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BY EMAIL AND RESS

July 12, 2024

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

Dear Ms. Marconi,

EB-2024-0216 – Chatham x Lakeshore Limited Partnership (CLLP) – 2025-2029 Transmission Revenue Requirement Application – Application and Evidence

Hydro One Networks Inc. (Hydro One), on behalf of Chatham x Lakeshore Limited Partnership (CLLP), is submitting CLLP's five-year Transmission Revenue Requirement Application for the period 2025-2029, using the Ontario Energy Board's (OEB) Regulatory Electronic Submission System.

Given that CLLP operates a single transmission asset, with minimal operating costs and no forecast capital expenditures, Hydro One proposes that this Application would be most effectively dealt with in written form. Moreover, Hydro One suggests the OEB make provision for a settlement conference to help expedite the Application.

CLLP will post electronic copies of the Application and supporting evidence on Hydro One's website for public access. An electronic copy of the Application and evidence has been submitted using the OEB's Regulatory Electronic Submission System.

Sincerely,

Kathleen Burke

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EXHIBIT LIST

Exhibit	Tab	Schedule	Attachment	Contents
A				**Administration**
A	1	1		Exhibit List
A	2	1		Application
A	2	1	1	Certification of Evidence
A	2	1	2	Certification of Deferral and Variance Account Balances
A	2	2		Compliance with Applicable Filing Requirements
A	2	2	1	Filing Requirement Checklist
A	2	3		Summary of Board Directives and Undertakings from Previous Proceedings
A	3	1		Executive Summary
A	4	1		Revenue Requirement Framework Summary
A	5	1		Description of the Partnership
A	6	1		Financial Information
A	6	2		CLLP Financial Statements - Historical Years
A	6	3		Reconciliation of Regulatory Financial Results with Audited Financial Statements (2023)
A	7	1		Draft Issues List
B				**Transmission System Plan**
B	1	1		Transmission System Overview
B	1	2		Company Values and Strategic Objectives
B	1	3		Summary of Capital Expenditures and In-Service Additions
B	1	3	1	Attachment 1: CLLP Transmission System Plan

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APPLICATION

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Chatham x Lakeshore Limited Partnership (CLLP) by its general partner, Chatham x Lakeshore GP Inc. (CLGP), for an Order or Orders made pursuant to section 78 of the Act approving rates for the transmission of electricity.

1. The applicant, CLLP, is a Limited Partnership. Hydro One Networks Inc. (HONI) is a Limited Partner of CLLP and CLGP is the general partner. In addition, up to five First Nation partners have been offered the opportunity to take ownership in 50% of the line through HONI's First Nations Equity Partnership model.[1] These five potential First Nation community partners are as follows:

    - Aamjiwnaang First Nation
    - Caldwell First Nation
    - Chippewas of the Thames First Nation
    - Chippewas of Kettle and Stony Point First Nation
    - Walpole Island First Nation

2. CLLP has its head office in Woodstock, Ontario. CLLP is expected to carry on the business of owning and operating transmission facilities in Ontario.

3. CLLP hereby applies (the Application) to the OEB, pursuant to Section 78 of the *Ontario Energy Board Act, 1998*, for an Order or Orders approving:

[1] Please see Exhibit A-05-01 for detail.

i. Revenue requirement of $1.8M for the period of 2024, when the project's assets will be placed in-service;[2]
ii. Rates revenue requirement for the 2025-2029 period;
iii. Filing a one-time update in 2025 to the cost of long-term debt to reflect the actual market rate achieved on the debt that HONI will issue in 2025, which will update and set the rates revenue requirements, effective January 1 each year, for the remaining term from 2026 through to 2029;
iv. Inclusion of CLLP's approved rates revenue requirement in the OEB's determination of the 2025 to 2029 Network pool of the Uniform Transmission Rates (UTRs);
v. The establishment and approval of new regulatory accounts effective January 1, 2025;
vi. An effective date of January 1, 2025;
vii. Other items that may be requested by CLLP in the course of this proceeding, and as may be granted by the OEB.

4. This Application is contingent on the approval of the application filed with the OEB on April 26, 2024 on behalf of HONI and CLLP.[3] The April 26, 2024 application includes a request by CLLP for a transmitter licence, a request by CLLP for approval to establish a deferral account to record revenue requirement once the Chatham to Lakeshore project is placed in-service, and a request to sell to CLLP transmission assets located between Chatham and Lakeshore transmission stations.

5. This Application has been prepared in accordance with the OEB's *Filing Requirements for Electricity Transmission Rate Applications* dated February 11, 2016.

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[2] In EB-2024-0146 currently before the OEB, CLLP requested approval to establish the CLLPDA for the purpose of recording the revenue requirement relating to the Chatham to Lakeshore Project once it is placed in service, and up until the OEB-approved effective date of CLLP's first revenue requirement application
[3] EB-2024-0146, see application filed April 26, 2024 page 3.

6. The persons affected by this Application are Ontario ratepayers. It is impractical to set out their names and addresses because they are too numerous.

FORM OF HEARING REQUESTED

7. The Application may be viewed on the Internet at the following address: https://www.hydroone.com/abouthydroone/RegulatoryInformation/txrates

8. CLLP requests that this Application be heard by way of a written hearing.

PROPOSED EFFECTIVE DATE

9. CLLP requests that the OEB's rate orders be effective January 1, 2025.

CONTACT INFORMATION

10. CLLP requests that a copy of all documents filed with the OEB by each party to this Application be served on the Applicant and the Applicant's counsel as follows:

a) The Applicant:

Eryn Mackinnon
Regulatory Advisor
Hydro One Networks Inc.

Mailing Address:
7th Floor, South Tower
483 Bay Street
Toronto, Ontario M5G 2P5
Telephone: (416) 345-4479
Electronic access: Regulatory@HydroOne.com

b) The Applicant's Counsel:

Ms. Raman Dhillon
Senior Legal Counsel
Hydro One Networks Inc.

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

Telephone:	(416) 859-0942
Fax:	(416) 345-6972
Electronic access:	Raman.Dhillon@HydroOne.com

DATED at Toronto, Ontario, this 12th day of July 2024.

Chatham x Lakeshore Limited Partnership
By its counsel,

Raman Dhillon

CERTIFICATION OF EVIDENCE

TO: ONTARIO ENERGY BOARD

The undersigned, Kathleen Burke, being Hydro One's Vice-President, Regulatory Affairs, hereby certifies that:

1. Hydro One Networks Inc. has prepared and is submitting this Application on behalf of Chatham x Lakeshore Limited Partnership;

2. This certificate is given pursuant to Chapter 1 of the Ontario Energy Board's *Filing Requirements for Electricity Transmission Applications* (last revised on February 11, 2016); and

3. The evidence submitted in support of CLLP's 2025-2029 revenue requirement application (EB-2024-0216) filed with the Ontario Energy Board is accurate, consistent and complete to the best of my knowledge.

4. The documents filed in support of CLLP's application do not include any personal information (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.

DATED this 12th day of July 2024.

Kathleen Burke

KATHLEEN BURKE

CERTIFICATION OF DEFERRAL AND VARIANCE ACCOUNT BALANCES

TO: ONTARIO ENERGY BOARD

The undersigned, Harry Taylor, being Hydro One's EVP, Chief Financial and Regulatory Officer, hereby certifies for and on behalf of Chatham x Lakeshore Limited Partnership that:

1. This certificate is provided to be consistent with Chapter 1 of the OEB's *Filing Requirements for Electricity Distribution Rate Applications*; and

2. Hydro One has the appropriate processes and internal controls for the preparation, review, verification and oversight of all deferral and variance accounts.

DATED this 10th day of July, 2024.

Harry P. Taylor

HARRY TAYLOR

COMPLIANCE WITH APPLICABLE FILING REQUIREMENTS

1.0 INTRODUCTION

CLLP has prepared this Application in accordance with the OEB's guidance in its *Filing Requirements for Electricity Transmission Rate Applications* (February 11, 2016) (Transmission Filing Requirements). CLLP has presented the content to align with Chapter 2 of the Transmission Filing Requirements (Chapter 2). To assist the OEB in its review of the Application, CLLP has prepared a checklist of the Transmission Filing Requirements including the relevant evidentiary references for each item. This checklist is provided as Attachment 1 to this Exhibit.

2.0 NON-APPLICABLE FILING REQUIREMENTS

Given that CLLP is a single transmission line asset with no customers and no operable assets, the following Transmission Filing Requirements are not applicable. These include:

1. Customer Engagement

- CLLP has not performed any customer engagement activities and analysis.

2. Transmission System Plan

- CLLP has prepared an abridged Transmission System Plan (TSP) given that it is not proposing capital expenditures during the rate period.
- Section 2.4 of Chapter 2 states that transmitters may wish to refer to Chapter 5 of the OEB's Filing Requirements for Electricity Distributors, Consolidated Distribution System Plan Filing Requirements (DSP Requirements) for further guidance on the content and structure of a TSP. CLLP has referred to the DSP Requirements to guide the preparation of its abridged TSP.

3. Working Capital Allowance

- It was established in B2M LP's 2015 transmission rates application (EB-2015-0026) that there is no need for a working capital allowance.

- The same situation applies for CLLP and therefore there is no request for a working capital allowance to be included in rate base.

4. Economic Overview / Load Forecast

- CLLP's transmission assets are comprised solely of a 230kV double-circuit transmission line. CLLP does not own any station assets, and does not have any delivery points. As a result, CLLP has no discrete, incremental load determinants to include in the UTR forecast.

- As proposed in this Application, the only rate pool applicable for CLLP assets will be the "Network" pool. Therefore, no further cost allocation methodology is presented in this application.

5. Other Revenue

- No external revenue is anticipated for CLLP.

6. Employee Compensation

- CLLP has no employees. Operations and management services are provided by HONI by a service level agreement as outlined in Exhibit F-03-01.

3.0 MATERIALITY THRESHOLD

In terms of the materiality threshold applicable to CLLP, 0.5% of the average of 5 years' revenue requirement in the revenue requirement period of $83k is applicable.

4.0 DEVIATIONS FROM THE FILING REQUIREMENTS

CLLP has complied with the OEB's policies and guidelines as set out in the Transmission Filing Requirements.

Transmission Filing Requirements Checklist

CLLP

EB-2024-0216

Adopted from 2016 Filing Requirement For Electricity Transmitters

Date: July 12, 2024

Filing Requirement Page # Reference		Yes/N/A	Evidence Reference, Notes
GENERAL REQUIREMENTS			
Ch 1, p 2	Certification that the evidence filed is accurate, consistent and complete	Yes	Exhibit A-02-01, Attachment 1
3	Confidential Information - Practice Direction has been followed	Yes	Exhibit A-02-01, Attachment 1
Ch 2, p 4	Provide Chapter 2 appendices that are applicable to their transmission applications	Yes	Appendix 2-AA/2-AB Capital Program/Expenditures: Exhibit B-01-03, Attachment 1 *Not applicable:* Appendix 2-AC on Customer Engagement, 2-G SQI, 2-H Other Operating Revenue, 2-I/2-IA/2-IB Load Forecast/CDM, 2-JA/JB/2-JC OMA Programs, 2-K Employee Costs, 2-N, 2-M
4	Written direct evidence is to be included before data schedules	Yes	Confirmed
4	Average of the opening and closing fiscal year balances must be used for items in rate base	Yes	Exhibit C-01-01
4	Total capitalization (debt and equity) must equate to total rate base	Yes	Exhibits C-01-01 and G-01-01
4	Data for the following years, at a minimum, must be provided: Test year = prospective rate year; Bridge year = current year; Four most recent historical years; Most recent OEB-approved test year	Yes	Hydro One has provided the required data in its evidence, Chapter 2 appendices applicable to Transmission, and in its custom spreadsheets
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	N/A	See Exhibit A-04-01
4	Documents are to be provided in bookmarked and text-searchable Adobe PDF format	Yes	Confirmed
4	Tables must also be provided in working Microsoft Excel spreadsheet format where available and practical	Yes	Confirmed
6	Materiality threshold: The applicant must provide justification for changes from year to year to its rate base, capital expenditures, operations, maintenance and administration costs and other items above a materiality threshold.	Yes	Exhibit A-02-02
6	State accounting standard(s) used in historical, bridge and test years and summarize changes since last filing	Yes	Exhibit A-06-01
EXHIBIT 1 - ADMINISTRATIVE DOCUMENTS			
Executive Summary			
Ch 2, p 8	Overview of past and expected future performance, business plan and objectives and how they align with RRFE objectives	Yes	Exhibit A-03-01
8	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-03-01
8	Revenue Requirement - request, changes from previous revenue requirement and drivers of change	Yes	Exhibit A-03-01
8	Budgeting Assumptions - Economic overview	N/A	Exhibit A-03-01 *Not applicable:* No capital expenditures
8	Load Forecast - Load growth and forecast methods	N/A	Exhibit A-03-01 *Not applicable*
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
9	Rate Base - Request for test years and change from last OEB approved	Yes	Exhibit A-03-01
9	Performance and Reporting - Proposed scorecard	Yes	Exhibit A-03-01
9	OM&A - Request for test years, changes from last OEB approved and drivers of change	Yes	Exhibit A-03-01
9	Cost of Capital - Whether cost of capital parameters are being used and rationale for deviations from methodology	Yes	Exhibit A-03-01
9	Cost Allocation + Rate Design - Summary of how costs are allocated to rate pools	Yes	Exhibit A-03-01
10	Deferral and Variance Accounts - Accounts requested for disposition, total disposition and disposition period and new deferral and variance accounts	Yes	Exhibit A-03-01
10	Bill Impacts - Summary of impacts at wholesale level and for typical retail customers	Yes	Exhibit A-03-01
Customer Engagement			
Ch 2, p 10	Customer engagement process and activities	N/A	*Not applicable:* CLLP has no customers
10	Customer needs including end-use load customers and generator customers	N/A	*Not applicable:* CLLP has no customers
10	How the application responds to customer needs	N/A	*Not applicable:* CLLP has no customers
10	Customer satisfaction surveys	N/A	*Not applicable:* CLLP has no customers
10	Appendix 2AC in the Distribution Filing Requirements helpful in structuring this evidence	N/A	*Not applicable:* CLLP has no customers
11	Responses to letters of comment	N/A	*Not applicable:* CLLP has no customers
Financial Information			
Ch 2, p 11	Non-consolidated Audited Financial Statements for 2 most recent years (i.e. 3 years of historical actuals)	N/A	Exhibit A-06-02
11	Detailed reconciliation of AFS with regulatory financial results	N/A	Exhibit A-06-03
11	Annual Report and MD&A for most recent year of parent company	Yes	Exhibit A-06-01
11	Rating Agency Reports	N/A	Exhibit A-06-01 CLLP Debt is managed and rated under Hydro One Networks
11	Prospectuses & information circulars for recent and planned public offerings	N/A	Exhibit A-06-01 CLLP Debt is managed and rated under Hydro One Networks
Administration			
Ch 2, p 11	Table of Contents	Yes	Exhibit A-01-01
11	Statement identifying customers materially affected by the application	Yes	Exhibit A-02-01
12	Internet address for viewing of application	Yes	Exhibit A-02-01
12	Primary contact information (name, address, phone, fax, email)	Yes	Exhibit A-02-01
12	Identification of legal representation	Yes	Exhibit A-02-01
12	Requested effective date	Yes	Exhibit A-02-01
12	Bill impacts for typical Ontario residential customer and Ontario General Service customer	Yes	Exhibit A-03-01
12	Form of hearing requested (written or oral)	Yes	Exhibit A-02-01
12	List of approvals requested including accounting orders	Yes	Exhibit A-02-01
12	Proposed length of the term and proposed method for establishing revenue requirement for each year of the term	Yes	Exhibit A-02-01
12	Changes in tax status	N/A	Exhibit F-06-01
12	Existing Accounting Orders	N/A	Exhibit A-06-01

12	Map of assets and operations showing where the utility operates within the province, and the communities serviced by the utility.	Yes	Exhibit B-01-01
12	Corporate and utility organizational structure, planned changes, rationale for changes and cost impact	Yes	Exhibit A-05-01
13	The Accounting Standard used and when it was adopted	Yes	Exhibit A-06-01
13	Deviations from filing requirements, if any	N/A	Exhibit A-02-02
13	Changes to methodologies used in previous applications	N/A	
13	Confirmation that accounting treatment is segregated for non-regulated business	N/A	
13	Indication of how prior OEB Decisions or Orders have been satisfied and impact on current application	Yes	Exhibit A-02-03
EXHIBIT 2 - Transmission System Plan			
General			*Note: CLLP has no planned Capital Expenditures*
Ch 2, p 13	Refer to Chapter 5 of the Distribution Filing Requirements	Yes	
13	The strategic plan for the utility and investment strategy	Yes	Exhibit B-01-02
13	The longer term economic and planning assumptions	N/A	
13	The asset management plan	Yes	Exhibit B-01-03, Attachment 1
13	A description of how investments are prioritized and selected	Yes	Exhibit B-01-03, Attachment 1
13	A discussion of transmission investments identified in the regional planning process	Yes	Exhibit B-01-03, Attachment 1
13	Highlights of recent and proposed investments and their fit with the strategic plan	Yes	Exhibit B-01-03, Attachment 1
13	A description of how the needs of customers and overall system planning policy objectives are being reflected	Yes	Exhibit B-01-03, Attachment 1
13	Commitments stemming from the Long Term Energy Plan or the Conservation First policy, and consideration for the OEB's statutory objectives, including facilitating a smart grid and the connection of renewables	N/A	
Asset Management Plan			
Ch 2, p 14	Asset management policy, strategy and objectives	Yes	Exhibit B-01-03, Attachment 1
14	Inventory and assessment of the condition of capital assets (by class and inclusion in BES), how this informs plan for capital expenditures and maintenance expenditures	Yes	Exhibit B-01-03, Attachment 1
14	Identify NERC exemptions, planned or in progress NERC exemption requests and associated costs if exemption denied	N/A	
Regional Considerations			
Ch 2, p 14	Regional planning process demonstrating that regional considerations have been considered and addressed	Yes	Exhibit B-01-03, Attachment 1
14	Final Regional Infrastructure Plan describing investments in transmission or distribution facilities in the TSP	Yes	Exhibit B-01-03, Attachment 1
14	Identify investments spanning more than one region	N/A	
Coordinated Planning with Third Parties			
Ch 2, p 15	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	Exhibit B-01-03, Attachment 1
Capital Expenditures			*Note : CLLP has no planned Capital Expenditures*
Ch 2, p 16	Summary of capital expenditures over the past five historical years 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 B-01-03, Attachment 1
16	Material Investments - For projects and programs: - a description of the need, scope and purpose of the project or program - customer attachments - load and capital costs - cost-benefit analysis - identify where "leave to construct" required or project is necessary to comply with a licence condition	N/A	No planned capital expenditures for the filing period.
16	Drivers of capital expenditure increases for the test year(s)	N/A	No planned capital expenditures for the filing period.
16	The basis for the estimated budget for the project or program	N/A	No planned capital expenditures for the filing period.
16	For the balance of capital expenditures, describe components of capital expenditure and provide a reconciliation of capital components to total capital budget	N/A	No planned capital expenditures for the filing period.
17	Written explanation of capital expenditure variances	Yes	Explanations for historical capital expenditures included. Exhibit B-01-03, Attachment 1
17	The proposed accounting treatment, including the treatment of cost of funds, for investments spanning more than one year	N/A	No planned capital expenditures for the filing period.
17	Cost benchmarking studies or utility cost comparisons	N/A	No planned capital expenditures for the filing period.
17	Continuous improvement or efficiency gains, how they will be achieved and benefit customers	Yes	Exhibit B-01-03, Attachment 1
17	A proposal to mitigate the potential for any significant earning by the transmitter above the regulatory net income	Yes	Exhibit A-04-01
EXHIBIT 3 - Rate Base			
Overview			
Ch 2, p 17	Opening and closing balances and the averages thereof gross assets and accumulated depreciation Rate base shall include an allowance for working capital Rate base must be supported by historical actuals, bridge year and test years	Yes	Exhibit C-01-01, Attachments 1 through 4
18	Continuity statements (year end balance, including interest during construction and overheads). Explanation for any restatement (e.g. due to change in accounting standards) Year over year variance analysis; explanation where variance greater than materiality threshold Hist. OEB-Approved vs Hist. Actual Hist. Act. vs. preceding Hist. Act. Hist. Act. vs. Bridge Bridge vs. Test	Yes	Exhibit C-01-01
18	Opening and closing balances of gross assets and accumulated depreciation must correspond to fixed asset continuity statements. Reconciliation must be between net book value balances reported on Appendix 2-BA and balances included in rate base calculation	Yes	Exhibit C-01-01
19	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
Gross Assets - PP&E and Accumulated Depreciation			
Ch 2, p 19	Breakdown by function (transmission plant, general plant, other plant) for required statements and analyses	Yes	Exhibit C-01-01
19	Detailed breakdown by major plant account for each functionalized plant item; For the test year(s), each plant item must be accompanied by a description.	Yes	Exhibit C-01-01
19	Detailed breakdown of the in-service capital additions for the test year(s)	Yes	Exhibit C-01-01
19	Continuity statements must reconcile to calculated depreciation expenses and presented by asset account	Yes	Exhibit C-01-01
Allowance for Working Capital			*Not Applicable:* CLLP requires no working capital - Exhibit C-01-01
Ch 2, p 19	Working Capital - Lead/Lag Study	N/A	
19	Lead/Lag Study - leads and lags measured in days, dollar-weighted	N/A	
19	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.	N/A	
Customer Connection and Cost Recovery Agreements			*Not Applicable:* CLLP has no customer driven Capital Expenditures
Ch 2, p 20	The transmitter should show customer contribution amounts separately as an offset to rate base.	N/A	

20	Agreements reviewed on reaching a fifth anniversary and aggregated estimate of total expected true-up contributions and proceeds from bypass agreements	N/A	
20	Financial and regulatory accounting treatment of true-up proceeds.	N/A	
Capitalization Policy			*Not Applicable:* CLLP has no overhead capitalized - Exhibit A-02-02
Ch 2, p 20	Capitalization policy, including changes since the last revenue requirement application	N/A	
20	Overhead costs on self-constructed assets	N/A	
20	Identification of burden rates and burden rates prior to changes, if any	N/A	
Capital Module			
Ch 2, p 21	Revenue Cap index may request a capital increment for discrete projects being placed in service after the rebasing year that are part of the Transmission System Plan; intended to come into service during the index period; Involve costs that the transmitter cannot manage through the revenue established through the index	N/A	
21	The request must address proposed approval criteria (materiality, need, prudence) and the process for implementation of the recovery of the capital increment.	N/A	
EXHIBIT 4 - Service Quality and Reliability Performance and Reporting			
Proposed Scorecard			
21	Propose a five-year scorecard including measures for public policy responsiveness, operational effectiveness, customer focus, financial performance and other relevant measures	Yes	Exhibit D-01-01
Reliability Performance			
22	Reliability performance measures: transmission frequency of delivery point interruptions, transmission duration of delivery point interruptions, unsupplied energy in minutes, transmission system unavailability	Yes	Exhibit D-01-01
22	Address performance standards for transmitters as set out in Chapter 4 of the TSC.	N/A	
22	Compare system performance with other systems both nationally and internationally	N/A	
Compliance Matters			
22	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	No outstanding non-compliance areas.
EXHIBIT 5 - Operating Revenue			
Load and Revenue Forecasts			*Not Applicable:* CLLP has no load forecast
23	Explanation of causes, assumptions and adjustments for volume forecast. Economic assumptions and data sources for customer and load forecasts	N/A	
23	Explanation of weather normalization methodology. Describe economic models, econometric models, end-use models customer forecast surveys and load shape analyses	N/A	
23	Detailed CDM forecast, with impact of CDM shown on the load forecast for each of the three rate pools. The applicant must also indicate how the forecast reflects IESO CDM forecasts and targets in the load forecast	N/A	
23	Impact of forecast embedded generation on the transmission system load accounted for	N/A	
Accuracy of Load Forecast and Variance Analyses			*Not Applicable:* CLLP has no load forecast
23	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	N/A	
24	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)	N/A	
24	All data used to determine the forecasts must be presented and filed in live MS Excel spreadsheet format	N/A	
Other Revenue			*Not Applicable:* CLLP has no other revenue
24	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	
24	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	
24	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	N/A	
24	Revenues or costs (including interest) associated with deferral and variance accounts must not be included in other revenue.	N/A	
EXHIBIT 6 - Operating Cost			
Overview			
Ch 2, p 25	Brief explanation of test year OM&A levels, cost drivers, significant changes, trends, inflation rate assumed, business environment changes, benchmarking, description of the continuous improvement or efficiency gains	Yes	Exhibit F-01-01 *Not applicable:* Benchmarking, description of continuous improvement or efficiency gains
Summary and Cost Driver Tables			
Ch 2, p 26	Summary of recoverable OM&A expenses	Yes	Exhibit F-02-01
26	Recoverable OM&A cost drivers	Yes	Exhibit F-02-01
26	Change in OM&A in test year attributable to a change in capitalized overhead	N/A	
26	OM&A variance analysis for test year with respect to bridge and historical years	Yes	Exhibit F-02-01
Program Delivery Costs with Variance Analysis			
Ch 2, p 26	O&M Costs for: - employee compensation - shared services - corporate cost allocation - purchase of non-affiliate services - one-time costs - OEB costs - Charitable and political donations	Yes	Exhibit F-02-01 Not applicable: Employee Compensation, Shared Services and Purchase of Non-Affiliate services
Employee Compensation			Not Applicable: CLLP has no employees
Ch 2, p 26	Employee complement, compensation and benefits	N/A	
26 - 27	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 headcount and compensation. Explanation for all years includes: - year over year variances - basis for performance pay, eligible employee groups, goals, measures and review process for pay-for-performance plans - benchmarking studies	N/A	
27	Employee benefit programs including pensions	N/A	
27	Most recent actuarial reports	N/A	
Shared Services and Corporate Cost Allocation			
Ch 2, p 27	Identification of shared services	Yes	Exhibit F-02-01

27	Allocation methodology for corporate and shared services	Yes	Exhibit F-04-01
28	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	Yes	Exhibit F-02-01
28	Variance analysis - test year vs last OEB approved and most recent actual	Yes	Exhibit F-02-01
28	Identification of any Board of Director costs for affiliates included in LDC costs	N/A	
Purchase of Non-Affiliate Services			
28	Procurement Policy	N/A	
28	Material transactions not in compliance with procurement policy or without a competitive tender - Give reasons for procurement, summarize nature and cost of product and describe how vendor was selected	N/A	
One-time Costs			
28	One-time costs - historical, bridge, test year costs. Explanation of cost recovery in test years. Costs in the test years will not result in an over recovery in future years.	N/A	
Regulatory Costs			
28	Regulatory costs - breakdown of actual and forecast costs Supporting information, legal fees, consultant fees, costs awards, etc.	Yes	Exhibit F-02-01
Charitable and Political Donations			
29	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	
29	Detailed information for all contributions that are claimed for recovery	N/A	
29	Charitable Donations - confirmation that political contributions not included	N/A	
Depreciation, Amortization and Depletion			
29	Depreciation, Amortization and Depletion details by asset group for historical, bridge and test years. Asset amount and rate of depreciation/amortization must tie back to the accumulated depreciation balances in the continuity schedule under rate base.	Yes	Exhibit F-05-01
29	Identification of any Asset Retirement Obligations and associated depreciation, accretion expense	N/A	
29	Identification of historical depreciation practice and proposal for test year. Variances from half year rule must be documented and supporting rationale provided	Yes	Exhibit F-05-01
29	Depreciation/amortization policy Summary of changes to depreciation/amortization policy since last CoS	Yes	Exhibit F-05-01
29	Explanation of any deviations from depreciating components of PP&E separately	N/A	
Taxes or PILs and Property Taxes			
30	Income tax or PILs calculations, derivation of adjustments for historical, bridge, test years	Yes	Exhibit F-06-01
30	Supporting schedules and calculations identifying reconciling items	Yes	Exhibit F-06-01, Attachment 1
30	Most recent federal and provincial tax returns	N/A	
30	Financial Statements included with tax returns if different from those filed with application	N/A	
30	Calculation of Tax Credits; redact where required (filing of unredacted versions is not required)	N/A	
30	Supporting schedules, calculations and explanations for other additions and deductions	Yes	Exhibit F-06-01
Non-recoverable and Disallowed Expenses			
30	Exclude from regulatory tax calculation any non-recoverable or disallowed expenses	N/A	
Integrity Checks			
31	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 F-06-01
31	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 F-06-01
31	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	N/A	
31	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 F-06-01
31	Loss carry-forwards, if any, from the tax returns (Schedule 4) agree with those disclosed in the application	Yes	Exhibit F-06-01
31	CCA is maximized even if there are tax loss carry-forwards	Yes	Exhibit F-06-01
31	A statement is included in the application as to when the losses, if any, will be fully utilized	Yes	Exhibit F-06-01
31	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 F-06-01
31	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 F-06-01
Z-Factor Claims			
31	Evidence that z-factor costs incurred meet eligibility criteria, amount recorded in deferral account, allocation of incremental revenue requirements to rate pools, calculation of incremental revenue requirement	N/A	
EXHIBIT 7 - COST OF CAPITAL AND CAPITAL STRUCTURE			
Capital Structure			
33	OEB's cost of capital parameters used	Yes	Exhibit G-01-01
33	Multi-year revenue requirement approvals must indicate whether cost of capital will be updated annually or fixed for all test years	Yes	Exhibit G-01-01
33	Long-term debt; Short-term debt; Preference shares and Common equity must be presented with the appropriate schedules	Yes	Exhibit G-01-03
33	Explanation for any changes in capital structure	Yes	Exhibit G-01-01
Cost of Capital (Return on Equity and Cost of Debt)			
34	Calculation of cost for each capital component	Yes	Exhibit G-01-01
34	Profit or loss on redemption of debt	Yes	Exhibit G-01-01
34	Copies of promissory notes or other debt arrangements with affiliates	Yes	Exhibit G-01-01
34	Explanation of debt rate for each existing debt instrument	Yes	Exhibit G-01-01
34	Forecast of new debt in bridge and test year - details including estimate of rate	Yes	Exhibit G-01-01
34	If proposing any rate that is different from the OEB guidelines, a justification of the proposed rate(s), including key assumptions	Yes	Exhibit G-01-01
Not-for-Profit Corporations			
34	Not for Profit Corporations - evidence that excess revenue is used to build up operating and capital reserves	N/A	
EXHIBIT 8 - DEFERRAL AND VARIANCE ACCOUNTS			
34	List of all outstanding DVA and sub-accounts; provide description of DVAs	N/A	
34	Completed DVA continuity schedule for period following last disposition to present - live Excel format	N/A	
34	Confirm use of interest rates established by the OEB by month or by quarter for each year	N/A	
35	Explanation if account balances in continuity schedule differs from trial balance in RRR and AFS	N/A	
35	A proposal for an allocator based on the proposed cost driver(s) and included in the continuity schedule	N/A	
35	Statement as to any new accounts, and justification.	Yes	Exhibit H-01-01
35	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 H-01-01
Disposition of Deferral and Variance Accounts			
36	Identify accounts for which disposition is sought	Yes	Exhibit H-01-01

36	Identify accounts for which disposition is not sought and the reasons	N/A	
36	Propose the method to be used for recovery or refund of balances that are proposed for disposition	Yes	Exhibit H-01-01
36	Provide a statement that the balances proposed for disposition before forecasted interest are consistent with the last Audited Financial Statements	N/A	
36	Provide an explanation for any variances greater than 5% between amounts proposed for disposition before forecasted interest and the amounts reported in the applicant's quarterly and annual RRR filings for each account	N/A	
36	Provide explanations even if such variances are below the 5% threshold if the variances in question relate to: (1) matters of principle (i.e. prior OEB decisions, and prior period adjustments); and/or, (2) the cumulative effect of immaterial differences over several accounts totaling to a material difference	N/A	
36	Show all relevant calculations, including the rationale for the allocation of each account, the proposed billing determinants and the length of the disposition period	N/A	
EXHIBIT 9 - Cost Allocation to Uniform Transmission Rate Pools: Charge Determinants			*Note: CLLP is allocated to the Network Pool*
36	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 I-01-01
36	Steps taken to functionalize the assets in the functional categories	Yes	Exhibit I-01-01
36	Allocation of revenue requirement to the rate pools and allocation factors for each asset or groups of assets	N/A	
36	Assignment of depreciation, return on capital, taxes and OM&A costs to rate pools and non-standard rate pools	N/A	
EXHIBIT 10 - Rate Design for Uniform Transmission Rates			
Bill Impact Information			
37	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 I-02-01
37	Bill impacts for typical customers and consumption levels.	Yes	Exhibit I-02-01
Setting the Uniform Transmission Rates			
37	Overview of how the UTR are established in Ontario and how these rates are determined	Yes	Exhibit I-02-01
37	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 I-02-01
37	Determination of the Export Transmission Service rates and the treatment of revenues generated through these rates	N/A	
37	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; - proposed revenue requirements and charge determinants as proposed in the application; - the calculation of the UTR 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	Yes	Exhibit I-02-01 Exhibit I-03-01 Exhibit I-03-01, Attachment 1 Exhibit I-03-01, Attachment 2

SUMMARY OF BOARD DIRECTIVES AND UNDERTAKINGS FROM PREVIOUS PROCEEDINGS

In the leave to construct decision for the Chatham to Lakeshore project (EB-2022-0140), the OEB stated that it "expects Hydro One to demonstrate the prudence of its route selection and associated real estate acquisition program and resulting impacts on the costs for the Chatham to Lakeshore Project in a future rebasing application".[1] This information is included in the Chatham to Lakeshore Asset Values Exhibit at Exhibit B-02-01.

