system). The Company may maintain different or lower levels of security for its assets that are not subject to these mandatory standards. The Company must also comply with various cyber-security and privacy-related regulatory requirements under the OEB's Ontario Cyber Security Framework and legislative and licence requirements relating to the collection, use and disclosure of personal information and information regarding consumers, wholesalers, generators and retailers.

Cyber-attacks or unauthorized access to corporate IT and OT systems could result in service disruptions and system failures, which could have a material adverse effect on the Company, including as a result of a failure to provide electricity to customers. Because it operates critical infrastructure, Hydro One may be at greater risk of cyber-attacks from third parties (including state run or controlled parties) that could impair or incapacitate its assets. In addition, in the course of its operations, the Company collects, uses, processes and stores information which could be exposed in the event of a cyber-security incident or other unauthorized access or disclosure, such as information about customers, suppliers, counterparties, employees and other third parties.

Security and system disaster recovery controls are in place; however, there can be no assurance that there will not be system failures or security breaches or that such threats would be detected or mitigated on a timely basis. Upon occurrence and detection, the focus would shift from prevention to isolation, remediation and recovery until the incident has been fully addressed. Any such system failures or security breaches could have a material adverse effect on the Company.

Environment Risk

The Company is subject to extensive Canadian federal, provincial and municipal environmental regulation. Failure to comply could subject the Company to fines or other penalties. In addition, the presence or release of hazardous or other harmful substances could lead to claims by third parties or governmental orders requiring the Company to take specific actions such as investigating, controlling and remediating the effects of these substances. Although Hydro One is not a large emitter of greenhouse gases, the Company monitors its emissions to track and report on all sources, including sulphur hexafluoride or "SF6". The Company could be subject to costs and other risks related to emissions. Contamination of the Company's properties could limit its ability to sell or lease these assets in the future.

In addition, actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities provided for in the Company's financial statements. The Company does not have insurance coverage for these environmental expenditures.

There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing or operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could result in delays and cost increases. Failure to obtain necessary approvals or permits could result in an inability to complete projects which may have a material adverse effect on the Company.

The Company's facilities are exposed to the effects of severe weather conditions and natural disasters. The Company recognizes the risks associated with potential climate change and has developed plans to respond as appropriate. Climate change may have the effect of shifting weather patterns and increasing the severity and frequency of extreme weather events and natural disasters, which could impact Hydro One's business. The Company's facilities may not withstand occurrences of these types in all circumstances. Notwithstanding Hydro One's efforts to adapt and increase grid resilience, the Company's facilities are exposed to risks which may have an adverse effect on grid resilience. The Company could also be subject to claims for damages from events which may be proximately connected with the Company's assets (for example, wildfires), claims for damages caused by its failure to transmit or distribute electricity or costs related to ensuring its continued ability to transmit or distribute electricity. The Company does not have insurance for damage to its transmission and distribution wires, poles and towers located outside its transmission and distribution stations resulting from these or other events. Where insurance is available for the Company's other assets and for damage claims, such insurance coverage may have deductibles, limits and/or exclusions that may still expose the Company to material losses.

Losses from lost revenues and repair costs could be substantial, especially for many of the Company's facilities that are located in remote areas.

In the event that the Company is unable to recover such costs, this could have a material adverse effect on the Company.

Labour Relations Risk

A substantial majority of the Company's employees are unionized and are primarily represented by either the PWU or the Society. Over the past several years, significant effort has been expended to increase Hydro One's flexibility to conduct operations in a more cost-efficient manner. Although the Company has achieved improved flexibility in its collective agreements, the Company may not be able to achieve further improvements, or at least not without increasing the risk of labour disruption. Hydro One Inc. reached a renewal collective agreement with the Society, covering the period from October 1, 2025 to March 31, 2028. Hydro One Inc. reached a renewal collective agreement with the PWU, covering the period from October 1, 2025 to March 31, 2028. Hydro One's collective agreement with the CUSW covers the period from May 1, 2022 to April 30, 2026. Additionally, the EPSCA and a number of building trade unions have agreements, to which Hydro One is bound, covering the period from May 1, 2025 to April 30, 2030.

Future negotiations with unions present the risk of a labour disruption or dispute, risk to the Company's ability to sustain the continued supply of electricity to customers, as well as potential risks to public safety and reputation. The Company also faces financial risks related to its ability to negotiate collective agreements consistent with its rate orders. Any of these could have a material adverse effect on the Company.

Risks Relating to Asset Condition, Capital Projects and Innovation

The Company continually incurs sustainment and development capital expenditures and monitors the condition of its assets to manage the risk of equipment failures and to determine the need for and timing of major refurbishments and replacements of its transmission and distribution infrastructure.

While traditionally a mature and stable industry, the electricity industry is facing rapid and dramatic technological change and increasing innovation, the consequences of which could have a material adverse effect on the Company, including a reduction in revenue.

Execution of the Company's capital expenditure programs is partially dependent on external factors, such as OEB approvals; environmental approvals; municipal permits; equipment outage schedules that accommodate the IESO, generators and customers; other interrelated projects being on schedule; supply chain availability and/or cost and schedule variability for equipment suppliers, contracted services, and consulting services; and availability of contractor resources including in relation to workforce and equipment. Many of these external factors are beyond the Company's control. There may also be a need for, among other things, *Environmental Assessment Act* (Ontario) approvals, approvals which require public meetings, appropriate engagement with Indigenous communities, OEB approvals of expropriation or early access to property, and other activities. Obtaining approvals and carrying out these processes may also be impacted by opposition to the proposed site of the capital investments. Delays in obtaining required approvals or failure to complete capital projects on a timely basis, or at all, could materially adversely affect transmission reliability or customers' service quality or increase maintenance costs which could have a material adverse effect on the Company. Failure to receive approvals for projects when spending has already occurred would result in the inability of the Company to recover the investment in the project as well as forfeit the anticipated return on investment. The assets involved may be considered impaired and result in the write off of the value of the asset, negatively impacting net income. If the Company is unable to carry out capital expenditure plans in a timely manner, equipment performance may degrade, which may reduce network capacity, result in customer interruptions, compromise the reliability of the Company's networks or increase the costs of operating and maintaining these assets. Any of these consequences could have a material adverse effect on the Company.

Increased competition for the development of large transmission projects and legislative changes relating to the selection of transmitters could impact the Company's ability to expand its existing transmission system, which may have an adverse effect on the Company. The Company may not be selected to build new transmission as part of a competitive process. To the extent that other parties are selected to construct, own and operate new transmission assets, the Company's share of Ontario's transmission network would be reduced. Any delays in these new transmitters' projects may impact the Company's own projects that it is undertaking to in-service these new transmission assets.

Work Force Demographic Risk

By the end of 2025, approximately 9% of the Company's employees who are members of the Company's defined benefit and defined contribution pension plans were eligible for retirement, and by the end of 2026, approximately 11% could be eligible. These percentages are not evenly spread across the Company's work force, but tend to be most significant in the most senior levels of the Company's staff and among management staff. During 2025, approximately 4% of the Company's work force (increased from 2% in 2024) elected to retire. Accordingly, the Company's continued success will be tied to its ability to continue to attract and retain sufficient qualified staff to replace the capability lost through retirements and meet the demands of the Company's work programs.

In addition, the Company expects the skilled labour market for its industry will remain highly competitive. Many of the Company's current and potential employees are sought after as they possess skills and experience that are also highly coveted by other organizations inside and outside the electricity sector. The failure to attract, retain and deploy qualified personnel for Hydro One's business could have a material adverse effect on the Company.

Risk Associated with Arranging Debt Financing

The Company expects to borrow to repay its existing indebtedness and to fund a portion of capital expenditures. Hydro One has substantial debt principal repayments coming due, including $925 million in 2026, $425 million in 2027 and $750 million in 2028. In addition, from time to time, the Company may draw on its syndicated bank credit facilities and/or issue short-term debt under Hydro One Inc.'s $2,300 million commercial paper program which would mature within one year of issuance. The Company also plans to incur continued material capital expenditures. Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of the Company's existing indebtedness and capital expenditures. The Company's ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by numerous factors, including the regulatory environment in Ontario, the Company's results of operations and financial position, market conditions, the ratings assigned to its debt securities by credit rating agencies, an inability of the Company to comply with its debt covenants, and general economic conditions (such as, among other things, changes in interest rates or international relations and geopolitical events that could cause weaker economic conditions or increase the volatility of the capital markets). A downgrade in the Company's credit ratings could restrict the Company's ability to access debt capital markets and increase the Company's cost of debt. Any failure or inability on the Company's part to borrow the required amounts of debt on satisfactory terms could impair its ability to repay maturing debt, fund capital expenditures and meet other obligations and requirements and, as a result, could have a material adverse effect on the Company. Increasing investor interest in ESG performance and reporting also has the potential to impact the cost and availability of the Company's funding, as these factors may be increasingly connected to the quality of the Company's ESG practices and related reporting, including reports addressing the allocation of funds and impact reporting under Hydro One's Sustainable Financing Framework.

Market, Financial Instrument and Credit Risk

Market risk refers primarily to the risk of loss that results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates as its regulated ROE is derived using a formulaic approach that takes into account anticipated interest rates. The Company issues debt from time to time to refinance maturing debt and for general corporate purposes. The Company is therefore exposed to fluctuations in interest rates in relation to such issuances of debt. Fluctuations in interest rates may also impact the funded position of Hydro One's Defined Benefit Pension Plan, and associated pension asset or liability (see also "Pension Plan Risk"). The Company is not currently exposed to material foreign exchange risk.

The OEB-approved adjustment formula for calculating ROE in a deemed regulatory capital structure of 60% debt and 40% equity provides for increases and decreases depending on changes in benchmark interest rates for Government of Canada debt and the A-rated utility corporate bond yield spread. For the transmission and distribution businesses, during the Custom Incentive Rate period from 2023 to 2027, the OEB does not expect to address annual rate applications for updates to allowed ROE, so fluctuations will have no impact to net income. The Company has interest rate exposure in 2026 and beyond associated with the refinancing of maturing short- and long-term debt, as well as with debt issued for general corporate purposes and under the Sustainable Financing Framework which may include debt issued in relation to growth in rate base. The Company periodically uses interest rate swap agreements to mitigate elements of interest rate risk.

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counterparty default. Hydro One monitors and minimizes credit risk through various techniques, including dealing with highly rated counterparties, limiting total exposure levels with individual counterparties, entering into agreements which enable net settlement, and monitoring the financial condition of counterparties. The Company does not trade in any energy derivatives. The Company is required to procure electricity on behalf of competitive electricity retailers and certain local distribution companies for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into the Company's service agreements with these retailers in accordance with the OEB's Retail Settlement Code.

The failure to properly manage these risks could have a material adverse effect on the Company.

Health and Safety Risk

Hydro One's work environment can be inherently dangerous and there is a risk to health and safety of the public, our employees and contractors, as well as possible resultant operational and/or financial impacts. The Company is subject to federal and provincial legislation and regulations relating to health and safety. Findings of a failure to comply with these requirements could result in penalties and reputational risk, which could negatively impact the Company. Failure to comply could subject the Company to fines or other penalties. Any regulatory decision to disallow or limit the recovery of such costs could have a material adverse effect on the Company.

Pension Plan Risk

Hydro One has the Hydro One Defined Benefit Pension Plan in place for the majority of its employees. Contributions to the pension plan are established by actuarial valuations which are required to be filed with the Financial Services Regulatory Authority of Ontario on a triennial basis. The most recently filed valuation was prepared as at December 31, 2024, and was filed in September 2025, covering a three-year period from 2025 to 2027. The next required valuation will be prepared as at December 31, 2027 and is expected to be filed by no later than September 2028. Hydro One's contributions to its pension plan satisfy, and are expected to continue to satisfy, minimum funding requirements. Contributions beyond 2027 will depend on the funded position of the plan, which is determined by investment returns, interest rates and changes in benefits and actuarial assumptions at that time. A determination by the OEB that some of the Company's pension expenditures are not recoverable through rates could have a material adverse effect on the Company, and this risk may be exacerbated if the amount of required pension contributions increases.

Hydro One currently reports and recovers its pension costs on a cash basis, and maintains the accrual method with respect to OPEBs. Transitioning from the cash basis to an accrual method for pension costs may have material negative rate impacts for customers or material negative impacts on the Company should recovery of costs be disallowed by the OEB.

See also "Regulatory Risks and Risks Relating to Hydro One's Revenues - Risk of Recoverability of Total Compensation Costs" for risks relating to recovery of pension costs.

Risk from Provincial Ownership of Transmission Corridors

The Province owns some of the corridor lands underlying the Company's transmission system. Although the Company has the statutory right to use these transmission corridors, the Company may be limited in its options to expand or operate its systems. Also, other uses of the transmission corridors by third parties in conjunction with the operation of the Company's systems, or adjacent land use by third parties, may increase safety or environmental risks, which could have a material adverse effect on the Company.

Litigation Risks

In the normal course of the Company's operations, it becomes involved in, is named as a party to and is the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to actual or alleged violations of law, common law damages claims, personal injuries, property damage, property taxes, land rights, the environment, contract disputes, claims by former employees and claims and proceedings by Indigenous groups. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Company, which could have a material adverse effect on the Company. Even if the Company prevails in any such legal proceeding, the proceedings could be costly and time-consuming and would divert the attention of management and key personnel from the Company's business operations, which could adversely affect the Company.

Transmission Assets on Third-Party Lands Risk

Some of the lands on which the Company's transmission assets are located are owned by third parties, including the Province and federal Crown, and are or may become subject to land claims by First Nations. The Company requires valid occupation rights to occupy such lands (which may take the form of land use permits, easements or otherwise). If the Company does not have valid occupational rights on third-party owned or controlled lands or has occupancy rights that are subject to expiry, it may incur material costs to obtain or renew such occupancy rights, or if such occupancy rights cannot be renewed or obtained it may incur material costs to remove and relocate its assets and restore the subject land. If the Company does not have valid occupancy rights and must incur costs as a result, this could have a material adverse effect on the Company or otherwise materially adversely impact the Company's operations.

Reputational, Public Opinion and Political Risk

Reputation risk is the risk of negative publicity or the public's negative perceptions towards Hydro One and the electricity industry that may result in a detrimental impact to Hydro One's business, operations or financial condition leading to a deterioration of Hydro One's reputation. Hydro One's reputation and/or brand could be negatively impacted by changes in public opinion, attitudes towards the Company's privatization, failure to deliver on its customer and/or stakeholder promises, failure to comply with mandatory reliability regulations established by the NERC and NPCC, failure to adequately respond to social issues raised by employees, partners and/stakeholders and other external forces. Adverse reputational events or political actions could have a material adverse effect on Hydro One's business and prospects including, but not limited to, delays or denials of requisite

approvals, such as denial of requested rates, and accommodations for Hydro One's planned projects, escalated costs, legal or regulatory action, and damage to stakeholder and community relationships. Any of these could have a material adverse impact on Hydro One and its business, financial condition and results of operations.

Risks Associated with Acquisitions

Acquisitions include inherent risks that some or all of the expected benefits may fail to materialize, or may not occur within the time periods anticipated, and Hydro One may incur material unexpected costs or liabilities. Realization of the anticipated benefits would depend, in part, on the Company's ability to successfully integrate the acquired business, including the requirement to devote management attention and resources to integrating business practices and support functions. The failure to realize the anticipated benefits, the diversion of management's attention, or any delays or difficulties encountered in connection with the integration could have an adverse effect on the Company's business, results of operations, financial condition or cash flows.

Infectious Disease Risk

An outbreak of infectious disease, in the form of an epidemic, a pandemic, or a similar public health threat, could materially adversely impact the Company. The extent of any such adverse impact on the Company is uncertain, and may depend on the length and severity of any such infectious disease outbreak, any resultant government regulations, guidelines and actions, and any related adverse changes in general economic and market conditions. Such circumstances could impact, in particular: the Company's operations and workforce, including security of supply, both with respect to availability and affordability, which individually or collectively may impact the Company's ability to complete operating and capital work programs as planned, including within scope and budget; certain financial obligations of the Company, including pension contributions and other post-retirement benefits, as a result of changes in prevailing market conditions; the Company's expected revenues; reductions in overall electricity consumption and load, both short term and long term; overdue accounts and bad debt increases as a result of changes in the ability of the Company's customers to pay; liquidity and the Company's ability to raise capital; the Company's ability to pay or increase dividends; the timing of increased rates; the Company's ability to recover incremental costs and lost revenues linked to the outbreak; the Company's ability to file regulatory filings on a timely basis; timing of regulatory decisions and the impacts those decisions may have on the Company or its ability to implement them; and customer and stakeholder needs and expectations.

The Company also faces risks and costs associated with implementation of business continuity plans and modified work conditions, including the risks and costs associated with maintaining or reducing its workforce, making the required resources available to its workforce to enable essential work, including remotely where possible, and to keep its workforce healthy, as well as risks and costs associated with recovery of normal operations. Furthermore, the Company is dependent on third party providers for certain activities, and relies on a strong international supply chain. Any significant disruption to those providers or the supply chain resulting from an outbreak of infectious disease could materially adversely impact the Company.

Risks Relating to the Common Shares of Hydro One Limited

Hydro One's common shares trade on the TSX. The trading price of the common shares has in the past been, and may in the future be, subject to significant fluctuations. These fluctuations may be caused by events or factors related or unrelated to Hydro One's operating performance and/or beyond its control, including: the risk factors described herein; general economic conditions within Ontario and Canada and globally, including changes in interest rates; inflation; the potential imposition of duties, tariffs or trade restrictions; changes in electricity prices; changes in electricity demand; weather conditions; actual or anticipated fluctuations in Hydro One's quarterly and annual results and the results of public companies similar to Hydro One; Hydro One's businesses, operations, results and prospects; Hydro One's reputation and its relationship with the Province; the timing and amount of dividends, if any, declared on the common shares; future issuances of common shares or other securities by Hydro One or Hydro One Inc.; Hydro One's relationship with its regulator; changes in government regulation, taxes, legal proceedings or other developments; shortfalls in Hydro One's operating results from levels forecasted by securities analysts; investor sentiment toward energy companies in general or companies adopting ESG performance and reporting practices and the achievement by companies of ESG targets; maintenance of acceptable credit ratings or credit quality; and the general state of the securities markets. These and other factors may impair the development or sustainability of a liquid market for the common shares and the ability of investors to sell common shares at an attractive price.

Risks Relating to the Company's Relationship with the Province

Ownership and Continued Influence by the Province and Voting Power; Share Ownership Restrictions

The Province currently owns approximately 47.1% of the outstanding common shares of Hydro One. The Electricity Act restricts the Province from selling voting securities of Hydro One (including common shares) of any class or series if it would own less than 40% of the outstanding number of voting securities of that class or series after the sale and in certain circumstances also requires the Province to take steps to maintain that level of ownership. Accordingly, the Province is expected to continue to maintain a significant ownership interest in voting securities of Hydro One for an indefinite period.

As a result of its significant ownership of the common shares of Hydro One, the Province has, and is expected indefinitely to have, the ability to determine or significantly influence the outcome of shareholder votes, subject to the restrictions in the Governance Agreement between Hydro One and the Province dated November 5, 2015 (Governance Agreement) (available on SEDAR+ at www.sedarplus.com). Despite the terms of the Governance Agreement in which the Province has agreed to engage in the business and affairs of the Company as an investor and not as a manager, there is a risk that the Province's engagement in the business and affairs of the Company as an investor will be informed by its policy objectives and may influence the conduct of the business and affairs of the Company in ways that may not be aligned with the interests of other investors. Notwithstanding the Governance Agreement, and in light of actions historically taken by the Province, there can be no assurance that the Province will not take other actions in the future that could be detrimental to the interests of investors in Hydro One. See "Risks Relating to Government Action" above.

The share ownership restrictions in the Electricity Act (Share Ownership Restrictions) and the Province's significant ownership of common shares of Hydro One together effectively prohibit one or more persons acting together from acquiring control of Hydro One. They also may limit or discourage transactions involving other fundamental changes to Hydro One and the ability of other shareholders to successfully contest the election of the directors proposed for election pursuant to the Governance Agreement. The Share Ownership Restrictions may also discourage trading in, and may limit the market for, the common shares and other voting securities.

Nomination of Directors and Confirmation of Chief Executive Officer (CEO) and Chair

Although director nominees (other than the CEO) are required to be independent of both the Company and the Province pursuant to the Governance Agreement, there is a risk that the Province will nominate or confirm individuals who satisfy the independence requirements but who it considers are disposed to support and advance its policy objectives and give disproportionate weight to the Province's interests in exercising their business judgment and balancing the interests of the stakeholders of Hydro One. This, combined with the fact certain matters require a two-thirds vote of the Board, could allow the Province to unduly influence certain Board actions such as confirmation of the Chair and confirmation of the CEO.

Board Removal Rights

Under the Governance Agreement, the Province has the right to withhold from voting in favour of all director nominees and has the right to seek to remove and replace the entire Board, including in each case its own director nominees but excluding the CEO and, at the Province's discretion, the Chair. In exercising these rights in any particular circumstance, the Province is entitled to vote in its sole interest, which may not be aligned with the interests of other stakeholders of Hydro One.

More Extensive Regulation

Although under the Governance Agreement, the Province has agreed to engage in the business and affairs of Hydro One as an investor and not as a manager and has stated that its intention is to achieve its policy objectives through legislation and regulation as it would with respect to any other utility operating in Ontario, there is a risk that the Province will exercise its legislative and regulatory power to achieve policy objectives in a manner that has a material adverse effect on the Company. See "Risks Relating to Government Action" above.

Prohibitions on Selling the Company's Transmission or Distribution Business

The Electricity Act prohibits the Company from selling all or substantially all of the business, property or assets related to its transmission system or distribution system that is regulated by the OEB. There is a risk that these prohibitions may limit the ability of the Company to engage in sale transactions involving a substantial portion of either system, even where such a transaction may otherwise be considered to provide substantial benefits to the Company and the holders of the common shares.

Future Sales of Common Shares by the Province

Although the Province has indicated that it does not intend to sell further common shares of Hydro One, the registration rights agreement between Hydro One and the Province dated November 5, 2015 (available on SEDAR+ at www.sedarplus.com) grants the Province the right to request that Hydro One file one or more prospectuses and take other procedural steps to facilitate secondary offerings by the Province of the common shares of Hydro One. Future sales of common shares of Hydro One by the Province, or the perception that such sales could occur, may materially adversely affect market prices for these common shares and impede Hydro One's ability to raise capital through the issuance of additional common shares, including the number of common shares that Hydro One may be able to sell at a particular time or the total proceeds that may be realized.

Limitations on Enforcing the Governance Agreement

The Governance Agreement includes commitments by the Province restricting the exercise of its rights as a holder of voting securities, including with respect to the maximum number of directors that the Province may nominate and on how the Province will vote with respect to other director nominees. Hydro One's ability to obtain an effective remedy against the Province, if the Province were not to comply with these commitments, is limited as a result of the *Proceedings Against the Crown Act* (Ontario). This legislation provides that the remedies of injunction and specific performance are not available against the Province, although a court may make an order declaratory of the rights of the parties, which may influence the Province's actions. A remedy of damages would be available to Hydro One, but damages may not be an effective remedy, depending on the nature of the Province's non-compliance with the Governance Agreement.

CRITICAL ACCOUNTING ESTIMATES AND JUDGMENTS

The preparation of Hydro One Consolidated Financial Statements requires the Company to make key estimates and critical judgments that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. Hydro One bases its estimates and judgments on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities, as well as identifying and assessing the Company's accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgments. Hydro One has identified the following critical accounting estimates and judgments used in the preparation of its Consolidated Financial Statements:

Revenues

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues. Billed revenues are based on the amount of electricity delivered as measured from customer meters. At the end of each month, the amount of electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption and changes in the composition of customer classes.

Regulatory Assets and Liabilities

Hydro One's regulatory assets represent certain amounts receivable from electricity customers in a future period and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities that generally represent amounts that are refundable to electricity customers in future rates. The regulatory assets mainly include amounts related to the deferred income taxes, post-retirement and post-employment non-service costs, costs related to designated broadband projects, environmental liabilities and share-based compensation costs. The Company's regulatory liabilities pertain primarily to deferral and variance accounts, and include amounts related to the pension benefit liability. The regulatory assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the amounts have been approved for inclusion in the electricity rates by the OEB, or if such approval is judged to be probable by management. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will include its regulatory assets and regulatory liabilities in setting future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or regulatory liability in setting future rates, the respective carrying amount would be reflected in results of operations, prospectively from the date the Company's assessment is made.

Employee Future Benefits

Hydro One's employee future benefits consist of pension and post-retirement and post-employment plans, and include pension, group life insurance, health care, and long-term disability benefits provided to the Company's current and retired employees. Employee future benefits costs are included in Hydro One's labour costs that are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets. Changes in assumptions affect the benefit obligation of the employee future benefits and the amounts that will be charged to results of operations or capitalized in future years. The following significant assumptions and estimates are used to determine employee future benefit costs and obligations:

Weighted Average Discount Rate

The weighted average discount rate used to calculate the employee future benefits obligation is determined at each year end by referring to the most recently available market interest rates based on "AA"-rated corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rate as at December 31, 2025 increased to 5.02% (2024 - 4.73%) for pension benefits and increased to 5.05% (2024 - 4.75%) for the post-retirement and post-employment plans. The increase in the discount rate has resulted in a corresponding decrease in employee future benefits liabilities for the pension, post-retirement and post-employment plans for accounting purposes. The liabilities are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates.

Expected Rate of Return on Plan Assets

The expected long-term rate of return on pension plan assets is 7.20% for the year ended December 31, 2025 (2024 - 7.00%). This rate is based on the long-term return expectations at the beginning of 2025 and reflects the pension plan target asset mix set out in the Statement of Investment Policies and Procedures dated August 13, 2024.

