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July 4, 2025

RESS & EMAIL

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

Attention: Ms. Nancy Marconi, Registrar

Dear Ms. Marconi:

Re: Wataynikaneyap Power LP - Application for Approval of 2026 Electricity Transmission Rates (EB-2025-0192)

We are legal counsel to Wataynikaneyap Power LP, a licensed Ontario electricity transmitter. Wataynikaneyap Power LP, by its general partner Wataynikaneyap Power GP Inc. (together, “WPLP”), is pleased to submit its application to the Ontario Energy Board (OEB) for approval of an electricity transmission revenue requirement and associated transmission rates for the 2026 test year.

If you have any questions, please do not hesitate to contact me at the number shown above.

Yours truly,

Jonathan Myers

cc: Ms. Margaret Kenequanash, WPLP
Mr. Duane Fecteau, WPLP
Mr. Charles Keizer, Torys LLP

Exhibit A, Tab 1, Schedule 1

Exhibit List

EXHIBIT LIST

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Exhibit A, Tab 2, Schedule 1

Application

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an application by Wataynikaneyap Power GP Inc. on behalf of Wataynikaneyap Power LP ("WPLP") for an Order or Orders made pursuant to section 78 of the Act, approving or fixing just and reasonable rates for the transmission of electricity.

APPLICATION

1. Wataynikaneyap Power GP Inc. ("Wataynikaneyap GP") is an Ontario corporation and the general partner of Wataynikaneyap Power LP ("Wataynikaneyap LP"), an Ontario limited partnership. Wataynikaneyap GP on behalf of Wataynikaneyap LP ("WPLP" or the "Applicant") holds an electricity transmission licence (ET-2015-0264) from the Ontario Energy Board (the "Board" or "OEB"). WPLP is seeking approval of an electricity transmission revenue requirement in respect of a single test year, commencing January 1, 2026.

2. The limited partnership interests in Wataynikaneyap LP are held 51% by First Nation LP and 49% by Fortis (WP) LP. First Nation LP is an Ontario limited partnership whose general partner is 2472881 Ontario Limited ("First Nation GP"). The limited partnership interests in First Nation LP are held directly and in equal shares by 24 First Nations (the "Participating First Nations"). Fortis (WP) LP is an Ontario limited partnership whose general partner is Fortis (WP) GP Inc. The limited partnership interests in Fortis (WP) LP are held by Fortis Inc. (80%) and indirectly by Algonquin Power & Utilities Corp. (20%). With respect to the corresponding general partnerships, the shares of Wataynikaneyap GP are held 51% by First Nation GP and 49% by Fortis (WP) GP Inc. The shares of First Nation GP are held directly and in equal shares by the Participating First Nations. The shares of Fortis (WP) GP Inc. are indirectly held by Fortis Inc. (100%).

3. WPLP was established for the purposes of developing, constructing, owning and operating a new electricity transmission system, approximately 1742 km in total length, in northwestern Ontario that will (i) reinforce transmission from a point near Dinorwic to Pickle Lake by means of the "Line to Pickle Lake", and (ii) provide transmission connections to remote Indigenous communities by means of the "Remote Connection Lines", which extend north of Pickle Lake and north of Red Lake (collectively, the "Transmission System").[1]

4. On April 1, 2019, the OEB granted WPLP leave to construct the Transmission System (EB-2018-0190). In addition, the OEB approved a bespoke cost recovery and rate framework for the Remote Connection Lines portion of the Transmission System, which results in a monthly fixed charge applicable to Hydro One Remote Communities Inc. ("HORCI"). The OEB also confirmed that, for the Line to Pickle Lake portion of the Transmission System, WPLP's revenue requirement will be recovered through the network charge component of the Uniform Transmission Rates ("UTRs").

5. This is WPLP's fifth transmission revenue requirement application. WPLP's first such application (EB-2021-0134) was in respect of its 2022 electricity transmission revenue requirement and associated rates effective April 1, 2022, and approval to charge HORCI a fixed charge for transmission service effective May 1, 2022. The second application was in respect of WPLP's 2023 transmission revenue requirement (EB-2022-0149), the third was in respect of WPLP's 2024 transmission revenue requirement (EB-2023-0168), and the fourth was in respect of WPLP's 2025 transmission revenue requirement (EB-2024-0176). In each of these proceedings, the parties reached complete settlement on all issues, which settlements were subsequently approved by the OEB.

6. In WPLP's most recent application (EB-2024-0176), the approved Settlement Agreement provided for a total 2025 revenue requirement of $176.2 million after accounting for the

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[1] WPLP's development, construction and operation of the Transmission System are also in accordance with the Guiding Principles which were approved by the leadership of the Participating First Nations.

2025 cost of capital, with recovery of $43.5 million through the UTR Network rate pool effective January 1, 2025 in respect of the Line to Pickle Lake portion of WPLP's transmission system, and recovery of $132.7 million through a monthly fixed charge of $11.1 million to HORCI effective January 1, 2025 in respect of the Remote Connection Lines portion of WPLP's transmission system.

7. In the current application, WPLP is seeking approval of a single-year cost of service revenue requirement for the 2026 test year, commencing on January 1, 2026. In accordance with the terms of the approved Settlement Proposal in EB-2024-0176, WPLP will file a multi-year revenue requirement application using an incentive-based regulatory method available to transmitters in 2026 for a rate period starting with the 2027 test year.

8. The Line to Pickle Lake went into service on August 12, 2022. WPLP proposes that the OEB incorporate the associated revenue requirement for the Line to Pickle Lake into the updated UTRs for existing transmitters effective January 1, 2026.

9. The Remote Connection Lines have gone into service in stages between Q4 2022 and Q2 2024, with the final segments being energized in May 2024. WPLP proposes to implement the monthly fixed charge to HORCI, reflecting all of the assets comprising the Remote Connection Lines, effective January 1, 2026.

10. On the basis of the foregoing, WPLP hereby applies to the OEB for orders approving:

    (a) A total revenue requirement of $133,031,093 for the 2026 test year (inclusive of the disposition of regulatory accounts as described below) and recovery thereof by means of:

        (i) the allocation to the Network UTR rate pool, the calculation of Network UTR charge determinants, and an amendment to UTRs, to allow for recovery of $29,685,502, being the portion of the total revenue requirement attributed to transmission service provided by the Line to Pickle Lake for the 2026 test year; and

(ii) a fixed charge of $8,612,133 per month, applicable to HORCI from January 1, 2026 to December 31, 2026, for recovery of $103,345,591, being the portion of the total revenue requirement attributed to transmission service provided by the Remote Connection Lines for the 2026 test year;

(b) The disposition of deferral and variance accounts, as follows:

(i) Final disposition of the audited balance of the Pikangikum Distribution System Deferral Account (established by the November 22, 2018 Decision and Order in EB-2018-0267) as at December 31, 2024, less the amount approved for disposition in the 2025 rate application, plus forecasted carrying charges to year-end 2025[2], and the addition of the corresponding costs to WPLP's revenue requirement in respect of the Remote Connection Lines for 2026, as detailed in Exhibits H-2-1;

(ii) Final disposition of the remaining portion of the audited balance of the COVID Construction Costs Deferral Account (established by the September 30, 2021 Decision and Order in EB-2021-0134), as at December 31, 2024, less the approved disposition amount included in the 2025 rate application, plus forecasted carrying charges for 2025[3], as further detailed in Exhibit H-2-1;

(iii) Final Disposition of the audited balances of the In-Service Date Variance Account (established by the September 30, 2021 Decision and Order in EB-2021-0134), as at December 31, 2024, less the amounts approved for

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[2] Given principal balance is nil at the end of 2025, there are no forecasted carrying charges for 2026.

disposition from this account in the 2025 rate application, plus forecasted carrying charges for 2025 and 2026, as further detailed in Exhibit H-2-1;

(iv) Final Disposition of the audited balances of the Deferred Contingency Deferral Account (established by the September 30, 2021 Decision and Order in EB-2021-0134), as at December 31, 2024, less the amounts approved for disposition from this account in the 2025 rate application, plus forecasted carrying charges for 2025 and 2026, as further detailed in Exhibit H-2-1;

(v) Final disposition of the audited balance of the Federal CIAC Variance Account (established by the November 30, 2023 decision in EB-2023-0168), as at December 31, 2024, plus forecasted carrying charges for 2025 and 2026, as further detailed in Exhibit H-2-1;

(vi) Partial disposition of the audited balances of the Construction Period Interest Costs Variance Account (established by the September 30, 2021 Decision and Order in EB-2021-0134), as at December 31, 2024, less the amounts approved for disposition from this account in the 2025 rate application, plus forecasted carrying charges for 2025 and 2026, as further detailed in Exhibit H-2-1:

(vii) Partial disposition of the audited balance of the OM&A Variance Account (formerly known as the Construction Period OM&A Variance Account, established by the November 29, 2022 decision in EB-2022-0149), as at December 31, 2024, less the amounts approved for disposition from this account in the 2025 rate application, plus forecasted carrying charges for 2025 and 2026, as further detailed in Exhibit H-2-1;

(c) The continuation during 2026, and discontinuation at the end of 2026, of the Pikangikum Distribution System Deferral Account, In-Service Date Variance

Account, Deferred Contingency Deferral Account, COVID Construction Costs Deferral Account and Federal CIAC Variance Account, as requested in Exhibit H-1-1; and

(d) The continuation in 2026 of the Construction Period Interest Costs Variance Account and the OM&A Variance Account, as requested in Exhibit H-1-1.

11. The evidence in support of this application has been prepared generally in accordance with the requirements set out in the OEB's *Filing Requirements for Electricity Transmission Rate Applications – Chapter 2, Revenue Requirement Applications*, dated February 11, 2016, subject to differences which reflect the unique nature of the application and the underlying transmission facilities, as described in Exhibit A-5-1.

12. The Applicant requests that copies of all documents filed with or issued by the OEB in connection with this Application be served on the Applicant and its counsel as follows:

Applicant:

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Chief Executive Officer
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Vice President – Finance and CFO
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Applicant’s Counsel:

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Fax: 416-865-7380	Fax: 416-865-7380
ckeizer@torys.com	jmyers@torys.com

13. Additional written evidence, as required, may be filed in support of this Application, which may be amended from time to time prior to the OEB’s final decision.

14. The Applicant requests that the OEB proceed by way of written hearing, pursuant to Section 32.01 of the OEB’s *Rules of Practice and Procedure*.