In the leave to construct decision for the Waasigan project (EB-2023-0198) the OEB included the following directive: "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."[2] This information is included in the Overhead Capitalization Methodology Exhibit at Exhibit C-02-01.

[1] EB-2022-0140, Decision and Order, November 24, 2022, p. 20.
[2] EB-2023-0198, Decision and Order, April 16, 2024, p. 19.

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EXECUTIVE SUMMARY

This Exhibit describes the key aspects of Chatham x Lakeshore Limited Partnership (CLLP)'s application (the Application) in respect of its proposed transmission revenue requirement for 2025 to 2029.

1.0 CHATHAM X LAKESHORE LIMITED PARTNERSHIP

CLLP is a limited partnership between Chatham x Lakeshore GP Inc. (CLGP) and Hydro One Networks Inc. (HONI). Up to five First Nations partners have been offered the opportunity to take ownership in 50% of the line: Aamjiwnaang First Nation, Caldwell First Nation, Chippewas of the Thames First Nation, Chippewas of Kettle and Stony Point First Nation, and Walpole Island First Nation.

By an Order in Council dated March 31, 2022, the Lieutenant Governor in Council declared that a new 230kV transmission line from the Chatham Switching Station to the new Lakeshore Transformer Station would be designated as a priority transmission project under section 96.1 of the OEB Act. The Chatham to Lakeshore project is part of a bulk transmission system reinforcement that is needed to address the near-to mid-term supply needs in the Windsor-Essex region, as determined in an IESO-initiated planning study.

CLLP's transmission system will consist of a 230kV double circuit line, C87H and C88H, from Chatham Switching Station (SS) to Lakeshore Transmission Station (TS). Each circuit is approximately 49 km in length. HONI owns the terminating stations (Chatham SS and Lakeshore TS).

2.0 APPROVALS REQUESTED

In this Application for 2025 to 2029 transmission revenue requirement, CLLP is requesting the Ontario Energy Board's (OEB) approval for:[1]

[1] As described in Exhibit A-02-01.

i. Revenue requirement of $1.8M for the period of 2024, when the project's assets will be placed in-service;[2]
ii. Rates revenue requirement for the 2025-2029 period;
iii. Filing a one-time update in 2025 to the cost of long-term debt to reflect the actual market rate achieved on the debt that HONI will issue in 2025, which will update and set the rates revenue requirements, effective January 1 each year, for the remaining term from 2026 through to 2029;
iv. Inclusion of CLLP's approved rates revenue requirement in the OEB's determination of the 2025 to 2029 Network pool of the Uniform Transmission Rates (UTRs);
v. The establishment and approval of new regulatory accounts effective January 1, 2025;
vi. An effective date of January 1, 2025; and
vii. Other items that may be requested by CLLP in the course of this proceeding, and as may be granted by the OEB.

This Application is contingent upon the approval of the application filed with the OEB on April 26, 2024 on behalf of HONI and CLLP.[3] The April 26, 2024 application includes a request by CLLP for a transmitter licence, a request by CLLP for approval to establish a deferral account to record revenue requirement once the Chatham to Lakeshore project is placed in-service, and a request to sell to CLLP transmission assets located between Chatham and Lakeshore transmission stations.

The inclusion of CLLP's rates revenue requirement in the UTR in 2025 will increase the current 2024 Network UTR from $5.78/kW[4] to $5.85/kW effective January 1, 2025. The Line Connection and Transformation Connection UTRs are unaffected by CLLP, as described in Sections 5.9 below.

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[2] In EB-2024-0147 currently before the OEB, CLLP requested approval to establish the CLLPDA for the purpose of recording the revenue requirement relating to the Chatham to Lakeshore Project once it is placed in service, and up until the OEB-approved effective date of CLLP's first revenue requirement application[3] EB-2024-0147, see application filed April 26, 2024 page 3.
[3] EB-2024-0147, see application filed April 26, 2024 page 3.
[4] EB-2023-0222, Decision and Rate Order on 2024 Uniform Transmission Rates, January 18, 2024.

The inclusion of CLLP's rates revenue requirement in the UTR in 2025 will result in a net impact on average transmission rates of 0.834% and a total bill impact of 0.09% ($0.13 per month) for a typical Hydro One Residential (HONI-Dx R1) customer consuming 750 kW per month and; similarly, a total bill impact of 0.06% ($0.28 per month) for a typical Hydro One energy-billed General Service (HONI-Dx GS<50kW) customer consuming 2,000 kWh per month. The annual changes in rates revenue requirement will subsequently decrease the average transmission rates, and the total bills for typical HONI-Dx R1 and HONI-Dx GS<50kW customers in the remaining years, from 2026 to 2029. A summary is provided in Table 7, below and further details are provided in Exhibit I-02-01.

3.0 REVENUE REQUIREMENT FRAMEWORK

CLLP proposes to set its revenue requirement for a five-year period using a forecast of OM&A and capital costs for each of the five years. Customer protection mechanisms such as earnings sharing mechanism (ESM) and off-ramps are proposed. Consistent with the OEB's *Handbook for Utility Rate Applications* (the Handbook), cost of capital is proposed to be fixed at 2025 levels subject only to one update to the cost of long-term debt.[5]

CLLP understands that the OEB's Renewed Regulatory Framework (RRF), as most recently set out in the Handbook, provides that electricity transmitters are to choose either Custom IR or a Revenue Cap IR.[6] However, the RRF was not conceived for a single-asset utility such as CLLP. Single-asset utilities typically have few, if any, capital expenditures in the years following the in-service of the new asset and their rate base declines over time. As a result, a revenue cap index framework, whereby the revenue requirement is updated each year by a factor based on inflation minus a productivity factor, may result in overearning for a single-asset utility. CLLP believes that its proposed approach will provide greater transparency to ratepayers in respect of its costs over the 2025-2029 period and will allow for its revenue requirement to be directly tied to its forecast costs over the entire period.

[5] As detailed in Exhibit G-01-01.
[6] Handbook page 24.

The approach has several benefits as described below in Sections 3.1, 3.2 and 3.3.

3.1 THE APPROACH DOES NOT DISCOURAGE PRODUCTIVITY

CLLP will have few, if any, opportunities to unilaterally achieve productivity improvements, regardless of the revenue requirement framework under which it will operate.

Specifically:

- CLLP will own and operate a double circuit 230kV transmission line that has assets with expected service lives of 70 to 90 years. As these assets are new, they require only a modest amount of OM&A;
- Given that there are no forecast capital expenditures, CLLP's main controllable costs will be maintenance and a small amount of administration. These costs are a small fraction of total costs and are significantly less than the non-controllable portions of CLLP's costs (Cost of Capital, Depreciation, Income Tax, Operations, Corporate Allocation). As a result, it is only in respect of a modest portion of OM&A costs that productivity can be achieved. Even in respect of the controllable portion of maintenance and administration costs:
    - CLLP's management and work programs will be provided by a service level agreement, resulting in minimal overhead as well as qualified and flexible resources when needed, allowing CLLP to remain cost efficient; and
    - CLLP's service level agreement will integrate HONI's productivity improvements into CLLP's maintenance operations.

As a result of the above, CLLP will receive the benefit of HONI's productivity improvements in CLLP's maintenance operations, regardless of the regulatory framework under which CLLP operates.

3.2 PROTECTIONS FOR RATEPAYERS

The approach proposed includes protections for ratepayers, including an ESM, a z-factor mechanism, an off-ramp mechanism and performance metrics.

3.2.1 EARNINGS SHARING MECHANISM (ESM)

CLLP proposes to share, with customers, 50% of any earnings that exceed the OEB-allowed regulatory return on equity (ROE) by more than 100 basis points in any year of the five-year term.

3.2.2 Z-FACTOR

CLLP is proposing, consistent with the Handbook, that the OEB's z-factor mechanism be available over the term of this five-year Application. The criteria that would apply to the use of the z-factor mechanism are detailed in exhibit A-04-01.

3.2.3 OFF-RAMPS

CLLP proposes to apply the OEB's existing off-ramp mechanism, a trigger mechanism with an annual return on equity dead band of plus or minus 300 basis points,[7] at which point a regulatory review of the revenue requirement arising from CLLP's five-year Application may be initiated.

3.2.4 PERFORMANCE METRICS

As detailed in Exhibit D-01-01, CLLP is proposing several performance measures which align with RRF outcomes. These measures protect customers by providing transparency in respect of the performance of CLLP's assets. They allow for verification that the assets are operated within the expected parameters and continue to serve the electricity consumers of Ontario effectively.

3.3 ANNUAL UPDATE APPLICATIONS WILL NOT BE REQUIRED

As a result of CLLP's proposed approach, annual updates to set the revenue requirements will not be required except for a one-time update in 2025 to the cost of long-term debt to reflect the actual market rate achieved on the debt that CLLP will issue in 2025, as detailed in Exhibit G-01-01 of this Application. This will update and set the rates revenue requirements, effective January 1 each year, for the remaining term from 2026 through to 2029. As a result, the OEB can use these final revenue requirements to set 2026, 2027,

[7] See Chapter 3 of Filing Requirements for Electricity Distribution Rate Applications, section 3.2.10.

2028 and 2029 UTRs. CLLP believes its proposal helps advance regulatory efficiency by eliminating the need for annual updates.

4.0 CLLP'S STRATEGIC PLAN

CLLP's plan on which this Application is based was informed by its values and strategic objectives described in the section below.

CLLP is sensitive to and has considered the needs of provincial ratepayers that have expressed a desire for low rates and high reliability. CLLP's plan supports these general ratepayer objectives by proposing no capital investments for 2025 - 2029, and a modest OM&A budget required to maintain CLLP's transmission operations.

CLLP's asset management process, as well as capital expenditure and operation and maintenance expenses for 2025-2029 are further described in Attachment 1 to Exhibit B-01-03.

4.1 CLLP'S VALUES AND STRATEGIC OBJECTIVES

CLLP, as part of the Hydro One family of companies, is driven primarily by the values of health and safety, and stewardship. CLLP's strategy and business values must operate with revenue that can balance the financing of the investment in infrastructure while maintaining affordable and reliable service.

CLLP will be 50% owned by First Nation partners over whose traditional territory the transmission line crosses.

The five-year vision associated with CLLP's strategic objectives is shown in Table 1. In managing its transmission assets, CLLP is committed to meeting the OEB's Renewed Regulatory Framework (RRF) outcomes as demonstrated by the alignment of CLLP's strategic objectives to the RRF outcomes.

Table 1 - CLLP Strategic Objectives*

RRF Outcomes	Strategic Objectives	Five-Year Vision
Customer Focus	Reliable Transmission	Maintain top-tier transmission reliability performance and improve long-term system reliability.
	Foster Indigenous Relationships	To foster positive relationships with the Indigenous communities of the partners.
Operational Effectiveness	Injury-Free	Ensure CLLP's operations and management services agreement is executed in accordance with good utility practice for employee and public safety.
	Cost Control	Secure a reasonable service agreement with HONI that minimizes cost.
Public Policy Responsiveness	Public Policy Responsiveness	Support government objectives by delivering on obligations mandated by government through legislation and regulatory requirements.
	Protecting the Environment	Sustainably manage CLLP's environmental footprint.
Financial Performance	Owner's Value	Achieve the Regulated Return on Equity allowed by the Ontario Energy Board.
	Ratepayer Value	Plan and strategically execute responsible investment in rate base assets to ensure the safety and reliability of the grid while ensuring manageable and stable rate impacts over the course of the planning period.

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

5.0 KEY ELEMENTS OF THE APPLICATION

5.1 REVENUE REQUIREMENT

CLLP's proposed 2025-29 revenue requirements are shown in Table 2.

Table 2 - Revenue Requirement ($M)*

Components	2025	2026	2027	2028	2029
OM&A	1.1	1.1	1.2	1.2	1.2
Depreciation	2.5	2.5	2.5	2.5	2.5
Income Taxes	0.1	0.1	0.1	0.1	0.1
Return on Capital	13.1	13.0[+]	12.9[+]	12.7[+]	12.5[+]
Total Base Revenue Requirement	**16.8**	**16.8**[+]	**16.7**[+]	**16.5**[+]	**16.4**[+]
Add: Other	1.8	0.0	0.0	0.0	0.0
Rates Revenue Requirement	**18.6**	**16.8**[+]	**16.7**[+]	**16.5**[+]	**16.4**[+]

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

+ In 2025, CLLP will file an application to update the cost of long-term debt to reflect the actual market rate achieved on the debt that it will issue in 2025. This will update the revenue requirements for the remaining term from 2026 through to 2029.

5.2 BUDGETING ASSUMPTIONS

CLLP has assumed generally 2% inflation in its OM&A budgets.

5.3 LOAD FORECAST

CLLP's assets are a part of a bulk transmission system reinforcement that is needed to address the near-to mid-term supply needs in the Windsor-Essex region, as determined in an IESO-initiated planning study.[8] CLLP has included no load forecast in this Application, as it has no metering points or delivery points for the purpose of establishing charge determinants. All power transported using CLLP's assets are delivered to the final customer by another transmitter and thus is included in another transmitter's load forecast. The revenue requirement is allocated to the provincial Network rate pool, as all assets serve the Network with no Transformation or individual customer services. Once the

[8] Hydro One Networks Inc. Leave to Construct Application, EB-2022-0140, Exhibit B-03-01.

revenue requirement by rate pool has been established, rates are determined by applying the Provincial charge determinants for each pool to the total revenue for each pool.

5.4 TRANSMISSION SYSTEM PLAN (TSP)

This section summarizes the major drivers and elements of CLLP's five-year TSP (Exhibit B-01-03, Attachment 1). CLLP has aligned its TSP in accordance with Chapter 2 of the Ontario Energy Board's (OEB) *Filing Requirements for Electricity Transmission Applications* published on February 11, 2016, with further guidance from Chapters 3 and 5 of the OEB's *Filing Requirements for Electricity Distribution Rate Applications*.

5.4.1 ASSET MANAGEMENT PROCESS

CLLP plans to enter into a Service Level Agreement with HONI to plan, organize, and execute the operation and maintenance of the assets and provide certain corporate and administrative support services. CLLP will rely on HONI's asset management process. HONI has continued to implement several refinements in its asset strategies and investment assessment to improve upon its asset management process, as documented in EB-2021-0110, Exhibit B-02-01, Section 2.2.

5.4.2 INVESTMENT PLANNING PROCESS

CLLP's operational needs will be assessed by HONI on an annual basis and be incorporated into HONI's investment planning process to establish a plan that addresses those operational needs while minimizing rate impacts. This planning process ultimately forms part of the overall asset management process, which is aimed at identifying and scoping the optimal timing of capital investments and asset maintenance throughout the life cycle of assets.

5.4.3 CAPITAL EXPENDITURES

CLLP's transmission system is limited to the components of a 230kV double circuit transmission line. Since this line is new, no capital investments are being planned for the 2025 to 2029 period as these assets are in good condition.

5.5 RATE BASE

The forecast rate base over the test period is provided in Table 3 below. Details are provided in Exhibit C-01-01.

Table 3 - Transmission Rate Base ($M) *

Description	2024	2025	2026	2027	2028	2029
Mid-Year Gross Plant	200.21[1]	202.7	205.1	205.1	205.1	205.1
Mid-Year Accumulated Depreciation	(0.2)[1]	(1.5)	(4.0)	(6.5)	(9.1)	(11.6)
Mid-Year Net Plant	**200.0**[1]	**201.2**	**201.1**	**198.6**	**196.0**	**193.5**
Cash Working Capital	0.0	0.0	0.0	0.0	0.0	0.0
Materials and Supply Inventory	0.0	0.0	0.0	0.0	0.0	0.0
Transmission Rate Base	**200.0**	**201.2**	**201.1**	**198.6**	**196.0**	**193.5**

* Exhibit Reference: C-01-01, Table 3

[1] 2024 rate base was calculated to reflect the full rate base, upon date of in-service, rather than the half-year rule, in alignment with other recent single-asset utility applications such as EB-2020-0150.

5.6 PERFORMANCE AND REPORTING

CLLP is proposing to track its performance by utilizing the measures approved by the OEB in EB-2018-0275 for NRLP and EB-2019-0178 for B2M LP.

Given the nature of CLLP's assets, the performance of the equipment does not lend itself to applying the typical measures that might be in place for other transmitters. CLLP's assets consist solely of a 230kV double circuit transmission line and do not include any terminal breakers or other operable assets. The demarcation point of each of the circuits is at a tower outside of the station as noted in Exhibit B-01-01. CLLP does not have any customer delivery points (or meter assets), which are the basis of common reliability performance measures such as SAIDI and SAIFI. However, HONI's SAIDI and/or SAIFI values can be impacted by outages caused by CLLP assets. CLLP is providing two performance metrics which measure interruptions to HONI delivery points caused by CLLP's circuits (T-SAIDI CLLP Contribution and T-SAIFI CLLP Contribution). Since CLLP will have no customers, no Customer Focus measures have been proposed. The performance measures, along with their associated RRF performance outcomes are shown in Table 4.

Table 4 - CLLP's Performance Measures*

RRF Outcomes	Performance Measure
Operational Excellence	Average System Availability (%)
Operational Excellence	T-SAIDI CLLP Contribution
Operational Excellence	T-SAIFI CLLP Contribution
Operational Excellence	Maintenance Cost ($K) per circuit kilometer[9]
Public Policy Responsiveness	NERC Vegetation Compliance

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

Further details on the methods and measures as well as the historical performance and forecast targets are documented in Exhibit D-01-01.

5.7 OPERATIONS, MAINTENANCE AND ADMINISTRATION (OM&A)

CLLP is managed by its general partner, CLGP, which plans to retain HONI under an SLA, to plan, organize, and execute the operation and maintenance of the assets and provide certain corporate and administrative support services as outlined in Exhibit F-03-01.

OM&A expenses are derived based upon the various work programs and functions performed by or on behalf of the partnership. As outlined in Table 5 below, the average annual OM&A forecast for the 2025 to 2029 period is $1.2M. OM&A costs consist of indirect costs to CLLP as a result of the SLA expected with HONI, and other incremental expenses expected to be directly incurred by CLLP.

Other Incremental Expenses include components that are directly incurred by CLLP and are outside of the SLA with HONI. These include components such as insurance, regulatory expenses, Managing Director costs, and other administrative expenses such as auditor and professional fees, and office lease. These expenses have been adjusted for inflation for the 2025 to 2029 forecast period.

[9] Circuit kms refer to total route kms multiplied by number of circuits per km. For CLLP, this is 49 kms x 2 circuits = 98 kms.

Further details are presented in Exhibit F-02-01.

Table 5 - Summary of OM&A ($ M)*

Description	Test				
	2025	2026	2027	2028	2029
Estimated SLA Costs	0.61	0.62	0.66	0.64	0.64
Incremental Expenses	0.48	0.50	0.52	0.54	0.56
Total OM&A	**1.09**	**1.12**	**1.18**	**1.17**	**1.20**

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

5.8 COST OF CAPITAL

Details of the cost of capital summary for each year are provided in Exhibit G-01-03. Table 6 below summarizes the return on capital for the 2025-2029 period.

Table 6 - 2025-2029 Return on Capital

	Return on Capital ($M)				
	2025	2026	2027	2028	2029
Long term debt	5.2	5.1+	5.1+	5.0+	5.0+
Short-term debt	0.5	0.5	0.5	0.5	0.5
Common Equity	7.4	7.4	7.3	7.2	7.1
Total	**13.1**	**13.0+**	**12.9+**	**12.7+**	**12.5+**

+ In 2025, CLLP will file an application, which will include a one-time update to the cost of long-term debt to reflect the actual market rate achieved on the debt that it will issue in 2025. This will update the revenue requirements for the remaining term from 2026 through to 2029.

CLLP's deemed capital structure for rate-making purposes is 60% debt and 40% common equity of utility rate base where the 60% debt component is comprised of 4% deemed short-term debt and 56% long-term debt.[10]

[10] Consistent with the Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084) and its subsequent Review of the Existing Methodology of the Cost of Capital for Ontario's Regulated Utilities, dated January 14, 2016.

At the time of the Draft Rate Order (DRO) in this proceeding, CLLP intends to update the 2025 to 2029 revenue requirements based on the OEB's release of its 2025 cost of capital parameters to reflect: (a) the OEB-prescribed 2025 return on equity and short-term debt rates; and (b) a long-term debt rate based on CLLP's forecast debt refinancing in 2025, using the September 2024 Consensus Forecast. The ROE and short-term debt rate parameters will remain fixed over the five-year rate term.

At the time of in-servicing the Chatham to Lakeshore transmission line, CLLP will issue a note in the amount of $112.7M representing 56% of CLLP's rate base, bearing interest at 4.58%. This rate reflects the OEB's deemed long-term debt rate for 2024. This note is planned to be refinanced during 2025 with debt issued on behalf of CLLP. The refinancing debt issue will mirror the terms included in an actual debt issue planned to be issued by Hydro One Inc. to third-party public debt investors. This is expected to occur in mid-2025. Following the update, in 2025, CLLP will file an application to update the cost of long-term debt to reflect the actual market rate achieved on debt issued in 2025, as requested for approval in this proceeding.

Further details regarding the cost of capital can be found in Exhibit G-01-01.

5.9 COST ALLOCATION AND RATE DESIGN

All assets associated with CLLP are classified as Network in accordance with HONI's functionalization of assets approved by the OEB for HONI's Transmission rate applications, most recently in EB-2021-0110.[11] Accordingly, the total rates revenue requirement associated with CLLP's transmission assets will be allocated to the Network pool. Further details regarding the cost allocation and rate design are provided in Exhibit I-01-01.

5.10 DEFERRAL AND VARIANCE ACCOUNTS

CLLP is requesting approval of two accounts as detailed in Exhibit H-01-01.

[11] EB-2021-0110, Exhibit H-01-02, Section 3.0 filed August 5, 2021

Moreover, in the CLLP Licencing and Deferral Account Application currently before the OEB (EB-2024-0147), CLLP requested approval to establish the CLLPDA for the purpose of recording the revenue requirement related to the Chatham to Lakeshore project once it is placed in service, and up until the OEB-approved effective date of CLLP's first revenue requirement application.[12]

A revenue requirement currently forecasted to be $1.8M is expected to be recorded in the CLLPDA upon the Chatham to Lakeshore Project being placed in-service this year. This revenue requirement for 2024 has been included in the 2025 rates revenue requirement requested in this Application.[13] At the time of the Draft Rate Order in this proceeding, CLLP will reflect any updates to the 2024 revenue requirement based on the OEB's decision in this proceeding. Accordingly, the CLLPDA may be closed once the DRO in this proceeding is approved.

5.11 BILL IMPACTS

A summary of the estimated impacts of this Application on average transmission rates and total bills for transmission and distribution-connected customers is provided in Table 7. Detailed calculations are provided in Exhibit I-02-01.[14]

The total bill impact for a typical HONI-Dx R1 customer consuming 750 kWh, and for a typical HONI-Dx GS<50kW customer consuming 2,000 kWh is determined based on the forecast change in the customer's Network Retail Transmission Service Rates (RTSR-N).

[12] EB-2024-0147, Application for Chatham x Lakeshore Limited Partnership (CLLP) Licencing and Deferral Account, Appendix 5, filed on April 26, 2024
[13] See Exhibit E-01-01.
[14] Bill impacts reflect CLLP's proposed rates revenue requirement in this Application, as per Sections 2.7.1 and 2.12 of the OEB's Chapter 2 filing requirements for Transmission Revenue Requirement Applications. Details on the net rates impact assessment for the total cost and load impact of the Chatham to Lakeshore Project in the Windsor-Essex Region are provided in Hydro One Networks Inc.'s Leave to Construct Application in EB-2022-0140, Exhibit B-09-01.

Table 7 - Summary of Impacts on Average Transmission Rates and Transmission and Distribution-Connected Customers

	2025	2026	2027	2028	2029
Rates Revenue Requirement ($M)	18.62	16.80	16.69	16.52	16.38
Net Impact on Average Transmission Rates	0.834%	-0.081%	-0.005%	-0.008%	-0.007%
Average Transmission Customer Total Bill Impact	0.101%	-0.010%	-0.001%	-0.001%	-0.001%
Typical Hydro One R1 Customer Total Bill Impact (750 kWh)	$0.129	$(0.013)	$(0.001)	$(0.001)	$(0.001)
	0.091%	-0.009%	-0.001%	-0.001%	-0.001%
Typical Hydro One GS<50kW Customer Total Bill Impact (2000 kWh)	$0.276	$(0.027)	$(0.002)	$(0.003)	$(0.002)
	0.063%	-0.006%	0.000%	-0.001%	-0.001%

Note: CLLP's rates revenue requirement impacts reflect its share of the transmission rates revenue requirement in UTRs.

6.0 CONCLUSION

CLLP’s Application will balance the needs of its system and assets and allow it to operate and maintain these assets in accordance with reliability standards and to satisfy regulatory, environmental, and legal requirements.

CLLP will operate under unique circumstances when considering its corporate structure, asset holdings, and operating and management arrangements. Over the five-year term, this Application will help ensure that CLLP’s assets are managed effectively to benefit electricity customers across Ontario.

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REVENUE REQUIREMENT FRAMEWORK SUMMARY

1.0 INTRODUCTION AND OVERVIEW

CLLP proposes to set its revenue requirement for a five-year period using a forecast of OM&A and capital (including tax) costs for each of the five years. Customer protection mechanisms such as an earnings sharing mechanism (ESM) and off-ramps are proposed. Consistent with the OEB's *Handbook for Utility Rate Applications* (the Handbook), cost of capital is proposed to be fixed at 2025 levels subject only to one update to the cost of long-term debt.[1]

CLLP understands that the OEB's Renewed Regulatory Framework (RRF), as most recently set out in the Handbook, provides that electricity transmitters are to choose either Custom IR or a Revenue Cap IR.[2] However, the RRF was not conceived for a single-asset utility such as CLLP. CLLP believes that its proposal has several benefits:

- it considers the appropriate framework for single-asset utilities with a declining rate base, providing transparency to ratepayers and lower potential for overearning than a revenue cap index framework, especially in the later years of a rate period; and
- it provides appropriate protection for ratepayers and does not disincentivize productivity.

Each of the points above is discussed below.

[1] As detailed in Exhibit G-01-01.
[2] Handbook page 24.

1.1 CONSIDERATION OF THE MOST APPROPRIATE REVENUE REQUIREMENT FRAMEWORK FOR CLLP AS A SINGLE-ASSET UTILTITY

In developing its Application, CLLP considered whether revenue cap index frameworks are appropriate for a single-asset utility such as CLLP. Single-asset utilities, such as CLLP, typically have few, if any, capital expenditures in the years following the new assets being placed in-service and their rate base declines over time. As a result, a revenue cap index framework, whereby the revenue requirement is updated each year by a factor based on inflation minus a productivity factor may result in overearning for a single-asset utility. On the other hand, single-asset utilities have unique expense trajectories, such as income tax, that may cause costs to vary substantially year over year.

To address this dynamic, CLLP is proposing the approach set out herein for its 2025-2029 revenue requirement. CLLP believes that this approach will provide greater transparency to ratepayers in respect of its costs over the 2025-2029 period and will allow for its revenue requirement to be directly tied to its forecast costs over the entire period. Protections for ratepayers, including an explanation of why this proposal does not disincentivize productivity, are discussed in the section below.

1.2 FRAMEWORK PROVIDES APPROPRIATE PROTECTION FOR RATEPAYERS

CLLP's proposal provides appropriate protection for ratepayers for a number of reasons, each of which is discussed in this section.

1.2.1 THE APPROACH DOES NOT DISCOURAGE PRODUCTIVITY

CLLP will have few, if any, opportunities to achieve productivity improvements, regardless of the revenue requirement framework under which it is operating at any given time.

Specifically:

- CLLP will own and operate a double circuit 230kV transmission line that has assets with expected service lives of 70 to 90 years. As these assets are new, they require only modest OM&A, and no capital expenditures are forecasted during the rate period.
- Given that there are no forecast capital expenditures, CLLP's main controllable costs will be maintenance and a small amount of administration. These costs are a small fraction of total costs and are significantly less than the non-controllable portions of CLLP's costs (Cost of Capital, Depreciation, Income Tax, Operations, Corporate Allocation). CLLP cannot independently achieve material productivity savings. Even in respect of the controllable portion of maintenance and administration costs:
  - CLLP's management and work programs will be provided by a service level agreement, resulting in minimal overhead as well as qualified and flexible resources when needed, allowing CLLP to remain cost efficient; and
  - CLLP's service level agreement will integrate HONI's productivity improvements into CLLP's maintenance operations.

As a result of the above, CLLP will receive the benefit of HONI's productivity improvements in CLLP's maintenance operations, regardless of the regulatory framework under which CLLP operates.

1.2.2 PROTECTIONS FOR RATEPAYERS

CLLP is proposing the following additional features in this Application to align its interests with those of customers and to provide an additional element of protection for customers.

EARNINGS SHARING MECHANISM (ESM)

Although significant overearning is not expected, CLLP proposes to share, with customers, 50% of any earnings that exceed the OEB-allowed regulatory return on equity (ROE) by more than 100 basis points in any year of the five-year term. The customer share of the earnings will be adjusted for any tax impacts and will be credited to the ESM deferral account for clearance at the time of CLLP's next rebasing, as further described in Exhibit H-01-01.

Z-FACTOR

CLLP is proposing, consistent with the Handbook, that the OEB's Z-factor mechanism be available over the term of this five-year Application. The criteria that would apply to the use of the Z-factor mechanism are those outlined by the OEB in Chapter 2 of the Filing Requirements for Electricity Transmission Applications, section 2.8.12.

Events that may necessitate the use of the Z-factor mechanism include:

- Extreme weather events, such as storms;
- Investments that are government-mandated or otherwise outside of management's control;
- Changes to IESO market rules;
- Changes to OEB codes, policies or other directions;
- Changes to accounting frameworks or technical standards;
- Changes to government policy, legislation, or regulation, such as environmental laws; and
- Any other one-time or ongoing events that meet the Z-factor criteria.

OFF-RAMPS

CLLP proposes to apply the OEB's existing off-ramp mechanism, a trigger mechanism with an annual ROE dead band of plus or minus 300 basis points,[3] at which point a regulatory review of the revenue requirement arising from CLLP's five-year Application may be initiated.

[3] See Chapter 3 of Filing Requirements for Electricity Distribution Rate Applications, section 3.2.10.

PERFORMANCE METRICS

As detailed in Exhibit D-01-01, CLLP is proposing a number of performance measures which align with RRF outcomes. These measures protect customers by providing transparency in respect of the performance of CLLP's assets. They allow for verification that the assets are operated within the expected parameters and continue to serve the electricity consumers of Ontario effectively.

2.0 ANNUAL UPDATE APPLICATIONS WILL NOT BE REQUIRED

As a result of CLLP's proposed approach, annual updates to set the revenue requirements will not be required except for a one-time update in 2025 to the cost of long-term debt to reflect the actual market rate achieved on the debt that CLLP will issue in 2025, as detailed in Exhibit G-01-01 of this Application. This will update and set the rates revenue requirements, effective January 1 each year, for the remaining term from 2026 through to 2029. As a result, the OEB can use these final revenue requirements to set 2026, 2027, 2028 and 2029 UTRs. CLLP believes its proposal helps advance regulatory efficiency by eliminating the need for annual updates.

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DESCRIPTION OF THE PARTNERSHIP

CLLP will be a limited partnership between Hydro One Networks Inc. (HONI), Chatham x Lakeshore GP Inc. and up to five First Nation partners offered the opportunity to take ownership in 50% of the line through HONI's First Nations Equity Partnership model. Please see Figure 2 below for the post-First Nation investment structure that is expected for CLLP.