Rates of return on the respective portfolios are determined with reference to respective published market indices. The expected rate of return on pension plan assets reflects the Company's long-term expectations. The Company believes that this assumption is reasonable because, with the pension plan's balanced investment approach, the higher volatility of equity investment returns is intended to be offset by the greater stability of fixed-income and short-term investment returns. The net result, on a long-term basis, is a lower return than might be expected by investing in equities alone. In the short term, the pension plan can experience fluctuations in actual rates of return.

Rate of Cost of Living Increase

The rate of cost of living increase is determined by considering differences between long-term Government of Canada nominal bonds and real return bonds, which increased from 1.81% per annum as at December 31, 2024 to approximately 1.89% per annum as at December 31, 2025. Based on the Bank of Canada's commitment to keep long-term inflation between 1.00% and 3.00%, in addition to current and anticipated trends, management believes that a long-term assumption of 2.00% per annum is reasonable for employee future benefits liability valuation purposes as at December 31, 2025 (2024 - 2.00%).

Salary Increase Assumptions

Salary increases should reflect general wage increases plus an allowance for merit and promotional increases for current members of the Plan and should be consistent with the assumptions for consumer price inflation and real wage growth in the economy. The merit and promotion scale was developed based on the salary increase assumption review performed in 2025. The review considered actual salary experience from 2019 to 2024 using valuation data for all active employees with defined benefit pension entitlements (split by age and service) and Hydro One's expectation of future salary increases. Additionally, the salary scale reflects negotiated salary increases over the contract period.

Mortality Assumptions

The Company's employee future benefits liability is also impacted by changes in life expectancies used in mortality assumptions. Increases in life expectancies of plan members result in increases in the employee future benefits liability. For the pension and post-retirement plans, the mortality assumption used as at December 31, 2025 is 90% of the 2014 Canadian Pensioners Mortality Private Sector table, projected generationally using an updated mortality improvement scale from the *Mortality Improvements Research* report, that was published by the Canadian Institute of Actuaries in April 2024 (scale "MI-2024"). The assumption at December 31, 2024 used mortality improvement Scale CPM-B. The multiplier applied to the assumed mortality table is based on the result of a mortality experience study that was conducted in 2021. For the post-employment plan, the mortality assumption used as at December 31, 2025 is the disability mortality table from the 2009 to 2015 Canadian Institute of Actuaries Group Long Term Disability Termination Study, which is the most recent publicly available table that reflects Canadian experience and is commonly used by Canadian plan sponsors.

Rate of Increase in Health Care Cost Trends

The costs of post-retirement and post-employment benefits are determined at the beginning of the year and are based on assumptions for expected claims experience and future health care cost inflation. For the post-retirement benefit plans, a study of Hydro One's historical per capita health care cost trend experience was conducted in 2017. The health and dental trends reflect the results of this study as well as macroeconomic inputs such as the expected long-term rates of general inflation and real GDP growth. The environment of high general inflation that was present in Canada in 2022 and 2023 resulted in short-term upward pressure on the cost of certain medical services covered by Hydro One's post-retirement and post-employment benefit plans. However, these effects were muted somewhat by plan design and government regulation. These effects in 2023 as well as any residual effects that have occurred in 2024 and 2025 have been captured though the use of actual claims experience from 2023, 2024 and year-to-date 2025 (through November 30) in the development of the per capita claims cost assumptions being used for the December 31, 2025 disclosures. Based on the above, Hydro One is not making any changes to its health care trend rate assumptions for the December 31, 2025 disclosures from what was used at December 31, 2024.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Disclosure controls and procedures are the processes designed to ensure that information is recorded, processed, summarized and reported on a timely basis to the Company's management, including its CEO and Chief Financial and Regulatory Officer (CFRO), as appropriate, to make timely decisions regarding required disclosure in the MD&A and consolidated financial statements. At the direction of the Company's CEO and CFRO, management evaluated disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, management concluded that the Company's disclosure controls and procedures were effective as at December 31, 2025.

Internal control over financial reporting is designed by, or under the direction of the CEO and CFRO to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with U.S. GAAP. The Company's internal control over financial reporting framework includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and disposition of the assets of the Company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of consolidated financial statements in accordance with U.S. GAAP, and that receipts and expenditures of the Company are being made only in accordance with authorization of management and directors of the Company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the Company's consolidated financial statements.

The Company's management, at the direction of the CEO and CFRO, evaluated the effectiveness of the design and operation of internal control over financial reporting based on the criteria established in the Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as at December 31, 2025.

Internal controls, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives and due to its inherent limitations, may not prevent or detect all misrepresentations. Furthermore, the effectiveness of internal control is affected by change and subject to the risk that internal control effectiveness may change over time.

There were no changes in the design of the Company's internal control over financial reporting during the three months ended December 31, 2025 that have materially affected, or are reasonably likely to materially affect, the operation of the Company's internal control over financial reporting.

Management will continue to monitor its systems of internal control over reporting and disclosure and may make modifications from time to time as considered necessary.

NEW ACCOUNTING PRONOUNCEMENTS

The following table presents Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board (FASB) that are applicable to Hydro One:

Recently Adopted Accounting Guidance

Guidance	Date issued	Description	ASU Effective Date	Impact on Hydro One
ASU 2024-02	March 2024	The amendments contain modifications to the codification that remove various concept statements which may be extraneous and not required to understand or apply the guidance or references used in prior statements to provide guidance in certain topical areas.	Fiscal years beginning after December 15, 2024.	No impact upon adoption
ASU 2023-09	December 2023	The amendments address investor requests for more transparency about income tax information through improvements to income tax disclosures primarily related to the rate reconciliation and income taxes paid information.	Annual periods beginning after December 15, 2024.	Adoption of the standard does not materially affect Hydro One's income tax disclosures.

Recently Issued Accounting Guidance Not Yet Adopted

Guidance	Date issued	Description	ASU Effective Date	Impact on Hydro One
ASU 2023-06	October 2023	The amendments represent changes to clarify or improve disclosure or presentation requirements of a variety of subtopics in the FASB Codification. Many of the amendments allow users to more easily compare entities subject to the U.S. Securities and Exchange's (SEC) existing disclosures with those entities that were not previously subject to the SEC's requirements. Also, the amendments align the requirements in the Codification with the SEC's regulations. Applicable to all entities, if by June 30, 2027 the SEC has not removed the applicable requirement from Regulation S-X or Regulation S-K, the pending content of the related amendment will be removed from the Codification and will not become effective for any entity.	Two years subsequent to the date on which the SEC's removal of that related disclosure becomes effective.	Under assessment
ASU 2024-03	November 2024	The amendments require public business entities to disclose additional information about specific expense categories in the notes to financial statements at interim and annual reporting periods, which are not generally presented in the current financial statements.	Annual periods beginning after December 15, 2026, and interim periods beginning after December 15, 2027.	Under assessment
ASU 2025-03	May 2025	The amendments require entities to apply the guidance for identifying the accounting acquirer in transactions where a business that qualifies as a Variable Interest Entity is acquired through the exchange of equity interests.	Annual and interim periods beginning after December 15, 2026.	No impact upon adoption
ASU 2025-05	July 2025	The amendments allow all entities to use a practical expedient when estimating expected credit losses for current accounts receivable and contract assets under Topic 606, by assuming that current conditions as of the balance sheet date remain unchanged over the asset's life. Additionally, entities other than public business entities that elect this expedient may adopt an accounting policy to consider post–balance sheet date collection activity in their credit loss estimates.	Annual and interim periods beginning after December 15, 2025.	No impact upon adoption
ASU 2025-06	September 2025	The amendments modernize accounting for internal-use software by removing outdated development stage references and introducing a capitalization threshold based on management authorization and project completion probability.	Annual periods beginning after December 15, 2027.	Under assessment
ASU 2025-09	November 2025	The amendments expand hedge-accounting eligibility and better align the guidance with common risk-management practices. Key updates allow grouping forecasted transactions with similar exposure, simplify hedging of choose-your-rate variable-rate debt, and broaden eligibility for hedging nonfinancial components. The guidance modernizes treatment of certain option-based derivatives and resolves mismatches in dual hedge relationships.	Annual and interim periods beginning after December 15, 2026.	Under assessment
ASU 2025-10	December 2025	The amendments establish authoritative GAAP for government grants, setting recognition, measurement, presentation, and disclosure requirements.	Annual and interim periods beginning after December 15, 2028.	Under assessment
ASU 2025-11	December 2025	The amendments clarify interim reporting by establishing a complete list of required GAAP interim disclosures. They introduce a disclosure principle requiring entities to report material events occurring after the annual reporting period. The Update also clarifies types of interim reports and the form and content of interim financial statements. Overall, the changes enhance clarity and consistency without altering existing disclosure requirements.	Interim reporting periods within annual reporting periods beginning after December 15, 2027.	Under assessment
ASU 2025-12	December 2025	The amendments clarify existing guidance, correct errors, and introduce minor improvements to numerous Codification Topics, thereby making the requirements easier for entities to understand and apply.	Annual and interim periods beginning after December 15, 2026.	Under assessment

SUMMARY OF FOURTH QUARTER RESULTS OF OPERATIONS

Three months ended December 31 *(millions of dollars, except EPS)*	2025	2024	Change
Revenues			
Transmission	491	505	(2.8%)
Distribution	1,757	1,583	11.0%
Other	20	7	185.7%
	2,268	2,095	8.3%
Costs			
Purchased power	1,287	1,060	21.4%
OM&A			
Transmission	80	128	(37.5%)
Distribution	153	204	(25.0%)
Other	25	41	(39.0%)
	258	373	(30.8%)
Depreciation, amortization and asset removal costs	287	286	0.3%
	1,832	1,719	6.6%
Income before financing charges, equity income and income tax expense	**436**	**376**	**16.0%**
Financing charges	175	158	10.8%
Equity income	3	—	—%
Income before income tax expense	**264**	**218**	**21.1%**
Income tax expense	30	17	76.5%
Net income	**234**	**201**	**16.4%**
Net income attributable to common shareholders of Hydro One	**233**	**200**	**16.5%**
Basic EPS	$0.39	$0.33	18.2%
Diluted EPS	$0.39	$0.33	18.2%
Assets Placed In-Service			
Transmission	953	754	26.4%
Distribution	351	342	2.6%
Other	6	4	50.0%
	1,310	**1,100**	**19.1%**
Capital Investments			
Transmission	629	476	32.1%
Distribution	303	313	(3.2%)
Other	7	10	(30.0%)
	939	**799**	**17.5%**

Net Income

Net income attributable to common shareholders for the quarter ended December 31, 2025 of $233 million is $33 million, or 16.5%, higher than the same period in the prior year, primarily due to:

- lower OM&A costs primarily resulting from lower corporate support costs; partially offset by
- lower revenues, net of purchased power,[8] resulting from regulatory adjustments, primarily due to higher earnings sharing in the current period, partially offset by higher revenues resulting from higher average monthly peak demand and energy consumption, as well as increased transmission and distribution revenues due to OEB-approved 2025 rates;
- higher financing charges attributable to an increase in outstanding long-term debt, partially offset by higher capitalized interest; and
- higher income tax expense primarily resulting from higher pre-tax earnings.

EPS

Basic EPS was $0.39 in the fourth quarter of 2025, compared to Basic EPS of $0.33 in the fourth quarter of 2024.

Revenues

The year-over-year decrease of $14 million, or 2.8%, in transmission revenues during the quarter primarily resulted from:

- regulatory adjustments, including a higher earnings sharing accrual in the current period; partially offset by
- higher average monthly peak demand; and
- higher revenues resulting from OEB-approved 2025 rates.

The year-over-year increase of $174 million, or 11.0%, in distribution revenues during the quarter primarily resulted from:

- higher purchased power costs, which are fully recovered from ratepayers and thus net income neutral;
- higher revenues resulting from OEB-approved 2025 rates; and
- higher energy consumption; partially offset by
- regulatory adjustments, mainly attributable to a higher earnings sharing accrual in the current period; and
- lower revenue associated with mutual storm assistance costs recovered from third parties in the prior year, which is offset in OM&A and therefore net income neutral.

Distribution revenues, net of purchased power,[8] decreased by 10.1% during the fourth quarter of 2025 compared to the prior year primarily due to:

- regulatory adjustments, including a higher earnings sharing accrual in the current period; and
- lower revenue associated with mutual storm assistance costs recovered from third parties, which is offset in OM&A and therefore net income neutral; partially offset by
- higher revenues resulting from OEB-approved 2025 rates; and
- higher energy consumption.

OM&A Costs

The year-over-year decrease of $48 million, or 37.5%, in transmission OM&A costs during the quarter was primarily due to:

- severance costs in the prior year;
- lower corporate support costs; and
- lower work program expenditures, including work related to facilities maintenance and vegetation management.

The year-over-year decrease of $51 million, or 25.0%, in distribution OM&A costs during the quarter was primarily due to:

- severance costs in the prior year;
- net income neutral items, including mutual storm assistance costs and lower fuel costs of Hydro One Remotes, both of which are offset in revenue; and
- lower corporate support costs; partially offset by
- higher work program expenditures, including emergency restoration and vegetation management.

The year-over-year decrease of $16 million, or 39.0%, in other OM&A costs during the quarter was due to various factors, including lower costs in Acronym primarily due to higher third party service costs in the prior year.

Depreciation, Amortization and Asset Removal Costs

Depreciation, amortization and asset removal costs for the fourth quarter of 2025 were comparable to the same period in 2024.

[8] See section "Non-GAAP Financial Measures".

Financing Charges

The $17 million, or 10.8%, increase in financing charges for the quarter ended December 31, 2025, was primarily due to an increase in outstanding long-term debt, partially offset by higher capitalized interest.

Income Tax Expense

Income tax expense for the fourth quarter of 2025 increased by $13 million compared to the same period in 2024. This resulted in a realized ETR of approximately 11.4% in the fourth quarter of 2025, compared to approximately 7.8% in the fourth quarter of the prior year.

The increase in ETR for the three months ended December 31, 2025 was primarily attributable to:

- higher pre-tax earnings; and
- lower deductible timing differences compared to the prior year.

Assets Placed In-Service

The increase in transmission assets placed in-service during the fourth quarter was primarily due to:

- timing of assets placed in-service for station refurbishments and replacements, including the Bruce A Transmission station, the Merivale Transmission Station, and the Lauzon Transmission Station; and
- investments placed in-service for customer connection projects; partially offset by
- investments placed in-service for the Chatham to Lakeshore Transmission Line; and
- lower volume of line refurbishments and wood pole replacements.

The increase in distribution assets placed in-service during the fourth quarter was primarily due to:

- investments placed in-service for Ontario's broadband initiative;
- assets placed in-service for the AMI 2.0 system; and
- higher volume of assets placed in-service for customer connections; partially offset by
- lower volume of wood pole replacements and line refurbishments;
- timing of assets placed in-service for system capability reinforcement projects; and
- assets placed in-service for the Orleans Operation Centre in the prior year.

Capital Investments

The increase in transmission capital investments during the fourth quarter was primarily due to:

- higher investments in the Waasigan Transmission Line Project;
- investments in the St. Clair Transmission Line Project;
- higher spend on major development projects; and
- higher spend on customer connections; partially offset by
- lower volume of line refurbishments and wood pole replacements.

The decrease in distribution capital investments during the fourth quarter was primarily due to:

- lower volume of wood pole replacements;
- investments in the Orillia Distribution Warehouse, Orillia Operation Centre, and Orleans Operation Centre; and
- lower volume of PCB transformer replacements; partially offset by
- investments in Ontario's broadband initiative; and
- investments in the AMI 2.0 system.

HOHL - CONSOLIDATING SUMMARY FINANCIAL INFORMATION

Hydro One Limited fully and unconditionally guarantees the payment obligations of its wholly-owned subsidiary, HOHL, issuable under the short form base shelf prospectus dated November 29, 2024. Accordingly, the following consolidating summary financial information is provided in compliance with the requirements of section 13.4 of National Instrument 51-102 - *Continuous Disclosure Obligations* providing for an exemption for certain credit support issuers. The tables below contain consolidating summary financial information as at and for the years ended December 31, 2025 and December 31, 2024 for: (i) Hydro One Limited; (ii) HOHL; (iii) the subsidiaries of Hydro One Limited, other than HOHL, on a combined basis; (iv) consolidating adjustments; and (v) Hydro One Limited and all of its subsidiaries on a consolidated basis, in each case for the periods indicated. Such summary financial information is intended to provide investors with meaningful and comparable financial information about Hydro One Limited and its subsidiaries. This summary financial information should be read in conjunction with Hydro One Limited's most recently issued annual and interim financial statements. This summary financial information has been prepared in accordance with U.S. GAAP, as issued by the FASB.

Year ended December 31 *(millions of dollars)*	**Hydro One Limited**		**HOHL**		**Subsidiaries of Hydro One Limited, other than HOHL**		**Consolidating Adjustments**		**Total Consolidated Amounts of Hydro One Limited**	
	2025	**2024**	**2025**	**2024**	**2025**	**2024**	**2025**	**2024**	**2025**	**2024**
Revenue	794	757	—	—	10,115	9,462	(1,868)	(1,735)	9,041	8,484
Net Income (Loss) Attributable to Common Shareholders	825	777	—	—	2,248	1,978	(1,734)	(1,599)	1,339	1,156

As at December 31 *(millions of dollars)*	**Hydro One Limited**		**HOHL**		**Subsidiaries of Hydro One Limited, other than HOHL**		**Consolidating Adjustments**		**Total Consolidated Amounts of Hydro One Limited**	
	2025	**2024**	**2025**	**2024**	**2025**	**2024**	**2025**	**2024**	**2025**	**2024**
Current Assets	940	953	—	—	4,172	4,229	(2,938)	(3,065)	2,174	2,117
Non-Current Assets	3,295	3,226	—	—	59,529	54,743	(25,327)	(23,404)	37,497	34,565
Current Liabilities	1,075	1,061	—	—	5,420	5,468	(2,905)	(3,028)	3,590	3,501
Non-Current Liabilities	425	425	—	—	40,475	36,291	(17,565)	(15,708)	23,335	21,008

FORWARD-LOOKING STATEMENTS AND INFORMATION

The Company's oral and written public communications, including this document, often contain "forward-looking information" within the meaning of applicable Canadian securities laws and "forward-looking statements" within the meaning of applicable U.S. securities laws (collectively, "forward-looking information"). Statements containing forward-looking information are made pursuant to the "safe harbour" provisions of applicable Canadian and U.S. securities laws. Forward-looking information in this document is based on current expectations, estimates, forecasts and projections about the Company's business, the industry, regulatory and economic environments in which it operates, and includes beliefs and assumptions made by the management of the Company. Such statements include, but are not limited to, statements regarding: the Company's corporate strategy; the Company's transmission and distribution rate and revenue requirement applications including the JRAP and its proposed investment plan, resulting and related decisions as well as resulting rates, recovery and expected impacts and timing; expectations about the Company's liquidity and capital resources and operational requirements; sustainability goals; the Operating Credit Facilities; expectations regarding the Company's financing activities; the Company's maturing debt; expectations and impact of the Company's credit ratings; the Company's ongoing and planned projects, initiatives and expected capital investments, including expected approvals, results, costs, funding sources and in-service and completion dates; expectations regarding the Company's Z-Factor application and impacts of its outcome; contractual obligations and other commercial commitments; the BBFA, as well as related regulations, and expected impacts; expectations regarding the Ministry's subsidies program to ISPs and its results and expected timeline; the Company's assessment of recovery and impacts related to the OEB-established generic variance and deferral accounts; expected impacts and results of the OEB's new cost of capital parameters; future pension plan contributions, including estimates of total Company pension contributions; the expected advancement and construction of various transmission stations and transmission lines in connection with the Province's first integrated energy plan and the target in-service dates; collective agreements and bargaining; Protect Ontario by Unleashing our Economy Act and expected impacts; the Company's expectations regarding participation in the TSF Registry and expected engagement with IESO and industry and the government decision on potential competitive procurement projects; dividends; non-GAAP financial measures; internal controls over financial reporting and disclosure; the MTN Program, including the expected filing of a new MTN Program prospectus; and accounting-related guidance and expected impacts. Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will," "would," "believe," "seek," "estimate," "goal," "aim," "target," and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore,

actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. Hydro One does not intend, and it disclaims any obligation, to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to, the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market or for Hydro One specifically; favourable decisions from the OEB and other regulatory bodies concerning outstanding and future rate and other applications; no unexpected delays in obtaining required regulatory approvals; no unforeseen changes in rate orders or rate setting methodologies for the Company's distribution and transmission businesses; no unfavourable changes in environmental regulation; continued use of U.S. GAAP; a stable regulatory environment; no significant changes to the Company's current credit ratings; no unforeseen impacts of new accounting pronouncements; no changes to expectations regarding electricity consumption; no unforeseen changes to economic and market conditions; completion of operating and capital projects that have been deferred; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to the Company, including information obtained from third-party sources. Actual results may differ materially from those predicted by such forward-looking statements. While Hydro One does not know what impact any of these differences may have, the Company's business, results of operations, financial condition and credit stability may be materially adversely affected if any such differences occur. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- regulatory risks and risks relating to Hydro One's revenues, including risks relating to actual performance against forecasts, competition with other transmitters and other applications to the OEB, the rate-setting models for transmission and distribution, the recoverability of capital expenditures, obtaining rate orders or recoverability of total compensation costs;
- risks associated with the Province's share ownership of Hydro One and other relationships with the Province, including potential conflicts of interest that may arise between Hydro One, the Province and related parties, risks associated with the Province's exercise of further legislative and regulatory powers, risks relating to the ability of the Company to attract and retain qualified executive talent or the risk of a credit rating downgrade for the Company and its impact on the Company's funding and liquidity;
- risks relating to the location of the Company's assets on Reserve lands, that the Company's operations and activities may give rise to the Crown's duty to consult and potentially accommodate Indigenous communities, and the risk that Hydro One may incur significant costs associated with transferring assets located on Reserves;
- the risk that the Company may be unable to comply with regulatory and legislative requirements or that the Company may incur additional costs for compliance that are not recoverable through rates;
- the risk of exposure of the Company's facilities to the effects of severe weather conditions, natural disasters, man-made events or other unexpected occurrences for which the Company is uninsured or for which the Company could be subject to claims for damage;
- risks associated with information system security and maintaining complex information technology and OT system infrastructure, including system failures or risks of cyber-attacks or unauthorized access to corporate information technology and OT systems;
- the risk of non-compliance with environmental regulations and inability to recover environmental expenditures in rate applications and the risk that assumptions that form the basis of the Company's recorded environmental liabilities and related regulatory assets may change;
- the risk of labour disputes and inability to negotiate or renew appropriate collective agreements on acceptable terms consistent with the Company's rate decisions;
- the risk that the Company may not be able to execute plans for capital projects necessary to maintain the performance of the Company's assets or to carry out projects in a timely manner or the risk of increased competition for the development of large transmission projects or legislative changes affecting the selection of transmitters;
- risks associated with asset condition, capital projects and innovation, including public opposition to or delays or denials of the requisite approvals and accommodations for the Company's planned projects;
- risks related to the Company's work force demographic and its potential inability to attract and retain qualified personnel;
- the risk that the Company is not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures, the risk of a downgrade in the Company's credit ratings or risks associated with investor interest in ESG performance and reporting;
- risks associated with fluctuations in interest rates and failure to manage exposure to credit and financial instrument risk;
- risks associated with economic uncertainty and financial market volatility;
- the risk of failure to mitigate significant health and safety risks;
- the risk of not being able to recover the Company's pension expenditures in future rates and uncertainty regarding the future regulatory treatment of pension, other post-employment benefits and post-retirement benefits costs;
- the impact of the ownership by the Province of lands underlying the Company's transmission system;
- the risk associated with legal proceedings that could be costly, time-consuming or divert the attention of management and key personnel from the Company's business operations;
- the impact if the Company does not have valid occupational rights on third-party owned or controlled lands and the risks associated with occupational rights of the Company that may be subject to expiry;
- risks relating to adverse reputational events or political actions relating to Hydro One and the electricity industry;

- the potential that Hydro One may incur significant expenses to replace functions currently outsourced if agreements are terminated or expire before a new service provider is selected;
- risks relating to acquisitions, including the failure to realize the anticipated benefits of such transactions at all, or within the time periods anticipated, and unexpected costs incurred in relation thereto;
- risks relating to an outbreak of infectious disease;
- the inability to continue to prepare financial statements using U.S. GAAP; and
- the risk related to the impact of any new accounting pronouncements.

Hydro One cautions the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail in the section entitled "Risk Management and Risk Factors" in this MD&A.

In addition, Hydro One cautions the reader that information provided in this MD&A regarding the Company's outlook on certain matters, including potential future investments, is provided in order to give context to the nature of some of the Company's future plans and may not be appropriate for other purposes.

Additional information about Hydro One, including the Company's Annual Information Form, is available on SEDAR+ at www.sedarplus.com, the U.S. Securities and Exchange Commission's EDGAR website at www.sec.gov/edgar.shtml, and the Company's website at www.HydroOne.com/Investors.

The Consolidated Financial Statements, Management's Discussion and Analysis (MD&A) and related financial information have been prepared by the management of Hydro One Limited (Hydro One or the Company). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements for the year ended December 31, 2025 and accompanying notes thereto (together, the Consolidated Financial Statements) have been prepared in accordance with United States (U.S.) generally accepted accounting principles (GAAP) and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgment, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected.

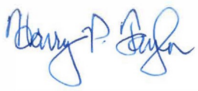
Management is responsible for establishing and maintaining adequate disclosure controls and procedures and internal control over financial reporting as described in the annual MD&A. Management evaluated the effectiveness of the design and operation of disclosure controls and procedures, and internal control over financial reporting based on the framework and criteria established in the Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective at a reasonable level of assurance as at December 31, 2025. As required, the results of that evaluation were reported to the Audit Committee of the Hydro One Board of Directors.