Dated at Toronto, Ontario, this 4th day of July, 2025.

WATAYNIKANEYAP POWER GP INC.
on behalf of WATAYNIKANEYAP POWER LP

By its counsel, Torys LLP

Jonathan Myers

Exhibit A, Tab 2, Schedule 2

Certificate of Evidence

CERTIFICATE OF EVIDENCE

The undersigned, being Duane Fecteau, Vice President Finance and CFO, hereby certifies for and on behalf of Wataynikaneyap Power LP that:

1. I am a senior officer of Wataynikaneyap Power PM Inc., duly authorized to submit this application on behalf of Wataynikaneyap Power LP;
2. This certificate is given pursuant to Chapter 1 of the Ontario Energy Board's *Filing Requirements for Electricity Transmission Applications* (last revised February 11, 2016); and
3. The evidence submitted in support of Wataynikaneyap Power LP's application for 2026 electricity transmission rates (EB-2024-0176) is accurate, consistent and complete to the best of my knowledge, and does not contain any personal information (as that phrase is defined in the *Freedom of Information and Protection of Privacy Act*, R.S.O. 1990, c. F.31), that is not otherwise redacted in accordance with rule 9A of the OEB's *Rules of Practice and Procedure*.

Dated this 4th day of July, 2025.

Duane Fecteau

Exhibit A, Tab 3, Schedule 1

Executive Summary

EXECUTIVE SUMMARY

A. OVERVIEW

WPLP became a licensed transmitter in 2015, and in 2016 construction of WPLP's Transmission System was declared by the Province of Ontario to be a priority project pursuant to section 96.1 of the *Ontario Energy Board Act, 1998*. After receiving leave to construct and approval of a unique cost recovery and rate framework in 2019, WPLP secured project financing and engaged an engineering, procurement and construction ("EPC") contractor through a competitive procurement process. WPLP's Transmission System went into service in segments, starting in the second half of 2022 and continuing throughout 2023, with the final segments of the system having gone into service in the first half of 2024. As such, 2025 is the first year in which the entire Transmission System will be operating for a full year. The Transmission System is comprised of 22 stations and approximately 1742 km of lines in northwestern Ontario, which have reinforced the transmission system in the region and extended transmission service to connect 16 remote First Nation communities to the provincial electricity grid for the first time.[1]

This is WPLP's fifth transmission revenue requirement application and is in respect of a 2026 test year. Key areas of focus in WPLP's prior annual revenue requirement applications, starting with the 2022 rate year, included WPLP's construction and in-servicing progress, its monitoring and oversight of the EPC contractor, including of the contractor's management of the construction impacts of the COVID-19 pandemic (which started approximately six months after the EPC contract was signed in September 2019), WPLP's transition from construction to operations, and the status of ongoing commercial discussions with the EPC contractor regarding COVID-19 impacts on cost and schedule and related access matters under the EPC contract.

The current application includes WPLP's first Transmission System Plan ("TSP"), which in accordance with the terms of its Settlement Agreement in its last revenue requirement proceeding it has prepared on a best-efforts basis. WPLP's next revenue requirement application will be for

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[1] The Project is designed to permit the potential future connection of a 17th community, McDowell Lake First Nation.

a multi-year rate period starting with a 2027 test year, and will include a more mature TSP. In the current application, WPLP is seeking approval for a materially lower revenue requirement for 2026 than was approved for 2025. This is largely due to deferral account recoveries, specifically the Federal CIAC Variance Account and Construction Period Interest Variance Accounts. Further details on the **r**ecovery of these accounts is provided as part of Exhibit H-2-1.

Since WPLP's last transmission revenue requirement application,[2] WPLP has been focused on operations, including engagement on permanent access plans and the vegetation management program, amendments to WPLP construction financing agreement as noted in Exhibit G-1-1, and monitoring construction close-out activities. In addition, as discussed in Exhibit H-2-2, WPLP continues to be engaged in commercial discussions with its EPC contractor regarding costs under the EPC Contract in relation to COVID-19 impacts and related access matters, the outcome of which will ultimately be recorded in the previously approved EPC COVID-Related Construction Costs Deferral Account.

This Schedule summarizes WPLP's current application in respect of its transmission revenue requirement for the 2026 test year and other related approvals (the "Application"). Section B, below, summarizes key background information about the Applicant, the Transmission System, context from prior proceedings, and the specific approvals requested in this Application. Section C summarizes the key elements of the Application, consistent with the headings and expectations set out in Section 2.3.1 of the Filing Requirements[3], including how WPLP has addressed certain aspects of the Filing Requirements in the context of filing a single test year Application.

Historical costs presented in this Application are consistent with WPLP's December 31, 2024 audited financial statements. Other information is current as of May 31, 2025.

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[2] EB-2024-0176, Decision and Order, December 10, 2024.

[3] Filing Requirements for Electricity Transmission Rate Applications – Chapter 2, Revenue Requirement Applications, dated February 11, 2016

B. BACKGROUND

1. The Applicant

WPLP is a Limited Partnership between First Nation LP, whose partnership interests are held directly by 24 Participating First Nations in equal shares, and Fortis (WP) LP, whose partnership interests are held by Fortis Inc. and indirectly by Algonquin Power & Utilities Corp.

Of the 24 Participating First Nations, which are from northwestern Ontario, 16 have been connected to WPLP's Transmission System as part of the Transmission Project.[4] All of the Participating First Nations have been instrumental in the development of WPLP's Transmission System, and are uniquely qualified to support the ongoing engagement, communication and Indigenous participation activities that have been necessary to facilitate successful project execution and construction, and which continue to be vital to the ongoing operation of the Transmission System.

Fortis Inc. is a diversified leader in the North American regulated electric and gas utility industry that leverages its knowledge, experience and expertise to support project management, engineering, operations, finance, regulatory and various corporate functions to support the successful construction and ongoing operation of the Transmission System.

WPLP's ownership structure is described in further detail in Exhibit A-4-1.

2. The Transmission System

WPLP's Transmission System operates as a single in-service transmission system in northwestern Ontario. One part of the system reinforces transmission to Pickle Lake (the "Line to Pickle Lake"). The balance of the system, connects the provincial power system to 16 remote First Nation

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[4] For Muskrat Dam First Nation, which has historically been served by an Independent Power Authority ("IPA"), the transmission system assets up to the community connection point were energized by WPLP in 2023, but community connection is pending IPA upgrades and information transfers, and is therefore expected to occur in 2025. The upgrades and information transfers are being coordinated by Indigenous Services Canada and are outside of WPLP's control, as further detailed in Attachment A of the most recent Semi-Annual Report dated April 15, 2025 in EB-2018-0190.

communities that have historically only been served by local diesel generation (the "Remote Connection Lines").[5]

The Line to Pickle Lake went into service in August 2022. It consists of: (a) a 230 kV switching station (Dinorwic SS[6]) at the location where WPLP's Transmission System connects to Hydro One's 230 kV system near Dinorwic; (b) an approximately 303 km single circuit 230 kV line running generally in a northeasterly direction from the Dinorwic area to the Pickle Lake area; and (c) a 230/115 kV transformer station (Pickle Lake TS[7]) in the Pickle Lake area, which supplies WPLP's Pickle Lake Remote Connection Lines and connects to Hydro One's Pickle Lake area 115 kV transmission system.

The Remote Connection Lines went into service in segments starting in late 2022, with further segments put in service in 2023 and the remaining segments put into service during the first half of 2024. The Remote Connection Lines consist of: (a) the Pickle Lake Remote Connection Lines, comprised of approximately 903 km of single circuit 115 kV, 44 kV and 25 kV transmission lines, as well as one switching station and nine transformer stations located generally to the north of the Pickle Lake TS; and (b) the Red Lake Remote Connection Lines, comprised of a 115 kV switching station (Red Lake SS) at WPLP's connection to Hydro One's 115 kV system near Red Lake, as well as approximately 535 km of single circuit 115 kV and 25 kV transmission lines, three additional switching stations and six transformer stations located generally to the north of the Red Lake SS.[8]

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[5] One of the 16 communities, Pikangikum First Nation, became grid-connected in 2018 through an interim 44 kV connection that was converted to 115 kV on May 12, 2023, and therefore now forms part of WPLP's Transmission System. The future connection of a 17th community, McDowell Lake First Nation, would also be supported through the Remote Connection Lines.

[6] The updated name of the switching station to Dinorwic SS from Wataynikaneyap SS is to be consistent with IESO registration naming.

[7] The updated name of the switching station to Pickle Lake TS from Wataynikaneyap TS is to be consistent with IESO registration naming.

[8] In EB-2018-0190, the OEB amended Schedule 1 of WPLP's Transmission Licence (ET-2015-0264) to reflect that the 44 kV and 25 kV segments of WPLP's Transmission System were deemed to be transmission facilities pursuant to Section 84(b) of the *Ontario Energy Board Act, 1998.*

The Remote Connection Lines provide transmission service to the 25 kV distribution systems that are or are in the process of becoming owned and operated by Hydro One Remote Communities Inc. ("HORCI") in each of the 16 connected First Nation communities.[9] Exhibit B-1-2 provides detailed descriptions of the components of WPLP's Transmission System and Appendix "A" thereto provides as a map showing the geographical location and extent of the system.

3. Context from Prior Proceedings

The following unique aspects from prior proceedings provide important context for the current Application.

(a) Cost Recovery and Rate Framework[10]

The OEB determined in the LTC Decision that the Line to Pickle Lake is a network facility and that cost recovery for the Line to Pickle Lake would be through the UTR Network charge in the normal course of setting transmission rates. Since its initial rate proceeding for the 2022 test year,[11] WPLP has therefore ensured that all costs directly related to the Line to Pickle Lake are recorded as such, and that any indirect costs included in its revenue requirement are appropriately allocated between the Line to Pickle Lake and the Remote Connection Lines.

With respect to the Remote Connection Lines, in the LTC proceeding WPLP proposed and the OEB approved an alternative cost recovery and rate framework that would be compatible with project-specific funding it expected to receive from the federal government. The proposal was also designed to ensure that the construction and operation of the Transmission System, and WPLP as a utility, would be financially viable, regardless of whether such funding is ultimately received.