Hydro One Networks Inc. (HONI)

HONI is a wholly owned subsidiary of Hydro One Inc., which in turn is a wholly-owned subsidiary of Hydro One Limited, a publicly listed business corporation. HONI acts as a Limited Partner of CLLP.

Chatham x Lakeshore GP Inc. (CLGP)

CLGP holds the general partner interests and carries out the general partner responsibilities of CLLP including management and oversight of the partnership. CLGP will be responsible for ensuring that the assets held by CLLP are operated and maintained in accordance with all applicable regulatory standards and HONI's maintenance and operating practices. CLGP will carry out these functions through an operations and management services agreement with HONI.

Please see Figure 1 below for the current CLLP structure.

First Nations Partners

Though negotiations are ongoing the potential First Nation partner communities are working through their respective protocols to make a final decision on the investment and to secure community approvals to execute final agreements which is expected later in 2024. The decision to invest in the project has been made available to five First Nations in the region, and should one or more decide not to invest, their portion of equity will be offered to the remaining First Nations partners who made a decision to invest. This will ensure the 50% First Nations ownership commitment is maintained. HONI has offered equity partnership to five potential First Nation community partners, named below:

- Aamjiwnaang First Nation (AFN)
- Caldwell First Nation (CFN)
- Chippewas of the Thames First Nation (COTTFN)
- Chippewas of Kettle and Stony Point First Nation (CKSPFN)
- Walpole Island First Nation (WIFN)

First Nation support has proven critical to the timely delivery of the Chatham to Lakeshore line. The established relationships and continued cooperation between AFN, CFN, COTTFN, CKSPFN, and WIFN, and HONI is critical to ensuring a timely and efficient in-servicing of the line and has reduced overall project risk, which will benefit the Ontario bulk electricity system and ultimately electricity customers across Ontario.

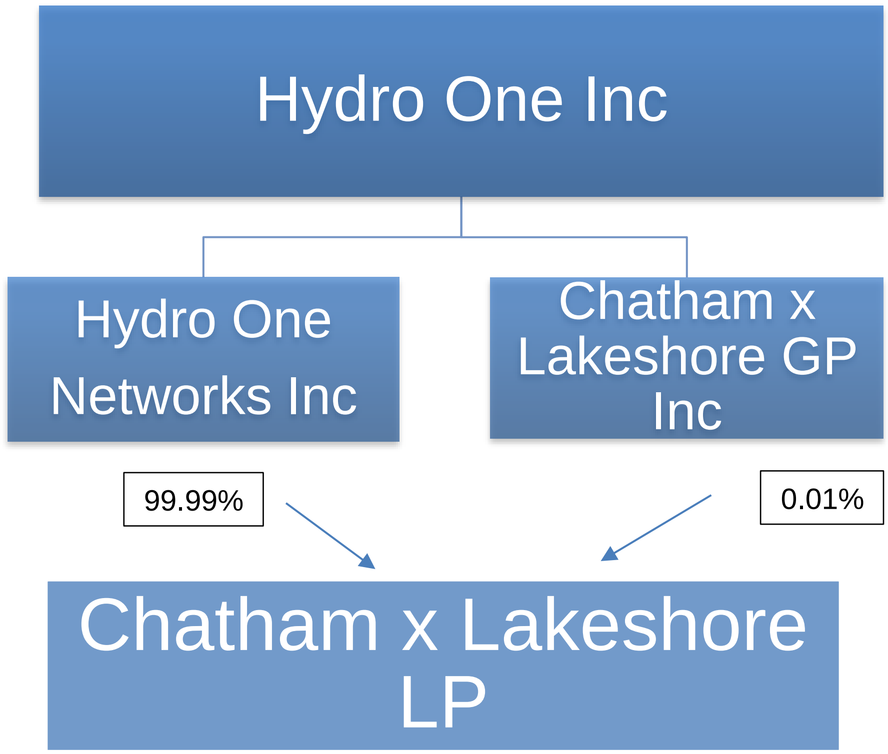

Figure 1: Current CLLP Structure

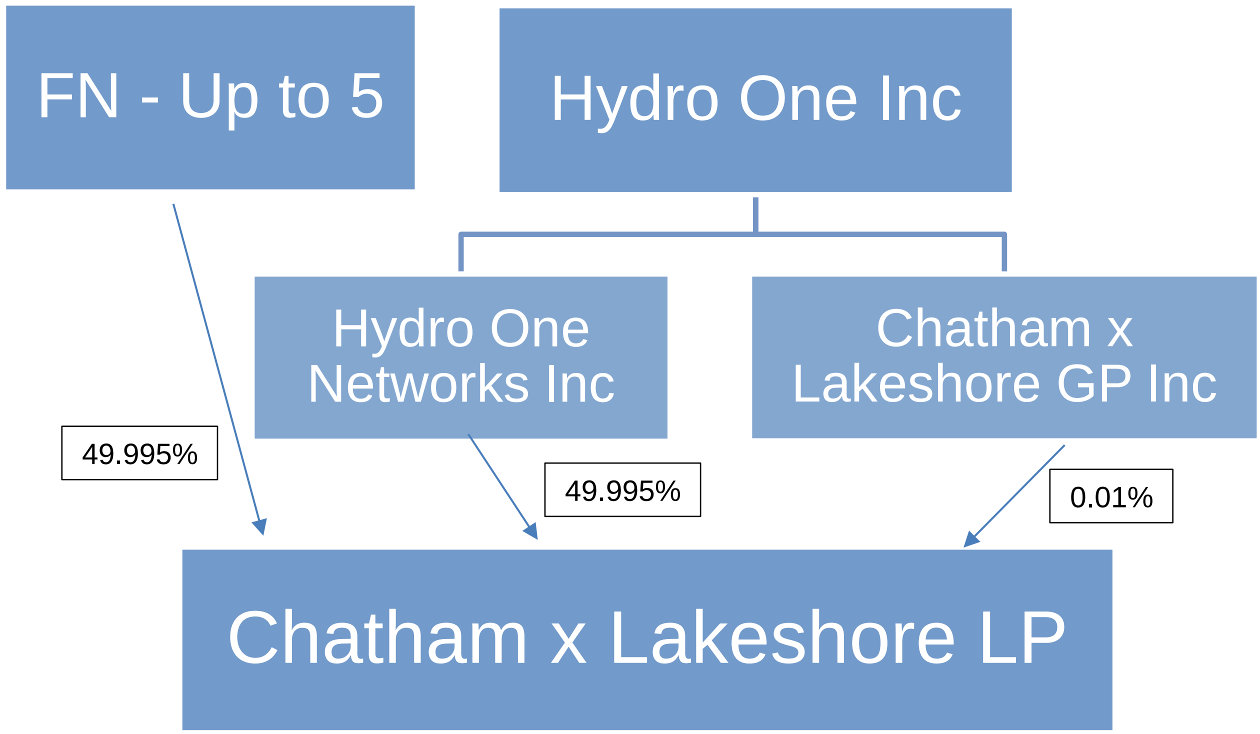

Figure 2: Proposed Post-First Nation Investment Structure

FINANCIAL INFORMATION

1.0 ACCOUNTING STANDARD

CLLP is requesting to use United States Generally Accepted Accounting Principles (US GAAP) for purposes of rate setting, regulatory accounting and regulatory reporting.

In HONI's 2023 - 2027 Custom IR application (EB-2021-0110), HONI was approved to continue using US GAAP as the basis of accounting for regulatory purposes.[1] Approval to use US GAAP for CLLP will facilitate Hydro One Inc.'s consolidated reporting for securities filing purposes, thus avoiding incremental costs and/or reduced productivity.

2.0 CHANGES TO ACCOUNTING POLICIES

In keeping with good corporate governance, CLLP will review and, if appropriate, revise its policies and procedures from time to time.

3.0 OTHER SUPPORTING FINANCIAL INFORMATION

As CLLP's debt will be managed under HONI, there are no rating agency reports, prospectuses or information circulars that are specific to CLLP. Please see EB-2021-0110, Exhibit A-06-03, Attachments 1 to 3, and Exhibit A-06-05, Attachment 1 for such information that was filed for HONI in its 2023 - 2027 Custom IR proceeding.

Hydro One Limited's most recent annual report, which includes its 2023 Management Discussion and Analysis and Consolidated Financial Statements, is included on the Hydro One corporate website at the link below:

- 2023 Annual Report

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CLLP FINANCIAL STATEMENTS - HISTORICAL YEARS

CLLP is a newly formed partnership and, as a result, there are no historical financial statements to include in this Application.

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RECONCILIATION OF REGULATORY FINANCIAL RESULTS WITH AUDITED FINANCIAL STATEMENTS (2023)

CLLP is a newly formed partnership and, as a result, there are no financial results to reconcile in this Application.

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ISSUES LIST

A. GENERAL

1. Has CLLP responded appropriately to all relevant Ontario Energy Board (OEB) directions from previous proceedings?
2. Are all elements of the proposed revenue requirement and their associated total bill impacts reasonable?

B. REVENUE REQUIREMENT FRAMEWORK

3. Is the proposed revenue requirement framework appropriate?
4. Is the proposed Earnings Sharing Mechanism appropriate?

C. TRANSMISSION SYSTEM PLAN

5. Are the proposed expenditure levels for capital appropriate?

D. PERFORMANCE

6. Is the proposed monitoring and reporting of performance adequate?

E. OPERATIONS MAINTENANCE & ADMINISTRATION COSTS

7. Are the proposed expenditure levels for 2025-2029 OM&A appropriate, including consideration of factors such as system reliability and asset condition?
8. Are the amounts proposed to be included in the revenue requirement for income taxes appropriate?
9. Is the proposed depreciation expense appropriate?

F. RATE BASE & COST OF CAPITAL

10. Are the amounts proposed for rate base and capital structure reasonable?
11. Is CLLP’s proposed overhead capitalization rate appropriate?
12. Is the forecast of long-term debt appropriate?
13. Is the 2025 update of the cost of long-term debt appropriate?

G. DEFERRAL/VARIANCE ACCOUNTS

14. Are the amounts proposed for disposition appropriate?
15. Are the proposed deferral and variance accounts appropriate?

H. COST ALLOCATION

16. Is the proposed cost allocation appropriate?

TRANSMISSION SYSTEM OVERVIEW

1.0 INTRODUCTION

Chatham x Lakeshore Limited Partnership (CLLP) is in the process of obtaining a license from the Ontario Energy Board (OEB) to own, operate and maintain transmission facilities in the Province of Ontario (EB-2024-0147). This Exhibit provides a description of CLLP's transmission assets, and a discussion on the requirements for CLLP within the electricity industry and regulatory framework in Ontario.

2.0 DESCRIPTION OF CLLP TRANSMISSION ASSETS

CLLP's transmission assets are comprised solely of a 230kV double-circuit transmission line comprised of circuits C87H and C88H. These circuits have a combined transfer capability of approximately 800 MW. However, from an operability perspective, prudent contingency planning and existing transfer capacity constraints upstream of these circuits limit the total transfer capacity to 400 MW. CLLP will increase the West of Chatham interface limit by 400 MW, from 1100 MW to 1500 MW. Additional capacity is also intended to support incremental load growth from within southwestern Ontario and neighboring regions.

There are four existing 230kV transmission circuits connecting Chatham SS and Lakeshore TS, whose nomenclatures are C64H, C65H, C42H and C43H. With the completion of this line, there will be six transmission circuits between Chatham SS and Lakeshore TS. The total route length of CLLP's double circuit transmission lines, C87H and C88H, from Chatham SS to Lakeshore TS is approximately 49km on a combination of a new corridor and widened existing 115kV transmission corridor. The route passes through one county and two municipalities (Essex, Chatham-Kent, and Lakeshore, respectively). The route of CLLP's double circuit transmission line is depicted in Figure 1.

The circuits C87H and C88H extend across the City of Chatham, the Town of Tilbury, and the Township of Comber in the Municipality of Lakeshore. The circuits terminate just southwest of Chatham SS at towers 1A and 1B inclusive, and just northeast of Lakeshore

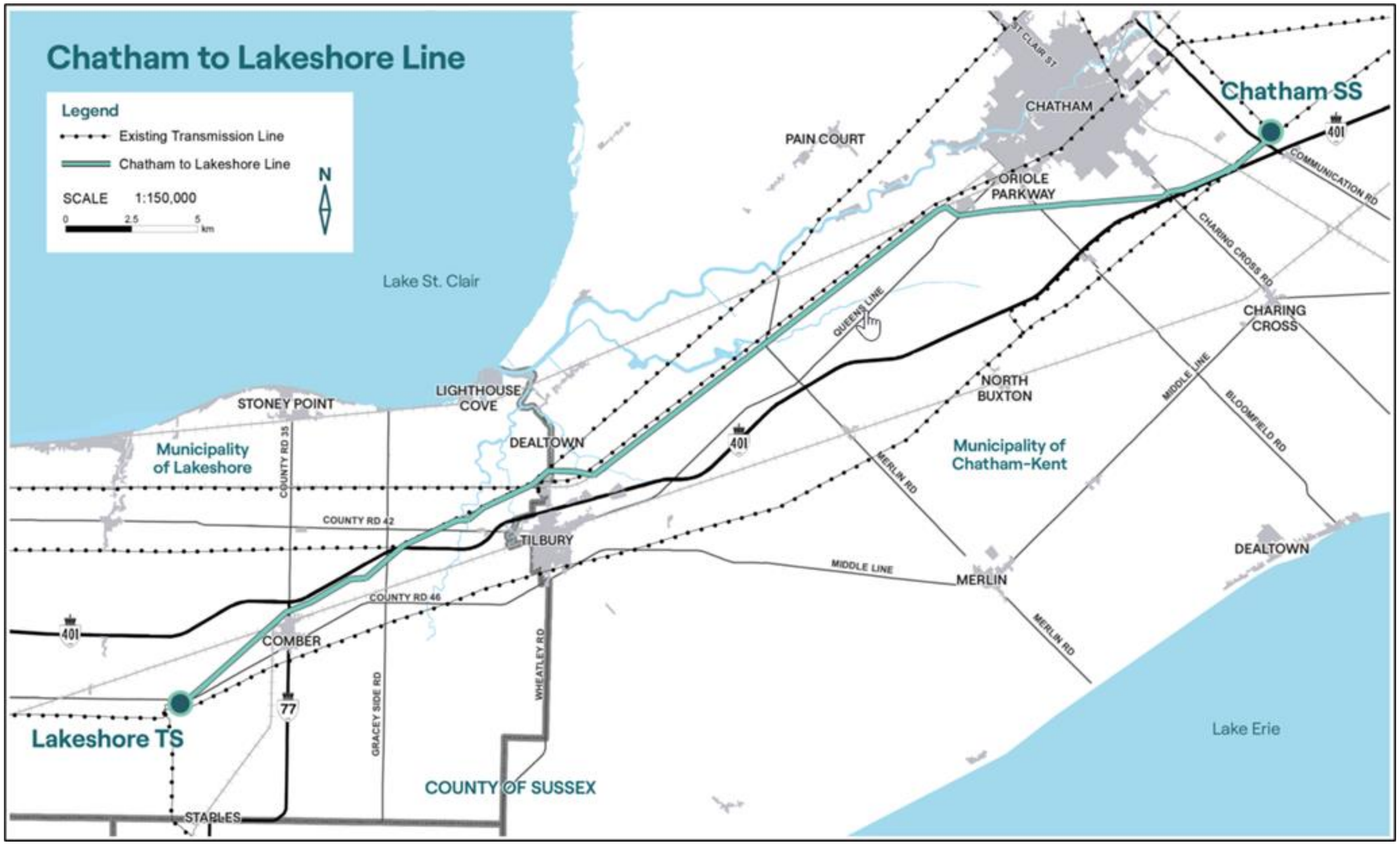
TS at towers 159A and 163B inclusive, at the station side dead-end insulator on the aforementioned towers.

The major components of these circuits include overhead conductors, steel support structures and foundations, insulators, and connecting hardware and grounding systems. CLLP also has rights to HONI's existing transmission corridor on which the circuits are located. A summary of CLLP's key assets is provided in Table 1.

Table 1 - Asset Summary

CLLP Assets	
Fixed Assets (Net Book Value)	See Exhibit C-01-01
Transmission System Voltages	230kV
Overhead Transmission Line Conductors	294 kms[1]
Steel Support Structures	170 towers
Line Insulators	1410 strings
Optical Ground Wire	49 kms
Shieldwire	49 kms

[1] Each of the 2 circuits is 49km in length with 3 phases (conductor strings) per circuit.



1 **Figure 1: CLLP Transmission System Map**

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COMPANY VALUES AND STRATEGIC OBJECTIVES

1.0 INTRODUCTION

This Exhibit provides an overview of CLLP's business objectives and company values. It also outlines CLLP's strategic goals and five-year vision.

2.0 CLLP'S PRIORITIES & OBJECTIVES

CLLP's priorities include safety, reliable and efficient stewardship of assets, and conducting its business in a manner that respects Indigenous peoples and their traditions.

The five-year vision associated with CLLP's strategic objectives is shown in Table 1. In managing its transmission assets, CLLP is committed to meeting the OEB's Renewed Regulatory Framework (RRF) outcomes as demonstrated by the alignment of CLLP's strategic objectives to the RRF outcomes.

Table 1 - CLLP Strategic Objectives

RRF Outcomes	Strategic Objectives	Five-Year Vision
Customer Focus	Reliable Transmission	Maintain top-tier transmission reliability performance and improve long-term system reliability.
	Foster Indigenous Relationships	To foster positive relationships with the Indigenous communities of the partners.
Operational Effectiveness	Injury-Free	Ensure CLLP's operations and management services agreement is executed in accordance with good utility practice for employee and public safety.
	Cost Control	Secure a reasonable service agreement with Hydro One Networks Inc. that minimizes cost.
Public Policy Responsiveness	Public Policy Responsiveness	Support government objectives by delivering on obligations mandated by government through legislation and regulatory requirements.
	Protecting the Environment	Sustainably manage CLLP's environmental footprint.
Financial Performance	Owner's Value	Achieve the Regulated Return on Equity allowed by the Ontario Energy Board.
	Ratepayer Value	Plan and strategically execute responsible investment in rate base assets to ensure the safety and reliability of the grid while ensuring manageable and stable rate impacts over the course of the planning period.

CLLP is proposing to track its performance using the outcomes described in Exhibit D-01-01 to ensure CLLP satisfies its five-year plan.

External and unexpected factors may impact CLLP's achievement of its outcomes. These include examples such as unforeseen weather events and material changes to codes and standards. However, all Operation & Maintenance work is completed to ensure compliance with regulatory requirements, good utility practice, and manage spending within budget.

SUMMARY OF CAPITAL EXPENDITURES AND IN-SERVICE ADDITIONS

CLLP's 230kV double circuit transmission line is new and planned to be energized on December 15, 2024. No capital projects are planned for 2025 to 2029. Further details on the asset life cycle and condition assessments are included in CLLP's Transmission System Plan found in Attachment 1 to this Exhibit.

Although a 230kV double circuit transmission line, if maintained properly, is extremely durable and resilient in normal circumstances, extraordinary events (including tornados and ice formations) can occur and cause damage to the line. These types of extreme weather events, while uncommon, may result in unplanned capital spending to repair the system. Due to the risk of major storm damage or other events, CLLP is proposing to continue to use a z-factor approach[1] to seek relief for unplanned spending. CLLP is satisfied with the efficacy of this mechanism to protect the partners from the impacts that could result from unforeseen events and is not requesting a change. In accordance with the OEB's Filing Requirements,[2] this mechanism would apply to the recovery of material costs (that meet the eligibility criteria) associated with unforeseen events that are outside the control of the transmitter's ability to manage, such as storms causing damage to its assets.

[1] See EB-2015-0026, Decision and Order, page 10
[2] See Section 2.8.12 of the OEB Filing Requirements for Electricity Transmission Applications

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Transmission System Plan

Forecast Period: 2025-2029

Chatham x Lakeshore Limited Partnership (CLLP)

TABLE OF CONTENTS

1.0 INTRODUCTION

Chatham x Lakeshore Limited Partnership (CLLP) prepared this 2025 to 2029 Transmission System Plan (TSP) in accordance with Chapter 2 of the Ontario Energy Board's (OEB) Filing Requirements for Electricity Transmission Applications published on February 11, 2016, with further guidance from Chapters 3 and 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (Incentive Rate-Setting Applications and Distribution System Plan), revised on June 15, 2023 and December 15, 2022, respectively (together, the "Filing Requirements").

The planning tools, processes, and investments outlined in this TSP are based upon the current state of the assets owned by the partnership, which are new. This TSP has been prepared for information purposes to support the overall Application and to be responsive to the Filing Requirements.

2.0 TRANSMISSION SYSTEM PLAN

2.1 TRANSMISSION SYSTEM PLAN OVERVIEW (*OEB FILING REQ. 2.4*)

This section summarizes the key components that make up the integrated TSP and contextualizes the quantitative and qualitative information provided throughout.

2.1.1 KEY ELEMENTS OF THE PLAN

CLLP's transmission line is comprised of two 230kV transmission circuits, C87H and C88H, between Chatham Switching Station (SS) and Lakeshore Transformer Station (TS). This line will be placed into service in 2024. Since the line is new, no capital investments are planned for the 2025 – 2029 period.

The forecast OM&A expenditure is a relatively small portion, less than 7%, of the total revenue requirement. The proposed OM&A funding will ensure that CLLP's assets are operated and maintained in accordance with good utility practice and reliability standards.

2.1.2 CUSTOMERS' PREFERENCES AND EXPECTATIONS

CLLP's 230kV double circuit transmission line is part of Ontario's bulk electric system, which helps to ensure the adequacy of supply to the province by connecting to major generating sources and delivering that power to major load centres in Ontario. CLLP has no delivery points and therefore does not serve any customers directly. Therefore, the partnership has not performed any independent customer research.

CLLP's five-year plan supports the general objective of maintaining long-term system reliability while ensuring manageable and stable rate impacts to ratepayers over the course of the planning period. The plan proposes no capital projects and includes a modest OM&A budget to maintain CLLP's transmission reliability. CLLP will enter into a Service Level Agreement (SLA) with HONI to provide maintenance and operational services on the transmission line for the next five years. Having this service provider, with its breadth of capabilities and local knowledge, provides assurance that the assets will be operated and maintained in accordance with good utility practices and reliability standards.

2.1.3 ANTICIPATED SOURCES OF EFFICIENCIES

The majority of CLLP's OM&A expense (accounting for approximately 53% of the average annual OM&A expense for 2025 - 2029) are for services that will be provided by HONI through an SLA. Efficiencies gained by HONI are passed through to CLLP. CLLP's asset is a 230kV double circuit transmission line that is located close to other transmission lines owned by HONI. Given the proximity of the assets, there are meaningful efficiencies inherent in having one party, HONI, plan and perform the work on the lines simultaneously.

CLLP's controllable costs, which comprise of directly incurred costs outside Service Level Agreements, are minimal but include certain administrative expenses. These include such items as insurance and the Managing Director's office.

2.1.4 PERIOD COVERED AND VINTAGE OF INFORMATION

This TSP covers the five-year forecast period from 2025 to 2029 inclusive. The information contained in this TSP is considered current as of year-end of 2023, unless otherwise noted.

2.1.5 IMPORTANT CHANGES TO THE ASSET MANAGEMENT PROCESS

CLLP is planning to retain HONI under a Service Level Agreement to plan, organize, and execute the operation and maintenance of the assets and provide certain corporate and administrative support. CLLP relies upon HONI's asset management process to develop its plan, as articulated in Section 3.1 Asset Lifecycle Optimization Policies and Practices below.

2.1.6 CONTINGENCIES OF PLAN

CLLP is not proposing any capital expenditures over the five-year term of this Application. Therefore, there are no plan contingencies required.

2.1.7 GRID MODERNIZATION

At this time, CLLP is not implementing any capital plans for future initiatives such as distributed energy resources, grid modernization or climate change.

2.2 PLANNING WITH THIRD PARTIES (*OEB FILING REQ. 2.4.2*)

CLLP is not a lead transmitter for any of the regional planning regions. CLLP's transmission lines are part of the bulk system. The bulk system planning is under the purview of the Independent Electricity System Operator (IESO) and is coordinated as part of that undertaking. If requested, CLLP will participate in the bulk system planning process and/or regional bulk system planning process, as per Section 3C of the Transmission System Code and the OEB endorsed Planning Process Working Group (the PPWG) Report, in compliance with CLLP's obligations as a licensed transmitter. CLLP is not expecting such a request in the foreseeable future.

2.3 PERFORMANCE MEASUREMENT FOR CONTINUOUS IMPROVEMENT

CLLP is proposing to track its performance by utilizing the measures equivalent to those approved for B2M LP by the OEB in proceeding EB-2019-0178 and for NRLP in proceeding EB-2018-0275. This is to ensure that CLLP is meeting its five-year plan as described in this Application. The performance measures will be tracked annually, and the results of this tracking will be reported to the OEB at the next proceeding. Further details on the methods and measures, as well as forecast targets, are documented in Exhibit D-01-01.

3.0 ASSET MANAGEMENT PROCESS *(OEB FILING REQ. 2.4.1)*

3.1 ASSET MANAGEMENT PROCESS OVERVIEW

CLLP seeks to identify and prioritize asset maintenance and capital investments in an optimal way throughout the life cycle of its assets. To achieve this goal, CLLP plans to work with HONI to undertake a strategic and methodical asset management process, drawing upon HONI's extensive expertise and experience to monitor its transmission system assets, identify and define needs, and determine the optimal timing for investment and maintenance activities in the future. In doing so, CLLP strives to ensure that it can deliver, over the long term, a level of transmission service that is responsive to operational needs, while also minimizing rate impacts and risks to electricity customers of Ontario.

3.2 OVERVIEW OF ASSETS MANAGED

This section summarizes the detailed characteristics and data on the assets covered by the asset management process, including service area, system configuration, asset condition, and asset utilization.

3.2.1 FEATURES OF THE SERVICE AREA

CLLP's 230kV double circuit transmission line includes circuits, C87H and C88H, running southwesterly from Chatham SS located in the Municipality of Chatham-Kent, traversing across the City of Chatham, the Town of Tilbury, the Township of Comber in the Municipality of Lakeshore, before terminating at Lakeshore TS located in the Municipality of Lakeshore. A map of the territory covered by the line is presented in Figure 1. These are primarily rural areas that generally allow for easy access to perform maintenance activities. However, the climate in these areas varies by season and may experience a variety of extreme weather conditions, such as blizzards, hail, ice storms, lightning, thunderstorms, extreme heat and tornadoes.

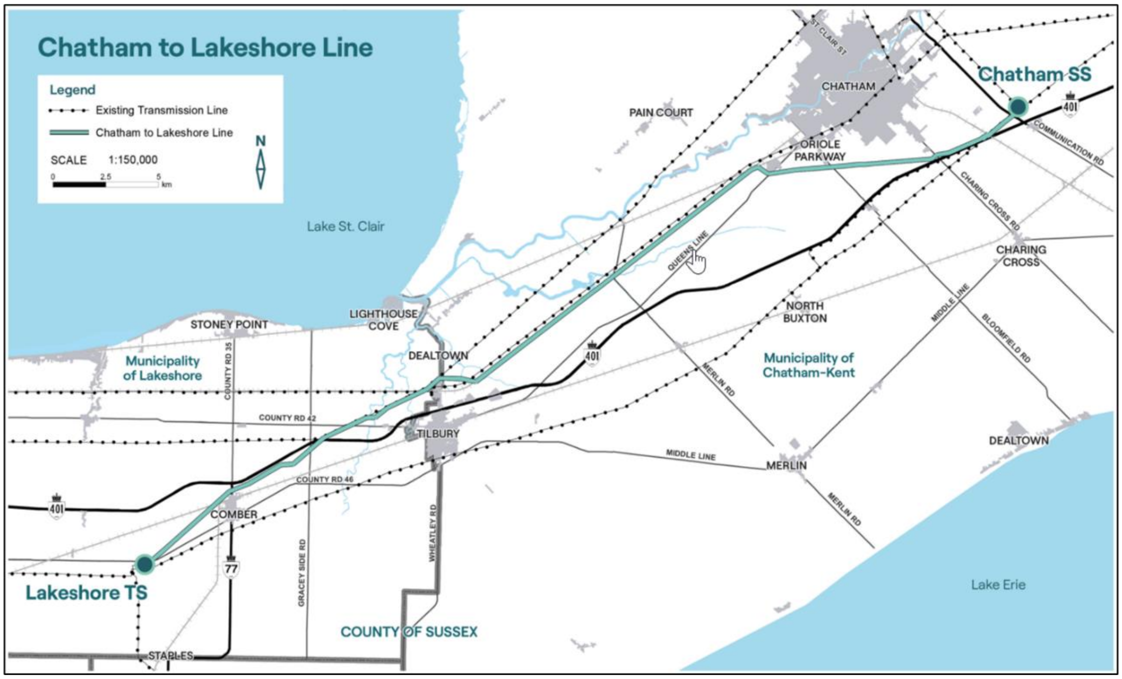

Figure 1: Map of Area Traversed by CLLP Line

3.2.2 SYSTEM CONFIGURATION

The circuits C87H and C88H extend across the City of Chatham, the Town of Tilbury, the Township of Comber in the Municipality of Lakeshore. The circuits terminate just southwest of Chatham SS at towers 1A and 1B inclusive, and just northeast of Lakeshore TS at towers 159A and 163B inclusive, at the station side dead-end insulator on the aforementioned towers. Table 1 provides a high-level description and quantity of major transmission assets that comprise the CLLP transmission line.

Table 1 - Asset Summary

Asset Type	Description	Quantity
Conductor	The conductor of an overhead transmission line is the asset responsible for transporting electricity between system nodes.	294 kms[1]
Steel Towers	Steel structures elevate transmission lines above the ground, providing clearance from ground objects and separation between the circuit conductors and other line components.	170
Insulators	Insulators provide mechanical support for overhead conductors and must provide electrical isolation between the energized conductors they support and the grounded towers to which they are attached.	1410
Optical Ground Wire	OPGW is used to provide a telecommunication path between Chatham SS and Lakeshore TS as well as lightning protection.	49 kms
Shield Wire	Shield wire is used for providing lightning protection and grounding continuity to transmission lines.	49 kms

These asset types are similar in all manner to those on HONI's transmission system. For further descriptions of each asset component and the maintenance plans please refer to HONI's Joint Rate Application (EB-2021-0110) in Exhibit B-02-01 Section 2.1.2.2, Key Transmission Assets.

3.2.3 ASSET CONDITION

This section presents the service profile and condition of CLLP's key transmission assets.

In-Service Profile

The Estimated Service Life ("ESL") is defined as the average time duration in years that assets can be expected to operate under normal system conditions and is determined by considering manufacturer guidelines and HONI's historical asset retirement data. Assets operating beyond ESL generally have an increasing likelihood of failure. Since all assets owned by CLLP are brand new, any reasonable expectation of failure due to ESL-related factors are several years or decades in the future.

[1] Each of the 2 circuits is 49 km in length with 3 phases (conductor strings) per circuit.

The asset profile, as presented in Table 2, provides the average age of the components and the ESL.

Table 2 - Asset Service Profile

Asset Type	Quantity	Average Age (years)	Expected Service Life (years)
Conductors	294 kms	0	90
Steel Towers	170 towers	0	80
Insulator Strings	1410 strings	0	70
OPGW	49 kms	0	40
Shield Wire	49 kms	0	60

Condition

The asset condition is presented in Table 3. Asset condition assessments are conducted for each asset as they reach an individual age threshold, which varies depending on asset type. These assessments are the primary driver for determining if assets on the system need to be replaced. Condition assessment results are categorized as “Good”, “Fair”, or “Poor” as per definitions below:

- **Good:** These assets are new or show minimal signs of deterioration.
- **Fair:** Assets that are experiencing deterioration and the condition of these assets is monitored for progression of further deterioration.
- **Poor:** Assets that have deteriorated to a point where their ability to continue providing the intended functionality or service is at risk.

Table 3 below outlines the condition of all CLLP assets.

Table 3 - Asset Condition Summary

Asset Type	Quantity	Poor	Fair	Good
Conductors	294 km	0%	0%	100%
Steel Towers	170 towers	0%	0%	100%
Insulators	1410 strings	0%	0%	100%
OPGW	49 kms	0%	0%	100%
Shield Wire	49 kms	0%	0%	100%

All of CLLP's assets are new; therefore, little degradation has occurred, and these assets are considered to be in good condition.