The Consolidated Financial Statements have been audited by KPMG LLP, an independent registered public accounting firm appointed by the shareholders of the Company. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in all material respects in conformity with U.S. generally accepted accounting principles. The Report of Independent Registered Public Accounting Firm outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control over financial reporting and disclosure. The Audit Committee of Hydro One met periodically with management, the internal auditors and the external auditors to satisfy itself that each group had properly discharged its respective responsibility with respect to the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit Committee, with and without the presence of management, to discuss their audit findings.

On behalf of Hydro One's management:

David Lebeter
President and Chief Executive Officer



Harry Taylor
Executive Vice President, Chief Financial and Regulatory Officer

To the Shareholders and Board of Directors of Hydro One Limited:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Hydro One Limited (the Company) as of December 31, 2025 and 2024, the related consolidated statements of operations and comprehensive income, changes in equity, and cash flows for each of the years then ended, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and the results of operations and its cash flows for each of the years then ended, in conformity with U.S. generally accepted accounting principles.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of a critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Evaluation of Regulatory Assets and Liabilities and the impact of rate regulation on the consolidated financial statements

As discussed in Note 2 to the consolidated financial statements, the Company accounts for its regulated operations in accordance with Financial Accounting Standards Board Accounting Standard Codification Topic 980, Regulated Operations (ASC 980). Under ASC 980, the actions of the Company's regulator may result in the recognition of revenue and costs in time periods that are different than non-rate-regulated enterprises. When this occurs, the Company records incurred and allowed costs that it has assessed are probable of recovery in future electricity rates as regulatory assets or property, plant and equipment. Obligations imposed or probable to be imposed by the regulator to refund previously collected revenue or expenditure of revenue collected from customers on future costs are recorded as regulatory liabilities. As disclosed in Note 11 to the consolidated financial statements, as of December 31, 2025, the Company's regulatory assets were $3,867 million and regulatory liabilities were $1,851 million.

We identified the evaluation of regulatory assets and liabilities and the impact of rate regulation as a critical audit matter. Accounting for regulated operations under ASC 980 affects multiple financial statement accounts and disclosures in the Company's consolidated financial statements. Assessing the accounting for regulated operations requires significant auditor judgment due to interpretations of regulatory decisions and judgments involved in evaluating the Company's assessment of the probability associated with recovery of regulatory assets and imposition of regulatory liabilities.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and implementation and tested the operating effectiveness of certain internal controls over the Company's regulatory accounting process. This included controls over the evaluation of the probability of (1) the recovery in future rates of costs deferred as regulatory assets, and (2) a refund of previously collected revenue or expenditure of revenue collected from customers on future costs that should be reported as regulatory liabilities, and controls over the monitoring and evaluation of regulatory developments that may affect the probability of recovering costs in future rates or imposing of regulatory liabilities. We evaluated the Company's assessment of the probability of recovery of the carrying amount for a selection of regulatory assets and for the imposition of a

selection of regulatory liabilities, through consideration of selected regulatory proceedings, decisions and accounting orders. For a selection of regulatory proceedings, decisions and accounting orders, we read the Company's assessment and interpretations. For a selection of regulatory assets and liabilities, we recalculated the amounts recorded based on methodologies approved by the regulator and agreed the data used in the calculations to the Company's underlying books and records. We compared the amounts calculated by the Company to the amounts recorded in the consolidated financial statements.

/s/ KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

We have served as the Company's auditor since 2008.

Toronto, Canada
February 12, 2026

HYDRO ONE LIMITED
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2025 and 2024

Year ended December 31 (*millions of Canadian dollars, except per share amounts*)	**2025**	**2024**
Revenues		
Distribution (includes $447 related party revenues; 2024 - $427) *(Note 27)*	6,557	6,175
Transmission (includes $2,390 related party revenues; 2024 - $2,254) *(Note 27)*	2,429	2,269
Other *(Note 27)*	55	40
	9,041	8,484
Costs		
Purchased power (includes $3,036 related party costs; 2024 - $2,705) *(Note 27)*	4,486	4,143
Operation, maintenance and administration *(Note 27)*	1,206	1,308
Depreciation, amortization and asset removal costs *(Note 4)*	1,111	1,066
	6,803	6,517
Income before financing charges, equity income and income tax expense	**2,238**	**1,967**
Financing charges *(Note 5)*	679	621
Equity income *(Note12)*	9	—
Income before income tax expense	**1,568**	**1,346**
Income tax expense *(Note 6)*	219	181
Net income	**1,349**	**1,165**
Other comprehensive income (loss)	3	(9)
Comprehensive income	**1,352**	**1,156**
Net income attributable to:		
Noncontrolling interest *(Note 26)*	10	9
Common shareholders	1,339	1,156
	1,349	**1,165**
Comprehensive income attributable to:		
Noncontrolling interest *(Note 26)*	10	9
Common shareholders	1,342	1,147
	1,352	**1,156**
Earnings per common share *(Note 24)*		
Basic	$2.23	$1.93
Diluted	$2.23	$1.92
Dividends per common share declared *(Note 23)*	$1.31	$1.24

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE LIMITED
CONSOLIDATED BALANCE SHEETS
At December 31, 2025 and 2024

As at December 31 *(millions of Canadian dollars)*	2025	2024
Assets		
Current assets:		
Cash and cash equivalents	549	716
Accounts receivable *(Note 7)*	1,083	911
Due from related parties	409	325
Other current assets *(Note 8)*	133	165
	2,174	2,117
Property, plant and equipment *(Note 9)*	31,450	29,093
Other long-term assets:		
Regulatory assets *(Note 11)*	3,857	3,503
Deferred income tax assets *(Note 6)*	135	127
Intangible assets *(Note 10)*	654	661
Goodwill	378	373
Other assets *(Note 12)*	1,023	808
	6,047	5,472
Total assets	**39,671**	**36,682**
Liabilities		
Current liabilities:		
Short-term notes payable *(Notes 15 & 17)*	100	200
Long-term debt payable within one year *(Notes 15, 16 & 17)*	925	1,150
Accounts payable and other current liabilities *(Note 13)*	2,086	1,809
Due to related parties	479	342
	3,590	3,501
Long-term liabilities:		
Long-term debt *(Notes 15, 16 & 17)*	18,092	16,329
Regulatory liabilities *(Note 11)*	1,621	1,476
Deferred income tax liabilities *(Note 6)*	1,799	1,452
Other long-term liabilities *(Note 14)*	1,823	1,751
	23,335	21,008
Total liabilities	**26,925**	**24,509**
Contingencies and Commitments *(Notes 29 & 30)*		
Subsequent Events *(Note 32)*		
Noncontrolling interest subject to redemption *(Note 26)*	19	19
Equity		
Common shares	5,721	5,713
Additional paid-in capital	25	28
Retained earnings	6,911	6,360
Accumulated other comprehensive loss	(9)	(12)
Hydro One shareholders' equity	12,648	12,089
Noncontrolling interest *(Note 26)*	79	65
Total equity	**12,727**	**12,154**
	39,671	**36,682**

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

Melissa Sonberg
Chair

Helga Reidel
Chair, Audit Committee

HYDRO ONE LIMITED
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the years ended December 31, 2025 and 2024

Year ended December 31, 2025 *(millions of Canadian dollars)*	**Common Shares**	**Additional Paid-in Capital**	**Retained Earnings**	**Accumulated Other Comprehensive Loss**	**Hydro One Shareholders' Equity**	**Non-controlling Interest (Note 26)**	**Total Equity**
January 1, 2025	5,713	28	6,360	(12)	12,089	65	12,154
Net income	—	—	1,339	—	1,339	8	1,347
Other comprehensive income	—	—	—	3	3	—	3
Distributions to noncontrolling interest *(Note 26)*	—	—	—	—	—	(10)	(10)
Contributions from sale of noncontrolling interest	—	—	—	—	—	16	16
Dividends on common shares *(Note 23)*	—	—	(788)	—	(788)	—	(788)
Common shares issued	8	(8)	—	—	—	—	—
Stock-based compensation	—	5	—	—	5	—	5
December 31, 2025	**5,721**	**25**	**6,911**	**(9)**	**12,648**	**79**	**12,727**

Year ended December 31, 2024 *(millions of Canadian dollars)*	**Common Shares**	**Additional Paid-in Capital**	**Retained Earnings**	**Accumulated Other Comprehensive Loss**	**Hydro One Shareholders' Equity**	**Non-controlling Interest (Note 26)**	**Total Equity**
January 1, 2024	5,706	30	5,947	(3)	11,680	65	11,745
Net income	—	—	1,156	—	1,156	7	1,163
Other comprehensive loss	—	—	—	(9)	(9)	—	(9)
Distributions to noncontrolling interest *(Note 26)*	—	—	—	—	—	(7)	(7)
Dividends on common shares *(Note 23)*	—	—	(743)	—	(743)	—	(743)
Common shares issued	7	(7)	—	—	—	—	—
Stock-based compensation	—	5	—	—	5	—	5
December 31, 2024	**5,713**	**28**	**6,360**	**(12)**	**12,089**	**65**	**12,154**

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE LIMITED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the years ended December 31, 2025 and 2024

Year ended December 31 *(millions of Canadian dollars)*	**2025**	**2024**
Operating activities		
Net income	1,349	1,165
Environmental expenditures *(Note 4)*	(3)	(11)
Adjustments for non-cash items:		
Depreciation and amortization *(Note 4)*	966	920
Regulatory assets and liabilities	240	81
Deferred income tax expense	76	140
Other	14	(10)
Changes in non-cash balances related to operations *(Note 28)*	53	249
Net cash from operating activities	**2,695**	**2,534**
Financing activities		
Long-term debt issued	2,698	2,781
Long-term debt repaid *(Note 15)*	(1,150)	(700)
Short-term notes issued	6,070	2,810
Short-term notes repaid	(6,170)	(2,890)
Dividends paid on common shares *(Note 23)*	(788)	(743)
Distributions paid to noncontrolling interest	(12)	(10)
Contributions received from sale of noncontrolling interest	16	—
Costs to obtain financing	(12)	(15)
Net cash from financing activities	**652**	**1,233**
Investing activities		
Capital expenditures *(Note 28)*		
Property, plant and equipment	(2,970)	(2,720)
Intangible assets	(80)	(88)
Additions to future use assets	(213)	(323)
Investment in equity investees *(Note 12)*	(261)	—
Capital contributions received *(Note 28)*	3	2
Other	7	(1)
Net cash used in investing activities	**(3,514)**	**(3,130)**
Net change in cash and cash equivalents	(167)	637
Cash and cash equivalents, beginning of year	716	79
Cash and cash equivalents, end of year	**549**	**716**

See accompanying notes to Consolidated Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Limited (Hydro One or the Company) was incorporated on August 31, 2015, under the *Business Corporations Act* (Ontario). On October 31, 2015, the Company acquired Hydro One Inc., a company previously wholly-owned by the Province of Ontario (Province). As at December 31, 2025, the Province held approximately 47.1% (2024 - 47.1%) of the common shares of Hydro One. The businesses of Hydro One are comprised of the following three segments:

- The Transmission segment consists of owning and operating Hydro One's transmission system which transmits high voltage electricity across the province, interconnecting local distribution companies and certain large directly connected industrial customers throughout the Ontario electricity grid. The transmission business consists of the transmission system operated by Hydro One Inc.'s rate-regulated subsidiaries, Hydro One Networks Inc. (Hydro One Networks), Hydro One Sault Ste. Marie LP (HOSSM), an approximate 80% (2024 - 100%) interest in Chatham x Lakeshore Limited Partnership (CLLP), an approximate 66% interest in B2M Limited Partnership (B2M LP) and an approximate 55% interest in Niagara Reinforcement Limited Partnership (NRLP). The Transmission segment also includes Hydro One Network's approximate 48% minority interest in the East-West Tie Limited Partnership (EWT LP), which was acquired on March 4, 2025.
- The Distribution segment owns and operates Hydro One's distribution system which delivers electricity to end customers and certain other municipal electricity distributors within Ontario. The distribution business consists of the distribution systems operated by Hydro One Inc.'s rate-regulated subsidiaries, Hydro One Networks and Hydro One Remote Communities Inc. (Hydro One Remotes).
- The Other segment consists principally of Hydro One's telecommunications business, which provides telecommunications support for the Company's transmission and distribution businesses, as well as certain corporate activities, and is not rate-regulated. The telecommunications business is carried out by Hydro One's wholly-owned subsidiary, Acronym Solutions Inc. (Acronym). In addition to supporting Hydro One's regulated business segments, Acronym offers a comprehensive suite of Information Communications Technology solutions. Hydro One's other segment also includes the deferred tax asset (DTA) which arose from the revaluation of the tax bases of Hydro One's assets to fair market value when the Company transitioned from the provincial payments in lieu of tax regime to the federal tax regime at the time of the Company's initial public offering in 2015. As this DTA is not required to be shared with ratepayers, the Company considers it to not be part of the regulated transmission and distribution segment assets and is included in the other segment. Furthermore, Hydro One's other segment also includes Aux Energy Inc., a wholly-owned subsidiary that provides energy solutions to commercial and industrial clients, and Ontario Charging Network LP (OCN LP), a wholly-owned subsidiary (2024 - a joint venture) that owns and operates electric vehicle fast charging stations across Ontario under the Ivy Charging Network brand.

Rate Setting

Transmission

On August 5, 2021 Hydro One Networks filed a custom Joint Rate Application (JRAP) for distribution and transmission revenue requirements for the 2023 to 2027 period. On November 29, 2022 the Ontario Energy Board (OEB) issued a Decision and Order (JRAP Decision) approving Hydro One Networks' transmission revenue requirement of $1,952 million for 2023, $2,073 million for 2024, $2,168 million for 2025, $2,277 million for 2026 and $2,362 million for 2027. Revenue requirements presented for 2024 to 2027 do not reflect the actual or expected updates resulting from the annual application process with the regulator to reflect OEB inflation factors.

On May 23, 2024, Hydro One Networks, on behalf of B2M LP, submitted B2M LP's five-year transmission revenue requirement application for the 2025 to 2029 period. On November 21, 2024, the OEB issued a Decision and Order approving B2M LP's five-year revenue requirement application, which includes a 2025 base revenue requirement of $38 million. Under the agreed-upon revenue requirement framework, there is no longer a requirement for B2M LP to file annual update applications with the OEB throughout the rate term, except for a one-time update in 2025, which the OEB approved in October 2025, setting the revenue requirements for 2026-2029.

On October 13, 2016, the OEB issued a Decision and Order for Hydro One Inc.'s Mergers, Amalgamations, Acquisitions and Divestitures of HOSSM, including the approval of a 10-year deferred rebasing period for the 2017 to 2026 period.

On July 12, 2024, Hydro One Networks, on behalf of CLLP, submitted CLLP's five-year transmission revenue requirement application for the 2025 to 2029 period. On December 17, 2024, the OEB issued a Decision and Order approving CLLP's revenue requirement application, which includes a 2025 base revenue requirement of $17 million, effective January 1, 2025. Under the agreed-upon revenue requirement framework, there is no longer a requirement for CLLP to file annual update applications with the OEB throughout the rate term, except for a one-time update in 2025, which the OEB approved in December 2025, setting the revenue requirements for 2026-2029.

On May 23, 2024, Hydro One Networks, on behalf of NRLP, submitted NRLP's five-year transmission revenue requirement application for the 2025 to 2029 period. On November 21, 2024, the OEB issued a Decision and Order approving NRLP's revenue requirement application, which includes a 2025 base revenue requirement of $9 million. Under the agreed-upon revenue requirement framework, there is no longer a requirement for NRLP to file annual update applications with the OEB throughout the rate term, except for a one-time update in 2025, which the OEB approved in October 2025, setting the revenue requirements for 2026-2029.

Distribution

On November 29, 2022 the OEB issued its JRAP Decision, approving Hydro One Networks' distribution revenue requirement of $1,727 million for 2023, $1,813 million for 2024, $1,886 million for 2025, $1,985 million for 2026 and $2,071 million for 2027. Revenue requirements presented for 2024 to 2027 do not reflect the actual or expected updates resulting from the annual application process with the regulator to reflect OEB inflation factors.

On August 31, 2022, Hydro One Remotes filed its distribution rate application for the 2023 to 2027 period. On March 2, 2023, the OEB approved Hydro One Remote's 2023 revenue requirement of $128 million with a price cap escalator index for 2024 to 2027, and a 3.72% rate increase effective May 1, 2023. Revenue requirements for 2024 to 2027 will be updated per the annual application process with the regulator to reflect OEB inflation factors.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation and Presentation

These consolidated financial statements (Consolidated Financial Statements) include the accounts of the Company and its subsidiaries. Inter-company transactions and balances have been eliminated.

Basis of Accounting

These Consolidated Financial Statements are prepared and presented in accordance with United States (U.S.) generally accepted accounting principles (GAAP) and in Canadian dollars.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to unbilled revenues, regulatory assets and regulatory liabilities, pension benefits, and post-retirement and post-employment benefits. Actual results may differ significantly from these estimates.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting in accordance with Financial Accounting Standards Board (FASB) Accounting Standard Codification (Codification) Topic 980, Regulated Operations, within the Company's regulated business, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from electricity customers in a future period and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities that generally represent amounts that are refundable to electricity customers in future rates. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will include its regulatory assets and regulatory liabilities in setting future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or regulatory liability in setting future rates, the respective carrying amount would be reflected in results of operations, prospectively from the date the Company's assessment is made.

Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term investments with an original maturity of three months or less.

Revenue Recognition

Transmission revenues predominantly consist of transmission tariffs, which are collected through OEB-approved uniform transmission rates (UTRs) which are applied against the monthly peak demand for electricity across Hydro One's high-voltage network. OEB-approved UTRs are based on an approved revenue requirement that includes a rate of return. The transmission tariffs are designed to recover revenues necessary to support the Company's transmission system with sufficient capacity to accommodate the maximum expected demand which is influenced by weather and economic conditions. Transmission revenues are recognized as electricity is transmitted and delivered to customers.

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues. Billed revenues are based on the amount of electricity delivered as measured from customer meters. At the end of each month, the amount of electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption and changes in the composition of customer classes.

Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered. Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are recorded at their estimated value, net of allowance for doubtful accounts. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Company's current lifetime expected credit losses (CECL) for all accounts receivable balances. The Company estimates the CECL by applying internally developed loss rates to all outstanding receivable balances by aging category on an undiscounted basis. Loss rates applied to the accounts receivable balances are based on historical overdue balances, customer payments and write-offs, which may be further supplemented from time to time to reflect management's best estimate of the loss. Accounts receivable are written-off against the allowance when they are deemed uncollectible. The allowance for doubtful accounts is affected by changes in volume, prices and economic conditions.

Noncontrolling interest

Noncontrolling interest represents the portion of equity ownership in subsidiaries that is not attributable to shareholders of Hydro One. Noncontrolling interest is initially recorded at fair value and subsequently the amount is adjusted for the proportionate share of net income or net loss and other comprehensive income (OCI) or other comprehensive loss (OCL) attributable to the noncontrolling interest and any dividends or distributions paid to the noncontrolling interest.

If a transaction results in the acquisition of all, or part, of a noncontrolling interest in a subsidiary, the acquisition of the noncontrolling interest is accounted for as an equity transaction. No gain or loss is recognized in consolidated net income or net loss or OCI or OCL as a result of changes in the noncontrolling interest, unless a change results in the loss of control by the Company.

Income Taxes

Income taxes are accounted for using the asset and liability method. Current income tax assets and current income tax liabilities are recognized based on the taxes refundable or payable on the current year's taxable income. Current and deferred income taxes are computed based on the tax rates and tax laws enacted as at the balance sheet date. Tax benefits associated with income tax positions are recorded only when the more-likely-than-not recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Consolidated Financial Statements. Management re-evaluates tax positions each period using new information about recognition or measurement as it becomes available.

Deferred Income Taxes

Deferred income tax assets and deferred income tax liabilities are recognized on all temporary differences between the tax bases and carrying amounts of assets and liabilities, including the carryforward of unused tax credits and tax losses to the extent that it is more-likely-than-not that these deductions, credits, and losses can be utilized. Deferred income tax assets and deferred income tax liabilities are measured at the tax rates that are expected to apply in the period when the asset is realized or the liability is settled, based on the tax rates and tax laws that have been enacted as at the balance sheet date.

Deferred income taxes associated with the Company's regulated operations which are considered to be more-likely-than-not to be recovered or refunded in future regulated rates charged to customers are recognized as deferred income tax regulatory assets and deferred income tax regulatory liabilities with an offset to deferred income tax expense.

Investment tax credits are recorded as a reduction of the related expenses or income tax expense in the current or future period to the extent it is more likely than not that the credits can be utilized.

Management reassesses the deferred income tax assets at each balance sheet date and reduces the amount to the extent that it is more likely than not that the deferred income tax asset will not be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more likely than not that the tax benefit will be realized.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions, and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the consolidated balance sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, and information technology. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis.

Property, plant and equipment in service consists of transmission, distribution, communication, and administration and service assets, as well as land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, as well as capitalized project development costs associated with deferred capital projects.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, as well as assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, including transformers, circuit breakers and switches.

Distribution

Distribution assets include assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include fibre optic and microwave radio systems, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.

Easements

Easements include a statutory easement for the use of transmission corridor and related abutting lands pursuant to Part IX.1 of the *Electricity Act, 1998* (Ontario) (Electricity Act), as well as other land rights for occupation.

Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost, which comprises purchased software, direct labour (including employee benefits), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Company's intangible assets primarily represent major computer applications.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized financing costs are a reduction of financing charges recognized in the consolidated statements of operations and comprehensive income. Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation and Amortization

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and amortization rates, as required by the OEB. Any changes arising from such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The most recent reviews resulted in changes to rates effective January 1, 2023 for Hydro One Networks' distribution and transmission businesses. A summary of average service lives and depreciation and amortization rates as at December 31, 2025 for the various classes of assets is included below:

	Average Service Life	Rate Range	Rate Average
Property, plant and equipment:			
Transmission	57 years	1% - 3%	2 %
Distribution	48 years	1% - 8%	2 %
Communication	17 years	1% - 11%	6 %
Administration and service	28 years	1% - 20%	5 %
Intangible assets	11 years	8% - 10%	6 %

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation, with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense.

Acquisitions and Goodwill

The Company accounts for business acquisitions using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair value at the date of acquisition. Costs associated with pending acquisitions are expensed as incurred. Goodwill represents the cost of acquired companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is not included in rate base.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. The Company performs a qualitative assessment to determine whether it is more likely than not that the fair value of the applicable reporting unit is greater than its carrying amount, no further testing is required. If the Company determines, as a result of its qualitative assessment, that it is more likely than not that the fair value of the applicable reporting unit is less than its carrying amount, a quantitative goodwill impairment assessment is performed. The quantitative assessment compares the fair value of the applicable reporting unit to its carrying amount, including goodwill. If the fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and as a charge to results of operations.

Based on the assessment performed as at September 30, 2025 and with no significant events since, the Company has concluded that goodwill was not impaired as at December 31, 2025.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, the Company evaluates whether impairment may exist by estimating future undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

Within its regulated business, the carrying costs of most of Hydro One's long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable. Hydro One regularly monitors the assets of its unregulated subsidiary Acronym for indications of impairment.

Management assesses the fair value of such long-lived assets using commonly accepted techniques. Techniques used to determine fair value include, but are not limited to, the use of recent third-party comparable sales for reference and internally developed discounted cash flow analysis. Significant changes in market conditions, changes to the condition of an asset, or a change in management's intent to utilize the asset are generally viewed by management as triggering events to reassess the cash flows related to these long-lived assets. As at December 31, 2025 and 2024, no asset impairment had been recorded for assets within either the Company's regulated or unregulated businesses.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers the external transaction costs related to obtaining financing and presents such amounts net of related debt on the consolidated balance sheets. Deferred issuance costs are amortized over the contractual life of the related debt on an effective-interest basis and the amortization is included within financing charges in the consolidated statements of operations and comprehensive income. Transaction costs for items classified as held-for-trading are expensed immediately.

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Company considers the carrying amounts of accounts receivable and amounts due from related parties to be reasonable estimates of fair value because of the short time to maturity of these instruments. The Company estimates the CECL for all accounts receivable balances, which are recognized as adjustments to the allowance for doubtful accounts. Accounts receivable are written-off against the allowance when they are deemed uncollectible. All financial instrument transactions are recorded at trade date.

The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk management policy disclosed in Note 16 - Fair Value of Financial Instruments and Risk Management.

Derivative Instruments and Hedge Accounting

The Company closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedging relationships.

The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value on the consolidated balance sheets. For derivative instruments that qualify for hedge accounting, the Company may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. The Company offsets fair value amounts recognized on its consolidated balance sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting, and which are designated as cash flow hedges, any unrealized gain or loss, net of tax, is recorded as a component of accumulated OCI (AOCI) or accumulated OCL (AOCL). Amounts in AOCI or AOCL are reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations and presented in the same line item as the earnings effect of the hedged item. Any gains or losses on the derivative instrument that represent hedge components excluded from the assessment of effectiveness are recognized in the same line item of the consolidated statements of operations as the hedged item. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the consolidated statements of operations and comprehensive income (loss) in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the consolidated statements of operations and comprehensive income (loss). The changes in fair value of the undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and are carried at fair value on the consolidated balance sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. The Company does not engage in derivative trading or speculative activities and had no embedded derivatives that required bifurcation as at December 31, 2025 or 2024.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where the Company has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. The Company also assesses, both at the inception of the hedge and on a quarterly basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of the Company's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

The Company recognizes the funded status of its defined benefit pension plan (Pension Plan) and its post-retirement and post-employment plans on its consolidated balance sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Defined benefit pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation (PBO) exceeds the fair value of the plan assets. Liabilities are recognized on the consolidated balance sheets for any net underfunded PBO. The net underfunded PBO may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the PBO of the plan, an asset is recognized equal to the net overfunded PBO. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Hydro One recognizes its contributions to the defined contribution pension plan (DC Plan) as pension expense, with a portion being capitalized as part of labour costs included in capital expenditures. The expensed amount is included in operation, maintenance and administration (OM&A) costs in the consolidated statements of operations and comprehensive income.