As part of the cost recovery and rate framework approved in the LTC Decision, the OEB approved exemptions from the provisions of the Transmission System Code that would otherwise have

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[9] HORCI continues to work with Muskrat Dam First Nation. An update on progress has been provided in the Semi-Annual Report dated April 15, 2025, filed pursuant to EB-2018-0190.

[10] EB-2018-0190, Decision and Order, April 1, 2019 (Revised April 29, 2019) ("LTC Decision"), Section 5.

[11] EB-2021-0134, Decision and Order, September 30, 2021 ("Initial Rate Decision").

required HORCI to make a capital contribution towards the cost of constructing the Remote Connection Lines. Instead, WPLP calculates a distinct revenue requirement for the Remote Connection Lines and recovers that revenue requirement through a monthly fixed charge to HORCI. In accordance with regulations under the *Ontario Energy Board Act*, the expense incurred by HORCI in respect of these monthly fixed charges forms part of HORCI's revenue requirement and thereby forms part of the Rural or Remote Rate Protection (RRRP) funding calculation and RRRP amounts payable to HORCI. Through this rate framework, costs associated with WPLP's Transmission System do not impact rates for customers in the connected First Nation communities. Moreover, some of the funding provided under the Federal Funding Framework will be used to offset the impacts on the RRRP amounts that the IESO will need to recover from all Ontario transmission customers such that costs associated with WPLP's Remote Connection Lines would not be expected to impact rates for any customers in Ontario until such time as the funds of the independent Trust (established pursuant to the Federal Funding Framework) are exhausted.

The Federal Funding Framework is discussed further in Exhibit I-4-1. Significantly, the distribution of federal funds to the independent Trust occurred on June 25, 2024, and a portion of the independent Trust proceeds were provided to WPLP to be applied as a CIAC on July 11, 2024. As such, the impact of such federal funding is incorporated into the current application. As noted below and described in Exhibit H-1-1, to address the revenue requirement impacts of the timing for the federal funds being distributed and applied as a CIAC, which was previously uncertain, the OEB in the 2024 Rate Application approved a variance account referred to as the Federal CIAC Variance Account.

Another key development in 2024, also described in Exhibit I-4-1, was that the parties to the Trust Agreement under the Federal Funding Framework agreed to an Amendment to the Trust Agreement which (i) excluded from the determination of WPLP's available Owner Equity the $68.71M in COVID-19 costs that were added to rate base in EB-2023-0168, thereby increasing WPLP's available Owner Equity under the Trust from $458M to $520M, and (ii) requires the independent Trust to make an additional CIAC to WPLP once WPLP has settled or otherwise resolved the amounts that are the subject of ongoing commercial discussions with the EPC

Contractor, recorded such amounts in the EPC COVID-Related Costs Deferral Account, and the OEB has reviewed and approved the prudence of the amounts that may be added to WPLP's rate base on disposition of the balance in the EPC COVID-Related Costs Deferral Account in a future application, inclusive of accumulated carrying charges. The amount of such additional CIAC will be equal to the approved rate base addition such that there would not ultimately be a rate base addition in respect of the disposition from the EPC COVID-Related Costs Deferral Account, thereby reducing the impact of COVID-19 on Ontario electricity ratepayers.[12]

(b) OM&A Variance

In the 2023 Rate Decision[13], the OEB approved a comprehensive settlement agreement, pursuant to which the parties agreed that WPLP would establish what was then called the Construction Period OM&A Variance Account, asymmetrical to the benefit of ratepayers, to record the difference, if any, between the annual forecast and actual OM&A expenses during the construction period, with any shortfall in actual spending relative to forecast to be returned to ratepayers in a future proceeding. This account was maintained in the 2024 Rate Decision[14] and in the Prior Rate Decision[15] for the 2025 test year. However, as part of the Prior Decision, the account was renamed the "OM&A Variance Account" to reflect that it would be used to record additional variance amounts for 2025 rather than maintaining it only for the purposes of facilitating recovery of the existing balance and applicable carrying costs. As discussed below, WPLP is proposing to partially dispose of the OM&A Variance Account, and to record any variances between approved and actual OM&A expense, along with applicable carrying charges for 2025 and 2026, as agreed in EB-2024-0176, but is not seeking to add to the principal balance in 2026.

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[12] The impact of the two changes to the Trust Agreement is to materially reduce the financial impact of the Project for Ontario ratepayers, as further discussed in Exhibit I-4-1.

[13] EB-2022-0149, Decision and Order, November 29, 2022 ("2023 Rate Decision").

[14] EB-2023-0168, Decision and Order, November 30, 2023 ("2024 Rate Decision").

[15] EB-2024-0176, Decision and Order, December 10, 2024 (the "Prior Rate Decision").

(c) COVID Cost Recovery

In the OEB-approved settlement agreement from the Initial Rate Decision, the parties agreed that WPLP may recover its audited 2020 year-end balance of COVID-related costs as an expense through disposition of the balance in the "COVID Construction Costs Deferral Account" over a 4-year period (i.e. 25% in each of 2022, 2023, 2024 and 2025).

In the settlement agreement approved in the 2023 Rate Decision, the parties agreed that WPLP would establish a new and distinct "2021-2023 COVID Construction Costs Deferral Account" to record audited year-end COVID-related costs from 2021 to 2023.

In the 2024 Rate Decision, the OEB authorized establishment of a further account, the "EPC COVID-Related Costs Deferral Account" to record costs, including applicable carrying charges, incurred and to be incurred by WPLP under its EPC contract that relate to 2020 or later and which are in respect of anticipated claims from the EPC contractor for cost and schedule relief under the EPC contract in relation to COVID and related access issues in the Whitefeather Forest area. The parties to the settlement approved in the 2024 Rate Decision agreed that the method of recovery – as capital or as expenses – will be subject to determination in a future application, and that the carrying cost shall on an interim basis be the OEB prescribed rate but shall be recalculated on the basis of the applicable CWIP rate if and when recovery is determined to be as capital.

See section C.11, below, as well as Exhibit H-2-2 for further details.

4. Approvals Requested

The primary purpose of this Application is to request approval of a total electricity transmission revenue requirement of $133,031,093 for a single test year, commencing January 1, 2026. A number of related approvals are also explicitly requested, including approvals for:

- allocation of WPLP's 2026 revenue requirement between the Line to Pickle Lake and the Remote Connection Lines as set out in Exhibit I-2-1, as well as:

  - recovery of the portion of WPLP's 2026 revenue requirement allocated to the Line to Pickle Lake, being $29,685,502, through adjustments to the 2026 Network UTR rate in the manner described in Exhibit I-3-1, and
  - recovery of the portion of WPLP's 2026 revenue requirement allocated to the Remote Connection Lines, being $103,345,591, through fixed monthly charges of $8,612,133, applicable to HORCI effective from January 1, 2026 to December 31, 2026, as described in Exhibit I-3-2;

- final disposition of the Pikangikum Distribution System Deferral Account, COVID Construction Costs Deferral Account, the In-Service Date Variance Account, Deferred Contingency Deferral Account and the Federal CIAC Variance Account, as more particularly set out in Exhibit H-2-1;
- partial disposition of the Construction Period Interest Costs Variance Account and the OM&A Variance Account, as more particularly set out in Exhibit H-2-1;
- the continuation during 2026, and discontinuation at the end of 2026, of the Pikangikum Distribution System Deferral Account, In-Service Date Variance Account, Deferred Contingency Deferral Account, COVID Construction Costs Deferral Account and Federal CIAC Variance Account, as requested in Exhibit H-2-1; and
- the continuation of the Construction Period Interest Costs Variance Account and the OM&A Variance Account, as requested in Exhibit H-2-1.[16]

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[16] For greater certainty, WPLP assumes that the EPC COVID-Related Costs Deferral Account will also be continued, in accordance with the terms established for the account.

C. KEY ELEMENTS OF THE APPLICATION

1. Revenue Requirement and Materiality Threshold

In this Application, WPLP requests approval of a 2026 test year revenue requirement of $133,031,093. Table 1, below, provides a summary of the derivation of WPLP's revenue requirement, with references to the relevant sections of the Application that substantiate each component.

Table 1 – 2026 Revenue Requirement Summary

	LTPL	**RCL**	**Total**	**Reference**
Gross Fixed Assets (avg)	321,759,981	1,001,637,154	1,323,397,135	C-3-1
Accumulated Depreciation (avg)	-23,937,770	-63,976,355	-87,914,125	C-3-1
Net Fixed Assets (avg)	297,822,211	937,660,799	1,235,483,010	C-3-1
Working Capital Allowance	0	0	0	C-4-1
Rate Base	297,822,211	937,660,799	1,235,483,010	C-1-1
Regulated Rate of Return	6.34%	6.34%	6.34%	G-2-1
Regulated Return on Rate Base	18,867,037	59,400,813	78,267,850	G-2-1
OM&A Expenses	6,025,286	32,328,524	38,353,810	F-2-1
Property Taxes	0	0	0	F-5-1
Depreciation Expense	6,536,434	20,327,124	26,863,558	F-4-1
Income Taxes	105,976	490,349	596,325	F-5-1
Service Revenue Requirement	31,534,733	112,546,810	144,081,543	
Other Revenue Offset	0	0	0	E-3-1
Base Revenue Requirement	**31,534,733**	**112,546,810**	**144,081,543**	
Disposition of Pikangikum Distribution System Deferral Account	0	-3,555	-3,555	H-2-1
Disposition of COVID Construction Costs Deferral Account (CCCDA)	-17,001	-7,380	-24,381	H-2-1
Disposition of In-Service Date Variance Account (ISDVA)	-224,793	6,771,416	6,546,623	H-2-1
Disposition of Period Interest Costs Variance Account (CPICVA)	334,137	1,404,524	1,738,661	H-2-1
Disposition of Deferred Contingency Deferral Account (DCDA)	13,261	52,725	65,986	H-2-1

Disposition of OM&A Variance Account	-1,954,835	-2,582,438	-4,537,273	H-2-1
Disposition of Federal CIAC Variance Account	0	-14,836,511	-14,836,511	H-2-1
Revenue Requirement for Rates	**29,685,502**	**103,345,591**	**133,031,093**	I-1-1

For transmitters requesting approval of revenue requirements greater than $10 million and less than or equal to $200 million, Section 2.1.1 of the Filing Requirements specifies a materiality threshold of 0.5% of revenue requirement. Based on the revenue requirement indicated in Table 1 above, WPLP's materiality threshold is approximately $665,155.