3.2.4 ASSET UTILIZATION

CLLP's circuits will increase the transfer capability of the west of Chatham area by approximately 400 MW. This 230kV double circuit transmission line is part of the bulk system and is operated in accordance with the planning criteria as part of the IESO-controlled grid. The adequacy of the bulk system is assessed by the IESO as part of the bulk system planning processes in accordance with NERC and NPCC Standards, including the IESO's Ontario Resource Transmission Assessment Criteria (ORTAC). The bulk system is currently within acceptable capacity levels.

3.3 ASSET LIFECYCLE OPTIMIZATION POLICIES AND PRACTICES

As documented in Section 3.1, CLLP plans to work with HONI to undertake a strategic and methodical asset management process, drawing upon HONI's extensive expertise and experience to monitor its transmission system assets. HONI has developed and implemented asset strategies for various components of the transmission system. The specific strategies related to overhead transmission line assets are outlined in detail in HONI's Joint Rate Application (EB-2021-0110) in Exhibit B-02-01, Section 2.2. The following sections provide an overview of the specific operations and maintenance activities and replacement strategies applicable to CLLP.

3.3.1 ROUTINE OPERATION AND MAINTENANCE

On behalf of CLLP, HONI will perform routine operation and maintenance of CLLP's transmission assets as follows.

Operating Services:

Operating services include the monitoring and control of the transmission system, in accordance with the requirements of CLLP's Transmission Licence and services required to fulfill all of CLLP's obligations under its Connection Agreement and the IESO-CLLP operating requirements. These services include, but are not limited to, the following:

- Alarm/asset monitoring, and minor control;
- Asset operation and switching;
- Emergency response to transmission system events;
- Outage processing;
- Crew dispatching;
- Record maintenance; and
- IT support of the power system applications used by operators.

Maintenance Services:

The maintenance services include all planned and corrective maintenance services of the transmission line assets and rights-of-way in accordance with the requirements and obligations of CLLP's Transmission Licence. Further details are outlined below.

a) Overhead Transmission Lines

On behalf of CLLP, HONI will routinely inspect the overhead transmission lines by ground and aerial-based patrols to identify safety and reliability defects. If significant defects are identified during the patrols, HONI will also undertake emergency repairs and response to restore power or minor corrective work to resolve reliability and safety problems with transmission line assets when necessary. This is unplanned work that constitutes minor corrective action and does not constitute replacement of major assets (towers, conductors, insulators etc.). As assets age, separate detailed assessments are also performed on individual conductor and structure assets to monitor the asset condition and determine when replacement is required.

b) Transmission Rights-of-Way

On behalf of CLLP, HONI plans to perform regular maintenance to maintain clearance distances between the energized circuits (C87H and C88H) and the vegetation located on and adjacent to the transmission right-of-way. In Southern Ontario, vegetation maintenance is performed on clearing cycles of six years. Cycle lengths have been set to ensure that rights-of-way are in good condition and maintain a sustainable level of reliability between maintenance cycles. CLLP's transmission line is subject to NERC Reliability Standard FAC-003 entitled '*Transmission Vegetation management Reliability Standard*', which requires CLLP to report all sustained outages caused by vegetation on 230kV circuits within CLLP's control. If vegetation management issues arise mid-cycle, HONI would undertake corrective action to resolve reliability and safety problems.

c) Shield Wire

On behalf of CLLP, HONI plans to utilize a condition-based asset management strategy to assess and prioritize the replacement of its shield wire fleet. Asset age is utilized to trigger condition assessments. Since OPGW is a relatively new asset type, asset age triggering condition assessments as well as the condition assessment process have yet to be determined. For all other shield wire, HONI plans to utilize Kinectrics LineVue inspection system to assess the condition of the shield wire (based on estimated tensile strength reductions, etc.). This is an economic method of traversing a span to assess shield wire condition without the need for an outage or intrusive testing. To prevent shield wire related outages and reduce risk to public safety, HONI plans to focus on replacing all shield wire that has been confirmed through condition assessment to be in poor condition.

A summary of the planned maintenance activities and frequency of maintenance can be found in Table 4.

Table 4 - Summary of Planned Maintenance Activities

Asset	Maintenance	Frequency	Description
Overhead Transmission Lines	Helicopter Patrol	3 year	High-speed patrol to identify major defects on overhead transmission line assets.
	Ground Patrol	12 years	More detailed ground-based patrol to identify defects on overhead transmission line assets.
	Thermovision	2 year	Identifies defective transmission line components by detecting their heat signature using infrared cameras.
Transmission Rights of Way	Line Clearing	6 years	Consists of trimming tree branches and removing any unhealthy trees on the edge of or adjacent to the right-of-way that has the potential to exceed CLLP’s clearances to the overhead transmission lines.
	Brush Control	6 years	Includes manual cutting, herbicide application and/or mechanical clearing to manage vegetation growth on the right-of-way to ensure adequate clearances and access to CLLP’s overhead transmission lines.
	Condition Patrol	6 years	A mid-cycle working inspection to identify and mitigate any vegetation which requires maintenance prior to the next scheduled line clearing or brush control activity.
	Property Owner Notifications	6 years	Prior to the execution of vegetation maintenance on rights-of-way, HONI contacts all required adjacent property owners and external stakeholders to communicate maintenance plans.
	Annual Vegetation Patrol	1 year	In accordance with NERC Standard FAC-003, CLLP is required to annually inspect all 230kV circuits.
Shield Wire	OPGW Condition Assessment	TBD	Condition assessment process for OPGW is currently being developed
	Other Shield Wire Condition Assessment	40 years	Inspection of wire using LineVue to calculate tensile strength reductions.

3.3.2 ASSET REPLACEMENT

CLLP’s planned replacement strategy is aligned with HONI’s strategy. Assets are replaced based on condition assessments. Once an asset condition is determined to be in poor condition, it is scheduled and prioritized for replacement. In the event of material unplanned capital replacement, CLLP proposes to utilize a z-factor claim approach in accordance with Section 2.8.12 of the OEB Filing Requirements, if necessary.

3.4 SYSTEM CAPABILITY ASSESSMENT RENEWABLE ENERGY GENERATION

The CLLP 230kV double circuit transmission line is operated in accordance with the planning criteria as part of the IESO-controlled grid based on the load, generation and import patterns. The CLLP circuits, C87H and C88H, are designed to allow for both the transfer of committed generating resources and the potential to enable new renewable resources in the Chatham-Kent region. If new generation requests emerge, the assessment of capacity need or limitation would be completed under the purview of the IESO as part of bulk system planning. At this time, there is no meaningful increase in the renewable energy generation connection forecast that is expected to affect CLLP's assets.

4.0 CAPITAL EXPENDITURE PLAN *(OEB FILING REQ. 2.4.3)*

This section provides the details of the overall plan that CLLP plans to undertake over the 2025 to 2029 rate period and other pertinent information regarding the elements of the planning process.

4.1 CAPITAL PLANNING PROCESS OVERVIEW

On behalf of CLLP, HONI plans to complete an annual investment planning process to establish a plan that appropriately reflects operational needs, while minimizing rate impacts. This planning process ultimately forms part of the overall asset management process, which is aimed at identifying and scoping the optimal timing of capital investments and asset maintenance throughout the life cycle of assets, as discussed in Section 3.3 above. CLLP's 2025 to 2029 plan is an output of this asset management framework.

4.2 CAPITAL AND OM&A EXPENDITURE SUMMARY

Table 5 provides a summary of CLLP's overall plan. CLLP is not anticipating any capital spending for the 2025 – 2029 period.

CLLP is forecasting modest system OM&A expenditures in the test year. Further details are presented in Exhibit F-02-01.

Table 5 - Overall Plan ($Millions)

OEB Appendix 2-AB

OEB Category	Forecast				
	2025	2026	2027	2028	2029
	Test	Test	Test	Test	Test
System Access	0.0	0.0	0.0	0.0	0.0
System Renewal	0.0	0.0	0.0	0.0	0.0
System Service	0.0	0.0	0.0	0.0	0.0
General Plant	0.0	0.0	0.0	0.0	0.0
Total Capital	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Total OM&A	**1.1**	**1.1**	**1.2**	**1.2**	**1.2**

4.3 JUSTIFYING CAPITAL EXPENDITURES

Since CLLP circuits are brand new, no capital expenditures are planned for 2025 – 2029.

CHATHAM TO LAKESHORE ASSET VALUES

1.0 PROJECT BACKGROUND

By an Order in Council dated March 31, 2022, the Lieutenant Governor in Council declared that a new 230kV transmission line from the Chatham Switching Station to the new Lakeshore Transformer Station would be designated as a priority transmission project under section 96.1 of the *OEB Act*.

On November 24, 2022, Hydro One obtained leave to construct the Chatham to Lakeshore project with a planned in-service date of December 2025. The approved project plan included:

- Approximately 49 km of 230kV double-circuit transmission line from the Chatham Switching Station (SS) to the Lakeshore Transformer Station (TS) on a combination of a new corridor and widened existing 115kV transmission corridor; and
- Terminal station modifications at Chatham SS and Lakeshore TS to accommodate the new transmission line.

The benefits of the Chatham to Lakeshore project are significant. The new transmission line facilities will ensure that load in the Windsor-Essex area can be adequately supplied and avoid the potential for increased congestion in the west of Chatham area. Once in service, the Chatham to Lakeshore project will increase transfer capability in Southwestern Ontario by 400MW. The new line will also improve the reliability and quality of energy supply by providing an additional transmission path for system generation to be delivered to the area west of Chatham as well as preserve the Ontario-Michigan intertie capability.

In the OEB's leave to construct decision, the OEB found that the estimated total Project capital cost was reasonable.[1]

[1] EB-2022-0140 Decision and Order dated November 24, 2022, p. 20.

2.0 EXPLANATION OF VARIANCES TO ORIGINAL ESTIMATE

The project estimate for the leave to construct application was developed using cost estimates and a fixed price bid from the selected EPC contractor. As with most projects, there were risks associated with estimating costs. HONI's cost estimate included an allowance for contingencies in recognition of these risks. The below risks were the major contributors to the total contingency suggested for this project:

- Land Acquisition – Risk of owners refusing HONI voluntary agreements leading to the necessity of expropriation;
- Subsurface Conditions – Unforeseen subsurface or environmental conditions might require additional mitigations or delay or stop construction progress; and
- Approvals and Permits – Risk of delays obtaining required approvals.

To account for the above contingencies, HONI included approximately $21M in contingency for the line work. The total line estimate in HONI's leave to construct application[2] was $235.2M based on an AACE Class 3 estimate (+30% / -20%).

The current total forecast cost of the line is $205.1M, resulting in total estimated savings of $30.1M.

Furthermore, the project is currently forecast to be in-service a year early with an in-service date of December 2024, as compared to the originally planned in-service date of December 2025. The reasons for the in-service advancement are:

- Early and meaningful engagement and partnership with local Indigenous communities.
- A collaborative approach on project planning with residents and community stakeholders via the Environmental Assessment, which allowed HONI to integrate local needs into project planning.
- Successfully achieving voluntary land right agreements with all affected property owners along the corridor in a timely manner, without the need for expropriation.

[2] EB-2022-0140 Exhibit B-07-01.

- Minister of Energy amending HONI's transmission licence to provide HONI the certainty to advance procurement activities to mitigate against potential supply chain constraints.

The advanced in-service date has contributed to $9.2M in reduced project interest costs. The remaining $20.9M of savings ($30.1M minus $9.2M) are due to:

- Successful avoidance of major risks materializing for the project, such as no expropriations, no stage 3 archaeological assessment being required, and minimal unfavorable soil conditions, for a savings of $12.1M[3]
- Reduction in overhead expenditures due to:
  - Lower direct cost expenditures resulting in a reduction of $3.1M
  - Enhancing the overhead methodology in Q3 2023 to Early Contractor Involvement Engineering Procurement and Construction Delivery Model projects for further savings of $4.6M
- Additional $1.1M in savings due to efficiencies and opportunities in the execution delivery of the project.

The current cost and schedule forecast allows for construction-related risks related to in-servicing the assets. CLLP will update its forecast in September to advise whether or not these risks have or are expected to materialize. It should be noted that the forecast expenditures for total project expenditure for the construction of the line assets is within the expected lower range of the AACE Level 3 estimate (+30% / -20%) that underpinned the leave to construct evidence.[4]

3.0 PRUDENCE OF REAL ESTATE ACQUISITION PROGRAM

In the leave to construct decision for the Chatham to Lakeshore project, the OEB noted that it expected HONI to demonstrate the prudence of its route selection and associated

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[3] See EB-2022-0140 Exhibit B-07-01 for a description of risks, see section above where anticipated risks are summarized.

[4] In Exhibit B-07-01 of the Chatham by Lakeshore section 92 application (EB-2022-0140), the Line construction estimate was $235,272K and the lower range of the AACE estimate is $188,217K.

real estate acquisition program and resulting impacts on the costs for the Chatham to Lakeshore project.[5]

As noted in section 2 above, the company was able to achieve voluntary land rights with all impacted property owners on this project. It did so through the implementation of a consistent, fair, open and transparent voluntary land acquisition program referred to as the Land Acquisition Compensation Principles (LACP). The principles of the program are founded upon HONI's experience with land acquisition matters for new transmission projects.

The program and its principles serve as a roadmap for affected property owners to assist property owners in understanding HONI's acquisition process. The basis for the compensation is determined by independent appraisers. All appraisers retained by HONI have received an Accredited Appraiser Canadian Institute (AACI) designation from the Appraisal Institute of Canada. This ensures that appraisals are conducted in accordance with professional standards established by the Appraisal Institute of Canada. Accredited independent appraisers prepare site-specific appraisal reports. These reports quantify the fair market value of each property interest on the Project Corridor along with injurious affection, if applicable.

HONI's central consideration is the need for affected property owners to have flexibility, choice and ample time to consider voluntary land agreements. Property owners are provided the necessary time throughout the process to review the materials, complete follow-up meetings and discussions with HONI's Real Estate Representative and obtain remuneration for independent legal advice.

Applying the LACP and its principles, HONI was able to secure all voluntary permanent land rights in advance of construction start and avoid costs associated with expropriation. The expropriation process can be lengthy resulting in increased costs compared to voluntary agreement.

[5] EB-2022-0140 Decision and Order dated November 24, 2022, p. 20.

RATE BASE

1.0 INTRODUCTION

This exhibit outlines CLLP's rate base for the test years of 2025-2029 and provides a description of each rate base component.

The rate base underlying the revenue requirement for each test year includes a forecast of net utility plant, calculated on a mid-year average basis. No working capital has been requested, as discussed in section 3 below.

2.0 UTILITY RATE BASE

CLLP's utility rate base calculations for the test years, including gross plant, accumulated depreciation and the resulting rate base, are filed at Exhibit C-01-01, Attachments 1 through 4.

CLLP's forecast rate base for the 2024 bridge year and 2025 to 2029 test years are shown in Table 1 below.

Table 1 - Transmission Rate Base ($ M)

Description	Bridge	Test				
	2024	2025	2026	2027	2028	2029
Mid-Year Gross Plant	200.21 [1]	202.7	205.1	205.1	205.1	205.1
Mid-Year Accumulated Depreciation	(0.2)[1]	(1.5)	(4.0)	(6.5)	(9.1)	(11.6)
Mid-Year Net Plant	**200.0[1]**	**201.2**	**201.1**	**198.6**	**196.0**	**193.5**
Cash Working Capital	0.0	0.0	0.0	0.0	0.0	0.0
Materials and Supply Inventory	0.0	0.0	0.0	0.0	0.0	0.0
Transmission Rate Base	**200.0**	**201.2**	**201.1**	**198.6**	**196.0**	**193.5**

[1] 2024 rate base was calculated to reflect the full rate base, upon date of in-service, rather than the half-year rule, in alignment with other recent single-asset utility applications such as EB-2020-0150.

Table 2 provides the 2024 bridge year and 2025 to 2029 test years continuity of total fixed assets and in-service additions. Further details in gross plant are discussed in Exhibit B-01-03, Attachment 1 from Sections 4.1 through 4.3.

Table 2 - Continuity of Fixed Assets Summary ($ M)

Description	Bridge	Test Year				
	2024	2025	2026	2027	2028	2029
Opening Gross Asset Balance	0.00	200.2	205.1	205.1	205.1	205.1
In-Service Additions	200.2	4.9[2]	0.0	0.0	0.0	0.0
Retirements	0.0	0.0	0.0	0.0	0.0	0.0
Sales	0.0	0.0	0.0	0.0	0.0	0.0
Transfers / Other	0.0	0.0	0.0	0.0	0.0	0.0
Closing Gross Asset Balance	**200.2**	**205.1**	**205.1**	**205.1**	**205.1**	**205.1**

[2] Reflects trailing costs for the CLLP Project. The rate base is estimated to be $205.1M once all trailing costs are included. No new capital expenditures are planned for the 2025 - 2029 period.

3.0 CASH WORKING CAPITAL

Consistent with the prior submitted transmission rate applications for B2M Limited Partnership (B2M LP) and Niagara Reinforcement Limited Partnership's (NRLP) 2025 to 2029 rates, CLLP's expenses and revenues are planned to be generally synchronized such that no working capital has been requested in this Application. Despite not having undertaken an independent assessment, CLLP believes that it is appropriate to have approximately zero working capital requirement, analogous to that of B2M LP and NRLP.

4.0 IN-SERVICE ADDITIONS

In-service additions represent increases to rate base as a result of capital work being declared in-service and ready for use.

Since CLLP's assets are new, CLLP expects the asset condition to remain in good condition and has no plans for any in-service additions during the rate period.

CLLP
Continuity of Property, Plant and Equipment
Bridge (2024), Test (2025-2029) Years
Year Ending December 31
Total - Gross Balances
($ Millions)

Line No.	Year	Opening Balance	Additions	Retirements	Sales	Transfers In/Out	Closing Balance	Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Bridge								
1	2024	-	200.21	-	-	-	200.21	
Test								
2	2025	200.21	4.89	-	-	-	205.10	202.66
3	2026	205.10	-	-	-	-	205.10	205.10
4	2027	205.10	-	-	-	-	205.10	205.10
5	2028	205.10	-	-	-	-	205.10	205.10
6	2029	205.10	-	-	-	-	205.10	205.10

CLLP

Continuity of Property, Plant and Equipment - Accumulated Depreciation
Bridge (2024) Test (2025-2029) Years
Year Ending December 31
Total - Gross Balances
($ Millions)

Line No.	Year	Opening Balance	Additions	Retirements	Sales	Transfers In/Out and Other	Closing Balance	Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Bridge								
1	2024	-	0.21	-	-	-	0.21	
Test								
2	2025	0.21	2.51	-	-	-	2.71	1.46
3	2026	2.71	2.54	-	-	-	5.26	3.98
4	2027	5.26	2.54	-	-	-	7.80	6.53
5	2028	7.80	2.54	-	-	-	10.34	9.07
6	2029	10.34	2.54	-	-	-	12.89	11.62

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard USGAAP
Year 2024

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -	$ 0.5		$ 0.5	$ -	$ 0.0		$ 0.0	$ 0.5
12	1610	Intangibles	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
	1665	Fuel holders, producers and acc.	$ -			$ -	$ -			$ -	$ -
	1675	Generators	$ -			$ -	$ -			$ -	$ -
N/A	1615	Land	$ -			$ -	$ -			$ -	$ -
1	1620	Buildings and fixtures	$ -			$ -	$ -			$ -	$ -
N/A	1705	Land	$ -			$ -	$ -			$ -	$ -
14.1	1706	Land rights	$ -	$ 78.2		$ 78.2	$ -	$ 0.1		$ 0.1	$ 78.1
1	1708	Buildings and fixtures	$ -			$ -	$ -			$ -	$ -
47	1715	Station equipment	$ -			$ -	$ -			$ -	$ -
47	1720	Towers and fixtures	$ -	$ 94.6		$ 94.6	$ -	$ 0.1		$ 0.1	$ 94.5
47	1730	Overhead conductors and devices	$ -	$ 26.9		$ 26.9	$ -	$ 0.0		$ 0.0	$ 26.9
47	1735	Underground conduit	$ -			$ -	$ -			$ -	$ -
47	1740	Underground conductors and devices	$ -			$ -	$ -			$ -	$ -
17	1745	Roads and trails	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
	1925	Computer software	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ -			$ -	$ -			$ -	$ -
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -			$ -	$ -			$ -	$ -
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue5	$ -			$ -	$ -				$ -
										$ -	$ -
		Sub-Total	**$ -**	**$ 200.2**	**$ -**	**$ 200.2**	**$ -**	**$ 0.2**	**$ -**	**$ 0.2**	**$ 200.0**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -			$ -	$ -			$ -	$ -
		Total PP&E	**$ -**	**$ 200.2**	**$ -**	**$ 200.2**	**$ -**	**$ 0.2**	**$ -**	**$ 0.2**	**$ 200.0**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**$ 0.2**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	$ 0.2

Notes:

1. Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2. The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3. The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4. The additions in column (E) must not include construction work in progress (CWIP).

5. Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6. The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard USGAAP
Year 2025

CCA Class [2]	OEB Account [3]	Description [3]	Cost				Accumulated Depreciation				
			Opening Balance	Additions [4]	Disposals [6]	Closing Balance	Opening Balance	Additions	Disposals [6]	Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ 0.5			$ 0.5	$ 0.0	$ 0.1		$ 0.1	$ 0.4
12	1610	Intangibles				$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
	1665	Fuel holders, producers and acc.	$ -			$ -	$ -			$ -	$ -
	1675	Generators	$ -			$ -	$ -			$ -	$ -
N/A	1615	Land	$ -			$ -	$ -			$ -	$ -
1	1620	Buildings and fixtures	$ -			$ -	$ -			$ -	$ -
N/A	1705	Land	$ -			$ -	$ -			$ -	$ -
14.1	1706	Land rights	$ 78.2	$ -		$ 78.2	$ 0.1	$ 0.8		$ 0.8	$ 77.3
1	1708	Buildings and fixtures	$ -			$ -	$ -			$ -	$ -
47	1715	Station equipment	$ -			$ -	$ -			$ -	$ -
47	1720	Towers and fixtures	$ 94.6	$ 3.8		$ 98.4	$ 0.1	$ 1.3		$ 1.4	$ 97.0
47	1730	Overhead conductors and devices	$ 26.9	$ 1.1		$ 28.0	$ 0.0	$ 0.4		$ 0.4	$ 27.6
47	1735	Underground conduit	$ -			$ -	$ -			$ -	$ -
47	1740	Underground conductors and devices	$ -			$ -	$ -			$ -	$ -
17	1745	Roads and trails	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
	1925	Computer software	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ -			$ -	$ -			$ -	$ -
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -			$ -	$ -			$ -	$ -
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue5	$ -			$ -	$ -				$ -
										$ -	$ -
		Sub-Total	**$ 200.2**	**$ 4.9**	**$ -**	**$ 205.1**	**$ 0.2**	**$ 2.5**	**$ -**	**$ 2.7**	**$ 202.4**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -			$ -	$ -			$ -	$ -
		Total PP&E	**$ 200.2**	**$ 4.9**	**$ -**	**$ 205.1**	**$ 0.2**	**$ 2.5**	**$ -**	**$ 2.7**	**$ 202.4**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**$ 2.5**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	$ 2.5

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard	USGAAP
Year	2026

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ 0.5			$ 0.5	$ 0.1	$ 0.1		$ 0.1	$ 0.4
12	1610	Intangibles				$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
	1665	Fuel holders, producers and acc.	$ -			$ -	$ -			$ -	$ -
	1675	Generators	$ -			$ -	$ -			$ -	$ -
N/A	1615	Land	$ -			$ -	$ -			$ -	$ -
1	1620	Buildings and fixtures	$ -			$ -	$ -			$ -	$ -
N/A	1705	Land	$ -			$ -	$ -			$ -	$ -
14.1	1706	Land rights	$ 78.2			$ 78.2	$ 0.8	$ 0.8		$ 1.6	$ 76.5
1	1708	Buildings and fixtures	$ -			$ -	$ -			$ -	$ -
47	1715	Station equipment	$ -			$ -	$ -			$ -	$ -
47	1720	Towers and fixtures	$ 98.4			$ 98.4	$ 1.4	$ 1.3		$ 2.7	$ 95.7
47	1730	Overhead conductors and devices	$ 28.0			$ 28.0	$ 0.4	$ 0.4		$ 0.8	$ 27.2
47	1735	Underground conduit	$ -			$ -	$ -			$ -	$ -
47	1740	Underground conductors and devices	$ -			$ -	$ -			$ -	$ -
17	1745	Roads and trails	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
	1925	Computer software	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ -			$ -	$ -			$ -	$ -
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -			$ -	$ -			$ -	$ -
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue5	$ -			$ -	$ -				$ -
										$ -	$ -
		Sub-Total	**$ 205.1**	**$ -**	**$ -**	**$ 205.1**	**$ 2.7**	**$ 2.5**	**$ -**	**$ 5.3**	**$ 199.8**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -			$ -	$ -			$ -	$ -
		Total PP&E	**$ 205.1**	**$ -**	**$ -**	**$ 205.1**	**$ 2.7**	**$ 2.5**	**$ -**	**$ 5.3**	**$ 199.8**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**$ 2.5**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	$ 2.5

Notes:

1. Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.
2. The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).
3. The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.
4. The additions in column (E) must not include construction work in progress (CWIP).
5. Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.
6. The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard USGAAP
Year 2027

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ 0.5			$ 0.5	$ 0.1	$ 0.1		$ 0.2	$ 0.3
12	1610	Intangibles				$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
	1665	Fuel holders, producers and acc.	$ -			$ -	$ -			$ -	$ -
	1675	Generators	$ -			$ -	$ -			$ -	$ -
N/A	1615	Land	$ -			$ -	$ -			$ -	$ -
1	1620	Buildings and fixtures	$ -			$ -	$ -			$ -	$ -
N/A	1705	Land	$ -			$ -	$ -			$ -	$ -
14.1	1706	Land rights	$ 78.2			$ 78.2	$ 1.6	$ 0.8		$ 2.4	$ 75.7
1	1708	Buildings and fixtures	$ -			$ -	$ -			$ -	$ -
47	1715	Station equipment	$ -			$ -	$ -			$ -	$ -
47	1720	Towers and fixtures	$ 98.4			$ 98.4	$ 2.7	$ 1.3		$ 4.0	$ 94.4
47	1730	Overhead conductors and devices	$ 28.0			$ 28.0	$ 0.8	$ 0.4		$ 1.2	$ 26.8
47	1735	Underground conduit	$ -			$ -	$ -			$ -	$ -
47	1740	Underground conductors and devices	$ -			$ -	$ -			$ -	$ -
17	1745	Roads and trails	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
	1925	Computer software	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ -			$ -	$ -			$ -	$ -
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -			$ -	$ -			$ -	$ -
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue5	$ -			$ -	$ -				$ -
										$ -	$ -
		Sub-Total	**$ 205.1**	**$ -**	**$ -**	**$ 205.1**	**$ 5.3**	**$ 2.5**	**$ -**	**$ 7.8**	**$ 197.3**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -			$ -	$ -			$ -	$ -
		Total PP&E	**$ 205.1**	**$ -**	**$ -**	**$ 205.1**	**$ 5.3**	**$ 2.5**	**$ -**	**$ 7.8**	**$ 197.3**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**$ 2.5**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	$ 2.5

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard	USGAAP
Year	2028

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ 0.5			$ 0.5	$ 0.2	$ 0.1		$ 0.2	$ 0.3
12	1610	Intangibles				$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
	1665	Fuel holders, producers and acc.	$ -			$ -	$ -			$ -	$ -
	1675	Generators	$ -			$ -	$ -			$ -	$ -
N/A	1615	Land	$ -			$ -	$ -			$ -	$ -
1	1620	Buildings and fixtures	$ -			$ -	$ -			$ -	$ -
N/A	1705	Land	$ -			$ -	$ -			$ -	$ -
14.1	1706	Land rights	$ 78.2			$ 78.2	$ 2.4	$ 0.8		$ 3.2	$ 75.0
1	1708	Buildings and fixtures	$ -			$ -	$ -			$ -	$ -
47	1715	Station equipment	$ -			$ -	$ -			$ -	$ -
47	1720	Towers and fixtures	$ 98.4			$ 98.4	$ 4.0	$ 1.3		$ 5.3	$ 93.1
47	1730	Overhead conductors and devices	$ 28.0			$ 28.0	$ 1.2	$ 0.4		$ 1.6	$ 26.4
47	1735	Underground conduit	$ -			$ -	$ -			$ -	$ -
47	1740	Underground conductors and devices	$ -			$ -	$ -			$ -	$ -
17	1745	Roads and trails	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
	1925	Computer software	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ -			$ -	$ -			$ -	$ -
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -			$ -	$ -			$ -	$ -
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue5	$ -			$ -	$ -				$ -
										$ -	$ -
		Sub-Total	**$ 205.1**	**$ -**	**$ -**	**$ 205.1**	**$ 7.8**	**$ 2.5**	**$ -**	**$ 10.3**	**$ 194.8**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -			$ -	$ -			$ -	$ -
		Total PP&E	**$ 205.1**	**$ -**	**$ -**	**$ 205.1**	**$ 7.8**	**$ 2.5**	**$ -**	**$ 10.3**	**$ 194.8**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**$ 2.5**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	$ 2.5

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard USGAAP
Year 2029

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ 0.5			$ 0.5	$ 0.2	$ 0.1		$ 0.3	$ 0.2
12	1610	Intangibles				$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
	1665	Fuel holders, producers and acc.	$ -			$ -	$ -			$ -	$ -
	1675	Generators	$ -			$ -	$ -			$ -	$ -
N/A	1615	Land	$ -			$ -	$ -			$ -	$ -
1	1620	Buildings and fixtures	$ -			$ -	$ -			$ -	$ -
N/A	1705	Land	$ -			$ -	$ -			$ -	$ -
14.1	1706	Land rights	$ 78.2			$ 78.2	$ 3.2	$ 0.8		$ 4.0	$ 74.2
1	1708	Buildings and fixtures	$ -			$ -	$ -			$ -	$ -
47	1715	Station equipment	$ -			$ -	$ -			$ -	$ -
47	1720	Towers and fixtures	$ 98.4			$ 98.4	$ 5.3	$ 1.3		$ 6.6	$ 91.8
47	1730	Overhead conductors and devices	$ 28.0			$ 28.0	$ 1.6	$ 0.4		$ 2.0	$ 26.0
47	1735	Underground conduit	$ -			$ -	$ -			$ -	$ -
47	1740	Underground conductors and devices	$ -			$ -	$ -			$ -	$ -
17	1745	Roads and trails	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
	1925	Computer software	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ -			$ -	$ -			$ -	$ -
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -			$ -	$ -			$ -	$ -
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue5	$ -			$ -	$ -				$ -
										$ -	$ -
		Sub-Total	**$ 205.1**	**$ -**	**$ -**	**$ 205.1**	**$ 10.3**	**$ 2.5**	**$ -**	**$ 12.9**	**$ 192.2**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -			$ -	$ -			$ -	$ -
		Total PP&E	**$ 205.1**	**$ -**	**$ -**	**$ 205.1**	**$ 10.3**	**$ 2.5**	**$ -**	**$ 12.9**	**$ 192.2**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**$ 2.5**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	$ 2.5

Notes:

1. Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.
2. The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).
3. The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.
4. The additions in column (E) must not include construction work in progress (CWIP).
5. Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.
6. The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

CLLP
Statement of Utility Average Rate Base
Bridge Year (2024) and Test Years (2025 to 2029)
Year Ending December 31
($ Millions)

Line No.	Particulars		2024	2025	2026	2027	2028	2029
	Electric Utility Plant							
1	**Gross plant**							
	Transmission Corridor Land Rights		78.2	78.2	78.2	78.2	78.2	78.2
	Towers and Fixtures		94.6	98.4	98.4	98.4	98.4	98.4
	Conductors and Devices		26.9	28.0	28.0	28.0	28.0	28.0
	Roads and Trails		0.0	0.0	0.0	0.0	0.0	0.0
	Intangible asset		0.5	0.5	0.5	0.5	0.5	0.5
	Total Gross Plant		**200.2**	**205.1**	**205.1**	**205.1**	**205.1**	**205.1**
2	Accumulated Depreciation		0.2	2.7	5.3	7.8	10.3	12.9
3	Net plant in-service		200.0	202.4	199.8	197.3	194.8	192.2
4	Average net plant for rate base [1]		200.0	201.2	201.1	198.6	196.0	193.5
5	Construction work in progress		0.0	0.0	0.0	0.0	0.0	0.0
6	Average net utility plant	$	200.0	201.2	201.1	198.6	196.0	193.5
	Working Capital							
7	Cash working capital		0.0	0.0	0.0	0.0	0.0	0.0
8	Materials and Supplies Inventory		0.0	0.0	0.0	0.0	0.0	0.0
9	Total working capital		0.0	0.0	0.0	0.0	0.0	0.0
10	Total rate base	$	200.0	201.2	201.1	198.6	196.0	193.5

[1] 2024 rate base was calculated to reflect the full rate base, upon date of in-service, rather than the half-year rule, in alignment with other recent single-asset utility applications such as EB-2020-0150

OVERHEAD CAPITALIZATION RATE

1.0 INTRODUCTION

This Exhibit outlines CLLP's overhead capitalization rate and methodology that was utilized during the project construction that set the opening rate base for the 2025 to 2029 transmission revenue requirement.