Defined Benefit Pension

Defined benefit pension costs are recorded on an accrual basis for financial reporting purposes. Pension costs are actuarially determined using the projected benefit method prorated on service and are based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases. Past service costs from plan amendments and all actuarial gains and losses are amortized on a straight-line basis over the expected average remaining service period of active employees in the plan, or over the estimated remaining life expectancy of inactive employees in the plan. Pension plan assets, consisting primarily of listed and unlisted equity securities, marketable and private debt, corporate and government debt securities as well as unlisted real estate and unlisted infrastructure investments, are recorded at fair value at the end of each year. Hydro One records a regulatory asset or regulatory liability equal to the net underfunded or overfunded PBO for its pension plan. Defined benefit pension costs are attributed to labour costs on a cash basis and a portion directly related to acquisition and development of capital assets is capitalized as part of the cost of property, plant and equipment and intangible assets. The remaining defined benefit pension costs are charged to results of operations (OM&A costs).

Post-retirement and Post-employment Benefits

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. For post-retirement benefits, past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or actuarial losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active employees in the plan or over the remaining life expectancy of inactive employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end, based on an annual actuarial report, with an offset to the associated regulatory account, to the extent of the remeasurement adjustment.

The actuarial gains and actuarial losses on post-employment obligations that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory account, to the extent of the remeasurement adjustment.

All post-retirement and post-employment benefit costs are attributed to labour costs and are either charged to results of operations (OM&A costs) or capitalized as part of the cost of property, plant and equipment and intangible assets (applies to the service cost component of benefit cost) and to regulatory assets for all other components of the benefit cost, consistent with their inclusion in OEB-approved rates.

Stock-Based Compensation

Share Grant Plans

Hydro One measures share grant plans based on fair value of share grants as estimated based on the grant date common share price. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. The Company records a regulatory asset equal to the accrued costs of share grant plans recognized in each period. Costs are transferred from the regulatory asset to labour costs at the time the share grants vest and are recovered in rates. Forfeitures are recognized as they occur.

Deferred Share Unit (DSU) Plans

The Company records the liabilities associated with its Directors' and Management DSU Plans at fair value at each reporting date until settlement, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the DSU liability is based on the Company's common share closing price at the end of each reporting period.

Long-term Incentive Plan (LTIP)

The Company measures the awards issued under its LTIP at fair value based on the grant date common share price. The fair value of liability-classified awards is based on the Company's common share closing price at the end of each reporting period. The related compensation expense is recognized over the vesting period on a straight-line basis. Forfeitures are recognized as they occur.

Loss Contingencies

Hydro One is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its Consolidated Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Company records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Consolidated Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. Hydro One records a liability for the estimated future expenditures associated with contaminated land assessment and remediation (LAR) and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. To the extent that the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the anticipated amount of future recovery of these environmental expenditures from customers. Hydro One reviews its estimates of future environmental expenditures annually, or more frequently if there are indications that circumstances have changed. Estimate changes are accounted for prospectively.

Asset Retirement Obligations

Asset retirement obligations are recorded for legal obligations associated with the future removal and disposal of long-lived assets. Such obligations may result from the acquisition, construction, development and/or normal use of the asset. Conditional asset retirement obligations are recorded when there is a legal obligation to perform a future asset retirement activity but where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. In such a case, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. This uncertainty is incorporated in the fair value measurement of the obligation.

When recording an asset retirement obligation, the present value of the estimated future expenditures required to complete the asset retirement activity is recorded in the period in which the obligation is incurred, if a reasonable estimate can be made. In general, the present value of the estimated future expenditures is added to the carrying amount of the associated asset and the resulting asset retirement cost is depreciated over the estimated useful life of the asset. The present value is determined with a discount rate that equates to the Company's credit-adjusted risk-free rate. Where an asset is no longer in service when an asset retirement obligation is recorded, the asset retirement cost is recorded in results of operations.

Leases

At the commencement date of a lease, the minimum lease payments are discounted and recognized as a lease obligation. Discount rates used correspond to the Company's incremental borrowing rates. Renewal options are assessed for their likelihood of being exercised and are included in the measurement of the lease obligation when it is reasonably certain they will be

exercised. The Company does not recognize leases with a term of less than 12 months. A corresponding Right-of-Use (ROU) asset is recognized at the commencement date of a lease. The ROU asset is measured as the lease obligation adjusted for any lease payments made and/or any lease incentives and initial direct costs incurred. ROU assets are included in other long-term assets, and corresponding lease obligations are included in other current liabilities and other long-term liabilities on the consolidated balance sheets.

The Company's lease portfolio consists primarily of operating leases; finance leases are not material and, when applicable, may be fully prepaid at commencement.

Subsequent to the commencement date, the lease expense recognized at each reporting period is the total remaining lease payments over the remaining lease term. Lease obligations are measured as the present value of the remaining unpaid lease payments using the discount rate established at commencement date. The amortization of the ROU assets is calculated as the difference between the lease expense and the accretion of interest, which is calculated using the effective interest method. Lease modifications and impairments are assessed at each reporting period to assess the need for a remeasurement of the lease obligations or ROU assets.

Equity Method Investments

The Company accounts for its investments in entities over which it has significant influence but not a controlling interest using the equity method of accounting. Significant influence is generally presumed to exist when the Company owns 20% to 50% of the voting stock of the investee, but can also exist when the Company owns less than 20% if it has the ability to exercise significant influence through other means. Under this method, the investment is initially recorded at cost and subsequently adjusted to recognize the Company's share of the earnings or losses of the investee, as well as any distributions received from the investee.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following table presents Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board (FASB) that are applicable to Hydro One:

Recently Adopted Accounting Guidance

Guidance	Date issued	Description	ASU Effective Date	Impact on Hydro One
ASU 2024-02	March 2024	The amendments contain modifications to the codification that remove various concept statements which may be extraneous and not required to understand or apply the guidance or references used in prior statements to provide guidance in certain topical areas.	Fiscal years beginning after December 15, 2024.	No impact upon adoption
ASU 2023-09	December 2023	The amendments address investor requests for more transparency about income tax information through improvements to income tax disclosures primarily related to the rate reconciliation and income taxes paid information.	Annual periods beginning after December 15, 2024.	Adoption of the standard does not materially affect Hydro One's income tax disclosures.

Recently Issued Accounting Guidance Not Yet Adopted

Guidance	Date issued	Description	ASU Effective Date	Impact on Hydro One
ASU 2023-06	October 2023	The amendments represent changes to clarify or improve disclosure or presentation requirements of a variety of subtopics in the FASB Codification. Many of the amendments allow users to more easily compare entities subject to the U.S. Securities and Exchange's (SEC) existing disclosures with those entities that were not previously subject to the SEC's requirements. Also, the amendments align the requirements in the Codification with the SEC's regulations. Applicable to all entities, if by June 30, 2027 the SEC has not removed the applicable requirement from Regulation S-X or Regulation S-K, the pending content of the related amendment will be removed from the Codification and will not become effective for any entity.	Two years subsequent to the date on which the SEC's removal of that related disclosure becomes effective.	Under assessment
ASU 2024-03	November 2024	The amendments require public business entities to disclose additional information about specific expense categories in the notes to financial statements at interim and annual reporting periods, which are not generally presented in the current financial statements.	Annual periods beginning after December 15, 2026, and interim periods beginning after December 15, 2027.	Under assessment
ASU 2025-03	May 2025	The amendments require entities to apply the guidance for identifying the accounting acquirer in transactions where a business that qualifies as a Variable Interest Entity is acquired through the exchange of equity interests.	Annual and interim periods beginning after December 15, 2026.	No impact upon adoption
ASU 2025-05	July 2025	The amendments allow all entities to use a practical expedient when estimating expected credit losses for current accounts receivable and contract assets under Topic 606, by assuming that current conditions as of the balance sheet date remain unchanged over the asset's life. Additionally, entities other than public business entities that elect this expedient may adopt an accounting policy to consider post–balance sheet date collection activity in their credit loss estimates.	Annual and interim periods beginning after December 15, 2025.	No impact upon adoption
ASU 2025-06	September 2025	The amendments modernize accounting for internal-use software by removing outdated development stage references and introducing a capitalization threshold based on management authorization and project completion probability.	Annual periods beginning after December 15, 2027.	Under assessment
ASU 2025-09	November 2025	The amendments expand hedge-accounting eligibility and better align the guidance with common risk-management practices. Key updates allow grouping forecasted transactions with similar exposure, simplify hedging of choose-your-rate variable-rate debt, and broaden eligibility for hedging nonfinancial components. The guidance modernizes treatment of certain option-based derivatives and resolves mismatches in dual hedge relationships.	Annual and interim periods beginning after December 15, 2026.	Under assessment
ASU 2025-10	December 2025	The amendments establish authoritative GAAP for government grants, setting recognition, measurement, presentation, and disclosure requirements.	Annual and interim periods beginning after December 15, 2028.	Under assessment
ASU 2025-11	December 2025	The amendments clarify interim reporting by establishing a complete list of required GAAP interim disclosures. They introduce a disclosure principle requiring entities to report material events occurring after the annual reporting period. The Update also clarifies types of interim reports and the form and content of interim financial statements. Overall, the changes enhance clarity and consistency without altering existing disclosure requirements.	Interim reporting periods within annual reporting periods beginning after December 15, 2027.	Under assessment
ASU 2025-12	December 2025	The amendments clarify existing guidance, correct errors, and introduce minor improvements to numerous Codification Topics, thereby making the requirements easier for entities to understand and apply.	Annual and interim periods beginning after December 15, 2026.	Under assessment

4. DEPRECIATION, AMORTIZATION AND ASSET REMOVAL COSTS

Year ended December 31 *(millions of dollars)*	2025	2024
Depreciation of property, plant and equipment	874	828
Amortization of intangible assets	89	81
Amortization of regulatory assets	3	11
Depreciation and amortization	966	920
Asset removal costs	145	146
	1,111	1,066

5. FINANCING CHARGES

Year ended December 31 *(millions of dollars)*	2025	2024
Interest on long-term debt	736	674
Interest on regulatory accounts	24	25
Interest on short-term notes	23	21
Realized loss (gain) on cash flow hedges (interest-rate swap agreements) *(Note 16)*	4	(4)
Other	19	18
Less: Interest capitalized on construction and development in progress	(110)	(89)
Interest earned on cash and cash equivalents	(17)	(24)
	679	621

6. INCOME TAXES

As a rate regulated utility company, the Company recovers income taxes from its ratepayers based on estimated current income tax expense in respect of its regulated business. The amounts of deferred income taxes related to regulated operations which are considered to be more likely-than-not to be recoverable from, or refundable to, ratepayers in future periods are recognized as deferred income tax regulatory assets or deferred income tax regulatory liabilities, with an offset to deferred income tax recovery or deferred income tax expense, respectively. The Company's consolidated income tax expense or income tax recovery for the period includes all current and deferred income tax expenses for the period net of the regulated accounting offset to deferred income tax expense arising from temporary differences to be recovered from, or refunded to, customers in future rates. Thus, the Company's income tax expense or income tax recovery differs from the amount that would have been recorded using the statutory income tax rate. As the Company operates in Ontario, it is subject to the combined Canadian federal and Ontario statutory rates of 26.5%.

The reconciliation between the statutory and the effective tax rates is provided as follows:

	2025		2024	
Year ended December 31	*(millions of dollars)*	*(percentage)*	*(millions of dollars)*	*(percentage)*
Income before income tax expense	1,568		1,346	
Income tax expense at statutory rate of 26.5% (2024 - 26.5%)	416	26.5 %	357	26.5 %
Increase (decrease) resulting from:				
Net temporary differences recoverable in future rates charged to customers:				
Capital cost allowance in excess of depreciation and amortization	(106)	(6.8)%	(83)	(6.2)%
Overheads capitalized for accounting but deducted for tax purposes	(54)	(3.4)%	(51)	(3.8)%
Interest capitalized for accounting but deducted for tax purposes	(29)	(1.8)%	(23)	(1.7)%
Pension and post-retirement benefit contributions in excess of pension expense	(5)	(0.3)%	(10)	(0.7)%
Non-refundable tax credit	(5)	(0.3)%	(3)	(0.2)%
Environmental expenditures	(1)	(0.1)%	(3)	(0.2)%
Other	1	0.1 %	(1)	(0.1)%
Net temporary differences attributable to regulated business	(199)	(12.7)%	(174)	(12.9)%
Net permanent differences	2	0.1 %	(2)	(0.1)%
Total income tax expense	219	14.0 %	181	13.4 %

The major components of income tax expense are as follows:

Year ended December 31 *(millions of dollars)*	2025	2024
Current income tax expense	144	38
Deferred income tax expense	75	143
Total income tax expense	219	181

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and deferred income tax liabilities reflect the future income tax consequences attributable to temporary differences between the tax bases and the financial statement carrying amounts of the assets and liabilities including the carry forward amounts of tax losses and tax credits. Deferred income tax assets and deferred income tax liabilities attributable to the Company's regulated business are recognized with a corresponding offset in deferred income tax regulatory assets and deferred income tax liabilities to reflect the anticipated recovery or repayment of these balances in the future electricity rates. As at December 31, 2025 and 2024, deferred income tax assets and deferred income tax liabilities consisted of the following:

As at December 31 (*millions of dollars*)	**2025**	**2024**
Deferred income tax assets		
Post-retirement and post-employment benefits expense in excess of cash payments	616	585
Regulatory assets and liabilities	491	449
Non-capital losses	91	105
Non-depreciable capital property	255	255
Tax credit carryforwards	211	245
Investment in subsidiaries	114	113
Capital losses	27	19
Environmental expenditures	15	16
Other	3	11
	1,823	1,798
Less: valuation allowance	(399)	(394)
Total deferred income tax assets	1,424	1,404
Deferred income tax liabilities		
Capital cost allowance in excess of depreciation and amortization	2,874	2,494
Pension assets	214	235
Total deferred income tax liabilities	3,088	2,729
Net deferred income tax liabilities	(1,664)	(1,325)

The net deferred income tax liabilities are presented on the consolidated balance sheets as follows:

As at December 31 (*millions of dollars*)	**2025**	**2024**
Long-term:		
Deferred income tax assets	135	127
Deferred income tax liabilities	(1,799)	(1,452)
Net deferred income tax liabilities	(1,664)	(1,325)

The valuation allowance for deferred income tax assets as at December 31, 2025 was $399 million (2024 - $394 million). The valuation allowance primarily relates to temporary differences for non-depreciable assets, investments in subsidiaries and capital losses carried forward.

As at December 31, 2025 and 2024, the Company had non-capital losses carried forward available to reduce future years' taxable income, which expire as follows:

Year of expiry (*millions of dollars*)	**2025**	**2024**
2036	1	1
2037	4	41
2038	90	92
2039	15	77
2040	9	14
2041	20	22
2042	29	38
2043	32	38
2044	59	51
2045	68	—
Total losses	327	374

7. ACCOUNTS RECEIVABLE

As at December 31 (*millions of dollars*)	2025	2024
Accounts receivable - billed	467	433
Accounts receivable - unbilled	673	539
Accounts receivable, gross	1,140	972
Allowance for doubtful accounts	(57)	(61)
Accounts receivable, net	1,083	911

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2025 and 2024:

As at December 31 (*millions of dollars*)	2025	2024
Allowance for doubtful accounts – beginning	(61)	(57)
Write-offs	23	18
Additions to allowance for doubtful accounts	(19)	(22)
Allowance for doubtful accounts – ending	(57)	(61)

8. OTHER CURRENT ASSETS

As at December 31 (*millions of dollars*)	2025	2024
Prepaid expenses and other assets	92	94
Materials and supplies	31	29
Regulatory assets *(Note 11)*	10	42
	133	165

9. PROPERTY, PLANT AND EQUIPMENT

As at December 31, 2025 *(millions of dollars)*	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	23,618	7,437	2,191	18,372
Distribution	15,338	5,053	304	10,589
Communication	1,539	1,327	57	269
Administration and service	2,578	1,101	46	1,523
Easements	821	124	—	697
	43,894	15,042	2,598	31,450

As at December 31, 2024 *(millions of dollars)*	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	22,359	7,100	1,616	16,875
Distribution	14,335	4,813	318	9,840
Communication	1,511	1,242	45	314
Administration and service	2,382	1,063	134	1,453
Easements	733	122	—	611
	41,320	14,340	2,113	29,093

Financing charges capitalized on property, plant and equipment under construction were $107 million in 2025 (2024 - $85 million).

10. INTANGIBLE ASSETS

As at December 31, 2025 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	1,585	960	29	654
Other	5	5	—	—
	1,590	965	29	654

As at December 31, 2024 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	1,481	872	51	660
Other	6	5	—	1
	1,487	877	51	661

Financing charges capitalized on intangible assets under development were $3 million in 2025 (2024 - $4 million). The estimated annual amortization expense for intangible assets is as follows: 2026 - $91 million; 2027 - $88 million; 2028 - $83 million; 2029 - $74 million; and 2030 - $66 million.

11. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One has recorded the following regulatory assets and liabilities:

As at December 31 *(millions of dollars)*	2025	2024
Regulatory assets:		
Deferred income tax regulatory asset	3,549	3,263
Broadband deferral	73	48
Post-retirement and post-employment benefits - non-service cost	49	72
Environmental	43	44
Getting Ontario Connected Act variance	39	24
Distribution rate riders	26	—
Incremental cloud computing implementation costs deferral	20	10
Stock-based compensation	18	24
Rural and remote rate protection (RRRP) variance	—	18
Other	50	42
Total regulatory assets	3,867	3,545
Less: current portion	(10)	(42)
	3,857	3,503
Regulatory liabilities:		
Pension benefit regulatory liability	610	647
Post-retirement and post-employment benefits	336	376
Earnings sharing mechanism (ESM) deferral	310	150
Retail settlement variance account (RSVA)	242	157
External revenue variance	75	31
Capitalized overhead tax variance	50	38
Other post-employment benefits (OPEB) asymmetrical carrying charge variance	49	33
Asset removal costs cumulative variance	48	26
Tax rule changes variance	36	34
Pension cost differential variance	30	21
Advanced Metering Infrastructure (AMI) 2.0 variance	29	7
Deferred income tax regulatory liability	9	4
Distribution rate riders	—	45
Other	27	29
Total regulatory liabilities	1,851	1,598
Less: current portion	(230)	(122)
	1,621	1,476

Deferred Income Tax Regulatory Asset and Liability

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. The Company has recognized regulatory assets and regulatory liabilities that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Company's income tax expense would have been recognized using the liability method and there would be no regulatory accounts established for income taxes to be recovered through future rates.

Broadband Deferral

The Company recognizes the incremental costs and incremental revenues attributable to carrying out activities pertaining to designated broadband projects as defined under *Building Broadband Faster Act* (Ontario) in this generic deferral account.

Post-Retirement and Post-Employment Benefits - Non-Service Cost

Hydro One has recorded a regulatory asset relating to the future recovery of its post-retirement and post-employment benefits other than service costs. The regulatory asset includes the applicable tax impact to reflect taxes payable. Prior to adoption of ASU 2017-07 in 2018, these amounts were capitalized to property, plant and equipment and intangible assets. In 2018 and 2019, the OEB approved the regulatory asset for Hydro One Networks' transmission business and distribution business, respectively. As part of Hydro One Networks' 2020 to 2022 Transmission Decision, the OEB concluded that the non-service cost component of Hydro One's OPEB costs shall be recognized as OM&A for both its transmission and distribution businesses. Furthermore, Hydro One Networks Distribution continued to record the non-service cost component of OPEBs in this account until the end of 2022. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of Hydro One Networks' transmission and distribution account balances as at December 31, 2020, including accrued interest, which were recovered from ratepayers over a one-year period ending December 31, 2023, and a three-year period ended December 31, 2025, respectively.

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate environmental contamination. A regulatory asset is recognized to the extent management considers it to be probable that environmental expenditures will be recovered in the future through the rate-setting process. For the year ended December 31, 2025, the Company has recorded a portion of the liability as a regulatory asset. In 2025, the revaluation adjustment increased the environmental regulatory asset by $2 million (2024 - $2 million) to reflect changes in the recoverable portion of the Company's PCB and LAR environmental liabilities. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudence and the timing of recovery of all of Hydro One's actual environmental expenditures.

Getting Ontario Connected Act Variance

On October 31, 2023, the OEB issued its Decision and Order approving the establishment of a generic sector-wide variance account, effective April 1, 2023. The account was established to record incremental costs of locating underground infrastructure resulting from the implementation of Provincial legislation: Bill 93, *Getting Ontario Connected Act, 2022*.

Distribution Rate Riders

As part of the JRAP Decision, the OEB approved the disposition of certain deferral and variance account balances as at December 31, 2020, including accrued interest, which were accumulated in distribution rate riders. The amounts were disposed of over a three-year period that ended December 31, 2025. The balance in the account is mostly comprised of excess returns to be collected from ratepayers in a future rate application.

Incremental cloud computing implementation costs deferral

On November 2, 2023, the OEB issued an Accounting Order approving the establishment of a generic sector-wide deferral account, effective December 1, 2023. The account was established to record incremental cloud computing implementation costs.

Stock-based Compensation

The Company recognizes costs associated with share grant plans as a regulatory asset as management considers it probable that share grant plans' costs will be recovered in the future through the rate-setting process. Share grant costs are transferred to labour costs at the time they vest and are issued, and are recovered in rates in accordance with recovery of these labour costs.

RRRP Variance

Hydro One Remotes receives RRRP amounts from the Independent Electricity System Operator (IESO). As at December 31, 2025, the Company recognized a regulatory liability representing the amounts over-collected to achieve breakeven net income, as regulated under the cost recovery model. In both 2025 and 2024, RRRP amounts received were higher than amounts required to achieve breakeven net income, and as such, the regulatory asset decreased by $24 million and $12 million, in 2025 and 2024, respectively.

Pension Benefit Regulatory Liability

In accordance with OEB rate orders, pension costs are recovered on a cash basis as employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). The Company recognizes the net unfunded or funded status of pension obligations on the consolidated balance sheets with an offset to the associated regulatory asset or regulatory liability. The pension benefit obligation is remeasured to the present value of the actuarially determined benefit obligation at each year end based on an annual actuarial report, with an offset to the associated regulatory asset or regulatory liability, to the extent of the remeasurement adjustment.

Post-Retirement and Post-Employment Benefits

In accordance with OEB rate orders, post-retirement and post-employment benefits costs are recovered on an accrual basis. The Company recognizes the net unfunded or funded status of post-retirement and post-employment obligations on the consolidated balance sheets with an incremental offset to the associated regulatory asset or regulatory liability, as the case may be. A regulatory asset or regulatory liability is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered or returned in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to the present value of the actuarially determined benefit obligation at each year end based on an annual actuarial report, with an offset to the associated regulatory asset or regulatory liability, as the case may be, to the extent of the remeasurement adjustment.

ESM Deferral

In March 2019, the OEB approved the establishment of an ESM deferral account for Hydro One Networks' distribution segment to record over-earnings including tax impacts. Under this mechanism, Hydro One shares 50% of regulated earnings that exceed the OEB-approved regulatory return-on-equity (ROE) by more than 100 basis points with distribution ratepayers. A similar account was also approved for B2M LP in January 2020, Hydro One Networks' transmission segment and NRLP in April 2020, and CLLP in December 2024. HOSSM's account was approved as part of the acquisition decision in October 2016 and became effective in 2022, with a 300 basis points threshold applied. The balance in the account as at December 31, 2025 mostly relates to Hydro One Networks' distribution and transmission businesses. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of Hydro One Networks' distribution business' balance as at December 31, 2020, including accrued interest, over a three-year period that ended December 31, 2025. The OEB also approved the disposition of the ESM account balances as at December 31, 2024 in Hydro One Networks' distribution and transmission businesses, B2M LP, NRLP, and HOSSM's 2026 rates application on a final basis.

RSVA

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. The RSVA account tracks the difference between the cost of power purchased from the IESO and the cost of power recovered from ratepayers. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of Hydro One Networks' distribution business' balance as at December 31, 2020, including accrued interest, over a three-year period that ended December 31, 2025. In December 2024, as part of the Decision and Order on 2025 distribution rates, the OEB approved, on an interim basis, the disposition of certain RSVA balances as at December 31, 2023, including accrued interest, over a one-year period that ended December 31, 2025. This disposition became final upon receipt of the Decision and Order on 2026 distribution rates issued in December 2025. The OEB also approved disposition of certain RSVA balances as at December 31, 2025, including accrued interest, over a one-year period ending December 31, 2026 on both an interim and final basis.

External Revenue Variance

The external revenue variance account balance reflects the difference between Hydro One Networks' transmission business' actual export service revenue and external revenues from secondary land use, and the OEB-approved amounts. The account also records the difference between actual net external station maintenance, engineering and construction services revenue, and other external revenue, and the OEB-approved amounts.

Capitalized Overhead Tax Variance

As part of the JRAP Decision, the OEB approved the establishment of a capitalized overhead tax variance account to capture the difference between the capitalized overheads deducted in calculating the regulatory tax expense included in rates and the actual capitalized overhead costs deducted in Hydro One's tax returns for Hydro One Networks' transmission and distribution businesses for the 2016 to 2027 period. Variance amounts are recognized at the earlier of (i) when the tax year has been audited by the Canada Revenue Agency or (ii) when the taxation year is statute barred.

OPEB Asymmetrical Carrying Charge Variance Account

On September 14, 2017, the OEB issued its Report of the Board: *Regulatory Treatment of Pension and OPEB Costs* that allowed rate-regulated utilities to track the difference between their pension and OPEB costs calculated under the accrual method and the cash payment method, effective January 1, 2018, and record the carrying charges associated with the balance on an asymmetrical basis. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of Hydro

One Networks' transmission and distribution account balances as at December 31, 2020, including accrued interest, which were returned to ratepayers over a one-year period ended December 31, 2023, and a three-year period ended December 31, 2025, respectively. As part of the same decision, the OEB approved the continuance of this account for Hydro One Networks' transmission business and the establishment of this account for Hydro One Networks' distribution business for 2023 to 2027.