2. Budgeting Assumptions

Where applicable, WPLP has assumed an inflation rate of 2%.

3. Load Forecast Summary

WPLP forecasts that the Network UTR demand determinants will increase by 16.1 MW in 2026, to a total of 210.0 MW. This is based on (i) load on the distribution systems in the ten First Nation communities connected to the North of Pickle Lake Remote Connection Lines, which are or will be supplied directly by WPLP's Transmission System,[17] and (ii) load on the distribution systems in the six First Nation communities connected to the North of Red Lake Remote Connection Lines, which are supplied directly by WPLP's Transmission System via HONI's transmission system, but which is not included in HONI's UTR charge determinant forecast. Details of WPLP's methodology for determining the monthly demand forecast for each community are provided in Exhibit E-1-1.

In consideration of the rate framework approved by the OEB for the Remote Connection Lines,[18] WPLP has requested approval of a fixed monthly charge, in the amount of $8,612,133, applicable to HORCI for service from the Remote Connection Lines. WPLP has therefore not included any

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[17] In the case of Muskrat Dam First Nation, community connection is pending IPA upgrades and information transfers, and is expected to occur in 2025. WPLP has included their load forecast in this 2026 rate application.

[18] See Section C.8 below for additional detail on the Remote Connection Lines rate framework.

Line Connection or Transformation Connection revenue requirements or charge determinants in its 2026 rate design.

4. Transmission System Plan

This is WPLP's first application that includes a Transmission System Plan ("TSP"). In accordance with the Prior Decision which recognizes certain limitations on WPLP, the TSP has been prepared on a best-efforts basis. It is comprised of the past five historical/bridge years from 2021-2025, and the five future years from 2026-2030. As WPLP's Transmission System is newly constructed, it requires minimal sustaining capital investment in the near term and the operational experience WPLP is gaining over the first full year of the entire system being in service during 2025 will help inform its capital planning going forward. Some elements of the TSP remain incomplete or under development given WPLP's limited time and resources since the conclusion of EB-2024-0176 and 2025 being the first full year of actuals based on the entire Transmission System being in service. WPLP will continue to develop its TSP for inclusion as part of its first multi-year rate application, which will be filed in 2026 for a rate period starting with the 2027 rate year.

(a) Investment Planning

The key components of WPLP's investment planning process are its Strategic Plan, O&M Strategy, Economic and Planning Assumptions and its Investment Strategy.

WPLP's Strategic Plan is reflected in the Mandate, Vision and Guiding Principles established by the leadership of the 24 Participating First Nations and supported by the partners during development of the Transmission Project. Following completion of the Transmission Project, WPLP initiated a process to engage with the First Nations to reaffirm and reinvigorate the Mandate, Vision and Guiding Principles in consideration of the transition to Operations. This renewed framework, once finalized, will provide the foundation for WPLP's overall organizational strategy, which will in turn influence the progression of WPLP's O&M and investment strategies.

WPLP's O&M Strategy is integrally linked to its preliminary Asset Management Plan and is therefore an important component of the initial TSP. WPLP has implemented its initial strategy, which has included third-party agreements for Inspection, Maintenance and Emergency Response ("IMER") activities and control room services, maximizing opportunities for Indigenous Participation through employment, contracting and capacity building, evaluating emerging technologies and work methods that support an O&M methods tailored to WPLP's unique circumstances, leveraging construction resources to support efficient Transmission System operations and recruiting internal resources to lead and support ramp-up of O&M programs during the transition from the construction phase. WPLP has also selected a service provider to perform required environmental monitoring and reporting activities and plans to contract for initial vegetation management services. Finally, WPLP is in the process of implementing a software-based Asset Management Condition Monitoring Solution, discussed below, which will assist WPLP in managing asset, inspection and testing data to support work planning and other utility functions.

WPLP's Economic and Planning Assumptions include a forecasted annual growth rate of 4% for load in the connected First Nations over the medium to long term. In addition, WPLP has started to receive inquiries related to connecting new industrial loads to its Transmission System. As no connection applicants have yet proceeded with Connection Estimates, WPLP has not included any investments related to new industrial connections in its future investment forecasts. In working with interested parties, WPLP will follow its OEB-approved Transmission Connection Procedures, which include important procedures for ensuring adequate capacity is maintained to meet the needs of the connected First Nations and to clarify for proponents their separate responsibility to engage directly with First Nations. In addition, WPLP monitors and participates in relevant regional planning processes, which may also drive the need for investments in the Transmission System.

WPLP's historical capital investments have been primarily focused on the development, construction, and placing into service of the Transmission Project. Given the age and condition of WPLP's Transmission System, it requires relatively minimal sustaining capital investment in the near term. WPLP expects the quantum and timing of future capital investments will be heavily influenced by the outcome of regional planning processes and connection requests that are currently in progress, as well as the evolution of its organizational and operations strategies. As the current Application is for a single test year, WPLP's planned capital expenditures are focused on the 2026 test year. WPLP has also considered projects and programs that will be further costed, prioritized and scheduled as part of the next TSP to be filed with WPLP's first multi-year rate plan.

(b) Asset Management Planning

To effectively manage the extensive data associated with in-service and commissioning records, inspection programs and diagnostic testing, and to help retrieve, sort and analyze this data to identify and prioritize maintenance needs, WPLP is in the process of implementing a software-based Asset Management Condition Monitoring Solution ("ENGIN"). Given that the majority of WPLP's assets have decades of estimated service life remaining, WPLP's current focus is on implementing its initial preventive maintenance strategy, which is primarily schedule-based, in parallel with implementing ENGIN to support the evolution to predictive and/or reliability-centered maintenance strategies. This strategy will include a comprehensive asset condition monitoring program which, using ENGIN, will determine health indices for each asset. However, meaningful asset health information and trending is not yet available. WPLP also tracks and monitors frequency and causes of planned and unplanned outages to inform its preventative and corrective maintenance strategies and investment planning, and is implementing annual and multi-year inspection and maintenance programs for its substation and line assets.

(c) Prior Sustaining Capital Expenditures

WPLP's historical sustaining capital expenditures by year are summarized in Table 2, below.

Table 2 – Sustaining Capital Expenditures by Year

RRFE Category	Capital Expenditures ($000's)				
	2021	2022	2023	2024	2025[19]
System Access	0	0	0	0	0

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[19] As noted in Exhibit D-2-1, at the time of filing there are ongoing wildfires within the region through which WPLP's Transmission System traverses. At the time of filing, the extent of damage to WPLP's facilities, if any, is unknown. Once this information becomes available, and if the circumstances warrant, WPLP will provide an update to its evidence.

System Renewal	0	0	359	326	800
System Service	0	0	0	0	0
General Plant	0	0	0	0	380
Total Sustaining Capital	**0**	**0**	**359**	**326**	**1,180**

The sustaining investments above relate to wood pole replacement costs due to woodpecker damage, as well as minor General Plant expenditures related to IT infrastructure and office equipment, consistent with the in-service additions forecasted in WPLP's 2025 rate application.

(d) Proposed 2026 Test Year Capital Expenditures

WPLP's planned capital expenditures for the 2026 test year are summarized in Table 3 below.

Table 3 – 2026 Capital Expenditures ($000's)

RRFE Category	Project / Program	Expenditure by Project/Program[20]
System Access	N/A	0
System Renewal	Wood Pole Replacement	800
System Service	N/A	0
General Plant	IT Hardware and Software	135
	IT Infrastructure and Business Systems	337
	Spare Equipment and Material Storage and Physical Security	400
	Outage / Emergency Response Preparedness	500
	Office Furniture and System Monitoring / Dispatch Workstations	500
Total Sustaining Capital		**2,672**

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[20] As noted in Exhibit D-2-1, at the time of filing there are ongoing wildfires within the region through which WPLP's Transmission System traverses. At the time of filing, the extent of damage to WPLP's facilities, if any, is unknown. Once this information becomes available, and if the circumstances warrant, WPLP will provide an update to its evidence.

(e) Future Projects and Programs

Capital projects and programs being considered for inclusion in the multi-year investment plans that will form part of WPLP's future TSPs include:

- System Access projects from potential mining project connections and potential relocation projects to accommodate realignments or new construction of winter and all-season roads near WPLP's transmission ROWs;
- System Renewal to address concerns of wood pole failure from woodpecker damage along the discrete sections of the Transmission System that use wood pole structures, and potentially from lightning strikes or wildfire damage. In addition, any replacements required for the small subset of asset classes with short service lives;
- System Service could include additional capacitive compensation in approximately the mid-2030s to address voltage drops, the potential need for which was identified by long-term planning studies completed during project development and will continue to be monitored. In addition, WPLP will assess opportunities for strategic investments to address reactive power compensation needs and extend the life of existing backup power solutions. Furthermore, it is possible that regional planning processes could drive additional investment needs on WPLP's Transmission System to increase load meeting capability and/or improve reliability in the North of Dryden area; and
- General Plant is expected to include regular investments in IT and OT systems, office furniture, fleet and facilities, the timing of which will be informed by the strategic planning and investment planning processes summarized above.

5. Rate Base

WPLP's forecasted rate base for the 2026 test year is summarized in Table 4. WPLP proposes to calculate its rate base for the 2026 test year using the half-year rule, consistent with section 2.8.10

of the Filing Requirements. Details of in-service additions and the derivation of WPLP's rate base are provided in Exhibit 'C'.

Table 4 – 2026 Rate Base

Item	**2026 Forecast ($000's)**		
	Opening	**Closing**	**Average**
Gross Fixed Assets	1,322,061	1,324,733	1,323,397
Less Accumulated Depreciation	(74,482)	(101,346)	(87,914)
Net Fixed Assets	**1,247,579**	**1,223,387**	**1,235,483**
Working Capital Allowance[21]	-	-	-
Total Rate Base	**1,247,579**	**1,223,387**	**1,235,483**

6. *Performance and Reporting*

In the approved Settlement Agreement from the Prior Rate Decision, WPLP agreed to address performance measurement and reporting in the current Application by filing, on a best-efforts basis, an initial proposed scorecard. Because 2025 is the first full year that WPLP's entire transmission system is in service, it is the first full calendar year for which WPLP is able to track information for scorecard measures for its entire system. In previous years, WPLP tracked information for typical scorecard measures related to safety, reliability and costs during the construction period so that information could be used in setting future performance expectations, with consideration for adjustments required to reflect the transition from construction to operation. With the filing of its initial proposed scorecard in the current Application, WPLP's interim performance measurement and reporting arrangements are no longer relevant. WPLP's initial proposed scorecard, along with discussion of its alignment with the four categories of outcomes from the OEB's Renewed Regulatory Framework, is provided in Exhibit D-1-1.