HONI Standard Overhead Capitalization Rate

To ensure that capital work reflects all of the costs incurred to enable assets to be placed into service and to operate for their intended use, HONI (a) capitalizes costs that are directly attributable to capital work, such as the purchase price for materials and equipment, and costs directly incurred to bring materials and equipment to work sites and to install and otherwise make them ready for service, and (b) capitalizes those of its common corporate costs, or 'overheads', that relate to its capital work. By including the portion of its overheads that relates to capital work in rate base, HONI aligns the recovery of its costs for capital-related work with the expected useful lives of the underlying assets, during which those assets are expected to provide benefits to customers.

Generally, overhead costs are allocated through the application of an overhead capitalization rate, which is a calculated percentage representing the amount of overhead costs that are required to support capital projects in a given year. A distinct overhead capitalization rate applies to each of Transmission and Distribution as a result of applying HONI's overhead capitalization methodology.

The current overhead capitalization rates for the Transmission and Distribution businesses were approved by the OEB in HONI's 2023-2027 Custom IR proceeding. Additional details regarding the current approved methodology can be found at EB-2021-0110, Exhibit C-08-02.

2.0 ECI-EPC DELIVERY MODEL

To execute large discrete projects, HONI has implemented the Early Contractor Involvement Engineering Procurement and Construction Delivery Model (referred to herein as "ECI-EPC Model"). The ECI-EPC Model engages the services of an external Owner's Engineer (OE) and the services of Engineering, Procurement, and Construction (EPC) contractors. This initiative allows the ECI-EPC contractors to be engaged at an earlier stage of development (typically at a preliminary budgetary estimate stage rather than near the end of detailed estimating or at construction initiation). As such, the ECI-EPC contractors perform many of the development functions that under the standard HONI delivery model would be performed internally by HONI.

Directed transmission line projects, such as CLLP, are expected to be tracked under the Affiliate Transmission Projects Regulatory Account established in EB-2021-0169 (ATP Account). The line component of the CLLP is incremental to the investment plan approved in HONI's rebasing application and was delivered under the ECI-EPC Delivery Model.

3.0 REFINEMENT OF STANDARD OVERHEAD CAPITALIZATION RATE FOR ECI-EPC MODEL PROJECTS

Following the development of the ECI-EPC Model, HONI engaged Atrium Economics to determine whether any refinement of the OEB-approved overhead capitalization methodology, and applicable rates for HONI's transmission business is required for projects utilizing the ECI-EPC Model. Through this review, Atrium Economics determined that the size and delivery model of projects utilizing the ECI-EPC Model warrants a refinement to the HONI OEB-approved overhead capitalization methodology, and its applicable rate, as the nature of the shared services provided by HONI are different than those provided under the HONI standard delivery model.

In the findings of the Atrium Economics Report[1] '*Overhead Capitalization Methodology for ECI-EPC Contracted Projects*', dated August 9, 2023 (Atrium Economics Report), Atrium Economics recommended that HONI use a blended overhead rate that would be

[1] EB-2023-0198, Exhibit B-07-01, Attachment 1.

determined by the weighted average portion of a project's type/source of costs, specifically the two differentiated types of project costs being:

i. ECI-EPC costs, which do not rely as heavily on HONI's corporate support functions and
ii. Non-ECI-EPC costs, that should attract the standard Transmission overhead rate as they rely on HONI's corporate support functions.

Section 4 of the Atrium Economics Report states that the common corporate costs incurred by HONI to support these ECI-EPC contracted projects is of a different level than standard HONI Transmission projects. A significant portion of each project's total cost relates to OE and EPC Contracted work (i.e., HONI determined that 79.5% of the capital expenditures will be payments to external contractor (or OE costs) and only 20.5% will relate to internal HONI incurred costs).[2] Section 5.3 in the Atrium Economics Report states that the resulting total direct capital and total applicable capital overhead costs associated with ECI-EPC contracted projects are utilized in an overhead capitalization rate calculation identical to the calculation used for HONI's Transmission business as approved by the OEB in the 2023-2027 Custom IR proceeding.[3] Furthermore, Section 5.4 in the Atrium Economics Report states that a blended rate was calculated using the overhead capitalization rate for costs associated with external contractor payments weighted at 79.5% and the standard delivery Transmission overhead capitalization rate weighted at 20.5%. The results are shown in Figure 3 of the Atrium Economics Report.[4]

The Atrium Economics Report references the Black & Veatch Report that was filed in the 2023-2027 Custom IR proceeding.[5] Atrium Economics noted that its staff member (Mr. Taylor), in his former capacity with and as a subcontractor to Black & Veatch, has been the lead expert in connection with the Black & Veatch Report. He is also the primary consultant and author of the Atrium Economics Report. HONI confirmed the proposal is

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[2] EB-2023-0198, Exhibit B-07-01, Attachment 1, p. 5.
[3] EB-2021-0110
[4] EB-2023-0198, Exhibit B-07-01, Attachment 1, p. 13.
[5] EB-2021-0110, Exhibit E-04-08, Attachment 1.

utilizing the same methodology that was agreed to by parties and accepted by the OEB in the 2023-2027 Custom IR proceeding.[6]

4.0 IMPACT OF REFINED METHODOLOGY ON THE CLLP

In accordance with, and following the methodology recommended by Atrium Economics described above, specific annual overhead capitalization rates have been developed for projects utilizing the ECI-EPC Model and are shown in Table 1 below.

Table 1 - Overhead Capitalization Rate for ECI-EPC Projects

ECI-EPC Projects	2024	2025	2026	2027	2028	5 Year Avg	Rounded
Blended Overhead Rate	2.02%	1.95%	2.10%	2.26%	2.37%	**2.14%**	**2.0%**

Note: the blended overhead rate has been reviewed and updated as part of the annual integrated business planning process. As such, Table 1 reflects the most up-to-date rates.

Consistent with the recommendations from the Atrium Economics Report, the overhead capitalization rates for projects utilizing the ECI-EPC Model are reviewed and updated annually as part of the annual integrated business planning process.

CLLP is the second[7] of several future projects that will utilize the refined ECI-EPC overhead capitalization rates.

[6] EB-2023-0198, Interrogatory Response to OEB Staff #21, part d), p. 4.
[7] The first Project to utilize the EPI-EPC Model and overhead capitalization rate for EPI-EPC Projects is the Waasigan Project (EB-2023-0198).

5.0 BENEFITS TO RATEPAYERS AND ALLOCATION OF COSTS

Ratepayer Benefits

The ECI-EPC Model provides several benefits to ratepayers including increased cost certainty, appropriate allocation of risk and appropriate allocation of common corporate costs to the project.

By having a third-party constructor engaged early in the project, the project proponent is able to evaluate EPC contractors prior to entering into a construction contract, which enables the tailoring of contract terms appropriately (and at a time that is advantageous to the project cost, scope and schedule). HONI's procurement process for the ECI-EPC projects allows for EPC contractors to obtain competitive market pricing from their suppliers and to identify and evaluate, engineering, procurement, construction, risks and opportunities during the development of their respective offers.

Further, with a significant portion of the early scope of project work being performed by the constructor instead of internally by HONI, HONI is able to avoid expanding its' internal corporate resources that would otherwise perform this service to meet demand for the large number of new transmission line projects. Of note, ECI-EPC contractors will appropriately charge their common corporate costs to the project. As such, if HONI were to allocate its common corporate costs at the existing HONI Transmission overhead capitalization rate, it would be allocating costs to the project inappropriately and in excess of the services incurred.

Allocation of Costs

HONI's corporate cost allocation methodology allows ratepayers to benefit from the HONI's organization structure of shared services rather than having a decentralized model for each regulated business. At the time of HONI's 2023 – 2027 Custom IR proceeding, the magnitude and certainty of potential partnerships such as CLLP was unknown, and the contemplation of a new affiliate/segment was not included in the 2020 Black & Veatch Study, which was relied upon to allocate overhead costs to capital work for each of the

Transmission and Distribution businesses as well as affiliates.[8] Although CLLP was not included in the study, the incremental costs related to CLLP that are put forth in this Application were also not considered as they were unknown.

As a result of the growing capital portfolio, related to projects that will form future partnerships and are captured in the ATP account, HONI's common corporate costs and shared services have increased, which were not contemplated within HONI's 2023-2027 Custom IR proceeding. Although these incremental costs are not embedded within approved envelopes, they are reflected in the actual implementation of the corporate cost allocation and overhead recovery methodology. To the extent that these actual incremental costs are allocated to the HONI segments, incremental pressure within the approved envelopes for 2023-2027 would occur. HONI would be expected to manage that cost pressure without a corresponding impact on ratepayers during that period. The incremental costs that are capitalized within CLLP are the appropriate allocation based on the methodology to ensure the cost causation guiding principles are followed.

6.0 CONCLUSION

HONI's projects that are executed under the ECI-EPC Model are multi-year and significantly larger in scale and cost compared to most of HONI's Transmission projects contemplated in its Transmission System Plan.

For the reasons outlined above, HONI submits that the use of the overhead capitalization rate for setting the initial rate base for ECI-EPC projects is appropriate, provides ratepayer and project cost benefits, and is consistent with HONI's existing OEB-approved cost allocation methodology.

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[8] Hydro One has applied the Overhead Capitalization Methodology as recommended by the 2020 Black & Veatch Study in calculating its requested revenue requirement in the 2023-2027 Custom IR proceeding.

ATRIUM ECONOMICS
CENTERED ON ENERGY

Hydro One Networks Inc.

Overhead Capitalization Methodology for ECI-EPC Contracted Projects

August 9, 2023

Table of Contents

List of Figures

1 Executive Summary

1.1 Introduction

Hydro One asked Atrium Economics, LLC ("Atrium") to provide guidance and advice on a methodology for appropriately recovering overhead capitalization ("OH Cap") costs for ECI-EPC Contracted Projects (as defined below) through the application of an Overhead Capitalization Rate ("OCR"). This report discusses the underlying theoretical, conceptual, and methodological procedures utilized by Hydro One in their current OH Cap methodology as approved by the Ontario Energy Board ("OEB") in Hydro One's Joint Transmission and Distribution Rate Application for 2023-2027 ("JRAP" or "2023-2027 Application")[1] and presents a recommended method of recovering OH Cap costs relating to ECI-EPC Contracted Projects, and discusses the implications of this approach.

1.2 Background

As of 2021, Hydro One is utilizing an Early Contractor Involvement ("ECI") delivery model for affiliate Transmission Line Projects[2] that engages the services of an external Owner's Engineer ("OE") and the services of Engineering, Procurement, and Construction ("EPC") contractor for each significant Transmission system expansion spanning multiple years ("ECI-EPC Contracted Projects" or "ECI-EPC Delivery Model"). These ECI-EPC Contracted Projects are contracted at a significantly earlier stage of development (typically at the budgetary estimate instead of the late detailed estimate or construction estimate stage); when compared to Hydro One's standard EPC delivery model ("Standard Delivery Model" or "Standard Hydro One Tx Projects") currently utilized for sustainment and natural growth of the Transmission System.[3] As such, under the ECI-EPC approach, the OE/EPC contractors perform many of the development functions that would be performed internally under the Standard Delivery Model. Hydro One uses the ECI-EPC Delivery Model for such projects instead of the Standard Delivery Model that supports delivering the primary transmission portfolio as these projects exceed Hydro One's current internal capacity built to support standard system requirements. Due to ECI, the ECI-

[1] EB-2021-0110

[2] "The OEB notes that the costs that are to be recorded in this account are for projects which are the subject of an Order in Council or direction from the Minister of Energy or a letter from the IESO." from Finding of Issue 1 on Page 7 of DECISION AND ORDER EB-2021-0169 issued October 7, 2021

[3] The Standard Delivery Model could also include instances where an EPC is not utilized.

EPC contractor will thoroughly understand the risks, costs, and challenges associated with the project, thus giving greater certainty to Hydro One on the overall schedule and cost.

Directed Transmission Line Projects that are expected to fall under the Affiliate Transmission Projects Regulatory Account established in EB-2021-0169 (the "ATP Account")[4], were not included in the JRAP and are anticipated to be performed under the ECI-EPC Delivery Model.

1.3 Principal Considerations & Conclusions

As explained in more detail in this report:

- Hydro One identified a need to review the appropriateness of its current method of recovering overhead costs from the ECI-EPC Contracted Projects.
- Hydro One retained Atrium to provide guidance and advice on reviewing the nature of shared services[5] provided by Hydro One for ECI-EPC Contracted Projects and provide a recommended methodology for appropriately recovering OH Cap costs for ECI-EPC Contracted Projects.
- Through the review, Atrium determined that the size and delivery model of Hydro One's ECI-EPC Contracted Projects warrants a refinement to the calculation of the OCR as the nature of the shared services provided by Hydro One are different than those provided under the Standard Delivery Model. As such, there are different implications on the common corporate costs incurred by Hydro One in support of these capital projects.
- Hydro One estimates that 79.5% of the costs associated with ECI-EPC Contracted Projects relate to external contractor payments, and 20.5% relate to internal Hydro One incurred costs.
- Through cost analyses, as detailed in Section 5 of this report, Atrium determined

[4] Various components of Station work with respect to the project may be executed using the ECI-EPC Delivery Model.

[5] Shared services means the centralized business operations that support multiple businesses, affiliated companies, or multiple parts of the same organization. Common corporate costs are costs incurred to provide shared services to Hydro One and its affiliate companies.

an appropriate OCR is 79.5% of the costs associated with external contractor payments, averaging 1.0% over five years.

- Atrium recommends applying the OCR rate that is currently applied to projects under the Standard Delivery Model to the 20.5% of project costs that relate to internal Hydro One incurred costs (i.e., not ECI-EPC costs).

- The resulting recommendation is for Hydro One to modify its current OH Cap recovery method for these ECI-EPC Contracted Projects such that the ECI-EPC Contracted Projects are subject to a blended OCR that reflects the appropriate burden placed on Hydro One’s shared services.

- This blended rate is calculated using the OCR mentioned above (five-year average of 1.0%) weighted at 79.5% and the standard OCR, currently applied capital projects under the Standard Delivery Model, to capital weighted at 20.5%.

- Atrium recommends using a five-year average as it reflects these projects’ long duration, and also recommends reviewing the five-year average annually. Refinements may be required for efficient and effective operational and accounting administration.

Atrium believes this recommended methodology for recovery of overhead costs associated with ECI-EPC Contracted Projects aligns with the criteria and methods currently employed by Hydro One to allocate costs incurred to provide shared services to Hydro One and its affiliate companies. Specifically, the ECI-EPC Contracted Projects overhead cost recovery methodology fairly attributes and recovers these costs from the ECI-EPC Contracted Projects, ensuring the prudent and fair cost allocation to Hydro One’s ratepayers.

2 Guiding Principles of Cost Allocation

2.1 The Need for Cost Allocation

Activities require cost allocation when existing accounting methodologies do not include tracking costs for providing services to recipients. Tracking one’s time is not always practical or preferred, as activity-based time tracking isn’t always an efficient use of one’s time and resources. In instances where activity-based time tracking is not preferable, utilizing cost allocation principles and methods is beneficial. For example, cost allocation is preferable to activity-based time for employees working on processes or projects that benefit multiple business entities simultaneously.

2.2 Principles Of Cost Allocation

With cost responsibility following cost causation as the guiding principle, company policy and allocation methodology should satisfy the following criteria:

- The method should be based on cost causation. Cost causation means a causal relationship exists between the basis used to allocate a cost and the cost incurred. Costs are recognized as being caused by a service or group of services if (i) the costs are brought into existence as a direct result of providing the service or group of services; or (ii) the costs are avoided if the service or group of services is not provided.
- If cost causation is inappropriate in a given situation, the method often utilized is benefits received (i.e., allocated to the business that received the benefits).
- Underlying data used for implementing the method should be obtained at a reasonable cost and be objectively verifiable in the initial and subsequent years.
- Estimates used for the allocation method should be unbiased, reasonably consistent with comparable data, and provided by employees familiar with the costs.

3 Hydro One's Current Corporate Overhead Recovery

3.1 Overview

Hydro One's Corporate Cost Allocation addresses the following considerations:

- Methods comply with the relevant provisions of the OEB Affiliate Relationships Code for Electricity Distributors and Transmitters.[6]
- Cost incurrence - The costs are needed to perform services the business requires.
- Cost allocation - The costs are appropriately allocated among businesses using cost drivers/allocation factors supported by principles of causality.
- Cost/benefit - The benefits received equal to or exceed the cost.

[6] Affiliate-Relationships-Code-ARC-Electricity-20100315.pdf (oeb.ca)

The Corporate Cost Allocation is detailed in Hydro One's 2023-27 Joint Rate Application (EB-2021-0110) within a Hydro One commissioned report by Black & Veatch relating to the Corporate Cost Allocation review undertaken in 2021.[7] This report finds the Corporate Cost Allocation continues to be appropriate for Hydro One because:

- It meets generally acceptable regulatory practices for cost allocation since it distributes costs based on cost causation, including the use of direct assignment when possible, and then using cost drivers.
- It has been accepted by the OEB.
- It has the support of Hydro One management and is understood and accepted by Hydro One, its affiliate companies, and the Transmission ("Tx") and Distribution ("Dx") businesses.
- It allows Hydro One, its affiliate companies, and the Tx and Dx businesses to determine precise charges by department and by activity. This transparency provides a basis for understanding the nature of the charges and value of the services received.
- It is well integrated with Hydro One's annual business planning process and produces reasonably stable results over time.
- It accommodates changes in Hydro One's organization and can be adapted easily to reflect those changes.

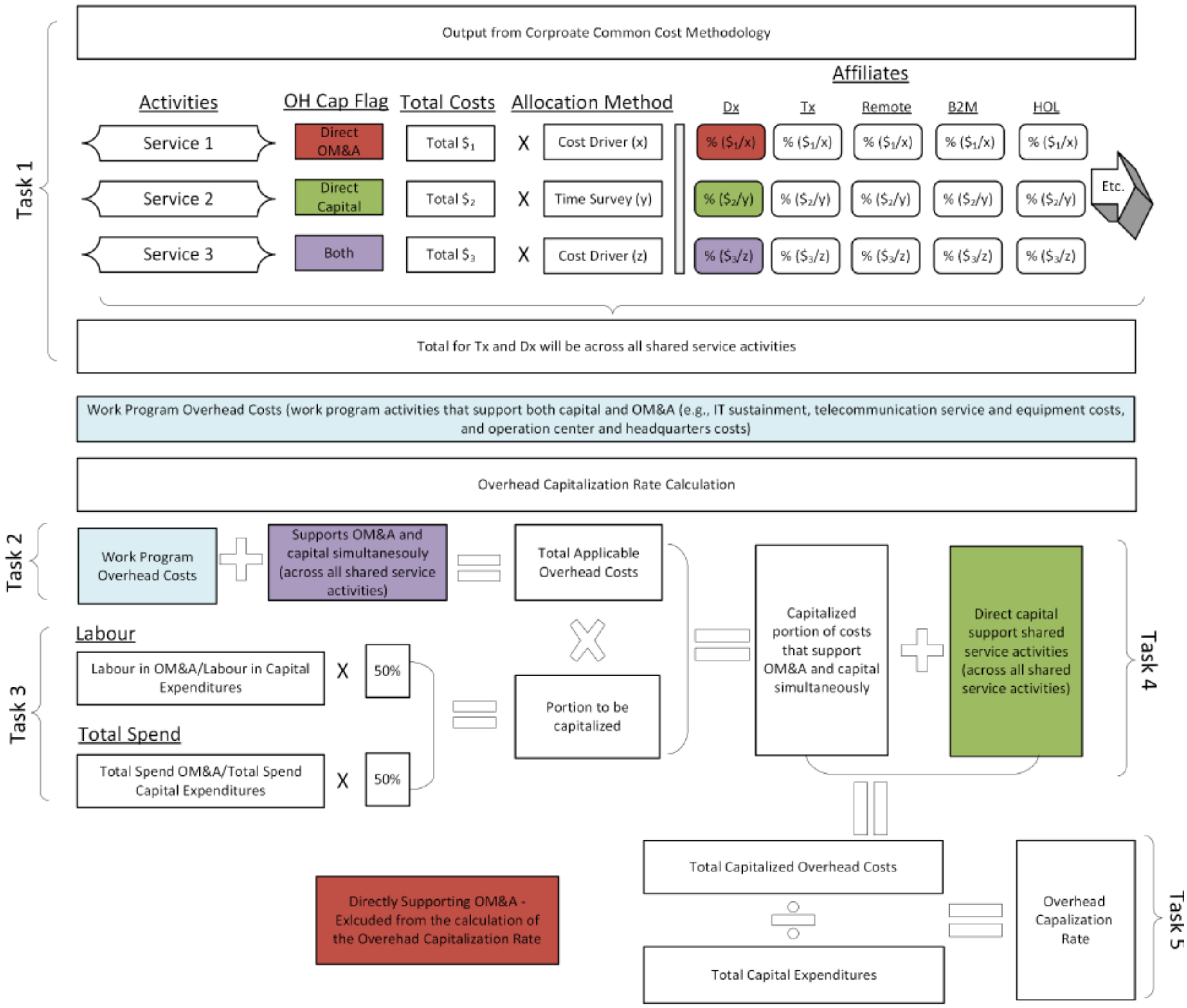
OCRs are percentages that are applied to the cost of Transmission and Distribution capital expenditures resulting in a portion of common corporate costs being included as part of capital expenditures for each business. The OCR is used to recover common corporate costs that are not directly recorded to capital expenditures due to the nature of the costs; either for employees who support capital expenditures but do not directly charge time to a specific capital project (assigned for less than three months or work on multiple projects simultaneously) or for employees who perform work that impacts both capital and OM&A projects.

The output from the Overhead Capitalization Rate Methodology consists of two percentages (Overhead Capitalization Rates for Tx and for Dx) that are applied to the costs of Tx and Dx

[7] Black & Veatch Report as filed in EB-2021-0110, Exhibit E-4-8, Attachment 1. Mr. Taylor of Atrium, in his former capacity with and as a subcontractor to B&V, has been the lead expert in connection with the B&V Report.

capital expenditures, as applicable, to recover the portion of common corporate costs that support capital expenditures for each business. This process is depicted in Figure 1 below.

Figure 1 – Overhead Capitalization Rate Methodology



4 Need for a Specific OCR for ECI-EPC Contracted Projects

Hydro One internally determines which projects will follow the ECI-EPC Delivery Model. Atrium's conclusion through interviews with Hydro One staff is that these ECI-EPC Contracted Projects are unique for several reasons: (i) their delivery model engages outsourced services much earlier in the project; (ii) they rely on outsourced services more fully and across more stages of the project; and (iii) their size and duration are higher than Standard Hydro One Tx

Projects. As such, the common corporate costs incurred by Hydro One to support these ECI-EPC Contracted Projects is of a different level than Standard Hydro One Tx Projects, as demonstrated by the following descriptions:

- A significant portion of each project's total cost relates to OE and ECI-EPC Contracted work (i.e.. Hydro One determined that 79.5% of the capital expenditures will be payments to external contractor and only 20.5% will relate to internal Hydro incurred costs).

- The EPC contractors are engaged much earlier in the process through Hydro One's ECI process and perform many of the development functions that, under the Standard Delivery Model, are undertaken internally by Hydro One.

- The projects are multi-year and significantly more extensive than most standard Transmission projects, which leads to a portion of Hydro One Common Corporate functions support being directly assigned from common corporate costs centers (e.g., most indigenous affairs, system planning, and land acquisition are all directly charging time to these projects).[8]

- For ECI-EPC Contracted Projects, the level of support provided by internal Hydro One functions per dollar of capital is significantly lower.[9]

5 Development of OCR Specific to ECI-EPC Contracted Projects

5.1 Review of Costs within OCR

One of the first steps conducted by Atrium was to review the Lines of Business that are designated as providing Common Corporate Costs directly to capital work or included as part of the overhead capital costs within the Overhead Capitalization Rate Methodology contained in Hydro One's 2023-2027 Application. The Applicable Capital Overhead costs are activities that

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[8] As noted in the Black & Veatch Report as filed in EB-2021-0110, "In instances when costs associated with Common Corporate Costs can be directly attributed to work for a specific affiliate and are expected to be for a minimum period of three months, those costs are transferred via variable timesheets or automatic transfers."

[9] An estimated 23 Hydro One staff will be dedicated to ECI-EPC projects with ~$500M annual capital expenditures, compared to ~4,200 Hydro One transmission staff (OEB application EB-2021-0110, Appendix 2-K) supporting ~$1,500M annual capital expenditures (EB-2021-0110, O-01-02, Table 4).

support both OM&A and capital and are split between (a) costs that remain in OM&A and (b) costs that will be included in the Overhead Capitalization Rate calculation by multiplying the Total Applicable Overhead Costs by a ratio developed using a 50/50 weighting of the Labour Content-Capital Ratio and the Total Spending-Capital Ratio.

Hydro One personnel indicated that employees within the Lines of Businesses included as Direct Capital in the Overhead Capitalization Rate Methodology will directly charge to these ECI-EPC Contracted Projects. These include Indigenous Relations, Planning, and System Control.

A second review was conducted to ascertain the methods used to assign the overhead capital costs to the Transmission business. Those allocation methods are provided below:

- Direct Assignment - Time Survey
- Capital, Labour, Revenue
- Headcount
- Internal - Total Cost Center Labour (non-labour)
- Program & Project Costs
- Project Costs Capital
- Union Employee Headcount
- Labour Costs
- Board of Directors Labour Costs
- Information System Direct Assignment
- Defined Contributions Headcount

While the Overhead Capitalization Rate Methodology uses cost drivers to allocate Direct Capital and Applicable Capital Overhead costs to the Transmission business, there is no separation between the projects within the Transmission business. However, information is available on the split of these cost drivers between ECI-EPC Contracted Projects and all other Standard Hydro One Tx Projects. This information was gathered and used to further disaggregate the allocation of Common Corporate Costs across different types of Transmission projects.

5.2 Disaggregate Transmission Related Direct Capital Costs & Applicable Capital Overhead Costs using Sub-Allocation Factors

As indicated above, the Common Corporate Costs allocated to the Transmission business relate to two distinct types of costs (1) Direct Capital - employees who support capital expenditures but do not directly charge time to a specific capital project, and (2) Overhead Capital - employees who perform work that impacts both capital and OM&A projects. The proposed method of developing an OCR for ECI-EPC Contracted Projects is first to disaggregate the Transmission related direct capital and overhead costs between those that support the ECI-EPC Contracted Projects and the Standard Hydro One Tx Projects. Sub-allocation factors were developed for each allocation method used in the Corporate & Shared Cost Allocation Methodology to disaggregate these costs. Figure 3 below maps the allocation factors used in the Corporate & Shared Cost Allocation Methodology to initially assign these costs to the Transmission business and the sub-allocation factors used to disaggregate costs between ECI-EPC Contracted and the Standard Hydro One Tx Projects. As mentioned above, most employees within the Line of Business (1) Indigenous Relations, (2) Planning, and (3) System Control are directly charging costs in support of these ECI-EPC Contracted Projects. These costs are allocated to the Transmission business using the allocation method 'Direct Assignment – Time Survey,' and the sub-allocation factor for these costs is 'Direct Assignment to Non-ECI.' There are additional costs within the allocation method 'Direct Assignment – Time Survey' relating to Facilities which was based on a headcount allocation between Transmission and Distribution, and the proposed method is to use Headcount as a sub-allocation factor for these Facilities' costs.

Figure 2 – Disaggregation of Tx Related Direct Capital Costs & Applicable Capital Overhead Costs

Allocation Method	Sub-Allocation Factor
Direct Assignment - Time Survey	Direct Assignment to Non -ECI, Headcount for Facilities
Capital, Labour, Revenue	Capital, Labour (50/50)
Headcount	Headcount
Internal - Total Cost Center Labour (non-labour)	Labour Costs
Program & Project Costs	Program & Project Costs
Project Costs Capital	Project Costs Capital
Union Employee Headcount	Union Employee Headcount
Labour Costs	Labour Costs
Board of Directors Labour Costs	Capital, Labour (50/50)
Information System Direct Assignment	Headcount
Defined Contributions Headcount	Headcount

Using a multi-factor allocation to allocate costs that cannot be directly charged and for which a single cost allocation factor cannot be easily identified is a widely respected and common practice across the utility industry. The Corporate & Shared Cost Allocation Methodology uses a three-factor formula, with each factor equally weighted, and is generally referred to as the Massachusetts Formula, where the three components of the factor are representative of (1) Capital, (2) Revenue, and (3) Labour. These costs are further disaggregated using a 50/50 weighting of capital and labour given the insufficiency of using revenue as a sub-allocation factor (i.e., ECI-EPC Contracted Projects may not have revenue for several years). The result of this process for the budget plan years (2023-2027) is a total Direct Capital and total Applicable Capital Overhead Costs associated with ECI-EPC Contracted Projects.

5.3 Calculate OCR for the Portion of ECI-EPC Contracted Projects Fully Outsourced to OEs and EPCs

The resulting total Direct Capital and total Applicable Capital Overhead Costs associated with ECI-EPC Contracted Projects are then utilized in an OCR Calculation identical to the OCR Calculation used for the Tx business as approved in Hydro One's 2023-2027 Application. The OCR Calculation is calibrated to contain inputs (e.g., total capital expenditures) relating only to ECI-EPC Contracted Projects. This aligns the numerator (i.e., the allocation of costs to these ECI-EPC Contracted Projects) with the denominator (i.e., total capital associated with ECI-EPC Contracted Projects). The resulting OCR for the 79.5% of costs associated with external contractor payments averaged 1.0% over five years.

5.4 Develop Blended Rate for ECI-EPC Contracted Projects

To account for the fact that 79.5% of the costs associated with ECI-EPC Contracted Projects relate to external contractor payments and 20.5% relate to internal Hydro One incurred costs, a blended rate was developed. This blended rate was calculated using the OCR for the 79.5% of costs associated with external contractor payments (described in Section 5.3) weighted at 79.5% and the standard delivery Tx OCR weighted at 20.5%. The results are shown in Figure 4 below.

Figure 3 – Blended OCR for ECI-EPC Contracted Projects

ECI-EPC Projects	2023	2024	2025	2026	2027	5-year avg	Rounded
Blended Overhead Rate	2.6%	2.6%	2.4%	2.5%	2.6%	2.5%	**3.0%**

Atrium reviewed the results of this updated OCR and evaluated the appropriateness of setting an annual OCR for ECI-EPC Contracted Projects compared to setting an OCR based on an average of overhead costs and capital expenditures. Atrium noted large deviations in forecasted capital expenditures associated with ECI-EPC Contracted Projects (e.g., the total capital expenditures for these projects can increase more than 100% without seeing a material change in overhead costs).[10] As such, Atrium suggested a five-year average should be used for the ECI-EPC OCR rate.

5.5 Application and Monitoring of the Overhead Capitalization Rates

The blended rates shown in Figure 4 are developed based on forecast numbers and other estimates. Hydro One reviews and adjusts the OCR periodically to reflect changes in capital spending and associated support costs. Capitalized overheads are trued-up (in-year) at year-end to reflect actual results for capital implemented under the Standard Delivery Model. Given the proposed multi-year average for the ECI-EPC Contracted Projects, Atrium recommends Hydro One annually evaluate the OCR calculation for each year and ascertain if the OCR for the 79.5% of costs associated with external contractor payments used in the blended rate should be updated.

6 Conclusions and Recommendations

Atrium recommends that Hydro One adopt a blended OCR based on the analyses conducted and described in Section 5 of this report. The recommended methodology and resulting OCR reflect the level of common corporate costs provided to these ECI-EPC Contracted Projects and are consistent with the following guiding regulatory principles:

- Defensible Cost Causation: To conform to regulatory principles, the methodology should show a causal link between recovery of overhead and facilitation costs and capital activity.
- Distinguishable Costs: The overhead costs should be distinguished from those directly charged to these projects (i.e., no duplication of costs and distinct sets of costs to be included in overhead).
- Transparency: The methodology and calculations should be easy to follow and understand by internal users and external reviewers.
- Stability: The methodology should remain stable from year-to-year and not result in disproportionately large variations.