Asset Removal Costs Cumulative Variance

In April 2020, the OEB approved the establishment of an asset removal costs cumulative variance account for Hydro One Networks' transmission business to record the difference between the revenue requirement associated with forecast asset removal costs included in depreciation expense and actual asset removal costs. This account is asymmetrical to the benefit of ratepayers on a cumulative basis. As part of the JRAP Decision received in November 2022, the OEB approved the continuance of this account for Hydro One Networks' transmission business and the establishment of this account for Hydro One Networks' distribution business for the 2023 to 2027 period.

Tax Rule Changes Variance

The 2019 federal and Ontario budgets (Budgets) provided certain time-limited investment incentives permitting Hydro One to deduct accelerated capital cost allowance of up to three times the first-year rate for capital investments acquired after November 20, 2018 and placed in-service before January 1, 2028 (Accelerated Depreciation). Following the enactment of the Budget measures in the second quarter of 2019, the OEB directed all Ontario regulated utilities including Hydro One to track the full revenue impact of the tax benefits related to the Accelerated Depreciation rules to ratepayers. The tax benefit to be returned to ratepayers in the future gave rise to a regulatory liability and resulted in a decrease in revenues as current rates do not include the benefit of the Accelerated Depreciation; therefore, the revenue subject to refund cannot be recognized. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of Hydro One Networks' transmission and distribution account balances as at December 31, 2020, including accrued interest, which were returned to ratepayers over a one-year period ended December 31, 2023, and a three-year period ended December 31, 2025, respectively.

Pension Cost Differential

Variances between the OM&A pension cost recognized and the cost embedded in rates as part of the rate-setting process for Hydro One Networks' transmission and distribution businesses are recognized as a regulatory asset or regulatory liability, as the case may be. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of Hydro One Networks' transmission and distribution account balances as at December 31, 2020, including accrued interest, which were returned to ratepayers over a one-year period ended December 31, 2023 and a three-year period ended December 31, 2025, respectively.

AMI 2.0 Variance

As part of the JRAP Decision, the OEB approved the establishment of the AMI 2.0 variance account. The account records the difference in revenue requirement impact including tax, if any, between the planned in-service additions included in the forecasted costs of the AMI 2.0 program over the 2023-2027 period and the actual in-service additions achieved as part of the AMI 2.0 program over the 2023-2027 period. The account is asymmetrical to the benefit of ratepayers.

12. OTHER LONG-TERM ASSETS

As at December 31 (*millions of dollars*)	**2025**	**2024**
Deferred pension assets *(Note 18)*	610	647
Investments in associates[1]	302	46
Right-of-Use assets *(Note 21)*	47	55
Other long-term assets	64	60
	1,023	808

[1] On March 4, 2025, Hydro One Networks completed the acquisition of an approximate 48% interest in the EWT LP for approximately $261 million in cash, including closing adjustments.

13. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

As at December 31 *(millions of dollars)*	2025	2024
Accrued liabilities	944	794
Accounts payable	371	348
Unearned revenue	313	336
Regulatory liabilities *(Note 11)*	230	122
Accrued interest	203	180
Lease obligations *(Note 21)*	14	14
Environmental liabilities	7	11
Derivative liabilities *(Note 16)*	4	4
	2,086	1,809

14. OTHER LONG-TERM LIABILITIES

As at December 31 *(millions of dollars)*	2025	2024
Post-retirement and post-employment benefit liability *(Note 18)*	1,672	1,590
Asset retirement obligations *(Note 20)*	43	38
Environmental liabilities *(Note 19)*	37	36
Lease obligations *(Note 21)*	29	41
Derivative liabilities *(Note 16)*	—	3
Other long-term liabilities	42	43
	1,823	1,751

15. DEBT AND CREDIT AGREEMENTS

Short-Term Notes and Credit Facilities

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under Hydro One Inc.'s commercial paper program which has a maximum authorized amount of $2,300 million. These short-term notes are denominated in Canadian dollars with varying maturities of up to 365 days. The commercial paper program is supported by Hydro One Inc.'s revolving standby credit facilities totalling $3,050 million.

As at December 31, 2025, Hydro One's consolidated committed, unsecured, and revolving credit facilities (Operating Credit Facilities) consisted of the following:

(millions of dollars)	Maturity	Total Amount	Amount Drawn
Hydro One Inc.			
Revolving standby credit facilities[1,2]	June 2030	3,050	—
Hydro One			
Five-year senior, revolving term credit facility[2]	June 2030	250	—
Total		3,300	—

[1] On June 1, 2024, Hydro One Inc. increased the committed amount under the Operating Credit Facilities by $750 million.
[2] On June 1, 2025, the maturity dates for the Operating Credit Facilities were extended from June 2029 to June 2030.

The Company may use the Operating Credit Facilities for working capital and general corporate purposes. If used, interest on the Operating Credit Facilities would apply based on Canadian benchmark rates. The Operating Credit Facilities include a pricing adjustment which can increase or decrease Hydro One's cost of funding based on its performance on certain sustainability performance measures, which are related to Hydro One's sustainability goals. The obligation of each lender to extend credit under its credit facility is subject to various conditions including that no event of default has occurred or would result from such credit extension.

Subsidiary Debt Guarantee

Hydro One Holdings Limited (HOHL) is an indirect wholly-owned subsidiary of Hydro One that may offer and sell debt securities. Any debt securities issued by HOHL are fully and unconditionally guaranteed by the Company. As at December 31, 2025 and 2024, no debt securities have been issued by HOHL.

Long-Term Debt

The following table presents long-term debt outstanding as at December 31, 2025 and 2024:

As at December 31 *(millions of dollars)*	2025	2024
1.76% Series 45 notes due 2025	—	400
2.97% Series 40 notes due 2025	—	350
5.54% Series 57 notes due 2025[1]	—	400
2.77% Series 35 notes due 2026	500	500
Floating-rate Series 56 notes due 2026[2]	425	425
4.91% Series 52 notes due 2028	750	750
3.02% Series 43 notes due 2029	550	550
3.93% Series 53 notes due 2029	550	550
2.16% Series 46 notes due 2030	400	400
7.35% Debentures due 2030	400	400
1.69% Series 49 notes due 2031	400	400
2.23% Series 50 notes due 2031	450	450
6.93% Series 2 notes due 2032	500	500
3.94% Series 61 notes due 2032	450	—
4.16% Series 54 notes due 2033	450	450
3.90% Series 64 notes due 2033	1,200	—
6.35% Series 4 notes due 2034	385	385
4.39% Series 59 notes due 2034	550	550
4.25% Series 60 notes due 2035	1,075	1,075
4.30% Series 62 notes due 2035	300	—
5.36% Series 9 notes due 2036	600	600
4.89% Series 12 notes due 2037	400	400
6.03% Series 17 notes due 2039	300	300
5.49% Series 18 notes due 2040	500	500
4.39% Series 23 notes due 2041	300	300
6.59% Series 5 notes due 2043	315	315
4.59% Series 29 notes due 2043	435	435
4.17% Series 32 notes due 2044	350	350
5.00% Series 11 notes due 2046	325	325
3.91% Series 36 notes due 2046	350	350
3.72% Series 38 notes due 2047	450	450
3.63% Series 41 notes due 2049	750	750
2.71% Series 47 notes due 2050	500	500
3.64% Series 44 notes due 2050	250	250
3.10% Series 51 notes due 2051	450	450
4.00% Series 24 notes due 2051	225	225
4.46% Series 55 notes due 2053	675	675
4.85% Series 58 notes due 2054	1,000	1,000
4.95% Series 63 notes due 2055	350	—
4.80% Series 65 notes due 2056	400	—
3.79% Series 26 notes due 2062	310	310
4.29% Series 30 notes due 2064	50	50
Hydro One Inc. long-term debt (a)	18,620	17,070
1.41% Series 2020-1 notes due 2027	425	425
Hydro One long-term debt (b)	425	425
	19,045	17,495
Add: Net unamortized debt premiums	39	41
Add: Realized mark-to-market gain[1]	—	3
Less: Unamortized deferred debt issuance costs	(67)	(60)
Total long-term debt	19,017	17,479

[1] In October 2023, Hydro One Inc. entered into a $400 million fixed-to-floating interest-rate swap agreement to convert the $400 million Medium Term Note (MTN) Series 57 notes matured October 20, 2025, into a variable rate debt. This swap was accounted for as a fair value hedge. In December 2023, this swap was terminated with a payment received of $6 million on settlement, which had been amortized over the term of the related note.

[2] The interest rates of the floating-rate notes are referenced to the daily compounded Canadian overnight repo rate average, plus a margin.

(a) Hydro One Inc. long-term debt

As at December 31, 2025, long-term debt of $18,620 million (2024 - $17,070 million) was outstanding, the majority of which was issued under Hydro One Inc.'s MTN Program. In February 2024, Hydro One Inc. filed a short form base shelf prospectus in connection with its MTN Program, which expires in March 2026.

In 2025, Hydro One Inc. issued long-term debt totalling $2,700 million (2024 - $2,750 million) and repaid long-term debt of $1,150 million (2024 - $700 million) under the MTN Program.

(b) Hydro One long-term debt

As at December 31, 2025, long-term debt of $425 million (2024 - $425 million) was outstanding. On August 19, 2024, Hydro One filed a short form base shelf prospectus (Universal Base Shelf Prospectus) with securities regulatory authorities in Canada. The Universal Base Shelf Prospectus allows Hydro One to offer, from time to time in one or more public offerings, debt, equity or other securities, or any combination thereof, during the 25-month period ending in September 2026. As at December 31, 2025, no securities have been issued under the Universal Base Shelf Prospectus. During the years ended December 31, 2025 and 2024, no long-term debt was issued or repaid.

The total long-term debt is presented on the consolidated balance sheets as follows:

As at December 31 *(millions of dollars)*	**2025**	**2024**
Current liabilities:		
Long-term debt payable within one year	925	1,150
Long-term liabilities:		
Long-term debt	18,092	16,329
Total long-term debt	19,017	17,479

Principal and Interest Payments

As at December 31, 2025, future principal repayments, interest payments, and related weighted-average interest rates were as follows:

	Long-Term Debt Principal Repayments *(millions of dollars)*	**Interest Payments** *(millions of dollars)*	**Weighted-Average Interest Rate** *(%)*
Year 1	925	792	2.8
Year 2	425	775	1.4
Year 3	750	751	4.9
Year 4	1,100	724	3.5
Year 5	800	675	4.8
	4,000	3,717	3.6
Years 6-10	5,760	2,800	4.2
Thereafter	9,285	4,927	4.5
	19,045	11,444	4.2

16. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

Hydro One classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices included within Level 1 that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest-rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

As at December 31, 2025 and 2024, the Company's carrying amounts of cash and cash equivalents, accounts receivable, due from related parties, short-term notes payable, accounts payable, and due to related parties are representative of fair value due to the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The carrying values and fair values of the Company's long-term debt as at December 31, 2025 and 2024 are as follows:

As at December 31 *(millions of dollars)*	2025 Carrying Value	2025 Fair Value	2024 Carrying Value	2024 Fair Value
Long-term debt, including current portion	19,017	18,721	17,479	17,364

Fair Value Measurements of Derivative Instruments

Fair Value Hedges

As at December 31, 2025 and 2024, Hydro One Inc. had no fair value hedges.

Cash Flow Hedges

As at December 31, 2025 and 2024, Hydro One Inc. had a $425 million, pay-fixed, receive-floating interest-rate swap agreement designated as a cash flow hedge. This cash flow hedge is intended to offset the variability of interest rates between December 21, 2023 and September 21, 2026.

As at December 31, 2025 and 2024, the Company had no derivative instruments classified as undesignated contracts.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities as at December 31, 2025 and 2024 is as follows:

As at December 31, 2025 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Long-term debt, including current portion	19,017	18,721	—	18,721	—
Derivative instruments *(Note 13)*					
Cash flow hedges, including current portion	4	4	—	4	—
	19,021	18,725	—	18,725	—

As at December 31, 2024 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Long-term debt, including current portion	17,479	17,364	—	17,364	—
Derivative instruments *(Notes 13 & 14)*					
Cash flow hedges, including current portion	7	7	—	7	—
	17,486	17,371	—	17,371	—

The fair value of the interest rate swaps designated as cash flow hedges is determined using a discounted cash flow method based on period-end swap yield curves.

The fair value of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no transfers between any of the fair value levels during the years ended December 31, 2025 or 2024.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss which results from changes in values, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates, as its regulated return on equity is derived using a formulaic approach that takes anticipated interest rates into account. The Company is not currently exposed to material commodity price risk or material foreign exchange risk.

The Company uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. The Company also uses derivative financial instruments to manage interest-rate risk. The Company may utilize interest-rate swaps designated as fair value hedges as a means to manage its interest rate exposure to achieve a lower cost of debt. The Company may also utilize interest-rate derivative instruments, such as cash flow hedges, to manage its exposure to short-term interest rates or to lock in interest-rate levels on forecasted financing.

A hypothetical 100 basis point increase in interest rates associated with variable-rate debt would not have resulted in a significant decrease to Hydro One's net income for the years ended December 31, 2025 and 2024, respectively.

For derivative instruments that are designated and qualify as cash flow hedges, the unrealized gain or loss, after tax, on the derivative instrument is recorded as OCI or OCL and is reclassified to net income or net loss in the same period during which the hedged transaction affects results of operations. The following table shows the amounts recorded in OCI/OCL and reclassified to financing charges for the years ended December 31, 2025 and 2024:

Year ended December 31 *(millions of dollars)*	**2025**	**2024**
Amounts recorded in OCI/OCL		
Before tax loss	2	1
After tax loss	1	1
Amounts reclassified to financing charges		
Before tax loss (gain)	4	(4)
After tax loss (gain)	3	(3)

This resulted in an AOCL of $3 million related to cash flow hedges as at December 31, 2025 (2024 - $5 million).

The Company estimates that the amount of AOCL, after tax, related to cash flow hedges to be reclassified to results of operations in the next 12 months is approximately $3 million. Actual amounts reclassified to results of operations depend on the interest rate in effect until the derivative contracts mature. For all forecasted transactions, as at December 31, 2025, the maximum term over which the Company is hedging exposures to the variability of cash flows is less than one year.

The Pension Plan manages market risk by diversifying investments in accordance with the Pension Plan's Statement of Investment Policies and Procedures. Interest rate risk arises from the possibility that changes in interest rates will affect the fair value of the Pension Plan's financial instruments. In addition, changes in interest rates can also impact discount rates which impact the valuation of the pension and post-retirement and post-employment liabilities. Currency risk is the risk that the value of the Pension Plan's financial instruments will fluctuate due to changes in foreign currencies relative to the Canadian dollar. Other price risk is the risk that the value of the Pension Plan's investments in equity securities will fluctuate as a result of changes in market prices, other than those arising from interest risk or currency risk. All three factors may contribute to changes in values of the Pension Plan investments. See Note 18 - Pension and Post-Retirement and Post-Employment Benefits for further details.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. As at December 31, 2025 and 2024, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a material amount of revenue from any single customer. As at December 31, 2025 and 2024, there was no material accounts receivable balance due from any single customer.

As at December 31, 2025, the Company's allowance for doubtful accounts was $57 million (2024 - $61 million). The allowance for doubtful accounts reflects the Company's CECL for all accounts receivable balances, which are based on historical overdue balances, customer payments and write-offs. As at December 31, 2025, approximately 7% (2024 - 7%) of the Company's net accounts receivable were outstanding for more than 60 days.

Hydro One manages its counterparty credit risk through various techniques including (i) entering into transactions with highly rated counterparties, (ii) limiting total exposure levels with individual counterparties, (iii) entering into master agreements which enable net settlement and the contractual right of offset, and (iv) monitoring the financial condition of counterparties. The Company monitors current credit exposure to counterparties on both an individual and an aggregate basis. The Company's credit risk for accounts receivable is limited to the carrying amounts on the consolidated balance sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The maximum credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts in an asset position at the reporting date. As at December 31, 2025 and 2024, Hydro One's credit exposure for all derivative instruments and applicable payables was with one financial institution with investment grade credit ratings as counterparty.

The Pension Plan manages its counterparty credit risk with respect to bonds by investing in investment-grade corporate and government bonds and with respect to derivative instruments by transacting only with highly rated financial institutions and by ensuring that exposure is diversified across counterparties.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One meets its short-term operating liquidity requirements using cash and cash equivalents on hand, funds from operations, the issuance of commercial paper, and the Operating Credit Facilities. The short-term liquidity under the commercial paper program, the Operating Credit Facilities, and anticipated levels of funds from operations are expected to be sufficient to fund the Company's operating requirements.

In February 2024, Hydro One Inc. filed a short form base shelf prospectus in connection with its MTN Program, which expires in March 2026. Hydro One's Universal Base Shelf Prospectus allows it to offer, from time to time in one or more public offerings, debt, equity or other securities, or any combination thereof, during the 25-month period ending on September 19, 2026.

On November 29, 2024, HOHL filed a short form base shelf prospectus (HOHL U.S. Debt Shelf Prospectus) with securities regulatory authorities in Ontario and the U.S., that expires in December 2026. The HOHL U.S. Debt Shelf Prospectus allows HOHL to offer, from time to time in one or more public offerings, debt securities, unconditionally guaranteed by Hydro One. As at December 31, 2025, no securities have been issued under the HOHL U.S. Debt Shelf Prospectus.

On August 18, 2025, Hydro One Inc. filed a short form base shelf prospectus (HOI U.S. Debt Shelf Prospectus) with securities regulatory authorities in Ontario and the U.S. The HOI U.S. Debt Shelf Prospectus allows Hydro One Inc. to offer, from time to time in one or more public offerings, U.S. debt securities, during the 25-month period ending on September 18, 2027. As at December 31, 2025, no securities have been issued under the HOI U.S. Debt Shelf Prospectus.

The Pension Plan's short-term liquidity is provided through cash and cash equivalents, contributions, investment income and proceeds from investment transactions. In the event that investments must be sold quickly to meet current obligations, the majority of the Pension Plan's assets are invested in securities that are traded in an active market and can be readily disposed of as liquidity needs arise.

17. CAPITAL MANAGEMENT

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing access to capital, the Company targets to maintain strong credit quality. As at December 31, 2025 and 2024, the Company's capital structure was as follows:

As at December 31 *(millions of dollars)*	**2025**	**2024**
Short-term notes payable	100	200
Long-term debt payable within one year	925	1,150
Less: cash and cash equivalents	(549)	(716)
	476	634
Long-term debt	18,092	16,329
Common shares	5,721	5,713
Retained earnings	6,911	6,360
Total capital	31,200	29,036

Hydro One Inc. has customary covenants typically associated with long-term debt. Long-term debt and credit facility covenants limit permissible debt to 75% of its total capitalization, limit the ability to sell assets, and impose a negative pledge provision, subject to customary exceptions. As at December 31, 2025, the Company was in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

18. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a Pension Plan, a supplementary pension plan (Supplementary Plan), post-retirement and post-employment benefit plans (Benefit Plans), and a DC Plan.

Pension Plan, Supplementary Plan, and Benefit Plans

The Pension Plan is a defined benefit contributory plan which covers eligible regular employees of Hydro One and its subsidiaries. The Pension Plan provides benefits based on the highest three-year average pensionable earnings up to March 31, 2025. Beginning April 1, 2025, all service for all groups on a go-forward basis will be calculated using the highest five-year average pensionable earnings. For management employees who commenced employment on or after January 1, 2004, and for Society-represented staff hired after November 17, 2005, benefits are based on the highest five-year average pensionable earnings for all their service. After retirement, pensions are indexed to inflation. Membership in the Pension Plan was closed to management employees who were not eligible to join the Pension Plan as of September 30, 2015. These employees are eligible to join the DC Plan.

Company and employee contributions to the Pension Plan are based on actuarial reports, including valuations performed at least every three years, and actual or projected levels of pensionable earnings, as applicable. The most recent actuarial valuation was performed effective December 31, 2024, and filed on September 23, 2025. Total annual cash Pension Plan employer contributions for 2025 were $68 million (2024 - $75 million). Estimated annual Pension Plan employer contributions for the years 2026, 2027, 2028, 2029, and 2030 are approximately $70 million, $73 million, $77 million, $81 million, and $85 million, respectively.

The Supplementary Plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan beyond the limitations imposed by the *Income Tax Act* (Canada). The Supplementary Plan obligation is included with other post-retirement and post-employment benefit obligations on the consolidated balance sheets.

Hydro One recognizes the funded or underfunded status of the Pension Plan and Benefit Plans as an asset or liability on its consolidated balance sheets, with offsetting regulatory assets and regulatory liabilities as appropriate. The funded benefit asset and underfunded benefit obligations for the Pension Plan and Benefit Plans, in the absence of regulatory accounting, would be recognized in AOCI. The impact of changes in assumptions used to measure pension and post-retirement benefit obligations is generally recognized over the expected average remaining service period of the employees and uses the corridor approach for the post-retirement benefit plan. For the post-employment benefit plan, the impact of changes in assumptions are recognized immediately in the net periodic benefit cost. The measurement date for the Plans is December 31.

The following tables provide the components of the funded status of the Company's Pension Plans and Benefit Plans as at December 31, 2025 and 2024:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31 *(millions of dollars)*	**2025**	**2024**	**2025**	**2024**
Change in PBO				
PBO, beginning of year	8,686	8,665	1,666	1,603
Current service cost	146	134	61	57
Employee contributions	81	74	—	—
Interest cost	411	401	80	75
Benefits paid	(457)	(427)	(76)	(71)
Net actuarial loss (gain)	40	(161)	19	2
PBO, end of year	8,907	8,686	1,750	1,666
Change in plan assets				
Fair value of plan assets, beginning of year	9,333	8,764	—	—
Actual return on plan assets	513	869	—	—
Benefits paid	(457)	(427)	(76)	(71)
Employer contributions	68	75	76	71
Employee contributions	81	74	—	—
Administrative expenses	(21)	(22)	—	—
Fair value of plan assets, end of year	9,517	9,333	—	—
(Funded) unfunded status	(610)	(647)	1,750	1,666

Hydro One presents its benefit obligations and plan assets net on its consolidated balance sheets as follows:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
As at December 31 *(millions of dollars)*	**2025**	**2024**	**2025**	**2024**
Other assets[1]	11	12	—	—
Deferred pension assets	610	647	—	—
Accrued liabilities	—	—	78	76
Post-retirement and post-employment benefit liability	—	—	1,672	1,590
Net (funded) unfunded status	(621)	(659)	1,750	1,666

[1] Represents the funded status of HOSSM defined benefit pension plan.

The funded or unfunded status of the Pension Plan and Benefit Plans refers to the difference between the fair value of plan assets and the PBO for the Pension Plan and Benefit Plans. The funded/unfunded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets.

The following table provides the PBO, accumulated benefit obligation (ABO) and fair value of plan assets for the Pension Plan:

As at December 31 *(millions of dollars)*	**2025**	**2024**
PBO	8,907	8,686
ABO	8,004	7,848
Fair value of plan assets	9,517	9,333

On an ABO basis, the Pension Plan was funded at 119% as at December 31, 2025 (2024 - 119%). On a PBO basis, the Pension Plan was funded at 107% as at December 31, 2025 (2024 - 107%). The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

Components of Net Periodic Benefit Costs

The following table provides the components of the net periodic benefit costs of the Pension Plan for the years ended December 31, 2025 and 2024:

Year ended December 31 *(millions of dollars)*	**2025**	**2024**
Current service cost	146	134
Interest cost	411	401
Expected return on plan assets, net of expenses	(663)	(603)
Amortization of prior service credit	(3)	(3)
Amortization of actuarial (gains) losses	(15)	14
Net periodic benefit credit	(124)	(57)
Charged to results of operations[1]	21	23

[1] The Company accounts for pension costs consistent with their inclusion in OEB-approved rates. During the year ended December 31, 2025, pension costs of $68 million (2024 - $75 million) comprised of $21 million (2024 - $23 million) charged to operations, and $47 million (2024 - $52 million) capitalized as part of the cost of property, plant and equipment and intangible assets.

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2025 and 2024 for the post-retirement and post-employment benefit plans:

Year ended December 31 *(millions of dollars)*	**2025**	**2024**
Current service cost	61	57
Interest cost	80	75
Amortization of prior service cost	10	10
Amortization of actuarial gains	(23)	(29)
Net periodic benefit costs	128	113
Charged to results of operations[1]	86	74

[1] The Company accounts for post-retirement and post-employment costs consistent with their inclusion in OEB-approved rates. During the year ended December 31, 2025, post-retirement and post-employment costs of $128 million (2024 - $113 million) were attributed to labour, of which $86 million (2024 - $74 million) was charged to operations, and $42 million (2024 - $39 million) was capitalized as part of the cost of property, plant and equipment and intangible assets.

Assumptions

The measurement of the obligations of the Pension Plan and Benefit Plans and the costs of providing benefits under the Pension Plan and Benefit Plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, the Company considers historical information as well as future expectations. The measurement of benefit obligations and costs is impacted by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, Hydro One's expected level of contributions

to the Pension Plan and Benefit Plans, the incidence of mortality, the expected remaining service period of plan participants, the level of compensation and rate of compensation increases, employee age, length of service, and the anticipated rate of increase of health care costs, among other factors. The impact of changes in assumptions used to measure the obligations of the Pension Plan and Benefit Plans is generally recognized over the expected average remaining service period of the plan participants. In selecting the expected rate of return on plan assets, Hydro One considers historical economic indicators that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by target asset class allocations. In general, equity securities, real estate and private equity investments are forecasted to have higher returns than fixed-income securities.