In terms of its achieved reliability performance, WPLP has tracked this information in three phases: (i) interim operation of its Pikangikum Distribution Line from December 2018 until it was

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[21] See Exhibit C-4-1 for a discussion of WPLP's rationale for not including a Working Capital Allowance.

incorporated into the Transmission System in May 2023, (ii) partial Transmission System operations from 2022 until 2024, and (iii) full Transmission System operations starting in 2025. Generally, the most significant drivers of outages during phases (i) and (ii) have been related to construction, lightning strikes and Hydro One loss of supply, with one material outage in 2024 resulting from a single tree contact. These trends should not be viewed as indicative of future performance for the fully operating system. Notwithstanding the impacts of Transmission System outages on WPLP's delivery points, WPLP has been working with HORCI to maximize the use of community-wide backup generation so as to reduce outage impacts for end-use customers in many of the connected First Nation communities.

The requirements in Chapter 4 of the Transmission System Code, for transmitters to develop performance standards that reflect historical performance of their systems at the customer delivery point level, make it necessary for WPLP as a new entrant transmitter to collect and analyze historical data before it can set future performance targets. WPLP is collecting and analyzing its reliability data to enable it to meet those requirements in future, while continuing to facilitate implementation of backup power in the connected First Nation communities.

7. OM&A Expense

WPLP's OM&A expenses include costs associated with the following activities:

- **Operation:** System control functions, inspection and operation of transmission station equipment, line patrols and inspections, environmental commitments and costs associated with land rights.

- **Maintenance:** Preventative maintenance programs designed to maintain asset health, corrective maintenance required to address deficiencies or deteriorating condition, including repairs of a non-capital nature during outages or other emergency conditions.

- **Administration & General:** Indigenous engagement, communications and participation, accounting, health, safety and environment, information technology, insurance, and general administration. This includes labour-related costs that are not specifically allocated to operation or maintenance activities.

Table 5, below, summarizes the total operating costs included in WPLP's proposed 2026 revenue requirement.

Table 5 – Summary of Operating Costs

Operating Cost Category	**2026 Test Year ($000's)**
Operations	18,096
Maintenance	10,875
Administration & General	9,382
Total OM&A Expenses	**38,354**
Depreciation and Amortization	26,864
Income Taxes	596
Total Operating Costs	**65,814**

While WPLP's total OM&A increases from approximately $33.6 million in 2025 (forecast) to approximately $38.4 million for 2026, this increase on an overall basis is a result of WPLP's growing operating requirements. More particularly, the increase in total OM&A from the 2025 bridge year to the 2026 test year is driven by: (1) ramp up of WPLP's vegetation management planning and field activities given the timing for when the right of way was cleared, with assumption of 50% of a typical annual brushing cycle, resulting in an additional $3.5 million cost from prior year , and (2) additional line inspection (including LiDAR scope not carried out in 2025) and substation activities resulting in an additional $1.8 million from the prior year. These increases are partially offset by lower affiliate and related party costs ($0.3M), and other administrative cost reductions ($0.2M). Detailed analysis of WPLP's 2026 operating costs, including support for WPLP's 2026 depreciation/amortization expense and income taxes, is provided in Exhibit F.

8. Cost of Capital

Consistent with its approach that was approved in the Prior Rate Decision, WPLP is proposing to use a deemed capital structure of 60% debt (4% short term debt, 56% long-term debt) and 40% common equity for rate-making purposes for the 2026 rate year.

WPLP's proposed revenue requirement reflects its use of the OEB's deemed rate of return on equity ("ROE") of 9.00% for 2025 rate applications, as established by the OEB's Decision and Order in the Generic Proceeding (EB-2024-0063), as a placeholder. WPLP's proposed cost of short-term debt reflects its use of the OEB's deemed short-term debt rate of 3.91% for 2025 rate applications, also as established by the OEB's Decision and Order in the Generic Proceeding, as a placeholder. WPLP will update these rates at a later stage of the proceeding to reflect the OEB's ROE and short-term debt rate for 2026 rate applications once the OEB publishes its cost of capital parameters for 2026. WPLP has calculated its cost of long-term debt based on the weighted average of the interest rates for its debt facilities. WPLP's capital structure and cost of capital parameters are summarized in Table 6 below.

Table 6 – Capital Structure and Cost of Capital

	Capitalization Ratio		**Cost Rate[22]**	**Return**
	(%)	**($)**	**(%)**	**($)**
Long-term Debt	56%	$691,870,486	4.60%	$31,858,166
Short-term Debt	4%	$49,419,320	3.91%	$1,932,295
Total Debt	60%	$741,289,806	4.56%	*$33,790,462*
Common Equity	40%	$494,193,204	9.00%	*$44,477,388*
Total	**100%**	**$1,235,483,010**	**6.34%**	**$78,267,850**

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[22] Consistent with the OEB's final cost of capital parameters for 2025, as determined in the Generic Proceeding.

9. Cost Allocation and Rate Design

In consideration of WPLP's unique cost recovery and rate framework, which is summarized in Section B.3(a) above, WPLP's 2026 revenue requirement is allocated between the Line to Pickle Lake, and the Remote Connection Lines, as summarized in Table 7 below.

Table 7 – Allocation of 2026 Revenue Requirement

	LTPL	**RCL**	**Total**
Revenue Requirement for Rates	29,685,502	103,345,591	133,031,093

Details supporting WPLP's 2026 revenue requirement allocation, rate design and bill impacts are presented in Exhibit 'I'.

WPLP's revenue requirement associated with the Line to Pickle Lake, which is $29,685,502 for the 2026 test year, all of which will be recovered through the UTR Network rate, is detailed in Exhibit I-3-1.

WPLP also proposes to establish a fixed monthly charge applicable to HORCI resulting from the Remote Connection Line portion of its revenue requirement. Based on the Remote Connection Lines revenue requirement and 12 months of in-service assets, the proposed monthly fixed charge is $8,612,133, effective January 1, 2026.

10. Deferral and Variance Accounts

WPLP has eight deferral and variance accounts that have been previously approved by the OEB.[23] In the current Application, WPLP is (a) seeking final disposition for five of its accounts (the Pikangikum Distribution System Deferral Account, the In-Service Date Variance Account, the

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[23] In addition, in 2025, WPLP is using the generic sub-accounts Return on Equity Variance Account and Deemed Short-term Debt Rate Variance Account to capture the revenue requirement impact as a result of OEB's Decision and Order in the Generic Proceeding on Cost of Capital and Other Matters (EB-2024-0063).

Deferred Contingency Deferral Account, the COVID Construction Costs Deferral Account, and the Federal CIAC Variance Account), (b) seeking partial disposition for two of its accounts (the Construction Period Interest Costs Variance Account and the OM&A Variance Account), and (c) not seeking disposition in full or in part for one of its accounts (the EPC COVID-Related Costs Deferral Account). Table 8, below, provides a summary of WPLP's existing deferral and variance account balances, as at December 31, 2024. WPLP is proposing to dispose of the net amount from the above dispositions, including carrying costs as specified in Exhibit H-2-1, over a 1-year period, consistent with the disposition period approved in EB-2024-0176.

Table 8: Existing Regulatory Account Balances (December 31, 2024)

Account	**Principal (Net)**	**Carrying Charges (Net)**	**Total**
1508 – Pikangikum Distribution System Deferral Account	$634,004	$59,123	$693,127
1508 – In-Service Date Variance Account	$5,439,257	$92,973	$5,532,231
1508 – Construction Period Interest Costs Variance Account	$21,569,327	$1,495,023	$23,064,350
1508 – COVID Construction Costs Deferral Account	$4,349,913	$603,153	$4,953,066
1508 – Deferred Contingency Deferral Account	$243,262	$13,124	$256,386
1508 –OM&A Variance Account	($9,680,566)	($274,140)	($9,954,705)
1508 - Federal CIAC Variance Account	($14,023,877)	($113,800)	($14,137,677)
1508 - EPC COVID-Related Costs Deferral Account[24]	$82,099,560	$1,761,849	$83,861,409

11. COVID-Related Impacts

The impacts of COVID-19 continue to be the subject of commercial discussions between WPLP and its EPC contractor. Pursuant to the approved Settlement Agreements in its prior rate proceedings, and as described in Exhibit H-2-2, WPLP:

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[24] Further information on the EPC COVID-Related Cost Deferral account is provided in Exhibit H-2-2.

- recorded its audited 2020 known COVID costs of approximately $17.4 million in the COVID Construction Costs Deferral Account (CCCDA), has been recovering those costs as an OM&A expense over the four-year disposition period (2022-2025) approved in EB-2021-0134, and in the current Application is seeking recovery of $24,381 in forecasted carrying charges for 2025 and to close the account at the end of 2026;

- recorded, in the 2021-2023 COVID Construction Costs Deferral Account (2021-2023 CCCDA), the incremental year-end COVID costs from 2021 to 2023, and disposed of (i) the audited year-end 2022 balance as capital, along with carrying charges at AFUDC, in the amount of approximately $68.3 million (EB-2023-0168), and (ii) the audited year-end 2023 balance as capital, along with carrying charges at AFUDC, in the amount of approximately $3.1 million (EB-2024-0176); and

- has been authorized to record, in the EPC COVID-Related Costs Deferral Account, costs, including applicable carrying charges, incurred and to be incurred by WPLP under its EPC Contract that relate to 2020 or later and which are in respect of anticipated claims from the EPC contractor for cost and schedule relief under the EPC Contract in relation to COVID and related access issues in the Whitefeather Forest area (EB-2023-0168). The method of recovery – as capital or as expenses – is subject to determination in a future application, but on an interim basis is the OEB prescribed rate, which will be recalculated on the basis of the applicable CWIP rate if and when recovery is determined to be as capital.