[10] This underscores the nature of these projects; that early involvement of third-party EPC contractors can be leveraged to undertake large capital expenditure projects with little additional overhead costs being incurred directly by Hydro One.

- Accuracy of Underlying Data: Any data used in the methodology should be accurate and able to be relied upon for the purposes intended (i.e., provide an appropriate measure and reasonable approximation of the underlying volume of activity or output).
- Flexibility/Adaptability: The methodology should accommodate changes in organizational structure, availability of data, business processes, and information systems with reasonable ease. Where possible, the method should automatically adjust for changes in circumstances (i.e., reconciliation processes).
- Cost-effectiveness: Methodologies should be cost-effective to implement. Additional accuracy may require significant incremental cost; thus, an appropriate balance is required between precision and cost, in relation to both implementation and ongoing costs.

PERFORMANCE MEASURES

1.0 INTRODUCTION

Given the nature of CLLP's system as a transmission line with no associated station assets or delivery points, the performance of the equipment does not lend itself to applying the typical measures that might be in place for other transmitters. CLLP's assets consist of a single 230kV double circuit transmission line between Chatham Switching Station and Lakeshore Transformer Station, but do not include any terminal breakers or other operable assets. The demarcation point of each of the circuits is at a tower outside of the station or junction, as noted in Exhibit B-01-01.

CLLP does not have any customer delivery points (or meter assets), which are the basis of interruption-based reliability performance measures like SAIDI and SAIFI. As a result, the traditional definition of SAIDI and SAIFI cannot be applied to CLLP. CLLP would provide two alternative performance metrics, which measure interruptions to HONI delivery points caused by CLLP's circuits (T-SAIDI CLLP Contribution and T-SAIFI CLLP Contribution). The revised performance metric descriptions are provided in Appendix A below.

2.0 PERFORMANCE MEASURES

To ensure consistency with performance measures utilized for Bruce to Milton Limited Partnership (B2M LP) and NRLP, CLLP is proposing to track its performance by utilizing the measures approved by the OEB in EB-2018-0275 for NRLP and EB-2019-0178 for B2M LP. Below are the proposed performance measures:

- Transmission System Average Interruption Frequency CLLP Contribution;
- Transmission System Average Interruption Duration CLLP Contribution;
- Average System Availability;
- NERC Vegetation Compliance; and
- Maintenance Cost per Circuit Kilometer.

The performance measures will be tracked annually, and the results of this tracking will be reported to the OEB at the next proceeding. CLLP has aligned its performance measures to the OEB's Renewed Regulatory Framework (RRF) outcomes to ensure that CLLP is monitoring and measuring performance relative to these outcomes. Table 1 provides a summary of the proposed targets for the years 2025 and 2029.

Table 1 - CLLP Performance Measures

RRF Outcomes	Performance Measure	Target				
		2025	2026	2027	2028	2029
Operational Excellence	Average System Availability (%)	100.0	100.0	100.0	100.0	100.0
Operational Excellence	T-SAIDI CLLP Contribution	0	0	0	0	0
Operational Excellence	T-SAIFI CLLP Contribution	0	0	0	0	0
Public Policy Responsiveness	NERC Vegetation Compliance	Comply	Comply	Comply	Comply	Comply
Operational Excellence	Maintenance Cost ($K) per circuit kilometre[1]	0.32	0.25	0.53	0.30	0.30

[1] Circuit kms refer to total route kms multiplied by number of circuits per km. For CLLP, this is 49 kms x 2 circuits = 98 kms.

In all cases, the performance measures verify that the assets are operating within expected parameters and continue to serve the electricity consumers of Ontario effectively.

Maintenance costs for CLLP are low for the 2025 to 2029 period primarily due to no planned major vegetation maintenance work for this period. Major vegetation maintenance is completed on a 6 year cycle and is required for compliance with NERC standards. As this is a new asset being in-serviced in 2024, the first planned major vegetation maintenance is expected in 2030. Maintenance unit costs are outlined in Table 1 above.

Other than vegetation management expenses, the overall maintenance expenses remain well below what would otherwise be expected for an average circuit. However, given the limited operational scope of CLLP assets, the cost comparisons may not be a fair comparison to the average costs of other transmitters. The comparison may suggest that other transmitters are higher cost, when in fact this may be due primarily to the broader set of assets in place.

APPENDIX A – DESCRIPTION OF THE PERFORMANCE MEASURES

Average System Availability

"System Availability" is a measure of the extent to which the transmission line(s) are available for use within the system. For the purposes of quantifying this metric, the cause of the forced outages that would contribute to the unavailability of the transmission lines would be limited to factors affecting assets owned by CLLP as opposed to any other equipment, owned by HONI, which could also cause the transmission line(s) to be removed from service.

$$\boxed{= 1 - \left(\frac{\sum_{i=1}^{N_L} F_{L_i}}{\mathrm{T_L}} \right) \text{ x}100\%}$$

- F_{Li} is the annual forced outage duration in hours due to transmission line-related outages of circuit L_i.
- T_L is the inventory (expressed in 100 km-hours) of all in-service transmission circuits.
- N_L is the total number of in-service transmission circuits

Contribution to Delivery Point Performance

CLLP assets do not contain any delivery points. As a result, traditional delivery point performance metrics do not apply. In place of these traditional metrics, two substitute performance metrics are utilized.

T-SAIDI (Transmission System Average Interruption Duration Index) Contribution (minutes per DP per year) measures the CLLP asset contribution to HONI's overall SAIDI. Similarly, T-SAIFI (Transmission System Average Interruption Frequency Index) Contribution (# of interruptions per DP per year) measures the CLLP asset contribution to HONI's overall SAIFI.

The formulae for the two measures are as follows:

$$T - SAIFI_{CLLP\ Contribution} = \frac{\sum_{i=1}^{k}(SF_i + MF_i)}{n}$$

$$T - SAIDI_{CLLP\ Contribution} = \frac{\sum_{i=1}^{k}(SD_i)}{n}$$

Where:

- *n* is the total number of HONI delivery points.
- *k* is the total number of HONI delivery points that may be impacted by CLLP circuits.
- SF and MF are the number of sustained and momentary interruptions experienced at Delivery Point i in a given year caused by CLLP circuits.
- SD is the duration of the sustained interruptions experienced at Delivery Point i in a given year caused by CLLP circuits.

Only forced direct outages are included in performance measures. Lines being removed from service due to non-circuit issues, i.e. subordinate outages, are excluded from performance measures. Only line outages are included in performance measures. Line terminal outages, such as outages caused by Protection & Control mis-operations, are excluded from performance measures as these terminal assets are not owned by CLLP.

<u>NERC Vegetation Compliance</u>

NERC Vegetation Compliance is a measure of the extent to which CLLP is compliant with NERC's Standard FAC-003-05 *'Transmission Vegetation Management'*. NERC developed a Transmission Vegetation Management Standard with the objective to prevent vegetation-related outages which could contribute to a cascading grid failure, especially under heavy electrical loading conditions. Each transmission owner is required to have a transmission vegetation management program designed to control vegetation on the active transmission line ROW in accordance with the requirements in NERC Standard FAC-003-05. Compliance with the Standard is mandatory and enforceable.

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REVENUE REQUIREMENT

1.0 SUMMARY OF REVENUE REQUIREMENT

CLLP follows standard regulatory practice and has calculated its revenue requirement as follows:

Table 1 - Revenue Requirement ($ M)

Components	2025	2026	2027	2028	2029	Reference
OM&A	1.1	1.1	1.2	1.2	1.2	Exhibit F-01-01
Depreciation	2.5	2.5	2.5	2.5	2.5	Exhibit F-05-01
Income Taxes	0.1	0.1	0.1	0.1	0.1	Exhibit F-06-01-01
Return on Capital	13.1	13.0[+]	12.9[+]	12.7[+]	12.5[+]	Exhibit G-01-03
Total Base Revenue Requirement	**16.8**	**16.8[+]**	**16.7[+]**	**16.5[+]**	**16.4[+]**	
Add: Other[1]	1.8[2]	0.0	0.0	0.0	0.0	Exhibit H-01-01
Rates Revenue Requirement	**18.6**	**16.8**	**16.7**	**16.5**	**16.4**	Exhibit E-01-01-01

[+] In 2025, CLLP will file an application to update the cost of long-term debt to reflect the actual market rate achieved on the debt that it will issue in 2025. This will update the revenue requirements for the remaining term from 2026 through to 2029.

The above rates revenue requirement is the amount required by CLLP to achieve its business objectives, responsible stewardship of a safe and reliable system, and impact on rates. The rates revenue requirement is also a reflection of CLLP's commitment to operating at the lowest practical cost. An excel version of the 2025 to 2029 revenue requirements has been provided at Attachment 1 of Exhibit E-01-01.

[1] The 2025 rates revenue requirement consists of the 2025 base revenue requirement of $16.8M and the forecast revenue requirement for 2024 of $1.8M. Please see Exhibit C-01-01 for more information.

[2] $1.8M is comprised of $0.5M of asset removal costs and $1.3M of revenue requirement associated with the 2024 rate base as shown in Exhibit C-01-01.

2.0 CALCULATION OF REVENUE REQUIREMENT

The details of the Revenue Requirement components are as follows:

Table 2 - OM&A Expense ($ M)*

	2025	2026	2027	2028	2029
Estimated SLA Costs	0.6	0.6	0.7	0.6	0.6
Incremental Expenses	0.5	0.5	0.5	0.5	0.6
Total OM&A	**1.1**	**1.1**	**1.2**	**1.2**	**1.2**

* Exhibit F-02-01

Table 3 - Depreciation and Amortization Expense ($ M)*

	2025	2026	2027	2028	2029
Depreciation	2.5	2.5	2.5	2.5	2.5
Total Depreciation Expense	**2.5**	**2.5**	**2.5**	**2.5**	**2.5**

*Exhibit F-05-01

Table 4 - Corporate Income Taxes ($ M)*

	2025	2026	2027	2028	2029
Taxable Income after loss carryforward	0.0	0.0	0.0	0.0	0.0
Tax Rate	26.5%	26.5%	26.5%	26.5%	26.5%
Subtotal	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Add: Corporate Minimum Tax	0.1	0.1	0.1	0.1	0.1
Total Income Taxes	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**

* Exhibit F-06-01, Attachment 1

Table 5 - Return on Capital ($ M)*

	2025	2026	2027	2028	2029
Return on Debt	5.7	5.6[+]	5.6[+]	5.5[+]	5.4[+]
Return on Equity	7.4	7.4	7.3	7.2	7.1
Return on Capital	**13.1**	**13.0**[+]	**12.9**[+]	**12.7**[+]	**12.5**[+]

* Exhibit G-01-03

[+] In 2025, CLLP will file an application to update the cost of long-term debt to reflect the actual market rate achieved on the debt that it will issue in 2025. This will update the revenue requirements for the remaining term from 2026 through to 2029.

3.0 REVENUE REQUIREMENT – YEAR OVER YEAR COMPARISON

There was no previously approved revenue requirement for CLLP. Therefore, this section of the Application is not applicable.

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CLLP

Calculation of Total Revenue Requirement (2025 to 2029)
Year Ending December 31
($ Millions)

Line No.	Particulars		Test 2025	Test 2026	Test 2027	Test 2028	Test 2029
	Cost of Service						
1	Operating, maintenance & administrative	$	1.1	1.1	1.2	1.2	1.2
2	Depreciation		2.5	2.5	2.5	2.5	2.5
3	Income taxes		0.1	0.1	0.1	0.1	0.1
4	Cost of service excluding return on capital	$	3.7	3.8	3.8	3.8	3.8
5	Return on capital		13.1	13.0	12.9	12.7	12.5
6	Total revenue requirement	$	16.8	16.8	16.7	16.5	16.4

OPERATING COSTS SUMMARY

1.0 INTRODUCTION

This Exhibit presents an overview of CLLP's operating costs and includes the following elements, for which the overall costs are shown in Table 1 below:

- Operation, Maintenance and Administrative (OM&A),
- Depreciation and Amortization, and
- Income Taxes.

Table 1 - Operating Costs ($ M)

Description	Bridge	Test				
	2024	2025	2026	2027	2028	2029
OM&A	0.0	1.1	1.1	1.2	1.2	1.2
Asset Removal Costs	0.5	0.0	0.0	0.0	0.0	0.0
Depreciation and Amortization	0.2	2.5	2.5	2.5	2.5	2.5
Income Taxes	0.0	0.1	0.1	0.1	0.1	0.1
Total Operating Costs	**0.7**	**3.7**	**3.8**	**3.8**	**3.8**	**3.8**

The annual average proposed operating costs for the 2025 to 2029 is forecast to be $3.8M. The increase from the Bridge Year to Test Years is due to higher OM&A and Depreciation expenses that reflect a full year of operation, as documented in Exhibit F-02-01, partially offset by the one-time asset removal costs in the bridge year.

2.0 KEY ELEMENTS OF OPERATING COSTS

CLLP's operating costs forecast has been developed to sustain the safe and reliable operation of its transmission assets.

2.1 OPERATION, MAINTENANCE AND ADMINISTRATIVE (OM&A)

CLLP is managed by its general partner, Chatham x Lakeshore GP Inc. (CLGP). CLGP intends to retain Hydro One Networks Inc. (HONI) under a Service Level Agreement, to plan and organize the operation and maintenance of the assets and provide certain corporate and administrative support as outlined in Exhibit F-03-01.

OM&A expenses are derived from various work programs and functions performed by or on behalf of the Partnership. Further details on the OM&A costs are provided in Exhibit F-02-01.

2.2 DEPRECIATION AND AMORTIZATION

The depreciation expense for CLLP in this Application is supported by the depreciation study Alliance Consultant Group (Alliance) conducted for HONI Transmission in support of HONI's 2023 to 2027 Custom IR application (EB-2021-0110). Further details are provided in Exhibit F-05-01.

2.3 INCOME TAXES

Under the *Income Tax Act*, a partnership is not taxable but is required to compute its taxable income, which is then allocated to its partners. Details of the calculation of the Income Tax expense are shown in Exhibit F-06-01.

SUMMARY OF OM&A EXPENDITURES

1.0 SUMMARY OF OM&A EXPENDITURES

The proposed Operation, Maintenance, and Administration (OM&A) expenses will support the work required by CLLP to meet public and employee safety objectives, maintain transmission reliability, and comply with regulatory requirements, environmental requirements, and Government direction. Key components in the build-up of OM&A requirements include:

- An estimate of the Service Level Agreement (SLA) expected to be entered into with HONI, and
- Ongoing Incremental Expenses directly incurred by the Partnership.

Table 1 provides a summary of the forecast OM&A expenditures for each year of the rate term, and a breakdown of the key components within OM&A. Tables 2 and 3 provide the breakdown of estimated SLA costs, and Incremental Expenses respectively.

Overall, CLLP's OM&A spending on a per asset basis is low in comparison to other transmitters in Ontario. This relates primarily to the characteristics of the assets that it owns. CLLP owns a 49 km 230kV double-circuit transmission line that requires periodic vegetation management expenses and operating services. Otherwise, costs are low because the line is new, and the company owns no station assets. Additionally, this type of asset is extremely reliable and has a low probability of fault or other incident requiring corrective maintenance or repair expenditures.

More details on the forecast spending on each of these components are included below.

Table 1 - Summary of OM&A ($ M)

Description	Bridge	Test				
	2024	2025	2026	2027	2028	2029
Estimated SLA Costs	0.00	0.61	0.62	0.66	0.64	0.64
Incremental Expenses	0.04	0.48	0.50	0.52	0.54	0.56
Total OM&A	**0.04**	**1.09**	**1.12**	**1.18**	**1.17**	**1.20**

2.0 KEY COMPONENTS OF THE OM&A EXPENDITURES

2.1 SERVICE LEVEL AGREEMENT COSTS

A significant portion of the OM&A expenses required to satisfy the obligation and objectives of CLLP arise as a result of the SLA between HONI and CLLP. The services that will be procured from HONI are not reasonably available in the market in the manner, type and quantity that fits with CLLP's requirements. There are no known service providers that can unilaterally provide these bundled services in this manner. Entering into a multi-vendor management arrangement would engender significant additional management costs. All services to be procured from HONI are done so on a fully allocated cost basis. This is similar to the services procured from HONI for B2M LP and NRLP.

Table 2 presents the required funding for these services from 2025 to 2029. Further details on these services are provided in the following sections.

Table 2 - Total Estimated Service Level Agreement Costs ($ M)

Description	Bridge	Test				
	2024	2025	2026	2027	2028	2029
Maintenance Expenses	0.00	0.03	0.02	0.05	0.03	0.03
Shared Asset Allocations	0.00	0.15	0.15	0.15	0.15	0.15
Administrative and Corporate Expenses	0.00	0.43	0.45	0.46	0.46	0.46
Total Service Level Agreement Costs	**0.00**	**0.61**	**0.62**	**0.66**	**0.64**	**0.64**

2.1.1 MAINTENANCE EXPENSES

The maintenance expenses relate to the maintenance services planned to be performed by HONI, on behalf of CLLP under an SLA. Examples of the services are:

- Overhead Transmission Lines maintenance including thermovision, helicopter and ground patrols; and
- Transmission Right-of-Way (RoW) maintenance, including mandatory annual NERC vegetation patrols, line clearing, brush control, condition patrol and property owner notifications.

Maintenance costs for CLLP are low for the 2025 to 2029 period primarily due to no planned major vegetation maintenance work for this period. Major vegetation maintenance is completed on a 6-year cycle and is required for compliance with NERC standards. Since this is a new asset being put into service in 2024, the first planned major vegetation maintenance is in 2030. Costs will be materially higher in 2030 but in-line with vegetation maintenance costs anticipated for similar 230kV RoWs. Maintenance expenses for 2024 to 2029 are outlined in Table 2 above.

Further details on the maintenance services are presented in CLLP's Transmission System Plan in Attachment 1 to Exhibit B-01-03.

2.1.2 SHARED ASSET ALLOCATION

CLLP is charged transfer pricing by HONI for the use of certain Shared Assets. The Shared Assets allocated to CLLP include major fixed assets and intangible assets, as well as minor fixed assets. The average forecast amount of $0.1M per year mainly relates to the use of HONI's SAP system, an enterprise-wide system that integrates work management, finance, supply chain and customer service and other enterprise software. Further details on the Shared Asset Allocation are described in Exhibit F-03-01.

2.1.3 ADMINISTRATIVE AND CORPORATE EXPENSES INCLUDING OPERATING SERVICES

The Administrative and Corporate Expenses include the costs arising from the support functions provided by HONI to CLLP for administrative services and systems. The investment in those systems and the cost of their operation are incurred by HONI but are allocated to Hydro One Inc. and its affiliates, including CLLP, based on a cost allocation methodology.

This methodology lowers costs for all the HONI affiliates by providing access to a sophisticated administration infrastructure at a lower cost than if each built its own unique and independent system. This sharing of the costs for a unified infrastructure benefits ratepayers through lower rates and has been accepted by the OEB in numerous previous proceedings, including B2M LP's 2015 to 2019 Transmission Rates Application (EB-2015-0026). Per the methodology, corporate cost allocations now include operating services as described below:

- Monitoring/Control of the transmission system, including alarm monitoring, asset monitoring, and minor control;
- Asset operation within HONI-prescribed limits including the application of HONI equipment directives and switching on HONI's transmission system to regulate CLLP's transmission system;
- Emergency Response to transmission system events, including response to IESO-directed emergency actions, and implementation of load shedding;
- Outage Processing including scheduling, planning. And submitting to IESO;

- Crew Dispatching, including 24/7 assessment contacting, and dispatching;
- Record Maintenance including retention of logged items, retention of SCADA information, and trip reports; and
- Power System IT Support of the power system applications used by operators.

Further details on the common corporate costs and cost allocation methodology are provided in Exhibit F-04-01.

2.2 INCREMENTAL EXPENSES

There are certain functions that must be executed directly by CLLP to meet its obligations and objectives that are not supported by the anticipated SLA with HONI. Table 3 presents the required funding for performance of these functions for 2025 to 2029. Further details on these functions are provided in the sections below.

Table 3 - Total Incremental Expenses ($ M)

Description	Bridge	Test				
	2024	2025	2026	2027	2028	2029
Insurance	0.01	0.10	0.10	0.11	0.11	0.12
Regulatory	0.00	0.05	0.05	0.05	0.06	0.06
Administrative	0.01	0.10	0.10	0.11	0.11	0.12
Managing Director's Office	0.02	0.23	0.24	0.25	0.26	0.27
Total Incremental Expense	**0.04**	**0.48**	**0.50**	**0.52**	**0.54**	**0.56**

2.2.1 INSURANCE

CLLP is obligated, by its partnership agreement and by good utility practice, to maintain an appropriate level of insurance to protect its assets, its owners and its customers from catastrophic loss. CLLP is fortunate to be able to leverage the existing HONI insurance policies, rather than procuring insurance protection unilaterally. This results in considerable savings for CLLP. The annual premiums for this insurance are about $0.1M.

2.2.2 REGULATORY

CLLP incurs regulatory expenses related to its transmission revenue requirement application proceedings, which require rebasing on a five-year term based on the OEB Filing Requirements. The total amount anticipated in 2025 is $0.05M to cover costs for notice, studies, intervenors, OEB hearing charges and other items incurred directly by CLLP. CLLP expects a similar level of regulatory expenses in the preparation of its next five-year transmission rate application and will need to manage this expense within the approved envelope.

2.2.3 ADMINISTRATIVE

CLLP incurs administrative expenses for other external fees and expenses not otherwise covered, such as auditor and professional fees, statutory remittances, and other items. The administrative expenses included in the test years are approximately $0.1M annually.

2.2.4 MANAGING DIRECTOR'S OFFICE

The partnership has a Managing Director, who is empowered to oversee and operate the partnership. The Managing Director's duties include:

- Monitoring and ensuring that the terms and conditions of the partnership agreement are fulfilled;
- Working with employees from HONI and other entities to ensure that the Applicant and its assets are properly maintained and administered;
- Managing and Chairing Advisory Committee meetings with the partners on a regular basis, as spelled out in the partnership agreement;
- Ensuring that the partners are kept well informed and advised of the partnership's operations, and educated on what it means to be a transmission owner and operator in Ontario;
- Authorizing the disbursement of funds by the partnership to meets its obligations and expenses;
- Instituting communications with communities and the public at large, through meetings, websites and other media;

- Representing the partnership with various stakeholders at hearings, industry events and other situations; and
- Any and all other duties that may be required to represent the partnership and effectively support its operations.

To complete these tasks, the Managing Director's Office is provided with an annual budget for things such as salary, office lease, communication, and other expenses that may be required. As such, the Managing Director's Office expense included in the test years is approximately $0.23M annually.

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AFFILIATE SERVICE AGREEMENTS

1.0 INTRODUCTION

This Exhibit discusses the agreements between CLLP and HONI for operations services, maintenance services, and common administrative and corporate services.

2.0 DEVELOPMENT OF THE SERVICE LEVEL AGREEMENT

CLLP and HONI identified the nature of the services required for the safe and prudent operation of CLLP's transmission assets in accordance with good utility practice. Per standard practice, prior to the in-service date, an Agreement for Operations and Management Services (the Agreement) will be established to capture these requirements.

3.0 TERMS AND CONDITIONS

In accordance with the transmission licence which CLLP expects to be issued as well as the OEB's Affiliate Relationships Code (ARC), and all other applicable codes, rules, orders and decisions of the OEB, the Agreement will describe the terms and conditions of the services that HONI will provide to CLLP. These include the provision of operations and management services, fees and taxes, invoicing and payment, budgets, accounts and right to audit, liability and force majeure events, dispute resolution procedures, confidentiality and intellectual property, and term and termination of the agreement. More details on the key clauses are provided below.

3.1 PROVISION OF OPERATIONS AND MANAGEMENT SERVICES

The Agreement will address the provision by HONI to CLLP of operations, maintenance, and certain common administrative and corporate services. A description of the services that are expected to be in the Agreement is provided in Table 1.

Table 1 - Service Level Agreement

Services Provider	Services Recipient(s)	Description of Services
Hydro One Networks Inc.	CLLP	**a) Operations Services** – monitoring and control of the transmission system, in accordance with the requirements of CLLP's transmission licence and all services required to fulfill all of CLLP's obligations under its Connection Agreement and the IESO-CLLP operating requirements.
Hydro One Networks Inc.	CLLP	**b) Maintenance Services** – all maintenance, repair and refurbishment services, in accordance with the requirements of CLLP's transmission licence and all services required to fulfill all of CLLP's obligations under its Connection Agreement and the IESO-CLLP operating requirements.
Hydro One Networks Inc.	CLLP	**c) Administrative and Corporate Services** – some corporate and administrative services provided by HONI, including finance and regulatory support, tax advice and returns preparation, treasury, communications and government relations, legal advice, real estate support, corporate security services, First Nations support and other services as required from time to time.

3.2 FEES

Pursuant to the ARC, where a utility provides to an affiliate a service, resource, product or use of an asset , for which a reasonably competitive market exists, the utility shall charge no less than the greater of (i) the market price of that service, product, resource or use of asset, or (ii) the utility's fully-allocated cost to provide that service, product, resource or use of asset. In purchasing such a service, resource, product or use of an asset from an affiliate, a utility shall pay no more than the market price for that service, product, resource or use of an asset. Where no reasonably competitive market exists, a utility shall charge no less than its fully-allocated cost to provide the service, product, resource or use of asset, and a utility receiving such service, product, resource or use of asset shall pay no more than the affiliate's fully-allocated cost to provide the service, product, resource or use of asset. The level of costs for CLLP's services will be determined in accordance with the principles above, where the fees charged for the operations services and management services provided by HONI to CLLP will be set in line with fully-allocated costs.

The services which will be procured by CLLP from HONI are not reasonably available in the market in the manner, type and quantity that fits with CLLP's requirements. There is no known provider that can unilaterally provide these bundled services in this manner. To enter into a multi-vendor management would give rise to significant additional management costs. As a result, the services procured from HONI are done so on a fully-allocated cost basis where CLLP relies on the methodology within the Black & Veatch (B&V) study previously completed for HONI.

3.3 SHARED ASSET ALLOCATION

CLLP is charged transfer pricing by HONI for the use of certain Shared Assets. The service level agreement expected between CLLP and HONI for services provided to, or received from, HONI are described above. The Shared Assets allocated to CLLP include major fixed assets and intangible assets, as well as minor fixed assets. For example, one significant Shared Asset is the SAP system, which is software that integrates work management, finance, supply chain and customer service and other enterprise software.

CLLP is a single asset transmission utility similar to B2M LP and NRLP and has similar Shared Asset usage. For this application, the Shared Asset allocation charged to CLLP is estimated by taking the average shared asset allocation amount per net fixed asset amount of B2M LP and NRLP and applying this rate against the net fixed asset amount of CLLP. The methodology for calculating the transfer pricing for B2M and NRLP is described in more detail in HONI's 2023 to 2027 Custom IR application in EB-2021-0110, Exhibit E-04-08 Attachment 1. The OEB accepted HONI's use of the Black & Veatch's Shared Asset allocation methodology in HONI's 2023 to 2027 Custom IR proceeding.

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COMMON CORPORATE COSTS, COST ALLOCATION METHODOLOGY

Common Corporate Costs are costs incurred to provide service on a shared basis among HONI and its affiliates, including CLLP. The provision of these services is centralized to enable them to be delivered efficiently. Common Corporate Costs are allocated among HONI and its affiliates, including CLLP, based on an established methodology that uses cost causality principles.

Common Corporate Costs include Corporate Common Functions and Services (CCF&S), Asset Management, Information Technology, and Operating Programs. As it relates to CLLP, the allocated CCF&S costs include services provided by Finance, Taxation, Planning, Security Operations, Real Estate Services, Indigenous Relations, Regulatory Affairs and General Counsel.

Since 2004, in connection with each major cost of service application, HONI has commissioned a study by Black & Veatch to recommend a best practice methodology to allocate common corporate costs among the business entities using the common services. The adopted methodology represents the industry's best practices, identifying appropriate cost drivers to reflect cost causality and benefits received. In B2M LP and NRLP's recent 2025 to 2029 Transmission Rates Applications (EB-2024-0116 and EB-2024-0117, respectively), the same corporate cost allocation prepared by an independent expert, Black & Veatch, in HONI's 2023 - 2027 Custom IR application (EB-2021-0110) was included. The forecast allocation of Common Corporate Costs to CLLP for the test years (2025 to 2029) is forecast to be an average of $0.5M annually based on the same methodology.

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DEPRECIATION EXPENSES

1.0 INTRODUCTION

The purpose of this exhibit is to summarize the method and amount of CLLP's depreciation and amortization expense for the 2025 to 2029 forecast years.

2.0 DEPRECIATION METHODOLOGY

The depreciation and amortization expense for CLLP's application for transmission revenue requirement for the 2025 to 2029 period will rely upon the updated depreciation study conducted by Alliance Consultant Group (Alliance) for Hydro One Networks Inc.'s (HONI) 2023-2027 Custom IR application (EB-2021-0110).

In EB-2021-0110, HONI engaged Alliance to perform a new depreciation study covering HONI's transmission, distribution and common assets as the basis for HONI's Transmission and Distribution depreciation and amortization expenses from 2023 to 2027. The OEB approved those expenses and the basis for their calculation.

In this Application, HONI's Alliance depreciation study will form the basis for CLLP's depreciation rates and depreciation expense for the 2025 to 2029 period. The depreciation rates for CLLP are derived from the projected useful lives (or projection lives) by asset account found in Alliance's depreciation study.[1] As a single asset transmission utility, CLLP's assets are similar in nature to certain HONI's transmission assets and are expected to perform in the same manner as the assets on which HONI's depreciation study was based. Accordingly, there is no value or need to incur significant additional expense to maintain unique depreciation rates for CLLP.

[1] EB-2021-0110, E-08-01, Attachment 1, Alliance Depreciation Study, Appendix E-1, p. 114 of 146

3.0 DEPRECIATION EXPENSE

As discussed above, CLLP relied upon HONI's updated depreciation study for transmission assets approved in HONI's 2023 - 2027 Custom IR Application (EB-2021-0110, Exhibit E-08-01, Attachment 1), which adopted the Alliance methodology to determine the depreciation expense for the test years. The bridge and test period depreciation expenses are summarized in Table 1.

Table 1 - CLLP Depreciation and Amortization Expenses ($ M)

Description	Bridge	Test				
	2024	**2025**	**2026**	**2027**	**2028**	**2029**
Depreciation On Fixed Assets	0.2[1]	2.5	2.5	2.5	2.5	2.5
Less Capitalized Depreciation	-	-	-	-	-	-
Asset Removal Costs	-	-	-	-	-	-
Losses/(Gains) On Asset Disposition	-	-	-	-	-	-
Total	**0.2**	**2.5**	**2.5**	**2.5**	**2.5**	**2.5**

[1] 2024 rate base was calculated to reflect the full rate base, upon date of in-service, rather than the half-year rule, in alignment with other recent single-asset utility applications such as EB-2020-0150

Detailed depreciation schedules are filed in Exhibit F-05-01, Attachment 1.