The following weighted average assumptions were used to determine the benefit obligations as at December 31, 2025 and 2024:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31	2025	2024	2025	2024
Significant assumptions:				
Weighted average discount rate	5.02 %	4.73 %	5.05 %	4.75 %
Rate of compensation scale escalation (long-term)	2.50 %	2.50 %	2.50 %	2.50 %
Rate of cost of living increase	2.00 %	2.00 %	2.00 %	2.00 %
Rate of increase in health care cost trends[1]	—	—	4.25 %	4.23 %

[1] 4.79% per annum in 2026, grading down to 4.25% per annum in and after 2032 (2024 - 4.85% per annum in 2025, grading down to 4.23% per annum in and after 2032).

The following weighted average assumptions were used to determine the net periodic benefit costs for the years ended December 31, 2025 and 2024. Assumptions used to determine current year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

Year ended December 31	2025	2024
Pension Benefits:		
Weighted average expected rate of return on plan assets	7.20 %	7.00 %
Weighted average discount rate	4.73 %	4.63 %
Rate of compensation scale escalation (long-term)	2.50 %	2.50 %
Rate of cost of living increase	2.00 %	2.00 %
Average remaining service life of employees *(years)*	15	15
Post-Retirement and Post-Employment Benefits:		
Weighted average discount rate	4.75 %	4.63 %
Rate of compensation scale escalation (long-term)	2.50 %	2.50 %
Rate of cost of living increase	2.00 %	2.00 %
Average remaining service life of employees *(years)*	16.5	16.1
Rate of increase in health care cost trends[1]	4.23 %	4.23 %

[1] 4.85% per annum in 2025, grading down to 4.23% per annum in and after 2032 (2024 - 4.92% per annum in 2024, grading down to 4.23% per annum in and after 2032).

The discount rate used to determine the current year pension obligation and the subsequent year's net periodic benefit costs is based on a yield curve approach. Under the yield curve approach, expected future benefit payments for each plan are discounted by a rate on a third-party bond yield curve corresponding to each duration. The yield curve is based on "AA" long-term corporate bonds. A single discount rate is calculated that would yield the same present value as the sum of the discounted cash flows.

The following approximate life expectancies were used in the mortality assumptions to determine the PBO for the Pension Plan and Benefit Plans as at December 31, 2025 and 2024:

As at December 31	2025	2024
Life expectancy at age 65 for a member currently at:	*(years)*	*(years)*
Age 65 - male	24	23
Age 65 - female	27	25
Age 45 - male	26	24
Age 45 - female	28	26

Estimated Future Benefit Payments

As at December 31, 2025, estimated future benefit payments to the participants of the Benefit Plans were:

(millions of dollars)	Pension Benefits	Post-Retirement and Post-Employment Benefits
2026	427	78
2027	433	78
2028	439	78
2029	445	79
2030	452	80
2031 through to 2035	2,397	423
Total estimated future benefit payments through to 2035	4,593	816

Components of Regulatory Accounts

A portion of actuarial gains and losses and prior service costs is recorded within regulatory accounts on Hydro One's consolidated balance sheets to reflect the expected regulatory inclusion of these amounts in future rates, which would otherwise be recorded in OCI. These amounts are reflected in the following table:

Year ended December 31 *(millions of dollars)*	2025	2024
Pension Benefits:		
Net actuarial loss (gain) for the year	210	(405)
Amortization of actuarial gain (loss)	15	(14)
Amortization of prior service credit	3	3
	228	(416)
Post-Retirement and Post-Employment Benefits:		
Actuarial loss for the year	28	4
Amortization of actuarial loss	15	18
	43	22

The following table provides the components of regulatory accounts that have not been recognized as components of net periodic benefit costs for the years ended December 31, 2025 and 2024:

Year ended December 31 *(millions of dollars)*	2025	2024
Pension Benefits:		
Actuarial gain	(610)	(647)
Post-Retirement and Post-Employment Benefits:		
Actuarial gain	(336)	(376)

Pension Plan Assets

Investment Strategy

On a regular basis, Hydro One evaluates its investment strategy to ensure that Pension Plan assets will be sufficient to pay Pension Plan benefits when it comes due. As part of this ongoing evaluation, Hydro One may make changes to its targeted asset allocation and investment strategy. The Pension Plan is managed at a net asset level. The main objective of the Pension Plan is to sustain a certain level of net assets in order to meet the pension obligations of the Company. The Pension Plan fulfils its primary objective by adhering to specific investment policies outlined in its Statement of Investment Policies and Procedures (SIPP), which is reviewed and approved annually by the Human Resource Committee of Hydro One's Board of Directors. The Company manages net assets by engaging external investment managers who are charged with the fiduciary responsibility of investing existing funds and new funds (current year's employee and employer contributions) in accordance with the approved SIPP. The performance of the underlying investment managers is monitored through a governance structure. Increases in net assets are a direct result of investment income generated by investments held by the Pension Plan and contributions to the Pension Plan by eligible employees and by the Company. The main use of net assets is for benefit payments to eligible Pension Plan members.

Pension Plan Asset Mix

As at December 31, 2025, the Pension Plan actual weighted average, target, and range asset allocations were as follows:

	Actual (%)	Target Allocation (%)	Range Allocation (%)
Equity securities	41	40	20 - 55
Debt securities	37	35	30 - 40
Real Estate and Infrastructure	22	25	0 - 35
	100	100	

As at December 31, 2025, the Pension Plan held $17 million (2024 - $16 million) Hydro One Inc.'s corporate bonds and $631 million (2024 - $703 million) of debt securities of the Province.

Concentrations of Credit Risk

Hydro One evaluated its Pension Plan's asset portfolio for the existence of significant concentrations of credit risk as at December 31, 2025 and 2024. Concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, concentrations in a type of industry, and concentrations in individual funds. As at December 31, 2025 and 2024, there were no significant concentrations (defined as greater than 10% of plan assets) of risk in the Pension Plan's assets.

The Pension Plan's Statement of Investment Beliefs and Guidelines provides guidelines and restrictions for eligible investments taking into account credit ratings, maximum investment exposure and other controls in order to limit the impact of this risk. The Pension Plan manages its counterparty credit risk with respect to bonds by investing in investment-grade and government bonds and with respect to derivative instruments by transacting only with highly rated financial institutions, and also by ensuring that exposure is diversified across counterparties. The risk of default on transactions in listed securities is considered minimal, as the trade will fail if either party to the transaction does not meet its obligation.

Fair Value Measurements

The following tables present the Pension Plan assets and liabilities measured and recorded at fair value on a recurring basis and their level within the fair value hierarchy as at December 31, 2025 and 2024:

As at December 31, 2025 *(millions of dollars)*	Level 1	Level 2	Level 3	Total
Pooled funds	—	—	3,277	3,277
Cash and cash equivalents	124	—	—	124
Short-term securities	—	182	—	182
Derivative instruments	—	2	—	2
Corporate shares - Canadian	102	—	—	102
Corporate shares - Foreign	2,736	255	—	2,991
Bonds and debentures - Canadian	—	2,677	—	2,677
Bonds and debentures - Foreign	—	106	—	106
Total fair value of plan assets[1]	2,962	3,222	3,277	9,461
Derivative instruments	—	1	—	1
Total fair value of plan liabilities[1]	—	1	—	1

[1] As at December 31, 2025, the total fair value of Pension Plan assets and liabilities excludes $62 million of interest and dividends receivable, $4 million of sold investments receivable, $5 million of pension administration expenses payable, $2 million of taxes payable, $nil payable to participants, and $2 million of purchased investments payable.

As at December 31, 2024 *(millions of dollars)*	**Level 1**	**Level 2**	**Level 3**	**Total**
Pooled funds	—	—	3,142	3,142
Cash and cash equivalents	106	—	—	106
Short-term securities	—	171	—	171
Derivative instruments	—	1	—	1
Corporate shares - Canadian	116	—	—	116
Corporate shares - Foreign	2,695	247	—	2,942
Bonds and debentures - Canadian	—	2,717	—	2,717
Bonds and debentures - Foreign	—	95	—	95
Total fair value of plan assets[1]	2,917	3,231	3,142	9,290
Derivative instruments	—	3	—	3
Total fair value of plan liabilities[1]	—	3	—	3

[1] As at December 31, 2024, the total fair value of Pension Plan assets and liabilities excludes $57 million of interest and dividends receivable, $1 million of sold investments receivable, $6 million of pension administration expenses payable, $2 million of taxes payable, $3 million payable to participants, and $1 million of purchased investments payable.

See Note 16 - Fair Value of Financial Instruments and Risk Management for a description of levels within the fair value hierarchy.

Changes in the Fair Value of Financial Instruments Classified in Level 3

The following table summarizes the changes in fair value of financial instruments classified in Level 3 for the years ended December 31, 2025 and 2024. The Pension Plan classifies financial instruments as Level 3 when the fair value is measured based on at least one significant input that is not observable in the markets or due to lack of liquidity in certain markets. The gains and losses presented in the table below could, therefore, include changes in fair value based on both observable and unobservable inputs. The Level 3 financial instruments are comprised of pooled funds whose valuations are provided by the investment managers. Sensitivity analysis is not provided as the underlying assumptions used by the investment managers are not available.

Year ended December 31 *(millions of dollars)*	**2025**	**2024**
Fair value, beginning of year	3,142	2,769
Realized and unrealized gains	136	262
Purchases	138	203
Sales and disbursements	(139)	(92)
Fair value, end of year	3,277	3,142

There were no transfers between any of the fair value levels during the years ended December 31, 2025 and 2024.

Valuation Techniques Used to Determine Fair Value

Pooled funds mainly consist of private equity, real estate infrastructure and private debt investments. Private equity investments represent private equity funds that invest in operating companies that are not publicly traded on a stock exchange. Investment strategies in private equity include limited partnerships in businesses that are characterized by high internal growth and operational efficiencies, venture capital, leveraged buyouts and special situations such as distressed investments. Real estate and infrastructure investments represent funds that invest in real assets which are not publicly traded on a stock exchange. Investment strategies in real estate include limited partnerships that seek to generate a total return through income and capital growth by investing primarily in global and Canadian limited partnerships. Investment strategies in infrastructure include limited partnerships in core infrastructure assets focusing on assets that are expected to generate stable, long-term cash flows and deliver incremental returns relative to conventional fixed-income investments. Private equity, real estate and infrastructure valuations are reported by the fund manager and are based on the valuation of the underlying investments which includes inputs such as cost, operating results, discounted future cash flows and market-based comparable data. Private debt valuations are reported by the fund manager. Private debt is credit that is extended to companies on a bilaterally negotiated basis. It is not readily marketable and takes a wide range of forms, such as senior secured and unsecured loans, infrastructure project financing, investments secured by real estate assets, and securitized lease/loan obligations supported by a pool of assets. Since these valuation inputs are not highly observable, private equity, real estate infrastructure and private debt investments have been categorized as Level 3 within pooled funds.

Cash equivalents consist of demand cash deposits held with banks and cash held by the investment managers. Cash equivalents are categorized as Level 1.

Short-term securities are valued at cost plus accrued interest, which approximates fair value due to their short-term nature. Short-term securities are categorized as Level 2.

Derivative instruments are used to hedge the Pension Plan's foreign currency exposure back to Canadian dollars. The notional principal amount of contracts outstanding as at December 31, 2025 was $405 million (2024 - $391 million). The most significant currencies being hedged against the Canadian dollar are the United States dollar, euro, and British pound sterling. The net

realized loss on contracts for the year ended December 31, 2025 was $4 million (2024 - $3 million net realized loss). The terms to maturity of the forward exchange contracts as at December 31, 2025 are within three months. The fair value is determined using standard interpolation methodology primarily based on the World Markets exchange rates. Derivative instruments are categorized as Level 2.

Corporate shares are valued based on quoted prices in active markets and are categorized as Level 1. Corporate shares which are valued based on quoted prices in active markets, but held within a pension investment holding company, are categorized as Level 2. Investments denominated in foreign currencies are translated into Canadian currency at year-end rates of exchange.

Bonds and debentures are presented at published closing trade quotations and are categorized as Level 2.

DC Plan

Hydro One established a DC Plan effective January 1, 2016. The DC Plan covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One up to an annual contribution limit. There is also a Supplementary Notional Plan that provides members of the DC Plan with employer contributions beyond the limitations imposed by the *Income Tax Act* (Canada) in the form of credits to a notional account. Hydro One contributions to the DC Plan for the year ended December 31, 2025 were $5 million (2024 - $5 million).

19. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2025 and 2024:

Year ended December 31, 2025 *(millions of dollars)*	**PCB**	**LAR**	**Total**
Environmental liabilities - beginning	6	41	47
Expenditures	(4)	(1)	(5)
Revaluation adjustment	(1)	3	2
Environmental liabilities - ending	1	43	44
Less: current portion	(1)	(6)	(7)
	—	37	37

Year ended December 31, 2024 *(millions of dollars)*	**PCB**	**LAR**	**Total**
Environmental liabilities - beginning	39	40	79
Expenditures	(34)	(3)	(37)
Revaluation adjustment	1	4	5
Environmental liabilities - ending	6	41	47
Less: current portion	(6)	(5)	(11)
	—	36	36

As at December 31, 2025, the estimated future environmental expenditures were as follows:

(millions of dollars)	
2026	7
2027	6
2028	2
2029	1
2030	2
Thereafter	26
	44

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred in order to generate future cash flow information. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, with respect to the PCB environmental liability, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures.

PCBs

Environment and Climate Change Canada regulations, enacted under the *Canadian Environmental Protection Act, 1999*, govern the management, storage and disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under previous regulations, Hydro One's PCBs were to be disposed of by the end of 2025, with the exception of specifically exempted equipment. On December 31st, 2025, regulations amending the *Canadian Environmental Protection Act, 1999* were published in the Canada Gazette, Part II. The amendments include deferring the end-of-use deadline for certain PCB-containing electrical equipment from December 31, 2025 to December 31, 2026. Contaminated equipment will generally be replaced, or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains PCBs in concentrations of less than 2 ppm.

As at December 31, 2025, the Company's best estimate of the total future expenditures to comply with current PCB regulations was $1 million (2024 - $6 million). These expenditures are expected to be incurred in 2026. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2025 to decrease the PCB environmental liability by $1 million (2024 - increase of $1 million).

LAR

As at December 31, 2025, the Company's best estimate of the total estimated future expenditures to complete its LAR program was $43 million (2024 - $41 million). These expenditures are expected to be incurred over the period from 2026 to 2051. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2025 to increase the LAR environmental liability by $3 million (2024 - $4 million).

20. ASSET RETIREMENT OBLIGATIONS

Hydro One records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities, as well as for the estimated expenditure for the future decommissioning and removal of some diesel generating stations and related assets operated by its subsidiary, Hydro One Remotes.

Asset retirement obligations, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an asset retirement obligation is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the asset retirement obligation, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its facilities in perpetuity, no asset retirement obligations have been recorded for these assets. If, at some future date, a particular facility is shown not to meet the perpetuity assumption, it will be reviewed to determine whether an estimable asset retirement obligation exists. In such a case, an asset retirement obligation would be recorded at that time.

In determining the amounts to be recorded as asset retirement obligations, the Company estimates the current fair value for completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 1.0% to 3.0% (2024 - 1.0% to 3.0%) depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's asset retirement obligations represent management's best estimates of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Asset retirement obligations are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively. As a result of its annual review of asset retirement obligations, the Company recorded a revaluation adjustment in 2025 to increase the asset retirement obligations related to the removal and disposal of asbestos-containing materials installed in some of its facilities by $3 million (2024 - $nil) and the asset retirement obligations related to decommissioning and removal of diesel generating station within the Hydro One Remotes operating territory by $1 million (2024 - $2 million).

As at December 31, 2025, Hydro One had recorded total asset retirement obligations of $43 million (2024 - $38 million), primarily consisting of the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities of $22 million (2024 - $18 million), and the decommissioning and removal of diesel generating stations of $20 million (2024 - $19 million).

21. LEASES

Hydro One has operating lease contracts for buildings used in administrative and service-related functions and storing telecommunications equipment. These leases have terms between three and five years with renewal options of additional three- to five-year terms at prevailing market rates at the time of extension. All leases include a clause to enable upward revision of the rental charge on an annual basis or on renewal according to prevailing market conditions or pre-established rents. There are no restrictions placed upon Hydro One by entering into these leases. Renewal options are included in the lease term when their exercise is reasonably certain. The Company also has a few finance lease arrangements, all of which were fully prepaid at commencement and are immaterial to the consolidated financial statements. Other information related to the Company's operating leases was as follows:

Year ended December 31 *(millions of dollars)*	**2025**	**2024**
Lease expense	17	17
Lease payments made	17	16

As at December 31	**2025**	**2024**
Weighted-average remaining lease term[1] *(years)*	3	4
Weighted-average discount rate	2.8 %	2.9 %

[1] Includes renewal options that are reasonably certain to be exercised.

As at December 31, 2025, future minimum operating lease payments were as follows:

(millions of dollars)	
2026	16
2027	14
2028	10
2029	3
2030	1
Thereafter	1
Total undiscounted minimum lease payments	45
Less: discounting minimum lease payments to present value	(2)
Total discounted minimum lease payments	43

As at December 31, 2024, future minimum operating lease payments were as follows:

(millions of dollars)	
2025	17
2026	15
2027	13
2028	10
2029	2
Thereafter	2
Total undiscounted minimum lease payments	59
Less: discounting minimum lease payments to present value	(4)
Total discounted minimum lease payments	55

Hydro One presents its ROU assets and lease obligations on the consolidated balance sheets as follows:

As at December 31 *(millions of dollars)*	**2025**	**2024**
Other long-term assets *(Note 12)*	47	55
Accounts payable and other current liabilities *(Note 13)*	14	14
Other long-term liabilities *(Note 14)*	29	41

22. SHARE CAPITAL

Common Shares

The Company is authorized to issue an unlimited number of common shares. As at December 31, 2025, the Company had 599,781,811 (2024 - 599,435,650) common shares issued and outstanding.

The amount and timing of any dividends payable by Hydro One is at the discretion of the Hydro One Board of Directors and is established on the basis of Hydro One's results of operations, maintenance of its deemed regulatory capital structure, financial condition, cash requirements, the satisfaction of solvency tests imposed by corporate laws for the declaration and payment of dividends and other factors that the Board of Directors may consider relevant.

The following tables presents the changes to common shares during the years ended December 31, 2025 and 2024:

	Ownership by		
Year ended December 31, 2025 *(number of shares)*	**Public**	**Province**	**Total**
Common shares - beginning	317,023,002	282,412,648	599,435,650
Common shares issued - LTIP[1]	10,492	—	10,492
Common shares issued - share grants[2]	335,669	—	335,669
Common shares - ending	317,369,163	282,412,648	599,781,811
	52.9 %	47.1 %	100 %

[1] In 2025, Hydro One issued 10,492 common shares from treasury in accordance with provisions of the LTIP.
[2] In 2025, Hydro One issued 335,669 common shares from treasury in accordance with provisions of the Power Workers' Union (PWU) and the Society Share Grant Plans.

	Ownership by		
Year ended December 31, 2024 *(number of shares)*	**Public**	**Province**	**Total**
Common shares - beginning	316,664,419	282,412,648	599,077,067
Common shares issued - LTIP[1]	9,905	—	9,905
Common shares issued - share grants[2]	348,678	—	348,678
Common shares - ending	317,023,002	282,412,648	599,435,650
	52.9 %	47.1 %	100 %

[1] In 2024, Hydro One issued 9,905 common shares from treasury in accordance with provisions of the LTIP.
[2] In 2024, Hydro One issued 348,678 common shares from treasury in accordance with provisions of the PWU and the Society Share Grant Plans.

Preferred Shares

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. As at December 31, 2025 and 2024, two series of preferred shares were authorized for issuance: the Series 1 preferred shares and the Series 2 preferred shares. As at December 31, 2025, and 2024, the Company had no Series 1 preferred shares and no Series 2 preferred shares issued and outstanding.

Hydro One may from time to time issue preferred shares in one or more series. Prior to issuing shares in a series, the Hydro One Board of Directors is required to fix the number of shares in the series and determine the designation, rights, privileges, restrictions and conditions attaching to that series of preferred shares. Holders of Hydro One's preferred shares are not entitled to receive notice of, to attend or to vote at any meeting of the shareholders of Hydro One except that votes may be granted to a series of preferred shares when dividends have not been paid on any one or more series as determined by the applicable series provisions. Each series of preferred shares ranks on parity with every other series of preferred shares, and are entitled to a preference over the common shares and any other shares ranking junior to the preferred shares, with respect to dividends and the distribution of assets and return of capital in the event of the liquidation, dissolution or winding up of Hydro One.

Share Ownership Restrictions

The Electricity Act imposes share ownership restrictions on securities of Hydro One carrying a voting right (Voting Securities). These restrictions provide that no person or company (or combination of persons or companies acting jointly or in concert) may beneficially own or exercise control or direction over more than 10% of any class or series of Voting Securities, including common shares of the Company (Share Ownership Restrictions). The Share Ownership Restrictions do not apply to Voting Securities held by the Province, nor to an underwriter who holds Voting Securities solely for the purpose of distributing those securities to purchasers who comply with the Share Ownership Restrictions.

23. DIVIDENDS

In 2025, common share dividends in the amount of $788 million (2024 - $743 million) were declared and paid.

See Note 32 - Subsequent Events for dividends declared subsequent to December 31, 2025.

24. EARNINGS PER COMMON SHARE

Basic earnings per common share (EPS) is calculated by dividing net income attributable to common shareholders of Hydro One by the weighted-average number of common shares outstanding.

Diluted EPS is calculated by dividing net income attributable to common shareholders of Hydro One by the weighted-average number of common shares outstanding adjusted for the effects of potentially dilutive stock-based compensation plans, including the share grant plans and LTIP, which are calculated using the treasury stock method.

	2025	2024
Net income attributable to common shareholders *(millions of dollars)*	1,339	1,156
Weighted-average number of shares		
Basic	599,692,817	599,342,299
Effect of dilutive stock-based compensation plans	1,020,183	1,318,179
Diluted	600,713,000	600,660,478
EPS		
Basic	$2.23	$1.93
Diluted	$2.23	$1.92

25. STOCK-BASED COMPENSATION

Share Grant Plans

Hydro One has two share grant plans (Share Grant Plans), one for the benefit of certain members of the PWU (PWU Share Grant Plan) and one for the benefit of certain members of the Society (Society Share Grant Plan).

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One from treasury to certain eligible members of the PWU annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on April 1, 2015, be employed on the date that the annual share issuance occurs and continue to have under 35 years of service. The requisite service period for the PWU Share Grant Plan began on July 3, 2015, which is the date that the share grant plan was ratified by the PWU. The number of common shares issued annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as of April 1, 2015, divided by $20.50, being the price of the common shares of Hydro One in its Initial Public Offering (IPO). The aggregate number of common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 3,979,062 common shares were granted under the PWU Share Grant Plan.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One from treasury to certain eligible members of the Society annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on September 1, 2015, be employed on the date that the annual share issuance occurs and continue to have under 35 years of service. Therefore, the requisite service period for the Society Share Grant Plan began on September 1, 2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as of September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One in its IPO. The aggregate number of common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 1,433,292 common shares were granted under the Society Share Grant Plan.

The fair value of the Hydro One 2015 share grants of $111 million was estimated based on the grant date share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. In 2025, 335,669 common shares (2024 - 348,678) were issued under the Share Grant Plans. Total share-based compensation recognized during 2025 was $1 million (2024 - $2 million) and was recorded as a regulatory asset.

A summary of share grant activity under the Share Grant Plans during the years ended December 31, 2025 and 2024 is presented below:

Year ended December 31, 2025	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	1,407,294	$20.50
Vested and issued[1]	(335,669)	—
Forfeited	(46,481)	$20.50
Share grants outstanding - ending	1,025,144	$20.50

[1] In 2025, Hydro One issued 335,669 common shares from treasury to eligible employees in accordance with provisions of the Share Grant Plans.

Year ended December 31, 2024	Share Grants (number of common shares)	Weighted-Average Price
Share grants outstanding - beginning	1,782,376	$20.50
Vested and issued[1]	(348,678)	—
Granted	1,092	—
Forfeited	(27,496)	$20.50
Share grants outstanding - ending	1,407,294	$20.50

[1] In 2024, Hydro One issued 348,678 common shares from treasury to eligible employees in accordance with provisions of the Share Grant Plans.

Directors' DSU Plan

Under the Directors' DSU Plan, directors can elect to receive credit for their annual cash retainer in a notional account of DSUs in lieu of cash. Hydro One's Board of Directors may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled. Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Company and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One's Board of Directors.

A summary of DSU awards activity under the Directors' DSU Plan during the years ended December 31, 2025 and 2024 is presented below:

Year ended December 31 *(number of DSUs)*	2025	2024
DSUs outstanding - beginning	107,296	94,624
Granted	21,033	22,293
Settled	(26,073)	(9,621)
DSUs outstanding - ending	102,256	107,296

For the year ended December 31, 2025, an expense of $2 million (2024 - $1 million) was recognized in earnings with respect to the Directors' DSU Plan. As at December 31, 2025, a liability of $6 million (2024 - $5 million) related to Directors' DSUs has been recorded at the closing price of the Company's common shares of $54.64. This liability is included in other long-term liabilities on the consolidated balance sheets.

Management DSU Plan

Under the Management DSU Plan, eligible executive employees can elect to receive a specified proportion of their annual short-term incentive in a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Company and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One's Board of Directors.

A summary of DSU awards activity under the Management DSU Plan during the years ended December 31, 2025 and 2024 is presented below:

Year ended December 31 *(number of DSUs)*	2025	2024
DSUs outstanding - beginning	85,690	134,370
Granted	14,219	16,600
Settled	(19,505)	(65,280)
DSUs outstanding - ending	80,404	85,690

For the year ended December 31, 2025, an expense of $2 million (2024 - $1 million) was recognized in earnings with respect to the Management DSU Plan. As at December 31, 2025, a liability of $4 million (2024 - $4 million) related to Management DSUs has been recorded at the closing price of the Company's common shares of $54.64. This liability is included in other long-term liabilities on the consolidated balance sheets.