For clarity, there may be additional COVID-related costs which are the subject of the commercial discussions currently ongoing between WPLP and its EPC contractor. These amounts are expected to be due primarily to productivity loss, incremental costs and schedule delays that the EPC Contractor takes the position arose from implementation of COVID-19 health and safety measures, as well as access issues in the Whitefeather Forest. These additional costs continue to be the subject of commercial discussions between WPLP and its EPC contractor and therefore remain uncertain in terms of quantum and responsibility. They may relate to any year of the construction period since the pandemic commenced in early 2020. If and when any amounts are recognized as having been incurred by WPLP upon the conclusion of the commercial discussions or upon otherwise being determined, such amounts, including applicable carrying charges[25], would be recorded in the EPC COVID-Related Costs Deferral Account, which is discussed in Exhibit H-1-1. As discussed in B.3(a), above, on final disposition of the balance in this account the independent Trust will make a further CIAC to offset the revenue requirement impact of such approved disposition.

12. Bill Impacts

WPLP's proposed 2026 revenue requirement will result in bill decreases from two perspectives. First, the Line to Pickle Lake portion of its revenue requirement will result in a decrease of $0.05/kW to the Network UTR rate, or a bill decrease of ($0.10) per month for a typical residential customer. Second, the Remote Connection Lines portion of its revenue requirement will result in decreased costs to HORCI, which will ultimately be funded through a decrease to the RRRP rate, which WPLP has calculated at ($0.0002)/kWh for 2026 or a bill decrease of ($0.16) per month for a typical residential customer.[26]

As detailed in Exhibit I-4-1, the combination of the decreased Network UTR and RRRP rates arising from this Application is estimated to result in a total bill decrease for a typical residential customer[27] of ($0.26) per month, or (0.18%). Details of bill impacts for a typical general service customer and for transmission-connected customers are also provided in Exhibit I-4-1.

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[25] WPLP will record carrying charges at the OEB prescribed rate for deferral and variance accounts, however carrying charges will be dependent on OEB's future ruling on the disposition of the balance recorded in the EPC COVID Account as capital or expense. Carrying charges will be calculated based on WPLP's actual cost of debt (AFUDC) if disposition of costs is deemed to be capital.

[26] Bill decrease before HST and OER adjustment.

[27] In this context, a typical residential customer is considered to be a Hydro One Networks Medium-Density (R1) customer, using 750 kWh/month on Time-of-Use rates. See Exhibit I-4-1 for details.

Exhibit A, Tab 4, Schedule 1

Corporate & Organizational Structure

CORPORATE & ORGANIZATIONAL STRUCTURE

The Applicant is Wataynikaneyap Power GP Inc. ("Wataynikaneyap GP") on behalf of Wataynikaneyap Power LP ("Wataynikaneyap LP") ("WPLP"). The Applicant holds an electricity transmission licence (ET-2015-0264).

A. Corporate Structure

Wataynikaneyap LP is an Ontario limited partnership whose general partner is Wataynikaneyap GP. As shown in the Corporate Structure provided in **Appendix 'A'**, the limited partnership interests in WPLP are held 51% by First Nation LP and 49% by Fortis (WP) LP. First Nation LP is an Ontario limited partnership whose general partner is 2472881 Ontario Limited ("First Nation GP"). The limited partnership interests in First Nation LP are held directly by the 24 Participating First Nations in equal shares. Fortis (WP) LP is an Ontario limited partnership whose general partner is Fortis (WP) GP Inc. The limited partnership interests in Fortis (WP) LP are held by Fortis Inc. (80%) and indirectly by Algonquin Power & Utilities Corp. (20%).

With respect to the corresponding general partnerships, the shares of Wataynikaneyap GP are held 51% by First Nation GP and 49% by Fortis (WP) GP Inc. The shares of First Nation GP are held directly by the 24 Participating First Nations in equal shares. The shares of Fortis (WP) GP Inc. are owned by FortisOntario Inc. and indirectly held by Fortis Inc. (100%).

The Applicant has established a head office in the Fort William First Nation Reserve. The Participating First Nations and Fortis Inc. are described below.

1. Participating First Nations

The Participating First Nations are a group comprised of 24 First Nations from northwestern Ontario. Of the 24 Participating First Nations, 16[1] (as marked with an "*" below) have or will

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[1] 15 of the 16 First Nations have been connected to the Transmission System with the remaining First Nation planned to be connected in 2025. WPLP will inform the OEB once the remaining First Nation is connected.

soon be connected to the WPLP Transmission System (the "Connected Communities").[2] The Participating First Nations are as follows:

1. Bearskin Lake First Nation*
2. Cat Lake First Nation
3. Deer Lake First Nation*
4. Kasabonika Lake First Nation*
5. Keewaywin First Nation*
6. Kingfisher Lake First Nation*
7. Kitchenuhmaykoosib Inninuwug*
8. Lac des Mille Lacs First Nation
9. Lac Seul First Nation
10. Mishkeegogamang First Nation
11. McDowell Lake First Nation
12. Muskrat Dam First Nation*
13. North Caribou First Nation*
14. North Spirit Lake First Nation*
15. Ojibway Nation of Saugeen
16. Pikangikum First Nation*
17. Poplar Hill First Nation*
18. Sachigo Lake First Nation*
19. Sandy Lake First Nation*
20. Slate Falls First Nation
21. Wabigoon Lake Ojibway Nation
22. Wapekeka First Nation*
23. Wawakapewin First Nation*
24. Wunnumin Lake First Nation*

2. Fortis

Fortis Inc. is a well-diversified leader in the North American regulated electric and gas utility industry, with 2024 revenue of $12 billion and total assets of $73 billion as at December 31, 2024. The corporation's 9,800 employees serve utility customers in five Canadian provinces, ten U.S. states and three Caribbean countries. Its regulated utilities account for virtually all of the Corporation's assets. FortisOntario Inc. is a wholly owned subsidiary of Fortis Inc.

B. Organizational Structure

For purposes of the ongoing operation of the utility, WPLP has agreements with Fortis-controlled Wataynikaniyap Power PM Inc. ("WPPM") and Participating First Nation-controlled Opiikapawiin Services LP ("OSLP"). WPPM and OSLP provide services to WPLP for the operation and maintenance of the Transmission System. Each party's roles and responsibilities are

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[2] The Project is designed to permit the potential future connection of a 17th community, McDowell Lake First Nation.

further described below. A corporate structure diagram that includes these service providers is provided in Section B of Exhibit F-3-1.

1. Wataynikaneyap Power PM Inc. ("WPPM")

Leveraging the knowledge, experience and expertise of Fortis Inc. and its subsidiaries in respect of all aspects of transmission system operations, WPPM is responsible for providing services related to operations, maintenance, administration, engineering, finance, regulatory and various corporate functions (including health and safety, environmental compliance, HR, IT and procurement). In addition, WPPM assigns scopes of work to OSLP on programs for WPLP relating to community engagement, community readiness, education & training, business readiness, communications, capacity building, and certain aspects of stakeholder engagement. Organizationally, WPPM provides these services in three functional areas:

- WPPM's Chief Operating Officer (COO) oversees all aspects of operations, maintenance, engineering, health and safety, as well as environmental compliance.
- WPPM's VP Finance & Chief Financial Officer (CFO) oversees all aspects of finance and accounting, procurement, risk management and regulatory affairs.
- WPPM's VP Corporate Services and Indigenous Relations oversees all aspects of legal services, HR and IT. This position is also responsible for overseeing WPPM's participation in the various recruitment, training, engagement and communication activities that are coordinated by OSLP. These activities aim to implement WPLP's commitment to providing meaningful Indigenous participation, including by delivering WPLP's Indigenous Engagement Plan and ensuring effective and ongoing communications with Indigenous peoples and communities.

Section B of Exhibit F-3-1 provides further details related to the Management Agreement between WPLP and WPPM, and WPLP's annual costs incurred pursuant to that agreement. Employee compensation details for direct employees of WPPM are provided in Section A of Exhibit F-3-1.

2. Opiikapawiin Services LP ("OSLP")

Leveraging the local and traditional knowledge, experience and expertise of the Participating First Nations, OSLP, under the direction of WPPM, is primarily responsible for helping to execute projects and programs for WPLP relating to community engagement, community readiness, workforce development, business readiness, communications, capacity building, and certain aspects of stakeholder engagement.

Through a Service Agreement with WPLP, OSLP continues to assist the Participating First Nations in building capacity[3] and obtaining meaningful participation in the Transmission Project for members of their communities. The mandate to coordinate and work with each Participating First Nation on their local knowledge, supports the development of professional capacity for future employees to operate and maintain the transmission system. OSLP maintains a labour pool database and a registry of Indigenous businesses to assist WPLP in filling employment and sub-contracting opportunities for the operation and maintenance of transmission system.

With respect to ongoing community engagement and project communications through operations, OSLP manages a community issue tracker, coordinates community engagement meetings and logistics, creates quarterly newsletters, provides notices of in-field activities (e.g., inspections, vegetation management, environmental monitoring) and coordinates communications through Community Liaisons to support engagement and communication activities. Consistent with the vision and mandate reflected in the Guiding Principles, education, training and capacity building will continue to be a focus, with a view to developing a pathway towards building a qualified workforce for all aspects of operations and, ultimately, 100% ownership by the Participating First Nations in 25 years.

OSLP continues to facilitate the transfer of distribution system assets to Hydro One Remote Communities Inc. ("HORCI") for the one community still served by an Independent Power

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[3] Including for example working with local Indigenous businesses to obtain the education, training and qualifications necessary for employment with WPLP or its operational contractors related to IMERS contract, environment monitoring, and vegetation management.

Authority ("IPA").[4] OSLP continues to monitor and facilitate the development and implementation of critical asset backup supply arrangements on behalf of WPLP for all communities that have become grid-connected through the Transmission Project. While the underlying activities relating to backup supply arrangements and transferring distribution system assets from IPAs to HORCI are beyond the scope of this Application, WPLP has been required as part of the Transmission Project to facilitate and report semi-annually to the OEB on the status of backup supply arrangements pursuant to the OEB's LTC Decision in EB-2018-0190, as well as the Settlement Agreement from EB-2021-0134, and WPLP has monitored the status of IPA distribution system transfers through regular reporting completed by OSLP.

As of March 31, 2025, the backup supply arrangements leverage the generation assets and associated infrastructure that previously served as the primary electricity supply for 8 of the 16 communities that were served by HORCI before connecting to the Transmission Project. These assets now serve these communities by providing emergency backup capacity during outages on or upstream of WPLP's transmission system. Regarding the remaining communities with similar centralized backup power conversions, OSLP is facilitating the continued work for the 5 former IPA communities, and facilitating work for the remaining 3[5] communities that will be provided with emergency backup supply for critical infrastructure locations, instead of on a community-wide basis.[6]

Section B of Exhibit F-3-1 provides further detail related to the Services Agreement between WPLP and OSLP, and the annual costs incurred/forecasted pursuant to that agreement.