CLLP
Depreciation & Amortization Expenses
2024 Bridge, 2025 - 2029 Test Years
Year Ending December 31
($ Millions)

Line No.	Particulars	2024 Deprn Rate	2024 Provision ($M)	2025 Deprn Rate	2025 Provision ($M)	2026 Deprn Rate	2026 Provision ($M)	2027 Deprn Rate	2027 Provision ($M)	2028 Deprn Rate	2028 Provision ($M)	2029 Deprn Rate	2029 Provision ($M)
		(a)	(b)	(a)	(b)	(a)	(b)	(a)	(b)	(a)	(b)	(a)	(b)
	Depreciation Expenses												
1	Major Fixed Assets												
2	Capital Contribution Paid	10.00%	0.00	10.00%	0.05	10.00%	0.05	10.00%	0.05	10.00%	0.05	10.00%	0.05
3	Land	0.00%	0.00	0.00%	0.00	0.00%	0.00	0.00%	0.00	0.00%	0.00	0.00%	0.00
4	Land-Rights	1.00%	0.07	1.00%	0.78	1.00%	0.78	1.00%	0.78	1.00%	0.78	1.00%	0.78
5	Towers and Fixtures	1.33%	0.11	1.33%	1.28	1.33%	1.31	1.33%	1.31	1.33%	1.31	1.33%	1.31
6	Overhead Lines	1.43%	0.03	1.43%	0.39	1.43%	0.40	1.43%	0.40	1.43%	0.40	1.43%	0.40
7	Depreciation on Fixed Assets		0.21		2.51		2.54		2.54		2.54		2.54
8	Less Capitalized Depreciation		-		-		-		-		-		-
9	Asset Removal Costs		-		-		-		-		-		-
10	Total Depreciation Expenses		0.21		2.51		2.54		2.54		2.54		2.54
	Amortization Expenses												
11	Other Amortization												
12	Total Amortization Expenses		-		-		-		-		-		-
13	Total Depreciation & Amortization Expenses		0.21		2.51		2.54		2.54		2.54		2.54
14	Depreciation & Amortization for recovery		0.21		2.51		2.54		2.54		2.54		2.54

CORPORATE INCOME TAXES

1.0 OVERVIEW

This Exhibit explains how CLLP proposes to calculate its income tax expenses for the purposes of rate recovery. Exhibit F-06-01, Attachment 1 contains detailed calculations of income tax for the bridge and test years, including supporting schedules and reconciliations, as needed. The bridge year is the first year of operation and thus, there is no historical period. The information provided in this Application is consistent with Section 2.8.11 of the Filing Requirements.

2.0 OVERVIEW OF INCOME TAXES

2.1 INTRODUCTION

CLLP is a limited partnership pursuant to the *Limited Partnerships Act* (Ontario). A partnership is not a taxpayer under the *Income Tax Act*. A partnership is required to compute its taxable income, which is then allocated and taxed in the hands of its partners. The expected CLLP partners include:

Partner	Interests	Description
Hydro One Networks Inc. (HONI)	LP	A corporation owned directly by Hydro One Inc.
First Nations Partners	LP	Though negotiations are ongoing, HONI has offered equity partnership to five potential First Nation community partners, named below: • Aamjiwnaang First Nation (AFN) • Caldwell First Nation (CFN) • Chippewas of the Thames First Nation (COTTFN) • Chippewas of Kettle and Stony Point First Nation (CKSPFN) • Walpole Island First Nation (WIFN)
Chatham x Lakeshore GP Inc. (CLGP)	GP	A corporation owned directly by Hydro One Inc.

The First Nations are exempt from corporate income tax. Therefore, the taxable income in CLLP that is allocated to the First Nations partners will not be subject to income tax. This leads to less total income tax paid, which is a savings to ratepayers.

2.2 REGULATORY INCOME TAX EXPENSE

Regulatory income taxes for CLLP are determined by applying the statutory tax rate to the regulatory taxable income allocated to HONI and CLGP, the taxable corporate partners of CLLP.

2.3 CORPORATE MINIMUM TAX

Ontario Corporate Minimum Tax (OCMT) is designed to impose a minimum tax based on financial statement income calculated without most tax adjustments. The OCMT paid in the year can be applied to reduce Ontario taxes payable in future year.[1] HONI and CLGP will be subject to OCMT in the Bridge year 2024 and Test years 2025 to 2029 as shown in Exhibit F-06-01, Attachment 1. OCMT expense is expected throughout the Bridge and Test period, resulting in the overall tax expense. These credits are expected to be accumulated and utilized in the future when there is sufficient taxable income.

2.4 INCOME TAX RATE (FEDERAL AND ONTARIO)

A combined income tax rate of 26.5% has been used for the forecast years, as set out in Table 1 below, comprising a federal rate of 15% and a provincial rate of 11.5%. Any variance between actual taxes payable and forecast taxes, because of tax policy and legislation changes, will be captured in a variance account for tax rate changes as per Section 7.1 of the 2006 Electricity Distribution Rate (EDR) Handbook, as described further in Exhibit H-01-01.

[1] OCMT has a 20-year carry forward period and it will expire unutilized after 20-year period.

Table 1 - Combined Income Tax Rates

	Bridge	Test
	2024	**2025 to 2029**
Federal Tax Rate (%)	15.00	15.00
Provincial Rate (%)	11.50	11.50
Total Statutory Tax Rate (%)	**26.50**	**26.50**

3.0 RECONCILIATION BETWEEN REGULATORY NET INCOME BEFORE TAX AND TAXABLE INCOME

Reconciliation between the regulatory net income before tax (NIBT) and taxable income is provided in Exhibit F-06-01, Attachment 1. This schedule shows how the taxable income is computed by adjusting the NIBT for items such as accounting depreciation and tax capital cost allowance (CCA). The calculation of test year CCA is provided in Exhibit F-06-01, Attachment 1. To make it easier to follow these reconciliations, CLLP has separated the tax adjustments into the following categories:

1. Recurring items that must be added or (deducted) because they have been included in the OM&A expenses in arriving at the revenue requirement, or for which appropriate tax adjustments are made (for example, depreciation versus CCA); and
2. Recurring items not in the revenue requirement.

4.0 OVERVIEW OF PROCESS TO ARRIVE AT TAXABLE INCOME

The starting point for the computation of CLLP taxable income is the NIBT as shown on the utility's income statement for the year. The NIBT is prepared by using U.S. Generally Accepted Accounting Principles, but taxable income is computed using the relevant income tax legislation, interpretations and assessing practices. Therefore, there are several adjustments that are typically made, where applicable, to the NIBT to arrive at taxable income and most of these adjustments are made to account for timing differences. Adjustment for timing differences can arise when: (1) expenditures are both capitalized and depreciated over time for both financial accounting and tax requirements, but the depreciation rates and depreciation methodology are different; or (2) costs that are expensed for financial accounting purposes but not for tax purposes or vice versa. A common item that increases NIBT (i.e., it is added back to NIBT for tax purposes) is financial accounting depreciation and amortization with CCA being the common item that reduces NIBT (i.e., it is deducted from NIBT for tax purposes). Consequently, the NIBT must be adjusted for amounts included (or deducted) for accounting purposes that are not income (or deductible) for tax return purposes.

5.0 TAXABLE TREATMENT OF REGULATORY ASSETS AND REGULATORY LIABILITIES

Regulatory assets and regulatory liabilities are typically recognized by the utility's balance sheets for forgone revenue or for expenses that have been incurred, for which recovery will be sought from ratepayers through future rates. Disposition of the deferral accounts is determined by the OEB.

For example, in the illustrative example shown in Table 2, assuming that a 26.5% tax rate applies, and a $100 expense is incurred, the utility will record a regulatory asset for the expense to be recovered in the future while tax will be allowed a deduction of the $100 for the year in which the expense is incurred in computing taxable income. If the OEB subsequently approves recovery of this expense over a two-year period through a rate rider, the utility will include the approved recovery amounts in computing taxable income for the year in which it is billed to ratepayers. The net result is that the utility has recovered the $100 cost although the income or expense has been taxed or deducted in different years.

Table 2 - Example of the Income Tax Treatment of Regulatory Assets and Regulatory Liabilities Disposition

	Year 1	Year 2	Year 3	CUMULATIVE
Income (deduction)	(100)	50	50	Nil
Tax Refund (payable)	26.5	(13.25)	(13.25)	Nil
Cash Inflow (outflow)	(73.5)	36.75	36.75	Nil

Therefore, regulatory assets and regulatory liabilities have not been included in computing tax payable for purposes of the revenue requirement since the associated tax benefit has or will be obtained through the tax system, within a reasonable time horizon (i.e., the application period).

6.0 INTEGRITY CHECKS

CLLP has performed the integrity checks as described in Section 2.8.11.2 of the Filing Requirements.

7.0 SUPPORTING ATTACHMENTS

The attachments supporting the determination of the income tax expense are provided in the following attachments:

Attachment 1: Calculation of Test Year Utility Income Taxes and Capital Cost Allowance

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CLLP

Calculation of Utility Income Taxes
Bridge (2024) and Test Years (2025 to 2029)
Year Ending December 31
($ Millions)

SUMMARY OF TAX EXPENSE

	2024	2025	2026	2027	2028	2029
Hydro One Networks Inc. (HONI)	0.0	0.1	0.1	0.1	0.1	0.1
Chatham X Lakeshore GP Inc	0.0	0.0	0.0	0.0	0.0	0.0
First Nations	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.0**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**

Chatham x Lakeshore LP

Line No.	Particulars	2024	2025	2026	2027	2028	2029
		(a)	(b)	(c)	(d)	(e)	(f)
	Determination of Taxable Income						
1	Regulatory Net Income (before tax)	0.6	7.5	7.5	7.4	7.3	7.2
2	Book to Tax Adjustments:						
3	Depreciation and amortization	0.2	2.5	2.5	2.5	2.5	2.5
4	Capital Cost Allowance	-13.9	-13.2	-12.2	-11.3	-10.5	-9.7
5	Other	0.5	0.0	0.0	0.0	0.0	0.0
6	Total Adjustments	-13.3	-10.7	-9.6	-8.7	-7.9	-7.2
7	**Regulatory Taxable Income/(Loss) before Loss Carry Forward**	**$ -12.7**	**$ -3.2**	**$ -2.1**	**$ -1.3**	**$ -0.6**	**$ 0.1**
	Allocation of Taxable Income						
8	Hydro One Networks Inc (HONI)	-6.3	-1.6	-1.1	-0.6	-0.3	0.1
9	Catham X Lakeshore GP Inc	0.0	0.0	0.0	0.0	0.0	0.0
10	First Nations	-6.3	-1.6	-1.1	-0.6	-0.3	0.0
11	Total	$ -12.7	$ -3.2	$ -2.1	$ -1.3	$ -0.6	$ 0.1
	Tax Rates						
12	Federal Tax	15.0 %	15.0 %	15.0 %	15.0 %	15.0 %	15.0 %
13	Provincial Tax	11.5 %	11.5 %	11.5 %	11.5 %	11.5 %	11.5 %
14	Total Tax Rate	26.5 %	26.5 %	26.5 %	26.5 %	26.5 %	26.5 %

Hydro One Networks Inc. (HONI)

Line No.	Particulars	2024	2025	2026	2027	2028	2029
		(a)	(a)	(b)	(c)	(d)	(e)
	Determination of Income Taxes						
1	Allocation of Taxable Income from CLLP	-6.3	-1.6	-1.1	-0.6	-0.3	0.1
2	Loss Carryforward	6.3	1.6	1.1	0.6	0.3	-0.1
3	Taxable Income after loss carryforward	0.0	0.0	0.0	0.0	0.0	0.0
4	Tax Rate	26.5 %	26.5 %	26.5 %	26.5 %	26.5 %	26.5 %
5	Income Tax Expense	**$ 0.0**	**$ 0.0**	**$ 0.0**	**$ 0.0**	**$ 0.0**	**$ 0.0**
	Loss Continuity Schedule						
	Opening Losses Carryforward	0.0	-6.3	-7.9	-9.0	-9.6	-9.9
	Losses (Incurred)/Utilized during the year	-6.3	-1.6	-1.1	-0.6	-0.3	0.1
	Closing Losses Carryforward	-6.3	-7.9	-9.0	-9.6	-9.9	-9.8
	Determination of Corporate Minimum Tax*						
	Allocation of Accounting Income from CLLP	0.3	3.8	3.8	3.8	3.7	3.7
	Corporate Minimum Tax Rate	2.7 %	2.7 %	2.7 %	2.7 %	2.7 %	2.7 %
	Corporate Minimum Tax Potentially Applicable	0.0	0.1	0.1	0.1	0.1	0.1
	Ontario Income Tax	0.0	0.0	0.0	0.0	0.0	0.0
	Corporate Minimum Tax Payable (Utilized)	**$ 0.0**	**$ 0.1**	**$ 0.1**	**$ 0.1**	**$ 0.1**	**$ 0.1**
	Opening CMT Credit Carryforward	0.0	0.0	0.1	0.2	0.3	0.4
	CMT Credit Incurred/(utilized)	0.0	0.1	0.1	0.1	0.1	0.1
	Closing CMT Credit Carryforward	0.0	0.1	0.2	0.3	0.4	0.5
	Total Tax Expense	**$ 0.0**	**$ 0.1**	**$ 0.1**	**$ 0.1**	**$ 0.1**	**$ 0.1**

*Includes the corporate minimum tax for HONI and Chatham X Lakeshore GP Inc

Chatham X Lakeshore GP Inc

Line No.	Particulars		2024		2025		2026		2027		2028		2029	
			(a)		(a)		(b)		(c)		(d)		(e)	
	Determination of Income Taxes													
1	Allocation of Taxable Income from CLLP		0.0		0.0		0.0		0.0		0.0		0.0	
2	Loss Carryforward		0.0		0.0		0.0		0.0		0.0		0.0	
3	Taxable Income after loss carryforward		0.0		0.0		0.0		0.0		0.0		0.0	
4	Tax Rate		26.5	%	26.5	%	26.5	%	26.5	%	26.5	%	26.5	%
5	Sub Total		0.0		0.0		0.0		0.0		0.0		0.0	
6	Additional Taxes due to Negative ACB		0.0		0.0		0.0		0.0		0.0		0.0	
7	**Income Tax Expense**	**$**	**0.0**	**$**	**0.0**		**0.0**		**0.0**		**0.0**		**0.0**	

First Nations

Line No.	Particulars		2024		2025		2026		2027		2028		2029	
			(a)		(a)		(b)		(c)		(d)		(e)	
	Determination of Income Taxes													
1	Allocation of Taxable Income from CLLP		-6.3		-1.6		-1.1		-0.6		-0.3		0.0	
2	Tax Rate		0.0	%	0.0	%	0.0	%	0.0	%	0.0	%	0.0	%
3	Income Tax Expense	$	**0.0**	$	**0.0**	$	**0.0**	$	**0.0**	$	**0.0**	$	**0.0**	
	Determination of Corporate Minimum Tax													
4	Allocation of Accounting Income from CLLP		0.3		3.7		3.7		3.7		3.6		3.6	
5	Corporate Minimum Tax Rate		0.0	%	0.0	%	0.0	%	0.0	%	0.0	%	0.0	%
6	Corporate Minimum Tax Payable	$	**0.0**	$	**0.0**	$	**0.0**	$	**0.0**	$	**0.0**	$	**0.0**	
7	**Total Tax Expense**	**$**	**0.0**	**$**	**0.0**	**$**	**0.0**	**$**	**0.0**	**$**	**0.0**	**$**	**0.0**	

CLLP

Calculation of Capital Cost allowance (CCA)
Bridge (2024) and Test Years (2025 to 2029)
Year Ending December 31
($ Millions)

2024

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
14.1 (Post-2017)	-	78.2	78.2		78.2	5.0%	3.9	74.3
47	-	122.0	122.0		122.0	8.0%	9.8	112.3
55	-	0.5	0.5		0.5	55.0%	0.3	0.2
UCC	-	200.7	200.7	-	200.7		13.9	186.7
						TOTAL CCA	**13.9**	

2025

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
14.1 (Post-2017)	74.3	-	74.3		74.3	5.0%	3.7	70.5
47	112.3	4.9	117.1		117.1	8.0%	9.4	107.8
55	0.2	-	0.2		0.2	55.0%	0.1	0.1
UCC	186.7	4.9	191.6	-	191.6		13.2	178.4
						TOTAL CCA	**13.2**	

2026

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
14.1 (Post-2017)	70.5	-	70.5	-	70.5	5.0%	3.5	67.0
47	107.8	-	107.8	-	107.8	8.0%	8.6	99.2
55	0.1	-	0.1	-	0.1	55.0%	0.1	0.0
UCC	178.4	-	178.4	-	178.4		12.2	166.2
						TOTAL CCA	**12.2**	

2027

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
14.1 (Post-2017)	67.0	-	67.0	-	67.0	5.0%	3.4	63.7
47	99.2	-	99.2	-	99.2	8.0%	7.9	91.2
55	0.0	-	0.0	-	0.0	55.0%	0.0	0.0
UCC	166.2	-	166.2	-	166.2		11.3	154.9
						TOTAL CCA	**11.3**	

2028

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
14.1 (Post-2017)	63.7	-	63.7	-	63.7	5.0%	3.2	60.5
47	91.2	-	91.2	-	91.2	8.0%	7.3	83.9
55	0.0	-	0.0	-	0.0	55.0%	0.0	0.0
UCC	154.9	-	154.9	-	154.9		10.5	144.4
						TOTAL CCA	**10.5**	

2029

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
14.1 (Post-2017)	60.5	-	60.5	-	60.5	5.0%	3.0	57.5
47	83.9	-	83.9	-	83.9	8.0%	6.7	77.2
55	0.0	-	0.0	-	0.0	55.0%	0.0	0.0
UCC	144.4	-	144.4	-	144.4		9.7	134.7
						TOTAL CCA	**9.7**	

CAPITAL STRUCTURE/COST OF CAPITAL

1.0 INTRODUCTION

The purpose of this Exhibit is to summarize the method and cost of financing CLLP's capital requirements for the 2025 to 2029 Application period. The cost of capital has been reflected in the revenue requirements for each year of this Application.

At the time of the Draft Rate Order (DRO) in this proceeding, CLLP intends to update the 2025 to 2029 revenue requirements based on the OEB's release of its 2025 cost of capital parameters to reflect: (a) the OEB-prescribed 2025 return on equity (ROE) and short-term debt rates; and (b) a long-term debt rate based on CLLP's forecast debt refinancing in 2025, using the September 2024 Consensus Forecast. The ROE and short-term debt rate parameters will remain fixed over the five-year rate term.

At the time of in-servicing the Chatham to Lakeshore transmission line, CLLP will issue a note in the amount of $112.7M representing 56% of CLLP's rate base, bearing interest at 4.58%. This rate reflects the OEB's deemed long-term debt rate for 2024. This note is planned to be refinanced during 2025 with debt issued by CLLP. The refinancing debt issue will mirror the terms included in an actual debt issue planned to be issued by Hydro One Inc. to third party public debt investors. This is expected to occur in mid-2025. Following the update, in 2025, CLLP will file an application, which will include a one-time update to the cost of long-term debt to reflect the actual market rate achieved on the debt that it will issue in 2025, as requested for approval in this proceeding. This will update and set the rates revenue requirements, effective January 1 each year, for the remaining term from 2026 through to 2029.

This approach is consistent with the last approved update to 2020 cost of long-term debt in the 2021 annual update application for NRLP (EB-2020-0225).[1]

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[1] Past approval of a one-time update to cost of long-term debt was approved in EB-2018-0275, NRLP's 2020-2024 Decision and Order, Schedule A, Issue 13

2.0 CAPITAL STRUCTURE

CLLP's deemed capital structure for rate-making purposes is 60% debt and 40% common equity of utility rate base where the 60% debt component is comprised of 4% deemed short-term debt and 56% long-term debt.

This structure is consistent with the OEB's Report on the Cost of Capital for Ontario's Regulated Utilities, dated December 11, 2009 (EB-2009-0084), and its subsequent Review of the Existing Methodology of the Cost of Capital for Ontario's Regulated Utilities, dated January 14, 2016.

2.1 COST OF CAPITAL SUMMARY

The cost of capital as described in this Exhibit has been reflected in the revenue requirement for each year of this Application. CLLP's proposed 2025 to 2029 cost of capital requirements are presented in Exhibit G-01-03.

As discussed above, when the OEB releases its 2025 cost of capital parameters during this proceeding, CLLP will update the revenue requirement for the 2025 test year to reflect: (a) the OEB-prescribed 2025 ROE and short-term debt rates; and (b) a long-term debt rate based on CLLP's weighted average of its existing debt rate and the rate on CLLP's forecast debt refinancing in 2025, using the September 2024 Consensus Forecast.

The test years' debt and equity summary schedules are provided at Exhibit G-01-03.

Hydro One expects the OEB to issue its Decision and Order before CLLP issues actual debt to finance its long-term debt component of its rate base. The future financing rate of CLLP's long-term debt is unknown and may have an impact on CLLP's financial performance if the actual cost is not reflected in rates. As such, CLLP proposes a one-time update to the cost of long-term debt to reflect the actual market rate achieved on the long-term debt it will issue in 2025.

3.0 RETURN ON COMMON EQUITY

CLLP's evidence reflects a return on equity (ROE) of 9.21% as a placeholder for 2025-2029 based on the cost of capital parameters released by the OEB on October 31, 2023, effective for January 1, 2024 rates. It is calculated according to the OEB's formulaic approach in Appendix B of the Cost of Capital for Ontario's Regulated Utilities report, dated December 11, 2009 (EB-2009-0084).

As set out above, CLLP will update the equity cost of capital for the 2025 test year by using the 2025 ROE to be prescribed by the OEB in the fall of 2024.

4.0 DEEMED SHORT-TERM DEBT

The OEB has determined that the deemed amount of short-term debt that should be factored into rate-setting be fixed at 4% of rate base. The deemed short-term rate of 6.23% is being used by CLLP as a placeholder for 2025 and is based on the Cost of Capital Parameters released by the OEB on October 31, 2023, for rates effective January 1, 2024.

CLLP will update the short-term debt rate for the 2025-2029 period based on the 2025 deemed short-term debt rate to be released by the OEB in the fall of 2024.

5.0 LONG-TERM DEBT

The OEB has determined that the deemed amount of long-term debt that should be factored into rate-setting be fixed at 56% of rate base, consistent with the OEB's report on the Cost of Capital for Ontario's Regulated Utilities, dated December 11, 2009 (EB-2009-0084). The forecast weighted average long-term debt rate is 4.62% for 2025. Details used in the calculation of the forecast long-term debt rate are presented at Exhibit G-01-02, Page 1.

At the time of DRO, CLLP will update the long-term debt rate for the 2025 test year based on the September 2024 Consensus Forecast, consistent with the proposed update of the return on common equity and deemed short-term interest rate.

5.1 CLLP LONG-TERM DEBT

Hydro One Inc. provides treasury services to CLLP. CLLP issues debt to Hydro One Inc. to reflect debt issued by Hydro One Inc. to third-party public debt investors. Hydro One Inc. plans to issue debt to third-party public debt investors in 2025, depending on market conditions at the time. Third-party public debt investors hold all of the long-term debt issued by Hydro One Inc. The debt portfolio for CLLP is detailed in Exhibit G-01-02.

5.2 CREDIT RATINGS

As an issuing entity, Hydro One Inc. obtains credit ratings from credit rating agencies as a requirement to issue medium-term notes in the Canadian public debt markets. Table 1 lists the credit ratings of Hydro One Inc.'s debt obligations by DBRS Limited, Moody's Investors Service and S&P Global Ratings:

Table 1 - Credit Ratings for Hydro One Inc.

Rating Agency	Short-term Debt	Long-term Debt
DBRS Limited (DBRS)	R-1(low)	A(high)
Moody's Investors Service (Moody's)	Prime-2	A3
S&P Global Ratings (S&P)	A-1(mid)	A

Rating agency reports are available at Exhibit A-06-03 of Hydro One's 2023-27 Custom IR Application for Transmission and Distribution (EB-2021-0110).

5.3 FORECAST DEBT

The OEB has determined in its Cost of Capital Report that the rate for new debt that is held by a third-party public debt investor will be the prudently negotiated contract rate. This would include recognition of premiums and discounts.

CLLP's planned borrowing requirement in 2025 is $112.7M, based on its most recent forecast. CLLP's borrowing requirements are determined based on its rate base and capital structure as discussed in Section 2 of this Exhibit.

For the purpose of this Application, CLLP's evidence reflects a long-term debt rate of 4.62%, as a placeholder for 2025 to 2029. From January to July 1, 2025, the OEB's deemed long-term debt for 2024 of 4.58% is applied and, from July 1, 2025, to December 31, 2029, CLLP has applied the long-term debt rates based on HONI's forecasts for new long term debt rate calculations for 2025, reflecting the April 2024 Consensus Forecasts and the average of indicative new issue spreads for April 2024. Table 2 lists the fixed-rate notes that Hydro One Inc. plans to issue for CLLP in 2025, as shown in lines 2 and 3 of Exhibit G-01-02, Page 1.

Table 2 - Forecast Debt Issues for 2025

Principal Amount ($M)	Term (Years)	Coupon
56.3	10	4.30%
56.3	30	4.50%

CLLP has calculated the weighted average debt rate to be 4.62% for 2025 and the forecast new long-term debt rate of 4.55% for 2026, as shown in Exhibit G-01-02.

CLLP assumes that for rates effective January 1, 2025, the forecast interest rate for CLLP's debt issues will be updated based on the September 2024 Consensus Forecasts and the average of indicative new issue spreads for September 2024 that will be obtained from the Hydro One Medium Term Note (MTN) dealer group for each planned issuance term.

5.4 INTEREST RATES ON 2025 FORECAST DEBT ISSUES

CLLP's borrowing will be financed at market rates applicable to Hydro One Inc. Table 3 summarizes the derivation of the forecast Hydro One Inc. yields for the planned 10-year and 30-year issuance terms for 2025.

Table 3 - Forecast Yield for 2025 Issuance Terms

	2025	
	10-year	**30-year**
Government of Canada	3.25%	3.15%
Hydro One Spread	1.05%	1.35%
Forecast Hydro One Yield	4.30%	4.50%

Each rate comprises the forecast Government of Canada bond yield plus the Hydro One Inc. credit spread applicable to that term. The ten-year Government of Canada bond yield forecast for 2025 is based on the average of the three-month and 12-month forecast from the April 2024 Consensus Forecast. The 30-year Government of Canada bond yield forecasts are derived by adding the April 2024 average spreads (30-year to 10-year for the 30-year forecast) to the 10-year Government of Canada bond yield forecast. Hydro One's credit spreads over the Government of Canada bonds are based on the average of indicative new issue spreads for April 2024 obtained from the Company's MTN dealer group for each planned issuance term.

CLLP assumes that, for rates effective January 1, 2025, the forecast interest rate for Hydro One Inc.'s debt issues will be based on the September 2024 Consensus Forecasts and the average of indicative new issue spreads for September 2024 that will be obtained from the Hydro One Inc. MTN dealer group for each planned issuance term.

5.5 TREASURY OM&A COSTS

Treasury OM&A costs are incurred to:

- execute borrowing plans and issue commercial paper and long-term debt;
- ensure compliance with securities regulations, bank and debt covenants;
- manage CLLP's daily liquidity position, control cash, and manage the company's bank accounts;
- settle all transactions and manage relationships with creditors; and
- communicate with debt investors, banks and credit rating agencies.

Treasury OM&A costs are provided in the long-term debt schedules for test years in Exhibit G-01-02.

5.6 OTHER FINANCING-RELATED FEES

Column (e) of Exhibit G-01-02 (Premium, Discount and Expenses) represents the costs of issuing debt. These costs are specific to each debt issue and include commissions, legal fees, debt discounts or premiums on issues and re-openings of issues relative to par, and hedge gains or losses.

Other financing-related fees include the Transmission allocation of Hydro One Inc.'s standby credit facility, annual credit rating agency, filing fees to security regulators, letters of credit, banking, custodial and trustee fees. These fees are summarized in the long-term debt schedules for the test years in Exhibit G-01-02.

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CLLP
Cost of Long-Term Debt Capital
Test Year (2025)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding at 12/31/2024 ($Millions)	Total Amount Outstanding at 12/31/2025 ($Millions)	1/1/2025 Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	15-Dec-24	4.58%	1-Jul-25	112.7	0.0	112.7	100.00	4.58%	112.7	0.0	60.7	2.8	
2	1-Jul-25	4.30%	1-Jul-35	56.3	0.2	56.1	99.58	4.35%	0.0	56.3	26.0	1.1	
3	1-Jul-25	4.50%	1-Jul-55	56.3	0.3	56.0	99.42	4.53%	0.0	56.3	26.0	1.2	
4		**Subtotal**							112.7	112.7	112.7	5.1	
5		Treasury OM&A costs										0.03	
6		Other financing-related fees										0.09	
7		**Total**							112.7	112.7	112.7	5.2	4.62%

Note 1 - All debt is 3rd party issued debt with fixed rates

CLLP
Cost of Long-Term Debt Capital
Test Year (2026)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/2025 ($Millions)	Total Amount Outstanding: at 12/31/2026 ($Millions)	1/1/2026 Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	1-Jul-25	4.30%	1-Jul-35	56.3	0.2	56.1	99.58	4.35%	56.3	56.3	56.3	2.5	
2	1-Jul-25	4.50%	1-Jul-55	56.3	0.3	56.0	99.42	4.53%	56.3	56.3	56.3	2.6	
3		**Subtotal**							112.7	112.6	112.7	5.0	
4		Treasury OM&A costs										0.03	
5		Other financing-related fees										0.09	
6		**Total**							112.7	112.6	112.7	5.1	4.55%

Note 1 - All debt is 3rd party issued debt with fixed rates

CLLP
Summary of Cost of Capital
Test Year 2025
Utility Capital Structure
Year Ending December 31
($ Millions)

		2025			
Line No.	**Particulars**	**($M)**	**%**	**Cost Rate (%)**	**Return ($M)**
		(a)	(b)	(c)	(d)
I	Long-term debt	112.7	56.0%	4.62%	5.2
2	Short-term debt	8.0	4.0%	6.23%	0.5
3	Deemed long-term debt	-	0.0%	4.62%	0.0
4	Total debt	120.7	60.0%	4.73%	5.7
5	Common equity	80.5	40.0%	9.21%	7.4
6	Total rate base	201.2	100.0%	6.52%	13.1

Long term debt ($M) based on Average Monthly Total Debt outstanding G-01-02
Long term debt % based on Projected Average Embedded Cost Rate G-01-02
Short term debt % based on OEB's 2024 Cost of Capital Parameters
Common Equity % based on OEB's 2024 Cost of Capital Parameters
Total rate base from C-01-01

CLLP
Summary of Cost of Capital
Test Year 2026
Utility Capital Structure
Year Ending December 31
($ Millions)

		2026			
Line No.	**Particulars**	**($M)**	**%**	**Cost Rate (%)**	**Return ($M)**
		(a)	(b)	(c)	(d)
I	Long-term debt	112.7	56.0%	4.55%	5.1
2	Short-term debt	8.0	4.0%	6.23%	0.5
3	Deemed long-term debt	(0.0)	(0.0%)	4.55%	(0.0)
4	Total debt	120.7	60.0%	4.66%	5.6
5	Common equity	80.4	40.0%	9.21%	7.4
6	Total rate base	201.1	100.0%	6.48%	13.0

Long term debt ($M) based on Average Monthly Total Debt outstanding G-01-02
Long term debt % based on Projected Average Embedded Cost Rate G-01-02
Short term debt % based on OEB's 2024 Cost of Capital Parameters
Common Equity % based on OEB's 2024 Cost of Capital Parameters
Total rate base from C-01-01

CLLP
Summary of Cost of Capital
Test Year 2027
Utility Capital Structure
Year Ending December 31
($ Millions)

		2027			
Line No.	**Particulars**	**($M)**	**%**	**Cost Rate (%)**	**Return ($M)**
		(a)	(b)	(c)	(d)
I	Long-term debt	112.1	56.5%	4.55%	5.1
2	Short-term debt	7.9	4.0%	6.23%	0.5
3	Deemed long-term debt	(0.9)	(0.5%)	4.55%	(0.0)
4	Total debt	119.1	60.0%	4.66%	5.6
5	Common equity	79.4	40.0%	9.21%	7.3
6	Total rate base	198.6	100.0%	6.48%	12.9

Long term debt ($M) based on Average Monthly Total Debt outstanding G-01-02
Long term debt % based on Projected Average Embedded Cost Rate G-01-02
Short term debt % based on OEB's 2024 Cost of Capital Parameters
Common Equity % based on OEB's 2024 Cost of Capital Parameters
Total rate base from C-01-01

CLLP
Summary of Cost of Capital
Test Year 2028
Utility Capital Structure
Year Ending December 31
($ Millions)

		2028			
Line No.	Particulars	($M)	%	Cost Rate (%)	Return ($M)
		(a)	(b)	(c)	(d)
l	Long-term debt	110.7	56.5%	4.55%	5.0
2	Short-term debt	7.8	4.0%	6.23%	0.5
3	Deemed long-term debt	(0.9)	(0.5%)	4.55%	(0.0)
4	Total debt	117.6	60.0%	4.66%	5.5
5	Common equity	78.4	40.0%	9.21%	7.2
6	Total rate base	196.0	100.0%	6.48%	12.7

Long term debt ($M) based on Average Monthly Total Debt outstanding G-01-02
Long term debt % based on Projected Average Embedded Cost Rate G-01-02
Short term debt % based on OEB's 2024 Cost of Capital Parameters
Common Equity % based on OEB's 2024 Cost of Capital Parameters
Total rate base from C-01-01

CLLP
Summary of Cost of Capital
Test Year 2029
Utility Capital Structure
Year Ending December 31
($ Millions)

Line No.	Particulars	2029 ($M)	%	Cost Rate (%)	Return ($M)
		(a)	(b)	(c)	(d)
l	Long-term debt	109.3	56.5%	4.55%	5.0
2	Short-term debt	7.7	4.0%	6.23%	0.5
3	Deemed long-term debt	(0.9)	(0.5%)	4.55%	(0.0)
4	Total debt	116.1	60.0%	4.66%	5.4
5	Common equity	77.4	40.0%	9.21%	7.1
6	Total rate base	193.5	100.0%	6.48%	12.5

Long term debt ($M) based on Average Monthly Total Debt outstanding G-01-02
Long term debt % based on Projected Average Embedded Cost Rate G-01-02
Short term debt % based on OEB's 2024 Cost of Capital Parameters
Common Equity % based on OEB's 2024 Cost of Capital Parameters
Total rate base from C-01-01

REGULATORY ACCOUNTS

1.0 INTRODUCTION

The purpose of this Exhibit is to provide a description of the regulatory accounts requested by CLLP and a proposal with respect to disposition.