Employee Share Ownership Plan

In 2015, Hydro One established Employee Share Ownership Plans (ESOP) for certain eligible management and non-represented employees (Management ESOP) and for certain eligible Society-represented staff (Society ESOP). Under the Management ESOP, the eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One. The Company matches 50% of their contributions, up to a maximum Company contribution of $25,000 per calendar year. Under the Society ESOP, the eligible Society-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One. The Company matches 25% of their contributions, with no maximum Company contribution per calendar year.

In 2024, Hydro One established ESOP for certain eligible PWU represented staff (PWU ESOP). Under the PWU ESOP, the eligible PWU-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One. The Company matches 33% of their contribution, with no maximum Company contribution per calendar year. In 2025, Company contributions made under the ESOP were $9 million (2024 - $5 million).

LTIP

Effective August 31, 2015, the Board of Directors of Hydro One adopted an LTIP. Under the LTIP, long-term incentives were granted to certain executive and management employees of Hydro One and its subsidiaries, and all equity-based awards would either be settled in newly issued shares of Hydro One from treasury or cash, subject to Hydro One's discretion, consistent with the provisions of the plan which also permit the participants to surrender a portion of their awards to satisfy related withholding taxes requirements. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares of Hydro One.

The LTIP provides flexibility to award a range of vehicles, including Performance Share Units (PSUs), Restricted Share Units (RSUs), stock options, share appreciation rights, restricted shares, DSUs, and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance.

PSUs and RSUs

A summary of PSU and RSU awards activity under the LTIP during the years ended December 31, 2025 and 2024 is presented below:

	PSUs		RSUs	
Year ended December 31 *(number of units)*	**2025**	**2024**	**2025**	**2024**
Units outstanding - beginning	286,554	142,925	322,925	186,971
Granted	179,731	189,104	154,754	158,757
Forfeited	(45,655)	(24,918)	(60,660)	(20,377)
Vested and issued	(21,449)	(20,557)	(25,396)	(2,426)
Units outstanding - ending	399,181	286,554	391,623	322,925

The grant date total fair value of the awards granted during the year ended December 31, 2025 was $16 million (2024 - $14 million). The compensation expense related to the PSU and RSU awards recognized by the Company during the year ended December 31, 2025 was $11 million (2024 - $10 million).

26. NONCONTROLLING INTEREST

Total noncontrolling interest consists of noncontrolling interests attributable to B2M LP, NRLP and CLLP. The following tables show the movements in total noncontrolling interest during the years ended December 31, 2025 and 2024:

Year ended December 31, 2025 *(millions of dollars)*	**Temporary Equity**	**Equity**	**Total**
Noncontrolling interest - beginning	19	65	84
Contributions from sale of noncontrolling interest	—	16	16
Net income attributable to noncontrolling interest	2	8	10
Distributions to noncontrolling interest	(2)	(10)	(12)
Noncontrolling interest - ending	19	79	98

Year ended December 31, 2024 *(millions of dollars)*	**Temporary Equity**	**Equity**	**Total**
Noncontrolling interest - beginning	20	65	85
Net income attributable to noncontrolling interest	2	7	9
Distributions to noncontrolling interest	(3)	(7)	(10)
Noncontrolling interest - ending	19	65	84

B2M LP

On December 17, 2014, the Saugeen Ojibway Nation (SON) acquired a 34.2% equity interest in B2M LP for consideration of $72 million, representing the fair value of the equity interest acquired. The SON's investment in B2M LP consists of $50 million of Class A units and $22 million of Class B units.

The Class B units have a mandatory put option which requires that upon the occurrence of an enforcement event (i.e., an event of default such as a debt default by the SON or insolvency event), Hydro One purchases the Class B units of B2M LP for net book value on the redemption date. The noncontrolling interest relating to the Class B units is classified on the consolidated balance sheet as temporary equity because the redemption feature is outside the control of the Company. The balance of the noncontrolling interest is classified within equity.

The following tables show the movements in B2M LP noncontrolling interest during the years ended December 31, 2025 and 2024:

Year ended December 31, 2025 *(millions of dollars)*	**Temporary Equity**	**Equity**	**Total**
Noncontrolling interest - beginning	19	44	63
Net income attributable to noncontrolling interest	2	5	7
Distributions to noncontrolling interest	(2)	(7)	(9)
Noncontrolling interest - ending	19	42	61

Year ended December 31, 2024 *(millions of dollars)*	**Temporary Equity**	**Equity**	**Total**
Noncontrolling interest - beginning	20	44	64
Net income attributable to noncontrolling interest	2	5	7
Distributions to noncontrolling interest	(3)	(5)	(8)
Noncontrolling interest - ending	19	44	63

NRLP

On September 18, 2019, Hydro One Networks sold to the Six Nations of the Grand River Development Corporation and, through a trust, to the Mississaugas of the Credit First Nation a 25.0% and 0.1% equity interest in NRLP partnership units, respectively, for total consideration of $12 million, representing the fair value of the equity interest acquired. On January 31, 2020, the Mississaugas of the Credit First Nation purchased an additional 19.9% equity interest in NRLP partnership units from Hydro One Networks for total cash consideration of $9 million. Following this transaction, Hydro One's interest in the equity portion of NRLP partnership units was reduced to 55%, with the Six Nations of the Grand River Development Corporation and the Mississaugas of the Credit First Nation owning 25% and 20%, respectively, of the equity interest in NRLP partnership units. The First Nations Partners' noncontrolling interest in NRLP is classified within equity.

The following table shows the movements in NRLP noncontrolling interest during the years ended December 31, 2025 and 2024:

Year ended December 31 *(millions of dollars)*	**2025**	**2024**
Noncontrolling interest - beginning	21	21
Net income attributable to noncontrolling interest	2	2
Distributions to noncontrolling interest	(3)	(2)
Noncontrolling interest - ending	20	21

CLLP

On December 17, 2024, transmission assets totalling $203 million were transferred from Hydro One Networks to CLLP. Effective June 1, 2025, Hydro One Networks sold 10% equity interest to Deshkan Ziibiing Chippewas of the Thames First Nation for cash consideration of $8 million. Effective July 1, 2025, Hydro One Networks sold an additional 10% equity interest to Southwest Indigenous Transmission Limited Partnership, owned by the Caldwell First Nation, for cash consideration of $8 million. The total consideration of $16 million represents the fair value of the equity interest acquired. Following these transactions, Hydro One's interest in the equity portion of CLLP partnership units was reduced to 80%. The First Nations Partners' noncontrolling interest in CLLP is classified within equity.

The following table shows the movements in CLLP noncontrolling interest during the years ended December 31, 2025 and 2024:

Year ended December 31 *(millions of dollars)*	**2025**	**2024**
Noncontrolling interest - beginning	—	—
Contributions from sale of noncontrolling interest	16	—
Net income attributable to noncontrolling interest	1	—
Noncontrolling interest - ending	17	—

27. RELATED PARTY TRANSACTIONS

The Province is a shareholder of Hydro One with approximately 47.1% (2024 - 47.1%) ownership as at December 31, 2025. The Ministry of Energy and Mines (Ministry) and the Ministry of Infrastructure (MOI) are related parties to Hydro One because they are controlled by the Province. The IESO, Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), and the OEB are related parties to Hydro One because they are controlled or significantly influenced by the Ministry. Hydro One also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province. The following is a summary of the Company's related party transactions during the years ended December 31, 2025 and 2024:

Year ended December 31 *(millions of dollars)*

Related Party	Transaction	2025	2024
Province	Dividends paid	370	350
Ministry	Broadband subsidy[1]	27	—
MOI	Broadband subsidy[1]	19	43
IESO	Power purchased	3,011	2,686
	Revenues for transmission services	2,388	2,252
	Amounts related to electricity rebates	1,110	1,170
	Distribution revenues related to rural rate protection	256	255
	Distribution revenues related to Wataynikaneyap Power LP	133	119
	Distribution revenues related to supply of electricity to remote northern communities	50	48
	Funding received related to Conservation and Demand Management programs	—	1
OPG	Power purchased	23	18
	Transmission revenues related to provision of services and supply of electricity	2	2
	Distribution revenues related to provision of services and supply of electricity	8	5
	Other revenues related to provision of services and supply of electricity	2	1
	Capital contribution received from OPG	20	3
	Costs related to the purchase of services	2	1
OEFC	Power purchased from power contracts administered by the OEFC	2	1
OEB	OEB fees	14	12

[1] On October 31, 2024, the MOI announced that it has developed a program to deliver up to $400 million in subsidies to internet service providers (ISPs) for work associated with designated broadband projects. The program is intended to enable ISPs to successfully and safely attach their material and equipment to the Company's poles to bring connectivity to rural communities as part of a designated broadband project as defined under *Building Broadband Faster Act (Ontario)*. A portion of these subsidies is used to reimburse Hydro One Networks on behalf of ISPs for their share of enablement costs incurred to facilitate the program to date. During 2025, Ministry replaced MOI in making broadband subsidy payments to Hydro One.

Sales to and purchases from related parties are based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances as at period end are interest-free and settled in cash. Invoices are issued monthly, and amounts are due and paid on a monthly basis.

28. CONSOLIDATED STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 *(millions of dollars)*	2025	2024
Accounts receivable	(169)	(81)
Due from related parties	(84)	(12)
Materials and supplies	(1)	6
Prepaid expenses and other assets *(Note 8)*	2	(26)
Other long-term assets	(5)	(34)
Accounts payable *(Note 13)*	23	7
Accrued liabilities	95	136
Unearned revenue *(Note 13)*	(23)	125
Due to related parties	137	40
Accrued interest *(Note 13)*	23	31
Long-term accounts payable and other long-term liabilities	(9)	8
Post-retirement and post-employment benefit liability	64	49
	53	249

Capital Expenditures

The following tables reconcile investments in property, plant and equipment and intangible assets and the amounts presented in the consolidated statements of cash flows for the years ended December 31, 2025 and 2024. The reconciling items include net change in accruals, transfers, and capitalized depreciation.

Year ended December 31, 2025 *(millions of dollars)*	Property, Plant and Equipment	Intangible Assets	Total
Capital investments	(3,289)	(77)	(3,366)
Reconciling items	319	(3)	316
Cash outflow for capital expenditures	(2,970)	(80)	(3,050)

Year ended December 31, 2024 *(millions of dollars)*	Property, Plant and Equipment	Intangible Assets	Total
Capital investments	(2,968)	(95)	(3,063)
Reconciling items	248	7	255
Cash outflow for capital expenditures	(2,720)	(88)	(2,808)

Capital Contributions

Hydro One enters into contracts governed by the OEB Transmission System Code when a transmission customer requests a new or upgraded transmission connection. The customer is required to make a capital contribution to Hydro One based on the shortfall between the present value of the costs of the connection facility and the present value of revenues. The present value of revenues is based on an estimate of load forecast for the period of the contract with Hydro One. Once the connection facility is commissioned, in accordance with the OEB Transmission System Code, Hydro One will periodically reassess the estimated load forecast which will lead to a decrease, or an increase in the capital contributions from the customer. The increase or decrease in capital contributions is recorded directly to property, plant and equipment in service. In 2025, there were $3 million capital contributions from these assessments (2024 - $2 million).

Supplementary Information

Year ended December 31 *(millions of dollars)*	2025	2024
Net interest paid	724	643
Income taxes paid	45	35

29. CONTINGENCIES

Legal Proceedings

Hydro One is involved in various lawsuits and claims in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Transfer of Assets

The transfer orders by which the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the *Indian Act* (Canada)). Currently, the OEFC holds these assets. Under the terms of the transfer orders, the Company is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. The Company cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. In 2025, the Company paid $3 million (2024 - $2 million) in respect of consents obtained for a permit that was issued in favour of the Company which would allow for the transfer of assets. In 2025, the Company recorded $6 million (2024 - $4 million) in respect of annual obligations under existing agreements, which includes assets that continued to be held by OEFC. If the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it may have to relocate these assets to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on the Company's results of operations if the Company is not able to recover them in future rate orders.

30. COMMITMENTS

A summary of Hydro One's commitments under outsourcing and other agreements due in the next five years and thereafter are as follows:

As at December 31, 2025 *(millions of dollars)*	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Outsourcing and other agreements	48	47	33	1	1	17

Outsourcing and Other Agreements

On July 31, 2025 Hydro One renewed the agreement for information technology services with Capgemini Canada Inc., with a three year term ending July 31, 2028, and includes an option to extend for two additional one-year terms.

Other Commitments

The following table presents a summary of Hydro One's other commercial commitments by year of expiry in the next five years and thereafter:

As at December 31, 2025 *(millions of dollars)*	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Operating Credit Facilities[1]	—	—	—	—	3,300	—
Letters of credit[2]	191	—	—	—	—	—
Guarantees[3]	540	—	—	—	—	—

[1] On June 1, 2025, the maturity date for the Operating Credit Facilities was extended to June 1, 2030.
[2] Letters of credit consist of $166 million letters of credit related to retirement compensation arrangements, an $18 million letter of credit provided to the IESO for prudential support, and $7 million in letters of credit for various operating purposes.
[3] Guarantees consist of $475 million prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries, as well as $60 million of guarantees provided by Hydro One to ONroute relating to OCN LP (OCN Guarantee) and $5 million relating to Aux Energy Inc.

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for Hydro One Inc.'s liability under the terms of a trust fund established pursuant to the supplementary pension plan for eligible employees of Hydro One Inc. The supplementary pension plan trustee is required to draw upon these letters of credit if Hydro One Inc. is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure Hydro One Inc.'s liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the letters of credit.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees and/or letters of credit if these purchasers fail to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of any letters of credit plus the amount of the parental guarantees.

31. SEGMENTED REPORTING

The Company has three reportable segments: Transmission, Distribution, and Other. The composition of these segments is described in Note 1 to the consolidated financial statements.

The designation of segments has been based on a combination of regulatory status and the nature of the services provided. Operating segments of the Company are determined based on information used by the Chief Operating Decision Maker (CODM) in deciding how to allocate resources and evaluate the performance of each of the segments. Hydro One's CODM consists of its Chief Executive Officer and certain members of the executive leadership team. The CODM evaluates segment performance based on income before financing charges, equity income, and income tax expense from continuing operations (excluding certain allocated corporate governance costs) (EBIT). The CODM considers the key components of EBIT to understand the variances to prior period on a quarterly basis and measures them against the Company's budget and forecast across each of the three segments on a monthly basis in order to properly allocate resources between and within the operating segments.

Year ended December 31, 2025 *(millions of dollars)*	**Transmission**	**Distribution**	**Other**	**Consolidated**
Revenues	2,429	6,557	55	9,041
Purchased power	—	4,486	—	4,486
Operation, maintenance and administration	447	661	98	1,206
Depreciation, amortization and asset removal costs	570	529	12	1,111
Income (loss) before financing charges, equity income and income tax expense	1,412	881	(55)	2,238
Capital investments	2,097	1,252	17	3,366

Year ended December 31, 2024 *(millions of dollars)*	**Transmission**	**Distribution**	**Other**	**Consolidated**
Revenues	2,269	6,175	40	8,484
Purchased power	—	4,143	—	4,143
Operation, maintenance and administration	475	721	112	1,308
Depreciation, amortization and asset removal costs	554	502	10	1,066
Income (loss) before financing charges, equity income and income tax expense	1,240	809	(82)	1,967
Capital investments	1,860	1,185	18	3,063

Total Assets by Segment:

As at December 31 *(millions of dollars)*	**2025**	**2024**
Transmission	23,630	21,630
Distribution	15,160	14,040
Other	881	1,012
Total assets	39,671	36,682

Total Goodwill by Segment:

As at December 31 *(millions of dollars)*	**2025**	**2024**
Transmission	157	157
Distribution	216	216
Other	5	—
Total goodwill	378	373

All revenues, assets and substantially all costs, as the case may be, are earned, held or incurred in Canada.

32. SUBSEQUENT EVENTS

Dividends

On February 12, 2026, common share dividends of $200 million ($0.3331 per common share) were declared.

CLLP

On January 2, 2026, Hydro One Networks sold to Walpole Island First Nation an approximate 10% equity interest in CLLP for total consideration of approximately $8 million. Following the completion of the transaction, Hydro One Networks' equity interest in CLLP was reduced to 70%. On February 2, 2026, Aamjiwnaang First Nation and Chippewas of Kettle & Stony Point First Nation collectively purchased an approximate 20% equity interest in CLLP through an equally-owned Limited Partnership for total consideration of approximately $16 million. Following the completion of the transaction, Hydro One Networks' equity interest in CLLP was reduced to 50%.

Corporate and Shareholder Information

Directors and Senior Leadership Team of Hydro One Ltd.

Directors

Melissa Sonberg (Chair)
David Hay
Debbie Hutton
Stacey Mowbray
Mitch Panciuk
Mark Podlasly
Helga Reidel
Michael W. Rencheck
Brian Vaasjo
Susan Wolburgh Jenah

Senior Leadership Team

David Lebeter
President and Chief Executive Officer

Ryan Docherty
EVP, Capital Portfolio Delivery

Teri French
EVP, Safety, Operations and Customer Experience

Cassidy McFarlane
General Counsel

Renée McKenzie
EVP, Digital and Technology Solutions

Lisa Pearson
EVP, Corporate Affairs

Harry Taylor
EVP, Chief Financial and Regulatory Officer

Megan Telford
Chief Operating Officer

Gillian Whitebread
EVP, Head of Human Resources

General Information

Corporate Office

483 Bay Street, South Tower
Toronto, ON
M5G 2P5
1-416-345-5000
HydroOne.com

Customer Inquiries

Customer Service: 1-888-664-9376
Report an Emergency (24 hours):
1-800-434-1235

Shareholder Services

If you are a registered shareholder and have inquiries regarding your account, wish to change your name or address, or have questions about dividends, duplicate mailings, lost stock certificates, share transfers or estate settlements, contact our transfer agent and registrar:

Computershare Trust Company of Canada

100 University Avenue, 8th Floor
Toronto, ON M5J 2Y1
1-514-982-7555 or 1-800-564-6253
service@computershare.com

Institutional Investors and Analysts

Institutional investors, securities analysts and others requiring additional financial information can visit HydroOne.com/Investors or contact us at: 1-416-345-6867
Investor.Relations@HydroOne.com

Media Inquiries

1-416-345-6868 or 1-877-506-7584
Media.Relations@HydroOne.com

Sustainability

Hydro One is committed to continuing to grow responsibly and we focus our social and environmental sustainability efforts where we can make the most meaningful impacts on both. To learn more, visit HydroOne.com/sustainability or email: Sustainability@HydroOne.com

Stock Exchange Listing

Toronto Stock Exchange (TSX): H
(CUSIP #448811208)

H TSX LISTED

Debt Securities

For details of the public debt securities of Hydro One and its subsidiaries, please refer to the "Debt Information" section under HydroOne.com/Investors

Independent Auditors

KPMG LLP

Online Information

Hydro One is committed to open and full financial disclosure and best practices in corporate governance. We invite you to visit the Investor Relations section of HydroOne.com/Investors where you will find additional information about our business, including events and presentations, news releases, regulatory filings, governance practices, sustainability and our continuous disclosure materials, including quarterly financial releases, annual information forms and management information circulars. You may also subscribe to our news by email to automatically receive Hydro One news releases electronically.

Common Share Dividend Information

2026 Expected Dividend Dates

Declaration Date	Record Date	Payment Date
February 12, 2026	March 11, 2026	March 31, 2026
May 12, 2026	June 10, 2026	June 30, 2026
August 6, 2026	September 9, 2026	September 29, 2026
November 9, 2026	December 9, 2026	December 31, 2026

Unless indicated otherwise, all common share dividends paid by Hydro One are designated as "eligible" dividends for the purposes of the *Income Tax Act* (Canada) and any similar provincial legislation.

Dividend Reinvestment Plan (DRIP)

Hydro One offers a convenient dividend reinvestment program for eligible shareholders to purchase additional Hydro One shares by reinvesting their cash dividends without incurring brokerage or administration fees. For plan information and enrolment materials or to learn more about the Hydro One DRIP, visit HydroOne.com/DRIP or Computershare Trust Company of Canada at InvestorCentre.com/HydroOne

Regulatory Stakeholders

Hydro One is committed to maintaining and enhancing constructive long-term relationships with its regulatory stakeholders.

Ontario

Provincial Government, Ministry of Energy and Mines
Policy, legislation, regulations

ONTARIO ENERGY BOARD

Ontario Energy Board (OEB)
Independent electric utility price and service quality regulation

ieso
Connecting Today.
Powering Tomorrow.

Independent Electricity System Operator (IESO)
Wholesale power market rules, intermediary, North American reliability standards

Canada Energy Regulator | Régie de l'énergie du Canada

Canadian Energy Regulator
Federal regulator, international power lines and substations

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

North American Electric Reliability Corporation (NERC)
Continent-wide bulk power reliability standards, certification, monitoring

NPCC, Inc.

Northeast Power Coordinating Council (NPCC)
Northeastern North American grid reliability, standards, compliance

For more information, visit
HydroOne.com/Regulatory

hydroOne

HydroOne.com

Photo taken by employee Kevin Heithoff,
Regional Maintainer 1 - Lines Distribution

ACCOUNTING INFORMATION – HOSSM

1.0 ORGANIZATIONAL STRUCTURE

Hydro One Sault Ste. Marie LP (HOSSM), formerly Great Lakes Power Transmission LP (GLPTLP), was formed on May 17, 2007 for the purpose of acquiring the assets and liabilities of the transmission division of Great Lakes Power Limited (GLPL), previously a related party due to common ownership. HOSSM is an OEB-licensed transmitter whose transmission system is located in the vicinity of Sault Ste. Marie, Ontario.

On October 31, 2016, Hydro One Inc. (Hydro One) completed the purchase of the GLPTLP from Brookfield Infrastructure following approval by the OEB issued on October 13, 2016 (EB-2016-0050). The OEB's approval included a ten-year deferred rebasing period extending through December 31, 2026. As part of the transaction, GLPTLP legally changed its name to HOSSM on January 16, 2017.

Hydro One Sault Ste. Marie Holdings LP is the Limited Partner and holds a 99.99% interest in HOSSM. Hydro One Sault Ste. Marie Inc., the General Partner, holds a 0.01% limited interest in HOSSM and is responsible for its management. The Limited Partner is indirectly owned by Hydro One Networks Inc. Both the General Partner and Hydro One Networks Inc. are wholly-owned subsidiaries of Hydro One Inc., which is wholly owned by Hydro One Limited.

Since the acquisition, HOSSM has continued to operate as a distinct regulated transmitter while progressively integrating certain corporate, operational and governance processes with those of Hydro One Transmission.

2.0 ACCOUNTING STANDARD

GLPTLP prepared its financial statements in accordance with International Financial Reporting Standards (IFRS Accounting Standards) as issued by the International Accounting Standards Board (IASB). Following the acquisition, HOSSM continued to prepare its financial statements under IFRS Accounting Standards throughout the

deferred rebasing period. HOSSM will continue to report under IFRS for financial reporting and rate-setting purposes until it is fully integrated into Hydro One Networks.

In accordance with section 2.2.2 of the OEB's Filing Requirements for Electricity Transmission Applications, transmitters that have adopted IFRS for financial reporting purposes are required to file revenue requirement applications on the basis of Modified IFRS (MIFRS). Under the MIFRS framework, transmitters are expected to comply with the most current IFRS Accounting Standards and identify in their rate applications accounting standard updates adopted since the last rebasing application together with any associated rate impacts.

Accordingly, the accounting information presented for HOSSM in this Application has been prepared on a MIFRS basis consistent with OEB filing requirements and reflects accounting policies that are consistent with those used in HOSSM's audited financial statements.

3.0 CHANGES TO ACCOUNTING POLICIES

During the deferred rebasing period approved by the OEB following Hydro One's acquisition of GLPTLP, several IFRS Accounting Standards became effective. Consistent with the OEB's Modified IFRS (MIFRS) filing requirements, HOSSM assessed the impact of these standards on its financial reporting and regulatory reporting, including consideration of potential impacts on revenue requirement, rate base, operating expenses and depreciation expense. The standard assessed included IFRS 15 *Revenue from Contracts with Customers*, IFRS 9 *Financial Instruments*, and IFRS 16 *Leases.* The adoption of these standards did not have a material impact on HOSSM's revenue requirement, rate base, operating expenses, depreciation expense, or overall financial position. However, they represented major changes to the IFRS reporting framework that required assessment during the deferred rebasing period.

In keeping with good corporate governance practices, HOSSM reviews and, where appropriate, revises its accounting policies and procedures from time to time. HOSSM

continues to monitor recently issued IFRS Accounting Standards and amendments, including IFRS 18 *Presentation and Disclosure in Financial Statements*, IFRS 20 *Regulatory Assets and Regulatory Liabilities*, IFRS 19 *Subsidiaries without Public Accountability: Disclosures*, and the IASB's *Annual Improvements to IFRS Accounting Standards*. These standards will become effective during the 2027-2032 rate period covered by this Application. Based on HOSSM's assessment to date, these standards are not expected to have a material impact on its revenue requirement, rate base, operating expenses, depreciation expense, financial position, or results of operations. HOSSM will continue to monitor developments and assess any impacts as implementation guidance evolves.

4.0 ACCOUNTING ORDERS

Please see Exhibit G-01-01, Attachment 1 for details.

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CORPORATE ORGANIZATION CHARTS

Attachment 1 sets out the corporate organizational structure for the Hydro One group of companies as of June 2026.

Attachment 2 sets out the executive and senior management positions within Hydro One.