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[4] See the most recent Indigenous Services Canada report on IPA and Backup Power, which was filed by WPLP as part of its Semi-Annual Report dated April 15, 2025, pursuant to EB-2018-0190.

[5] One of these three communities, Wawakapewin First Nation, continues to hold discussions to determine whether an alternative, to critical asset backup only, is available.

[6] Details and status of backup power solutions for the 16 connected Indigenous communities are provided in WPLP's semi-annual reports, filed pursuant to OEB's Decision and Order in EB-2018-0190. The most recent semi-annual report is dated April 15, 2025.

APPENDIX 'A'

Applicant's Corporate Structure

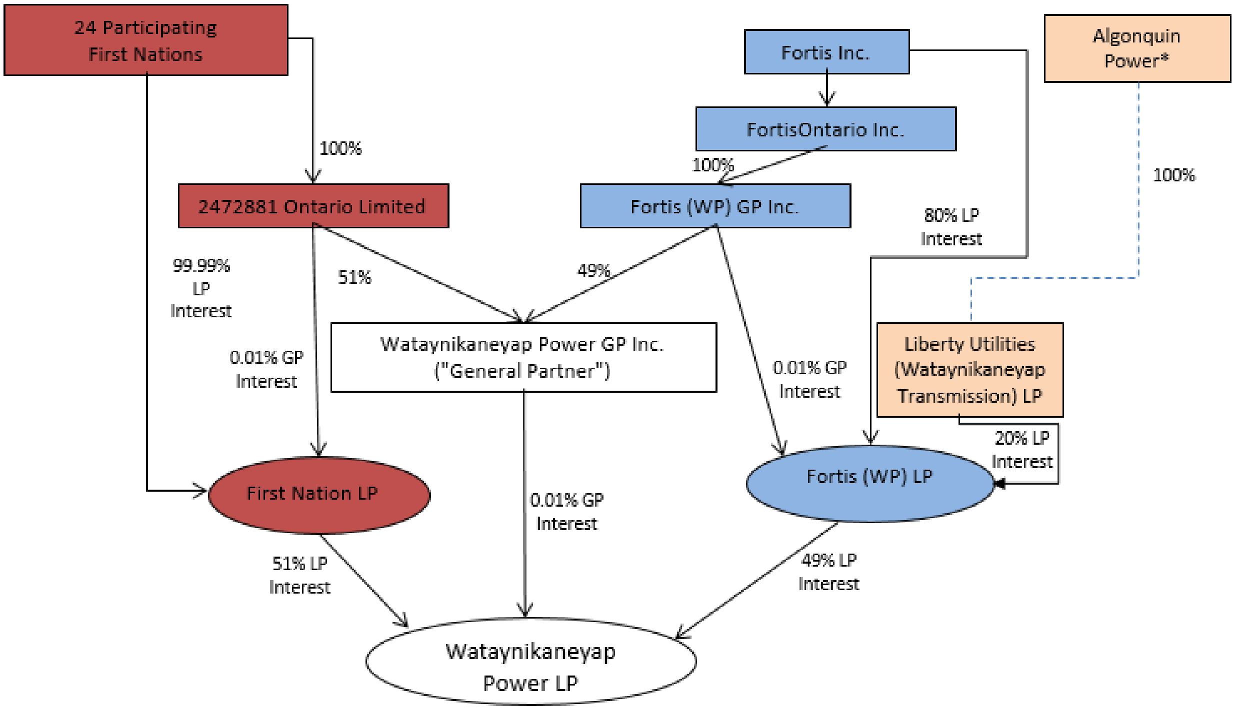
24 Participating First Nations
100%
2472881 Ontario Limited
99.99% LP Interest
0.01% GP Interest
51%
First Nation LP
51% LP Interest
Fortis Inc.
FortisOntario Inc.
100%
Fortis (WP) GP Inc.
49%
Watavnikaneyap Power GP Inc. ("General Partner")
0.01% GP Interest
0.01% GP Interest
Algonquin Power*
100%
80% LP Interest
Liberty Utilities (Wataynikaneyap Transmission) LP
20% LP Interest
Fortis (WP) LP
49% LP Interest
Wataynikaneyap Power LP

Exhibit A, Tab 5, Schedule 1

Compliance with OEB Filing Requirements

COMPLIANCE WITH OEB FILING REQUIREMENTS

WPLP has prepared this Application generally in conformance with the guidance set out in the OEB's *Filing Requirements for Electricity Transmission Rate Applications – Chapter 2: Revenue Requirement Applications* (February 11, 2016) (the "Filing Requirements"). However, due to the unique nature of the application, being for a new transmission system for which the Bridge year is the first full calendar year that it is in service, and which is subject to a unique cost recovery and rate framework previously approved by the OEB, there are certain elements of the Filing Requirements that are not relevant to or compatible with the Application. These, along with WPLP's plans for transitioning to a multi-year revenue requirement framework, are summarized below and further addressed throughout the Application.

A. Irrelevant or Incompatible Aspects of the Filing Requirements

Section 2.4 of the Filing Requirements establish the need for evidence on asset condition, planning and prioritization of capital expenditures, as well as consideration of regional planning, which are required to be presented in a consolidated and dedicated exhibit in the application and referred to as the Transmission System Plan ("TSP"). In granting leave to construct in EB-2018-0190, the OEB approved construction of the Transmission Project and found that its impacts with respect to price, reliability and quality of service are reasonable. In its prior rate applications which were filed while the Transmission Project was under construction and portions of the system were being put into service, in lieu of a TSP, WPLP filed detailed information about its Transmission Project and the elements of the project underlying its rate proposals. Recognizing that the 2025 Bridge year is the first full year for which the Transmission Project is fully in service, and the limited time and resources available for WPLP to develop the TSP in time for the 2026 rate year, the approved Settlement Proposal in EB-2024-0176 contemplates that WPLP will file an initial TSP in the current application on a best efforts basis. As such, some of the sections in Exhibit B contain only preliminary or incomplete information.

Sections 2.0 and 2.6 of the Filing Requirements discuss the value that the OEB places on cost and performance benchmarking evidence and transmission scorecards. In its previous rate applications, WPLP addressed the OEB's performance and scorecard expectations relative to WPLP's circumstances while the Transmission Project was under construction and being put into service in segments. Recognizing that the 2025 Bridge year is the first full year for which the Transmission Project is fully in service, and the limited time and resources available for WPLP to address performance benchmarking and develop the transmission scorecard in accordance with the filing requirements in time for the 2026 rate year, the approved Settlement Proposal in EB-2024-0176 contemplates that WPLP will in the current Application address performance measurement and reporting, including by filing an initial performance scorecard, on a best efforts basis. As such, some of the sections in Exhibit D are preliminary in nature, or based on historical performance associated with only portions of the Transmission Project or the Pikangikum Distribution System (which was converted to form part of the transmission system on May 12, 2023) being in service.

Furthermore, pursuant to the Settlement Agreement in EB-2021-0134, in respect of the Line to Pickle Lake and the portions of the Remote Connection Lines that were placed into service in 2022, WPLP agreed to monitor performance on the basis of the reliability and operating performance metrics set out below without establishing performance targets and to report to the OEB on such performance, based on data as at Year End 2022, which was filed with the OEB on May 12, 2023. Pursuant to the Settlement Agreement in EB-2023-0168, WPLP agreed to continue to monitor its performance on the same basis and report to the OEB on such performance in approximately April 2024, based on data as at year end 2023, and in approximately April 2025, based on data as at year end 2024. WPLP filed the report based on Year End 2023 data on April 23, 2024, and the report based on Year End 2024 data on April 24, 2025. As discussed in Exhibit D-1-1, WPLP will monitor and report on reliability and operating performance using the initial proposed scorecard for 2026, and will update its monitoring and reporting based on the performance scorecard in its first multi-year revenue requirement application for a period starting with a 2027 test year.

The reliability and performance metrics that WPLP continues to monitor for in 2025 are as follows:

- Total Recordable Injuries Frequency Rate ("TRIFR") - # of recordable injuries per 200,000 hours worked, using Canadian Electricity Association definition of "recordable injuries";
- Recordable Injuries - # of recordable injuries per year, using Canadian Electricity Association definition of "recordable injuries";
- Violations of NERC FAC-003-4 Vegetation Compliance Standard (in respect of the Line to Pickle Lake portion of the transmission system only);
- OM&A cost per kilometre of line and OM&A cost per station;
- Average system availability;
- Transmission System Average Interruption Duration Index (T-SAIDI); and
- Transmission System Average Interruption Frequency Index (T-SAIFI).

Section 2.1 of the Filing Requirements includes general expectations related to including details from the most recent OEB-approved test year, historical years and a bridge year, as well as related expectations around year-over-year variance analysis. These requirements are not entirely applicable to WPLP's current transmission rate application given the actual in-service dates of assets in the 2022, 2023 and 2024 historical years. However, Exhibit A-5-2 provides context for the Application arising from prior OEB proceedings, and Exhibit B and F provide variance analysis relating to WPLP's capital costs and OM&A expenses.

Sections 2.7.1 and 2.7.2 of the Filing Requirements set out the OEB's expectations in relation to forecasting charge determinants for the UTR rate pools, including requirements for weather normalization, economic and econometric models, CDM forecasting, and historical variance analysis. Exhibit E-1-1 proposes an alternative demand forecasting methodology employed by WPLP, in consideration of data availability and the immaterial contribution to the UTR charge determinants.[1] This demand forecasting methodology is consistent with what has been approved for WPLP in prior rate applications.

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[1] The change in Network UTR determinants resulting from WPLP's load forecast is 0.007%, and WPLP's load forecast is not included in the Line Connection or Transformation Connection UTR charge determinants.

Section 2.8.11.2 of the Filing Requirements requires a statement in the application as to when loss carryforwards, if any, will be fully utilized. WPLP's income tax calculations provided in Exhibit F-5-1 show that WPLP has a significant loss carryforward for 2026, primarily resulting from Capital Cost Allowance ("CCA") deductions. WPLP does not expect to fully utilize its loss carryforwards prior to filing a multi-year revenue requirement application, and WPLP therefore proposes to address forecasting of loss carryforwards at that time.