2.0 DESCRIPTION OF REGULATORY ACCOUNTS REQUESTED

In this Application, CLLP requests approval to establish the following regulatory accounts as described herein.

- Forgone Revenue Deferral Account
- Earnings Sharing Mechanism (ESM) Deferral Account

The proposed regulatory accounts will be established consistent with the OEB's requirements as set out in the Accounting Procedures Handbook, subsequent OEB direction, or as per specific requests initiated by CLLP. The draft accounting orders are provided in Attachments 1 and 2 of this Exhibit.

CLLP plans on utilizing the following OEB generic account, as established in the OEB's *Report on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR)*[1], in the event there are entries related to unanticipated legislated tax changes over the rate term:

- Tax Rate and Rule Changes Variance Account

2.1 FORGONE REVENUE DEFERRAL ACCOUNT (ACCOUNT 1508)

This account is requested in the event that the OEB's decision in respect of UTRs is not issued in time for UTRs to be implemented effective January 1 of a given year and as a result, there is a need to track foregone revenue for CLLP. The forgone revenue deferral account will record any differences between the existing rates revenue requirement

[1] EB-2008-0046, *Report on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR)*

recovered as part of existing UTRs of a given year and the actual OEB-approved rates revenue requirement that should be collected under the updated UTRs of a given year. Any balance will be interest improved and submitted for disposition at CLLP's next rate application.

2.2 ESM DEFERRAL ACCOUNT (ACCOUNT 2435)

The ESM deferral account, effective January 1, 2025, will record any over-earnings realized during any year of the five-year term of the 2025-2029 revenue requirement application that is above 100 basis points of the deemed return on equity.

The use of an ESM provides protection for ratepayers if forecasts differ from actual results over the five-year period. The 100 basis points is consistent with the OEB-approved threshold for HONI's transmission business. The ratepayer's share of the earnings is adjusted for any tax impacts and is credited to the deferral account.

CLLP will share with customers 50% of any earnings that exceed the regulated return on equity reflected in this Application by more than 100 basis points in any year of the five-year term.

2.3 TAX RATE AND RULE CHANGES VARIANCE ACCOUNT (ACCOUNT 1592)

The Tax Rate and Rule Changes Variance account will track the revenue requirement impact of any differences that may arise in the case of:

- a legislative or regulatory change to the tax rates or rules compared to costs approved by the OEB as part of transmission rates; and
- a change in, or a disclosure of, a new assessment or administrative policy that is published in the public tax administration or interpretation bulletins by relevant federal or provincial tax authorities.

CLLP plans to use this account to track the revenue requirement impact of any legislative or regulatory changes to tax rates or rules during the 2025 to 2029 term.

3.0 ACCOUNTS SOUGHT FOR DISPOSITION

3.1 CXL TRANSMISSION LINE REVENUE REQUIREMENT DEFERRAL ACCOUNT (CLLPDA)

In the CLLP Licencing and Deferral Account Application currently before the OEB (EB-2024-0147), CLLP requested approval to establish the CLLPDA for the purpose of recording the revenue requirement related to the Chatham to Lakeshore project once it is placed in service, and up until the OEB-approved effective date of CLLP's first revenue requirement application.[2]

A revenue requirement currently forecasted to be $1.8M is expected to be recorded in the CLLPDA upon the Chatham to Lakeshore Project being placed in-service this year. This revenue requirement for 2024 has been included in the 2025 rates revenue requirement requested in this Application (see Exhibit E-01-01). At the time of the Draft Rate Order in this proceeding, CLLP will reflect any updates to the 2024 revenue requirement based on the OEB's decision in this proceeding. Accordingly, the CLLPDA may be closed once the DRO in this proceeding is approved.

4.0 ACCOUNTING AND CONTROL PROCESS

The accounts noted above will be managed in a consistent manner. When applicable, they will be updated monthly, and interest applied to the monthly opening principal balance in each account according to the OEB-approved rate. Balances will be reported to the OEB as part of the quarterly reporting process and will be consistent with the last audited financial statements.

A certification on account balances consistent with Chapter 1 of the OEB's *Filing Requirements for Electricity Distribution Rate Applications* has been provided at Exhibit A-02-01-02.

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[2] EB-2024-0147, Application for Chatham x Lakeshore Limited Partnership (CLLP) Licencing and Deferral Account, Appendix 5, filed on April 26, 2024

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TRANSMISSION ACCOUNTING ORDER – FORGONE REVENUE DEFERRAL ACCOUNT

CLLP proposes the establishment of a new "Forgone Transmission Revenue Deferral Account" to record any differences between revenue earned by CLLP under existing Uniform Transmission Rates (UTR) in a given year, and the revenues that would have been received in a given year under the approved UTRs based on OEB-approved rates revenue requirement ("Forgone Revenue"). The account will capture the Forgone Revenue from the first day of the year to the date when the approved rates revenue requirement is reflected in an update to the UTRs.

The account will be established as Account 1508, Other Regulatory Assets – Sub-Account "Forgone Transmission Revenue Deferral Account". CLLP will record interest on the balance in the sub-account using the interest rates set by the OEB. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

The following outlines the proposed accounting entries for this account:

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

To record the difference between the existing rates revenue requirement recovered as part of existing UTRs of a given year and the actual OEB-approved rates revenue requirement that should be collected under the updated UTRs of a given year.

USofA #	Account Description
DR: 1508	Other Regulatory Assets – Sub account “Forgone Revenue Deferral Account”
CR: 6035	Other Interest Expense

To record interest improvement on the principal balance of the “Forgone Revenue Deferral Account”.

TRANSMISSION ACCOUNTING ORDER – ESM DEFERRAL ACCOUNT

The Earnings Sharing Mechanism (ESM) Deferral Account shall record 50% of earnings that exceed the regulatory return on equity (ROE) reflected in this Application by more than 100 basis points in any year of the five-year term through CLLP's transmission revenue. CLLP shall use a methodology which is similar to what is outlined in the annual RRR 2.1.5.6 filing. The calculation of actual ROE shall use the actual rate base for that period. The ROE calculation shall be normalized for revenue impacting items such as entries that are recorded in the year which relate to prior years to normalize the in-year net income. The portion of CLLP owned by Hydro One is subject to tax and will be included as part of the calculation of ROE.

The account will be established as Account 2435, Accrued Rate-Payer Benefit effective January 1, 2025. CLLP shall record interest on any balance in the sub-account using the interest rates set by the OEB. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

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

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

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

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

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

COST ALLOCATION AND RATE DESIGN

1.0 COST ALLOCATION

All assets associated with CLLP are classified as Network in accordance with HONI's functionalization of assets approved by the OEB for HONI's Transmission Rate Applications, most recently in EB-2021-0110.[1] Accordingly, the total rates revenue requirement associated with CLLP's transmission assets will be allocated to the Network pool. A listing of the CLLP assets by functional category is provided below in Table 1.

Table 1 - CLLP Assets by Functional Category

Circuit	Section	From	To	Functional Category
C87H	1	Chatham SS	Lakeshore TS	Network
C88H	1	Chatham SS	Lakeshore TS	Network

The CLLP Network rates revenue requirement for the purpose of setting Uniform Transmission Rates (UTRs) effective for the 2025 test year is $18.62M,[2] $16.80M for 2026, $16.69M for 2027, $16.52M for 2028 and $16.38M for 2029, as determined in Exhibit E-01-01.

2.0 CHARGE DETERMINANTS

There are no customer delivery points supplied directly from the CLLP assets, and as such the CLLP Network charge determinant for the purpose of setting UTRs is zero. All power transported using CLLP's assets are delivered to the final customer by another transmitter and thus is included in another transmitter's load forecast.

[1] EB-2021-0110, Exhibit H-01-02, Section 3.0 filed August 5, 2021
[2] The 2025 rates revenue requirement consists of the 2025 base revenue requirement of $16.82M and the forecast revenue requirement for 2024 of $1.80M.

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OVERVIEW OF UNIFORM TRANSMISSION RATES

1.0 INTRODUCTION

Transmission rates in Ontario have been established on a uniform basis for all transmitters in Ontario since April 30, 2002, as per the OEB's Decision in RP-2001-0034/RP 2001 0035/RP-2001-0036/RP-1999-0044. The current Uniform Transmission Rates (UTR) Schedules, which were effective on January 1, 2024, as part of the OEB's Decision and Rate Order in EB-2023-0222 issued on January 18, 2024, are filed as Exhibit I-03-01, Attachment 1. Exhibit I-03-01, Attachment 2 shows the revenue requirement and charge determinant details used to derive the currently approved 2024 UTRs.[1]

Since rates are established on a uniform basis, CLLP's requested rates revenue requirement is a contributor to the total revenue requirement to be collected from the provincial UTR. The rates revenue requirement for all the other transmitters in the province approved to participate in the UTR must be added to that of CLLP in order to calculate the total transmission rates revenue requirement to be collected via the UTR.[2]

The total rates revenue requirement from all transmitters must be allocated to the Network, Line Connection and Transformation Connection rate pools in order to establish uniform rates by pool. The revenue requirement for CLLP will be allocated to the Network rate pool, as discussed in Exhibit I-01-01. The rates revenue requirements by rate pool for the other transmitters are allocated to either the Network rate pool, or in proportion to HONI's Transmission rates revenue requirement across the three rate pools.

[1] EB-2023-0222, Decision and Rate Order, January 18, 2024.
[2] The other transmitters currently included in the UTRs are Hydro One Networks Inc. (Hydro One), Hydro One Networks Sault Ste. Marie LP (HOSSM), Five Nations Energy Inc. (FNEI), Canadian Niagara Power Inc. (CNPI), Wataynikaneyap Power LP (WPLP), Upper Canada Transmission 2, Inc., operating as East-West Tie Limited Partnership (EWTLP), B2M Limited Partnership (B2M LP), and Niagara Reinforcement Limited Partnership (NRLP).

Once the total rates revenue requirement by rate pool has been established, rates are determined by applying the Provincial charge determinants for each rate pool to the total revenue for each rate pool. The Provincial charge determinants are the sum of all charge determinants, by rate pool, approved by the OEB for each of the transmitters participating in the UTR.

The 2025 UTR schedule is provided in Exhibit I-04-01, Attachment 1, and the rates revenue requirement and charge determinants details used to calculate the 2025 UTRs are provided in Exhibit I-04-01, Attachment 2. The 2025 UTR calculation includes the 2025 CLLP rates revenue requirement and the currently approved values for the other transmitters.[3]

2.0 BILL IMPACTS

This section reflects the bill impacts of CLLP's proposed rates revenue requirement in this Application, as per Sections 2.7.1 and 2.12 of the OEB's Chapter 2 filing requirements for Transmission Revenue Requirement Applications. CLLP's assets are a part of a bulk transmission system reinforcement that is needed to address the near-to mid-term supply needs in the Windsor-Essex region, as determined in an IESO-initiated planning study.[4] Details on the net rates impact assessment for the total cost and load impact of the Chatham to Lakeshore Project bulk transmission reinforcement project in the Windsor-Essex Region is provided in Hydro One Networks Inc.'s Leave to Construct Application in EB-2022-0140, Exhibit B-09-01.

The impact of transmission rates on a customer's total bill varies between transmission-connected and distribution-connected customers. Table 1 shows the estimated average transmission cost as a percentage of the total bill for a transmission-connected customer.

[3] See EB-2023-0222, Decision and Order on 2024 Uniform Transmission Rates, page 4, Table 1
[4] Hydro One Networks Inc. Leave to Construct Application, EB-2022-0140, Exhibit B-03-01.

Table 1 - Estimated Transmission Cost as a Percentage of Total Electricity Market Costs

Figure	Cost Component	¢/kWh	Source
A	Commodity	10.43	IESO Monthly Market Report December 2023
B	Wholesale Market Service Charges	0.48	IESO Monthly Market Report December 2023
C	Wholesale Transmission Charges	1.51	IESO Monthly Market Report December 2023
D	**Total Monthly Cost for TX-Connected Customers**	**12.42**	**D=A+B+C**
E	Transmission as % of Total Cost for TX-Connected Customers	12.2%	E=C/D

The CLLP 2025 rates revenue requirement represents approximately 0.834% of the total rates revenue requirement across all transmitters, which is approximated by adjusting the 2024 overall approved UTR revenue requirement to include the CLLP 2025 rates revenue requirement.[5] This percentage has been applied to CLLP's changes in revenue requirement to calculate the net impact on average transmission rates for each year in the test period, from 2025 to 2029. Figure E (12.2%) from Table 1 above has been applied to the net impact on average transmission rates to estimate the bill impact on transmission-connected customers in the test period, as shown in Table 2.

[5] Exhibit I-04-01, Attachment 1

Table 2 - Average Bill Impacts on Transmission-Connected Customers

	2024	2025	2026	2027	2028	2029
Rates Revenue Requirement [1]	$0	$18,617,562	$16,801,075	$16,692,080	$16,523,123	$16,379,253
% Change in Rates Revenue Requirement over prior year		100.0%	-9.8%	-0.6%	-1.0%	-0.9%
% Impact of load forecast change		0.0%	0.0%	0.0%	0.0%	0.0%
Net Impact on Average Transmission Rates [2]		**0.834%**	**-0.081%**	**-0.005%**	**-0.008%**	**-0.007%**
Transmission as a % of Tx-connected customer's Total Bill		12.2%	12.2%	12.2%	12.2%	12.2%
Estimated Average Transmission Customer Bill Impact [3]		**0.101%**	**-0.010%**	**-0.001%**	**-0.001%**	**-0.001%**

[1] There is no rates revenue requirement in CLLP's 2024 in-servicing year. 2025-2029 rates revenue requirement per Exhibit E-01-01.

[2] The calculation of net impact on transmission rates accounts CLLP's 2025 rates revenue requirement as 0.834% of the total rates revenue requirement across all transmitters.

[3] The calculation of estimated average transmission customer bill impact is the net impact on average transmission rates on the transmission portion of a transmission connected customer's total bill (i.e. 0.834% x 12.2% = 0.101% in 2025).

The total bill impacts for a typical medium density residential (HONI-Dx R1) customer consuming 750 kWh monthly and a typical General Service Energy less than 50 kW (HONI-Dx GS<50kW) customer consuming 2,000 kWh monthly are determined based on the forecast change in the customer's Retail Transmission Service Rates (RTSRs) for each year during the test period, as detailed in Table 3.

1 **Table 3 - Bill Impacts for Typical Distribution-Connected Customers**

	Calculation[1]	2024	2025	2026	2027	2028	2029
CLLP's Rates Revenue Requirement ($M)[2]	A	-	18.618	16.801	16.692	16.523	16.379
CLLP's 2025 Rates Revenue Requirement as % of UTR Network Revenue Requirement[3]	B	1.355%					
Estimated Net Impact on RTSR-Network[4]	$C=(A/A_{PY}-1)*B_{2024}$		1.355%	-0.132%	-0.009%	-0.014%	-0.012%
Typical Medium Density Residential (HONI-Dx R1) Customer Consuming 750 kWh per Month							
		2024	**2025**	**2026**	**2027**	**2028**	**2029**
RTSR Network Charge ($)[5],[6]	$D=D_{PY}*(1+ C)$	9.523	9.652	9.639	9.638	9.637	9.636
RTSR Connection Charge ($)[5],[7],[8]	E	7.021	7.021	7.021	7.021	7.021	7.021
Total RTSR Charge ($)	F=D+E	16.544	16.673	16.660	16.659	16.658	16.657
Estimated Change in RTSR Network Charge ($)[8]	$G=C*D_{PY}$		0.129	(0.013)	(0.001)	(0.001)	(0.001)
Total Bill ($)[8]	$H=H_{PY}+D$	141.102	141.231	141.218	141.218	141.216	141.215
Increase as a % of Total bill	$I=G/H_{PY}$		0.091%	-0.009%	-0.001%	-0.001%	-0.001%
Typical General Service Energy less than 50 kW (HONI-Dx GS<50kW) Customer Consuming 2,000 kWh per Month							
		2024	**2025**	**2026**	**2027**	**2028**	**2029**
RTSR Network Charge ($) [5],[6]	$J=J_{PY}*(1+ C)$	20.386	20.662	20.635	20.633	20.630	20.628
RTSR Connection Charge ($) [5],[7],[8]	K	16.221	16.221	16.221	16.221	16.221	16.221
Total RTSR Charge ($)	L=J+K	36.606	36.883	36.855	36.854	36.851	36.848
Estimated Change in RTSR Network Charge ($) [8]	$M=C*J_{PY}$		0.276	(0.027)	(0.002)	(0.003)	(0.002)
Total Bill ($) [9]	$N=N_{PY}+M$	441.578	441.855	441.827	441.826	441.823	441.820
Increase as a % of Total bill	$O=M/N_{PY}$		0.063%	-0.006%	0.000%	-0.001%	-0.001%

[1] Inputs are current year (CY) unless otherwise denoted (e.g. PY refers to the value from the previous year). Calculations are for 2025-2029 values.

[2] CLLP's 2025-2029 rates revenue requirement as per Exhibit E-01-01.

[3] Represents CLLP's 2025 Rates Revenue Requirement as a share of the approved total 2024 UTR Network Revenue Requirement of $1,373,508,207 as per OEB Decision and Rate Order, EB-2023-0222, 2024 Uniform Transmission Rates Update-Schedule A, January 18, 2024.

[4] The calculation of net impact on HONI-Dx's RTSR Network is CLLP's change in rates revenue requirement relative to the total 2024 UTR Network revenue requirement.

[5] HONI-Dx's currently approved RTSRs are based on the Preliminary 2024 UTRs, EB-2023-0222, September 28, 2023.

[6] Represents the approved 2024 RTSR Network ($/kWh) effective January 1, 2024 per the OEB Decision and Rate Order, EB-2023-0030, December 14, 2023, multiplied by the monthly consumption (i.e. 750kWh/month HONI-Dx R1 or 2,000 kWh/month HONI-Dx GS<50kW), multiplied by the corresponding approved loss factor.

[7] Represents the approved 2024 RTSR Connection ($/kWh) effective January 1, 2024 approved per the OEB Decision and Rate Order, EB-2023-0030, December 14, 2023, multiplied by the monthly consumption (i.e. 750kWh/month HONI-Dx R1 or 2,000 kWh/month HONI-Dx GS<50kW), multiplied by the corresponding approved loss factor.

[8] CLLP's rates revenue requirement is wholly allocated to the Network rate pool. As a result, CLLP's rates revenue requirement impacts RTSR-N, and not RTSR-C.

[9] Total 2024 bill including HST, based on time-of-use commodity price effective November 1, 2023 and distribution rates effective January 1, 2024 approved per Distribution Rate Order EB-2023-0030, dated December 14, 2023, with 19.3% Ontario Energy Rebate (effective November 1, 2023), $0.42 Smart Meter Entity Charge (effective January 1, 2023) and Distribution Rate Protection cap of $39.49 (effective July 1, 2023 for HON-Dx R1). 2025-2029 total bills reflect the year over year estimated change in RTSR-N, and does not account for corresponding adjustments for HST and OER.

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CURRENT ONTARIO TRANSMISSION RATE SCHEDULES

The current UTR Schedules were approved as part of the Decision and Rate Order dated January 18, 2024 in EB-2023-0222. The approved rate schedules, and the revenue requirement and charge determinants for all transmitters used to establish the current UTR and revenue disbursement allocators are included in the following attachments.

Attachment 1: 2024 Ontario Uniform Transmission Rate Schedules
Attachment 2: 2024 Uniform Transmission Rates and Revenue Disbursement Allocators

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SCHEDULE B

2024 UNIFORM TRANSMISSION RATE SCHEDULES

DECISION AND RATE ORDER

EB-2023-0222

JANUARY 18, 2024

2024 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

EB-2023-0222

The rates contained herein shall be implemented effective January 1, 2024

Issued: January 18, 2024
Ontario Energy Board

TERMS AND CONDITIONS

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

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

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

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

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

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

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

(H) EMBEDDED CONNECTION POINT In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a distribution feeder to the Transmission Delivery Point. In above situations: •The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO- administered market. •The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

RATE SCHEDULE: (PTS) PROVINCIAL TRANSMISSION RATES

APPLICABILITY:

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

	Monthly Rate ($ per kW)
Network Service Rate (PTS-N): $ Per kW of Network Billing Demand [1,2]	**5.78**
Line Connection Service Rate (PTS-L): $ Per kW of Line Connection Billing Demand [1,3]	**0.95**
Transformation Connection Service Rate (PTS-T): $ Per kW of Transformation Connection Billing Demand [1,3,4]	**3.21**

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

Notes:

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

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

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

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

TERMS AND CONDITIONS OF SERVICE:

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

RATE SCHEDULE: (ETS) EXPORT TRANSMISSION SERVICE

APPLICABILITY:

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

	Hourly Rate
Export Transmission Service Rate (ETS):	$1.78 / MWh

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

TERMS AND CONDITIONS OF SERVICE:

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

SCHEDULE A

2024 REVENUE DISBURSEMENT ALLOCATOR

DECISION AND RATE ORDER

EB-2023-0222

JANUARY 18, 2024

Uniform Transmission Rates and Revenue Disbursement Allocators

Effective January 1, 2024

Transmitter	Revenue Requirement			
	Network	Line Connection	Transformation Connection	Total
Hydro One	$1,206,861,187	$212,168,826	$605,276,749	$2,024,306,762
HOSSM	$25,645,763	$4,508,581	$12,862,112	$43,016,456
FNEI	$4,762,380	$837,237	$2,388,475	$7,988,092
CNPI	$2,770,591	$487,076	$1,389,534	$4,647,201
WPLP	$33,585,573	-	-	$33,585,573
EWTLP	$54,921,609	-	-	$54,921,609
B2MLP	$36,395,939	-	-	$36,395,939
NRLP	$8,565,165	-	-	$8,565,165
All Transmitters	**$1,373,508,207**	**$218,001,720**	**$621,916,870**	**$2,213,426,797**

Transmitter	Total Annual Charge Determinants (MW)*			
	Network	Line Connection	Transformation Connection	
Hydro One	233,393.428	226,543.453	192,711.042	
HOSSM	3,498.236	2,734.624	635.252	
FNEI	230.410	248.860	73.040	
CNPI	522.894	549.258	549.258	
WPLP	156.151	-	-	
EWTLP	-	-	-	
B2MLP	-	-	-	
NRLP	-	-	-	
All Transmitters	**237,801.119**	**230,076.195**	**193,968.592**	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW/Month)	**5.78**	**0.95**	**3.21**	
Hydro One Allocation Factor	**0.87866**	**0.97325**	**0.97325**	
HOSSM Allocation Factor	**0.01867**	**0.02068**	**0.02068**	
FNEI Allocation Factor	**0.00347**	**0.00384**	**0.00384**	
CNPI Allocation Factor	**0.00202**	**0.00223**	**0.00223**	
WPLP Allocation Factor	**0.02445**	**0.00000**	**0.00000**	
EWTLP Allocation Factor	**0.03999**	**0.00000**	**0.00000**	
B2MLP Allocation Factor	**0.02650**	**0.00000**	**0.00000**	
NRLP Allocation Factor	**0.00624**	**0.00000**	**0.00000**	
Sum of Allocation Factors	**1.00000**	**1.00000**	**1.00000**	

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

Note 1: Hydro One Revenue Requirement and Charge Determinants per OEB Decision and Order EB-2023-0127 dated September 19, 2023.
Note 2: HOSSM Revenue Requirement and Charge Determinants per OEB Decision and Order EB-2023-0130 dated October 24, 2023.
Note 3: FNEI Revenue Requirement and Charge Determinants per OEB Revenue Requirement and Charge Determinant Order EB-2016-0231 dated January 18, 2018.
Note 4: CNPI Revenue Requirement and Charge Determinants per OEB Decision and Order EB-2015-0354 dated January 14,2016.
Note 5: WPLP Revenue Requirement and Charge Determinants per OEB Decision and Order EB-2023-0168 dated November 30, 2023.
Note 6: EWTLP Revenue Requirement per OEB Decision and Order EB-2023-0298, Upper Canada Transmission 2, Inc. dated December 12, 2023.
Note 7: B2MLP Revenue Requirement per OEB Decision and Order EB-2023-0129 dated September 7, 2023.
Note 8: NRLP Revenue Requirement per OEB Decision and Order EB-2023-0128 dated September 7, 2023.
Note 9: The revenue requirements of HOSSM, FNEI, and CNPI are allocated to the three transmission rate pools on the same basis as is used for Hydro One. The revenue requirements of WPLP, EWTLP, B2MLP and NRLP are allocated entirely to the Network rate pool. The total revenue requirements for each of the three transmission rate pools are then divided by the total charge determinants for each rate pool to establish the UTRs to two decimal places. The IESO uses the revenue collected from the UTRs to settle on a monthly basis with all rate-regulated transmitters using the revenue allocation factors.
Note 10: The allocation factors for each transmitter other than Hydro One are calculated by dividing each transmitter's revenue requirement assigned to each transmission rate pool by the total transmitters revenue requirement for each rate pool. The allocation factors are rounded to five decimal places for each transmitter. The sum of these individual transmitter allocation factors is then deducted from 1.0 to determine the allocation factor for Hydro One.

PROPOSED ONTARIO TRANSMISSION RATE SCHEDULES

The current 2024 UTR Schedules and the revenue requirement and charge determinants for all transmitters are updated with CLLP's 2025 rates revenue requirement to establish the proposed 2025 UTRs and revenue disbursement allocators which are included in the following attachments.

Attachment 1: Proposed 2025 Ontario Uniform Transmission Rate Schedules

Attachment 2: Proposed 2025 Uniform Transmission Rates and Revenue Disbursement Allocators

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SCHEDULE B

2025 UNIFORM TRANSMISSION RATE SCHEDULE

DECISION AND RATE ORDER

EB-2024-XXXX

MONTH DD, YYYY

2025 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULE

EB-2024-XXXX

The rates contained herein shall be implemented effective January 1, 2025

Issued: Month DD, YYYY
Ontario Energy Board

TERMS AND CONDITIONS

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

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

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

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

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

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

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

(H) EMBEDDED CONNECTION POINT In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a distribution feeder to the Transmission Delivery Point. In above situations: •The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO- administered market. •The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

RATE SCHEDULE: (PTS) PROVINCIAL TRANSMISSION RATES

APPLICABILITY:

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

	Monthly Rate ($ per kW)
Network Service Rate (PTS-N):	**5.85**
$ Per kW of Network Billing Demand [1,2]	
Line Connection Service Rate (PTS-L):	**0.95**
$ Per kW of Line Connection Billing Demand [1,3]	
Transformation Connection Service Rate (PTS-T):	**3.21**
$ Per kW of Transformation Connection Billing Demand [1,3,4]	

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

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

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

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

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

TERMS AND CONDITIONS OF SERVICE:

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

RATE SCHEDULE: (ETS) EXPORT TRANSMISSION SERVICE

APPLICABILITY:

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

	Hourly Rate
Export Transmission Service Rate (ETS):	$1.78 / MWh

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

TERMS AND CONDITIONS OF SERVICE:

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

SCHEDULE A

2025 REVENUE DISBURSEMENT ALLOCATOR

DECISION AND RATE ORDER

EB-2024-XXXX

MONTH DD, YYYY

Uniform Transmission Rates and Revenue Disbursement Allocators
Effective January 1, 2025

Transmitter	Revenue Requirement ($)			
	Network	**Line Connection**	**Transformation Connection**	**Total**
Hydro One	$1,206,861,187	$212,168,826	$605,276,749	$2,024,306,762
HOSSM	$25,645,763	$4,508,581	$12,862,112	$43,016,456
FNEI	$4,762,380	$837,237	$2,388,475	$7,988,092
CNPI	$2,770,591	$487,076	$1,389,534	$4,647,201
WPLP	$33,585,573	$0	$0	$33,585,573
EWTLP	$54,921,609	$0	$0	$54,921,609
B2MLP	$36,395,939	$0	$0	$36,395,939
NRLP	$8,565,165	$0	$0	$8,565,165
CLLP	$18,617,562	$0	$0	$18,617,562
All Transmitters	$1,392,125,769	$218,001,720	$621,916,870	$2,232,044,359

Transmitter	Total Annual Charge Determinants (MW)*			
	Network	**Line Connection**	**Transformation Connection**	
Hydro One	233,393.428	226,543.453	192,711.042	
HOSSM	3,498.236	2,734.624	635.252	
FNEI	230.410	248.860	73.040	
CNPI	522.894	549.258	549.258	
WPLP	156.151	0.000	0.000	
EWTLP	0.000	0.000	0.000	
B2MLP	0.000	0.000	0.000	
NRLP	0.000	0.000	0.000	
CLLP	0.000	0.000	0.000	
All Transmitters	237,801.119	230,076.195	193,968.592	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	**Line Connection**	**Transformation Connection**	
Uniform Transmission Rates ($/kW-Month)	**5.85**	**0.95**	**3.21**	
Hydro One Allocation Factor	**0.86693**	**0.97325**	**0.97325**	
HOSSM Allocation Factor	**0.01842**	**0.02068**	**0.02068**	
FNEI Allocation Factor	**0.00342**	**0.00384**	**0.00384**	
CNPI Allocation Factor	**0.00199**	**0.00223**	**0.00223**	
WPLP Allocation Factor	**0.02413**	**0.00000**	**0.00000**	
EWTLP Allocation Factor	**0.03945**	**0.00000**	**0.00000**	
B2MLP Allocation Factor	**0.02614**	**0.00000**	**0.00000**	
NRLP Allocation Factor	**0.00615**	**0.00000**	**0.00000**	
CLLP Allocation Factor	**0.01337**	**0.00000**	**0.00000**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

Note 1: Hydro One Revenue Requirement and Charge Determinants per OEB Decision and Order EB-2023-0127 dated September 19, 2023.
Note 2: HOSSM Revenue Requirement and Charge Determinants per OEB Decision and Order EB-2023-0130 dated October 24, 2023.
Note 3: FNEI Revenue Requirement and Charge Determinants per OEB Revenue Requirement and Charge Determinant Order EB-2016-0231 dated January 18, 2018.
Note 4: CNPI Revenue Requirement and Charge Determinants per OEB Decision and Order EB-2015-0354 dated January 14, 2016.
Note 5: WPLP Revenue Requirement and Charge Determinants per OEB Decision and Order EB-2023-0168 dated November 30, 2023.
Note 6: EWTLP Revenue Requirement per OEB Decision and Order EB-2023-0298, Upper Canada Transmission 2, Inc. dated December 12, 2023.
Note 7: B2M LP Revenue Requirement per OEB Decision and Order EB-2023-0129 dated September 7, 2023.
Note 8: NRLP Revenue Requirement per OEB Decision and Order EB-2023-0128 dated September 7, 2023.
Note 9: CLLP Revenue Requirement per E-01-01.
Note 10: The revenue requirements of HOSSM, FNEI, and CNPI are allocated to the three transmission rate pools on the same basis as is used for Hydro One. The revenue requirements of WPLP, EWTLP, B2M LP, NRLP and CLLP are allocated entirely to the Network rate pool. The total revenue requirements for each of the three transmission rate pools are then divided by the total charge determinants for each rate pool to establish the UTRs to two decimal places. The IESO uses the revenue collected from the UTRs to settle on a monthly basis with all rate-regulated transmitters using the revenue allocation factors.
Note 11: The allocation factors for each transmitter other than Hydro One are calculated by dividing each transmitter’s revenue requirement assigned to each transmission rate pool by the total transmitters revenue requirement for each rate pool. The allocation factors are rounded to five decimal places for each transmitter. The sum of these individual transmitter allocation factors is then deducted from 1.0 to determine the allocation factor for Hydro One.