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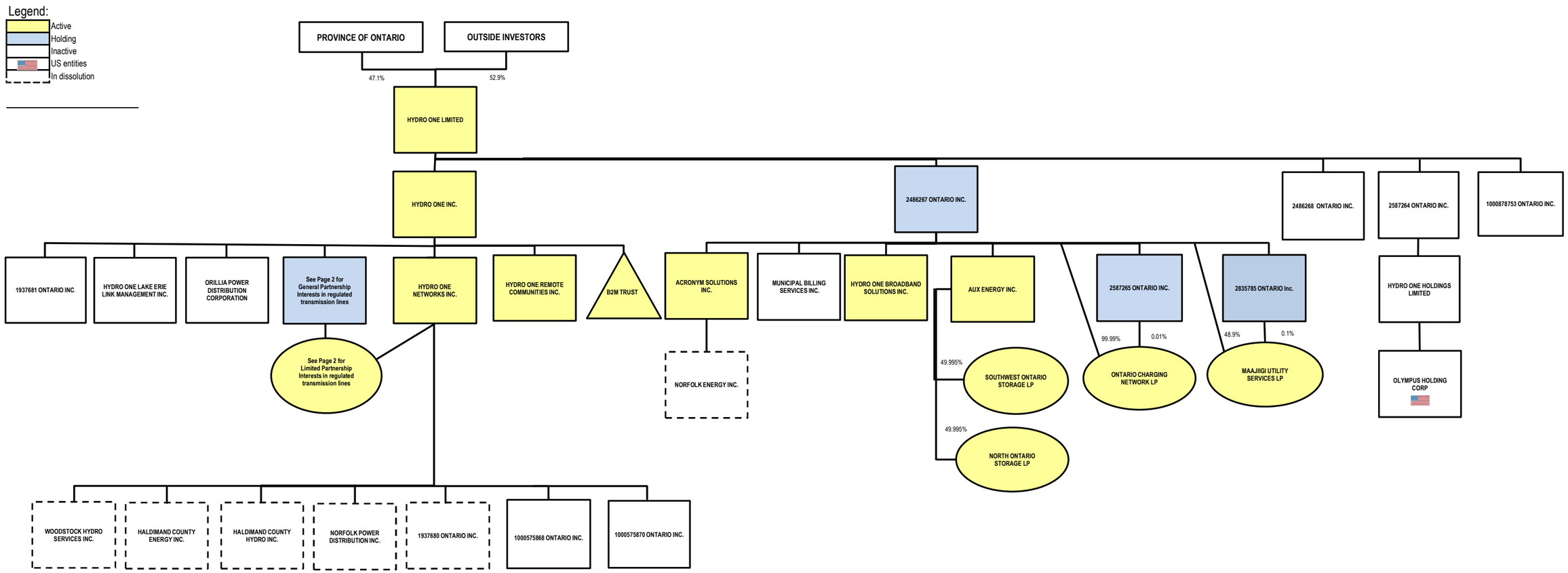
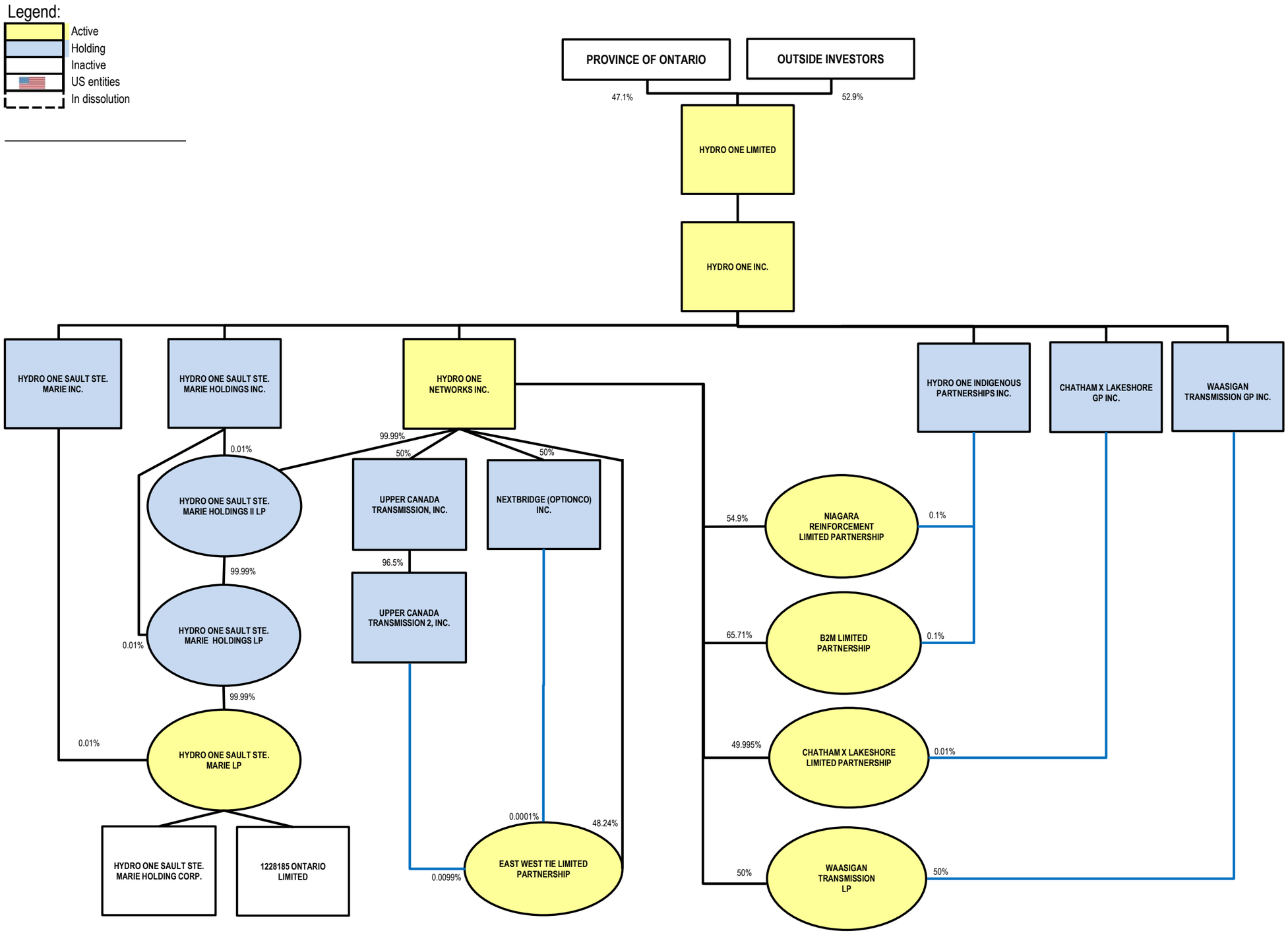
HYDRO ONE
ORGANIZATIONAL CHART AS AT 2026-06-30 (PAGE 1)



HYDRO ONE

ORGANIZATIONAL CHART AS AT 2026-06-30 (PAGE 2 - PARTNERSHIP INTEREST)



Hydro One Organizational Structure

Effective September 15, 2026

Megan Telford
President and CEO

Ryan Docherty

EVP, Capital Portfolio Delivery

- Sonny Karunakaran, VP, Strategic Projects & Partnerships
- Kathleen McCorriston, VP, Construction & Engineering
- Scott Vicary, VP, Portfolio Management
- Kyle Higgins, Director, Business Performance

Teri French

EVP, Safety, Operations and Customer Experience

- Gianni DiFilippo, VP, Distribution Operations
- Lorraine Gray, VP, System Operations & Station Services
- Aimee Oabel, VP, Forestry & Integration Services
- Robert Globocki, VP, Customer & Billing Operations
- Janet Holt, VP, Health & Safety
- Kevin Mann, Director, Remotes
- Sonja Wasyk, Director, Business Performance
- Faruq Remtulla, Director, Project Delivery (Broadband)

Harry Taylor

EVP, Chief Financial and Regulatory Officer

- Daniel Armstrong, SVP, Treasury & Corporate Development
- Kathleen Burke, VP, Regulatory Affairs
- Joel Jodoin, VP, Finance
- Lindsay Zylstra, VP, Supply Chain & Fleet Services
- Kristopher Wentzel, VP, Internal Audit
- Wassem Khalil, Director, Investor Relations

Lisa Pearson

EVP, Corporate Affairs

- Bronwen Evans, VP, Communications & Marketing
- Bonnie Hiltz, VP, Government & Stakeholder Relations
- Matthew Jackson, VP, Indigenous Partnerships & Business Development

Renée McKenzie

EVP, Digital and Technology Solutions

- Eddie Ng, VP, Security & Infrastructure
- Kevin Marcotte, VP, Strategy & Planning
- Jonathan Rebick, VP, Business Solutions
- Pete Mitskos, VP, Grid Technologies
- Carter Cousineau, VP, Data, Analytics & AI
- Robert Dodds, Director, Project Delivery

Gillian Whitebread

EVP and Head of Human Resources

- Rob Berardi, SVP, Transformation and Acronym[1]
- Vacant, VP, Labour Relations
- Vatche Rubenyan, VP, Total Rewards and Human Capital Management
- Deborah Antenore, VP, People Strategies & HR Initiatives
- Julie Ricketts Daniel, VP, Facilities and Real Estate[2]
- Chris Sider, Director, Business Performance

Cassidy McFarlane

General Counsel

- Vacant, VP, Law Division
- Farah Alexis, Chief Ethics Officer
- Erin Kinlin, Corporate Secretary
- Carolyn Tsen, Director, Pensions

[1] Retirement date effective October 1, 2026
[2] Start date effective September 30, 2026

ACQUIRED DISTRIBUTION AND TRANSMISSION UTILITIES

1.0 INTRODUCTION

This Exhibit provides an overview of the evidence in this Application regarding consolidations, partnerships and collaboration. Section 1.0 addresses the acquisitions of Orillia Power Distribution Corporation and Peterborough Distribution Inc. while Section 2.0 provides an overview of the evidence and requests in this Application in relation to Hydro One Sault Ste. Marie Limited Partnership. The last section, Section 3.0, responds to section 2.1.10 of the OEB filing requirements that requests information on the extent to which Hydro One has investigated potential opportunities for consolidation or collaboration/partnerships with other distributors.

2.0 ORILLIA POWER DISTRIBUTION CORPORATION (OPDC) AND PETERBOROUGH DISTRIBUTION INC. (PDI)

On April 30, 2020, the OEB approved Hydro One Inc.'s purchase of the shares of Orillia Power Distribution Corporation (OPDC), [1] as well as the purchase of assets of Peterborough Distribution Inc. (PDI)[2] (together, the Acquired Utilities). The shares of OPDC were purchased on September 1, 2020 and the assets of PDI on August 1, 2020. Both of these entities' assets were integrated into Hydro One's distribution system on June 1, 2021. A ten-year deferred rebasing period was approved by the OEB for both OPDC and PDI, commencing on the respective purchase dates and expiring on August 31, 2030 and July 31, 2030, respectively. Accordingly, the first rate year in which the Acquired Utilities can be integrated into Hydro One's rate structure is 2031.

In this Application, Hydro One proposes to integrate the Acquired Utilities into Hydro One Distribution for rate-making purposes.

In Exhibit L-01-02, Hydro One describes its proposal for harmonizing customers formerly served by the Acquired Utilities into its existing rate classes effective January 1, 2031.

[1] EB-2018-0270, Decision and Order.
[2] EB-2018-0242, Decision and Order.

Exhibit L-01-03 describes Hydro One's proposed cost allocation approach to appropriately reflect the costs of serving these acquired customers. In Exhibit L-02-01, Hydro One discusses its proposed approach for setting the rates for these acquired customers under Hydro One's rate structure. Finally, Exhibit L-03-01 describes the benefits of Hydro One's proposal to integrate the customers of the Acquired Utilities into Hydro One's distribution rate structure. The benefits to both the customers of the Acquired Utilities and Hydro One's legacy customers are discussed. Exhibit L-03-01 also details the savings achieved as a result of consolidation.As detailed in Exhibit L-03-01, the acquisition and rate harmonization of the two Acquired Utilities have resulted in an overall reduction of $12.6M in the total revenue requirement that would otherwise need to be collected from distribution customers had the acquisitions not taken place.

The total revenue of $41.0M to be collected from the acquired customers demonstrates that acquired customers, as a group, benefit from the fact that they will pay $6.1M less in revenue collected through their rates as compared to what they would otherwise have been paying had their prior distribution utilities not been acquired. This represents a reduction of 13% in the average rates that acquired customers would otherwise have paid.

Hydro One's legacy customers benefit from the fact that $6.5M in revenues that are over and above the incremental revenue requirement driven by the rate harmonization of the Acquired Utilities will now be recovered from the acquired customers instead of Hydro One's legacy customers.

In addition, as shown in Exhibit L-03-01, Table 8, the residential, general service energy and general service demand customers of the former OPDC and PDI will pay lower distribution charges in 2031 under Hydro One's proposed rate harmonization than they would have paid had the acquisitions not taken place, and essentially all of these customers will also see lower total bills.

Both of the Acquired Utilities have been integrated into Hydro One's operations and planning. However, the Acquired Utilities have been excluded from Hydro One

Distribution's capital expenditures and in-service additions in this Application until January 1, 2031, which is the date they will be integrated into Hydro One Distribution for rate-making purposes. An overview of the investments related to the Acquired Utilities is provided in Distribution System Plan (DSP) Section 3.8 Attachment 1, within the Appendix 2-AA Capital Projects ORZ and Appendix 2-AA Capital Projects PRZ Tabs. The Investment Summary Documents (ISDs) provided as attachments to DSP Section 3.11 provide further details related to capital expenditures for the Acquired Utilities until December 31, 2030. Historical fixed asset and rate base information is provided in Exhibits C-04-01, C-04-02 and C-04-03.

The premium on these acquisitions was paid by Hydro One's shareholder, and has not and will not be recovered from customers. [3] Moreover, there were no incentives/commitments beyond the purchase price that are proposed to be entered into rate base or revenue requirement.

2.0 HYDRO ONE SAULT STE. MARIE LIMITED PARTNERSHIP (HOSSM)

In the OEB's Decision and Order in EB-2016-0050, the OEB approved the acquisition of HOSSM by Hydro One Inc. as well as a ten-year deferral rebasing period. In the same decision, the OEB determined that HOSSM would continue with its 2016 revenue requirement and could bring forward a separate rate application, proposing a revenue cap index for the deferred rebasing period. In its Decision in EB-2018-0218, the OEB approved HOSSM's proposed revenue cap index methodology and determined that the methodology would be used to calculate HOSSM's base transmission revenue requirement for the years 2019 to 2026.

At the time of the acquisition of HOSSM, it was understood that HOSSM and Hydro One would continue to operate as separate licensed transmitters due to debt covenants in place until 2023 which prevented HOSSM from being amalgamated absent the consent

[3] EB-2018-0242, Filed 2018-10-12, Exhibit A, Tab 2, Schedule 1, p. 20 of 24, lines 6-7 and EB-2018-0270, Filed 2018-09-26, Exhibit A, Tab 2, Schedule 1, p. 21 of 25, lines 3-4.

of the debt holders. Although HOSSM had to remain financially and legally separate, it has been operationally integrated into Hydro One since October 1, 2018.

Prior to 2023, steps were taken to plan the merging of HOSSM into Hydro One. At that time, a permit held by HOSSM in relation to transmission assets on First Nation reserve lands was found to be not assignable. As a result, HOSSM cannot transfer its transmission assets to Hydro One, as the permit must be transferred along with the assets and cannot be transferred to Hydro One without being amended. Amending the permit requires the conclusion of negotiations with the Indigenous community that can take time. Hydro One took steps to begin work with the Indigenous community and continues to work to advance those discussions. Once a mutual agreement is reached, both parties will be positioned to approach the Federal government for consent to the permit amendment. While the exact timing is not yet known, the intent is to advance this work in alignment with the Indigenous community's priorities, with the expectation that this will not occur before the conclusion of this Application but could potentially occur during the 2028-2032 period.

As a result of the above, while HOSSM has been operationally integrated into Hydro One, it will be kept legally and financially separate until the permit is amended and HOSSM's assets can be transferred to Hydro One.

In Hydro One's prior application for the 2023-2027 period (EB-2021-0110), Hydro One indicated as follows with respect to HOSSM:[4]

> Before the end of HOSSM's deferred rebasing period Hydro One will seek approval for an appropriate regulatory approach to reflect a rebasing of HOSSM for 2027. Such an approach will respect the completion of the deferred rebasing period, consider customer interests and benefits, and bridge the end of HOSSM's deferred rebasing period and the commencement of a new rate period for Hydro One in 2028, which will include Hydro One and HOSSM on a combined basis.

[4] EB-2021-0110, Exhibit A-08-01, p.3.

In alignment with the above plan, HOSSM filed an application with the OEB on May 20, 2026 (EB-2026-0170), requesting that its approved base revenue requirement for 2026 ($49,246,640) be utilized for 2027 on an interim basis. The OEB approved this request on July 14, 2026.

Therefore, in this Application, HOSSM is separately applying for its 2027-2032 revenue requirements and has provided evidence in support of rebasing for 2027 and 2028, determined using a cost of service, forward test year approach, with a Custom IR framework for the period 2029 to 2032 as set out in Exhibit A-04-02.

HOSSM's proposal is to rebase 2027 in this Application by adjusting the approved 2028 HOSSM rates revenue requirement by the difference between the 2027 interim revenue requirement and the final approved 2027 revenue requirement in this Application. In other words, HOSSM's approved 2028 rates revenue requirement will be adjusted downwards by including a refund to customers to reflect the aforementioned difference between the 2027 interim and final revenue requirement, which is a credit owing to customers as described in Exhibit A-04-02, for the purpose of determining the 2028 UTRs.

The above approach preserves the completion of the deferred rebasing period by providing for a rebasing of 2027 as part of this Application, while also considering customer interests and benefits, and aligning HOSSM's rate period with Hydro One Transmission going forward.

A listing of evidence related to HOSSM is included in its Filing Requirement Checklist at Exhibit A-02-03, Attachment 3.

3.0 CONSOLIDATION AND COLLABORATION WITH OTHER DISTRIBUTORS

Hydro One consistently aims to deliver reliable and quality electricity service in a cost-effective manner. One way of achieving this aim is through Hydro One's extensive collaboration with other Ontario distributors.

Hydro One distributes electricity to almost 1.5 million residential and business customers, covering approximately 75% of the geographic area of Ontario. Consequently, Hydro One either neighbours or is a host distributor to almost all other distributors in the province. As a host distributor to numerous embedded distributors across the province including many small local distribution companies (LDCs) that serve fewer than 30,000 customers, Hydro One is continuously collaborating with embedded distributors. The host distributor relationship innately requires ongoing coordination with respect to planning, load forecasting, connections, metering, settlement, and outage management.

Similarly, Hydro One actively engages with other LDCs as part of industry associations, joint regulatory or technical initiatives, exploration of joint procurement, and emergency restoration mutual assistance. With respect to the latter, aging infrastructure and significant weather events have triggered major event restorations that have required Hydro One to leverage third-party mutual assistance agreements with other utilities to ensure expeditious power restoration.

Given Hydro One's provincial footprint and scale, Hydro One is continually investigating potential opportunities for consolidation. Since Hydro One's last revenue requirement application, Hydro One obtained OEB approval to acquire the electricity distribution assets of Chapleau Public Utilities Corporation (CPUC).[5] Prior to the acquisition of CPUC, Hydro One managed the day-to-day operations of CPUC's business and served CPUC customers on behalf of CPUC pursuant to an OEB Decision and s. 59 Order issued on May 23, 2023, appointing Hydro One as interim licensee for the CPUC service area (EB-2023-0144). The CPUC transaction demonstrates how an operational relationship under s. 59 of the OEB Act ultimately led to a full consolidation under s. 86. As outlined in Hydro One's latest Status Report on the Operations of Cat Lake Public Utility (Cat Lake),[6] Hydro One is actively investigating a similar conclusion to its long-term operation of Cat Lake under s. 59. Hydro One will obtain any necessary approvals associated with any potential transaction with Cat Lake should a transaction materialize.

[5] See EB-2023-0328.
[6] See EB-2026-0192.

Further to this, with respect to consolidations, Hydro One has actively explored consolidation opportunities with contiguous and nearby LDCs where such opportunities appeared beneficial. While no MAADs transaction has resulted from these efforts to date, each opportunity was assessed through preliminary due diligence and discussions. Ultimately, the parties were unable to reach agreement on commercial terms and decided not to move forward together. Hydro One remains open to future consolidation opportunities and will pursue them only where they can deliver clear value to customers and meet all applicable OEB requirements.

Beyond these items, Hydro One has consented to dozens of service area amendments and asset sales where it is more cost-effective to transfer service areas or assets to another distributor with the aim of ensuring cost-effective delivery across the sector. Hydro One will continue to actively evaluate opportunities for consolidation, partnerships and/or collaborative initiatives that improve efficiency, reliability and customer value.

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DRAFT ISSUES LIST

1. GENERAL

1.1 Have the applicants responded appropriately to all relevant OEB directions from previous rate proceedings?

1.2 Are the rates and total bill impacts resulting from the Hydro One Transmission, Hydro One Distribution, and HOSSM application reasonable?

1.3 Were customer engagement activities sufficient to enable customer needs and preferences to be considered in the formulation of the proposed spending?

1.4 Is the proposed effective date for each of Hydro One Transmission, Hydro One Distribution and HOSSM appropriate?

2. CUSTOM APPLICATION

2.1 Are all components of the Hydro One Transmission and HOSSM proposed Transmission Custom Incentive Rate Methodologies appropriate?

2.2 Are all components of the Hydro One Distribution proposed Distribution Custom Incentive Rate Methodologies appropriate?

2.3 Are the proposed Hydro One Transmission, Hydro One Distribution, and HOSSM scorecards appropriate?

3. TRANSMISSION SYSTEM PLAN

3.1 Are the proposed Hydro One Transmission and HOSSM capital expenditures, prepaid expenditures and in-service additions arising from the Transmission System Plan appropriate?

3.2 Does the Transmission System Plan sufficiently address the unique rights and concerns of Indigenous customers and rights-holders?

4. DISTRIBUTION SYSTEM PLAN

4.1 Are the proposed Hydro One Distribution capital expenditures, prepaid expenditures, and in-service additions arising from the Distribution System Plan appropriate?

4.2 Does the Distribution System Plan sufficiently address the unique rights and concerns of Indigenous customers and rights-holders?

5. GENERAL PLANT SYSTEM PLAN

5.1 Are the proposed General Plant capital expenditures, prepaid expenditures and in-service additions arising from the General System Plan appropriate?

5.2 Are the methodologies used to allocate Common Corporate capital expenditures and to determine the Overhead Capitalization Rates appropriate?

5.3 Does the General Plant System Plan sufficiently address the unique rights and concerns of Indigenous customers and rights-holders?

6. OPERATIONS MAINTENANCE & ADMINISTRATION AND COMPENSATION COSTS

6.1 Are the proposed Hydro One Transmission and HOSSM OM&A expenditures appropriate?

6.2 Are the proposed Hydro One Distribution OM&A expenditures appropriate?

6.3 Are the methodologies used to allocate Common Corporate OM&A Costs and Other OM&A costs to Hydro One Transmission, Hydro One Distribution, and to HOSSM appropriate?

6.4 Are the amounts proposed to be included in the revenue requirements for income taxes appropriate?

6.5 Are the proposed depreciation expenses appropriate?

6.6 Are the compensation related costs appropriate?

7. RATE BASE, COST OF CAPITAL AND REVENUE REQUIREMENT

7.1 Are the amounts proposed for the Hydro One Transmission, Hydro One Distribution and HOSSM rate bases (including working capital allowances) reasonable?

7.2 Are the proposed costs of capital (interest on debt, return on equity) and capital structures for Hydro One Transmission, Hydro One Distribution and HOSSM appropriate?

7.3 Are the proposed calculations of the Hydro One Transmission, Hydro One Distribution and HOSSM Revenue Requirements appropriate?

7.4 Have all impacts of any changes in accounting standards, policies, estimates and adjustments been properly identified and recorded, and is the rate-making treatment of each of these impacts appropriate?

8. LOAD FORECAST

8.1 Are the proposed load forecast methodologies and the resulting load forecasts appropriate for each of Hydro One Transmission, Hydro One Distribution, and HOSSM?

9. DEFERRAL/VARIANCE ACCOUNTS

9.1 Are the proposed amounts for disposition, and the continuance or discontinuation of the Hydro One Transmission, Hydro One Distribution and HOSSM existing deferral and variance accounts for each of Transmission and Distribution appropriate?

9.2 Are the proposed new or modified Hydro One Transmission, Hydro One Distribution and HOSSM deferral and variance accounts appropriate?

10. COST ALLOCATION FOR TRANSMISSION

10.1 Is the proposed Hydro One Transmission and HOSSM cost allocation appropriate?

11. COST ALLOCATION AND RATE DESIGN FOR DISTRIBUTION

11.1 Is the proposed Hydro One Distribution cost allocation appropriate?

11.2 Is the proposed Hydro One Distribution rate design appropriate?

11.3 Are the proposed billing determinants appropriate?

11.4 Are the proposed revenue-to-cost ratios for all rate classes over the test period appropriate?

11.5 Is the rate harmonization proposal for the customers of the Acquired Utilities appropriate?

11.6 Are the proposed Retail Transmission Service Rates appropriate?

11.7 Are the proposed bill impact mitigation measures appropriate?

12. OTHER CHARGES AND REVENUES

12.1 Are Other Revenue forecasts for each of Hydro One Transmission and Hydro One Distribution appropriate?

12.2 Are the proposed Hydro One Distribution Specific Service Charges appropriate?

WITNESS LIST

Witnesses are listed in the footer of each exhibit. The final list of witnesses will be provided in advance of the technical conference in this proceeding.

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CURRICULA VITAE

Curricula Vitae information will be filed prior to the technical conference in this proceeding.

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