B. Transitioning to a Multi-Year Revenue Requirement Framework

As indicated in Exhibit A-2-1, WPLP committed to filing a multi-year revenue requirement application in 2026, using an incentive-based regulatory method available to transmitters, for a rate period starting with the 2027 test year.

Exhibit A, Tab 5, Schedule 2

Summary of Prior OEB Proceedings and Directives

SUMMARY OF PRIOR OEB PROCEEDINGS & DIRECTIVES

This schedule provides a summary of the directives and expectations identified by the OEB in prior WPLP proceedings and indicates the status of or steps taken by WPLP to respond to those aspects as part of the present Application. As this is WPLP's fifth transmission revenue requirement application, a number of the requirements established by the OEB in prior WPLP proceedings have already been addressed and are no longer relevant but are set out here for purposes of providing regulatory context for the Application.

A. Electricity Transmission Licence (EB-2015-0264)

On September 8, 2015, WPLP filed an application under section 60 of the OEB Act for an electricity transmission licence. On November 19, 2015, the OEB granted the licence to WPLP for a period of five years and specified that the licence shall not take effect until the date upon which the OEB is satisfied that WPLP has been selected by appropriate authorities as a developer of transmission assets in Ontario, or the date upon which the OEB, on the application of WPLP, amends schedule 1 of the licence to specify the transmission facilities to be owned and/or operated by WPLP, whichever is earlier.

B. Electricity Transmission Licence Amendment (EB-2016-0258)

On July 29, 2016, the OEB received a directive from the Minister of Energy under section 28.6.1(1) of the OEB Act requiring the OEB without a hearing to amend WPLP's transmission licence to require it to develop and seek approvals for the Line to Pickle Lake and for the Remote Connection Lines so as to enable connection of sixteen named remote Indigenous communities to the provincial electricity grid. On September 1, 2016, the OEB amended WPLP's licence to reflect the directive and amended the term of the licence to 20 years.

C. Development Costs Deferral Account (EB-2016-0262)

On August 26, 2016, WPLP applied to the OEB under section 78 of the OEB Act for an accounting order authorizing the establishment of a new deferral account to record costs incurred in relation to the development of the Wataynikaneyap Transmission Project. On March 23, 2017, the OEB approved the establishment of the account, with an effective date of November 23, 2010, which coincides with the date from which costs may be recorded in the account (being the date the 2010 Long-Term Energy Plan, which identified the Line to Pickle Lake as a priority project, was issued). The OEB specified that WPLP may not record costs relating to start-up or partnership formation, or costs incurred prior to November 23, 2010.

The OEB also specified (and OEB staff clarified by letter issued May 12, 2017) that WPLP must record in a sub-account all funding received for development activities from any source, government or otherwise, whether or not repayment is expected, so as to facilitate the future determination (at the time of disposition) as to whether any component of the costs to be recovered from ratepayers should be offset by any funding received from such other sources. OEB staff further clarified that WPLP does not need to record equity contributions from the partners of WPLP, and that the requirement to record funding applies to funding received both directly and indirectly by WPLP, where “indirectly” received funds include those received by a predecessor, affiliate or other entity related to or previously related (at the time the funding was received) to WPLP or WPGP or a predecessor, and that this includes funding received by the partners of WPLP. As noted below, in EB-2021-0134 the OEB determined based on the approved Settlement Agreement that the costs to be recovered from ratepayers should not be offset by any of the funding received from other sources, as recorded in this sub-account, and that the sub-account should therefore be discontinued.

In approving the Development Costs Deferral Account, the OEB also required WPLP to file semi-annual reports, which WPLP did under EB-2016-0262 until it commenced reporting under EB-2018-0190 in late 2019. As described below, the required content for the semi-annual reports was modified by the OEB’s decisions approving the Settlement Agreements in EB-2021-0134 and EB-2022-0149. It was further modified in EB-2024-0176, where the approved Settlement accepted WPLP’s proposal that the October 15, 2024 semi-annual report be the last report relating to the CWIP account, operating plans and community energization dates, and that subsequent reports, if necessary, be limited to reporting on backup power and IPA transfers until implementation is completed.

D. Electricity Distribution Licence (EB-2017-0236 and EB-2022-0244)

On June 15, 2017, WPLP applied to the OEB for an electricity distribution licence to support WPLP's plan to develop, construct, own and operate an approximately 117 km distribution line between Red Lake and the Pikangikum First Nation Reserve (EB-2017-0136). WPLP indicated that there was an urgent need for grid connection of the Pikangikum First Nation on an interim basis until such time as it can be served by WPLP's Transmission System. WPLP further indicated its plan to construct the line largely to 115 kV standards, but to connect it to Hydro One's distribution system and to operate at a distribution voltage of 44 kV for a period of approximately 3-4 years from late 2018, after which it would be connected to and form part of WPLP's Transmission System. On September 28, 2017, the OEB granted the distribution licence for a 5-year term from September 28, 2017. On September 22, 2022, in EB-2022-0244, the OEB extended the term of WPLP's electricity distribution licence until June 30, 2023. The Pikangikum Distribution System was converted to form part of the Transmission System on May 12, 2023. On June 16, 2023, following WPLP's request to cancel its electricity distribution licence, the OEB confirmed that the licence was cancelled.

E. Pikangikum Distribution Costs Deferral Account and Licence Amendments (EB-2018-0267)

On September 7, 2018, WPLP applied to the OEB for an accounting order to establish a deferral account for the purpose of recording and facilitating the future recovery of costs relating to the operation of WPLP's distribution system that connects the Pikangikum First Nation to Hydro One's distribution system near Red Lake, as well as to amend WPLP's distribution licence to exempt it from metering and settlement requirements pertaining to host and embedded distributors. On November 22, 2018, the OEB approved the application. The OEB specified that the costs to be recorded in the account are the OM&A costs for the distribution system, as well as any capital costs that may be incurred after the in-service date which are not paid for by funding from Indigenous and Northern Affairs Canada (INAC)[1], including its successors. As noted above, the

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[1] Now known as Indigenous Services Canada ("ISC").

Pikangikum Distribution System was converted to form part of the Transmission System on May 12, 2023. In WPLP's 2023 transmission rate proceeding (EB-2022-0149) and 2024 transmission rate proceeding (EB-2023-0168), the OEB approved the continuation of the Pikangikum Distribution System Deferral Account, and the partial disposition of the audited account balances for December 31, 2021 and December 31, 2022, respectively. WPLP's current requests related to this account are set out in Exhibit H.

F. Leave to Construct and Cost Recovery / Rate Framework (EB-2018-0190)

On June 8, 2018, WPLP applied to the OEB for leave to construct approximately 1,732 km[2] of electricity transmission and interconnection facilities, comprised of the Line to Pickle Lake and the Remote Connection Lines. The application was amended October 5, 2018 and January 28, 2019. In addition, WPLP requested approval for a unique cost recovery and rate framework under which the revenue requirement for the Remote Connection Lines would be charged through a fixed monthly service charge to Hydro One Remote Communities Inc. (HORCI) and the revenue requirement for the Line to Pickle Lake would be recovered through the Network pool of the Uniform Transmission Rates (UTRs). WPLP also requested various other relief, including a determination that the 44 kV and 25 kV segments be deemed to be transmission facilities and various exemptions from the Transmission System Code (TSC) in relation to the Remote Connection Line facilities. The OEB approved the application on April 1, 2019 (revised April 29, 2019). In the decision, the OEB directed WPLP to use CWIP Account 2055 to record construction costs and to transfer approximately $54 million in development costs that had been recorded in the Development Costs Deferral Account to the CWIP Account. The OEB also required as a condition of approval that WPLP provide semi-annual updates to the OEB on its CWIP account and on the progress of backup supply arrangements for the connecting communities.[3]

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[2] As a result of minor routing changes, the total as-built transmission line length is approximately 1,742 km.

[3] Details and status of backup power solutions for the 16 connected Indigenous communities are provided in WPLP's semi-annual reports, filed pursuant to OEB's Decision and Order in EB-2018-0190. The most recent semi-annual report is dated April 15, 2024.

In its decision, the OEB made a number of findings that directly related only to WPLP's initial transmission rate application, as well as other findings that continue to be relevant in the current Application. These are as follows:

- The OEB stated, at pp. 12-13 of the decision, that "WPLP is required to provide updated Project costs as part of its future transmission rate applications in accordance with the OEB filing requirements. The OEB requires that WPLP's first transmission rate application shall provide details of the updated costs of the Project as defined by the Owner's Engineer (actuals to date and forecasts), variance analysis of Project scope, costs and schedule compared to the original estimates, and the degree to which the Project contingency has been utilized. WPLP shall also make best efforts to provide information on any other costs that may impact this Project at the time of its inaugural rate case. Further, the OEB agrees with WPLP that any further variance analysis provided as construction progresses would consider actual or forecast costs compared to the updated cost estimates that are presented in the initial rate application." WPLP addressed these requirements primarily in Exhibit B, Tab 1, Schedule 5 and Exhibit H, Tab 2, Schedule 2 of its prior rate applications.

- The OEB, on pp. 27-28 of the decision, approved WPLP's proposed cost recovery and rate framework, stating:

    - "The OEB approves the inclusion of the net capital cost associated with the Remote Connection Lines in WPLP's rate base and a monthly fixed charge applied to HORCI – in lieu of a capital contribution – to recover the capital and operating costs related to the Remote Connection Lines. The amount of the monthly fixed charge will be addressed in WPLP's transmission rate cases involving the Remote Connection Lines, when the specific elements of WPLP's revenue requirement will be approved." See Exhibit I, Tab 3, Schedule 2 of the present Application.

    - "In relation to the Line to Pickle Lake, the approved revenue requirement will be determined in WPLP's first transmission rate case involving that part of the

Project[4], for recovery through the network charge component of the UTR." See Exhibit I, Tab 3, Schedule 1 of the present Application.

- "WPLP is directed to use CWIP Account 2055 to record construction costs, a standard account included in the OEB's Uniform System of Accounts . . . Construction costs will be accumulated in the standard CWIP account for future disposition. Entries to the CWIP account will be reviewed for approval when WPLP proposes to add the related assets to rate base." WPLP indicated that it would have three sub-accounts similar to what it used in the development costs deferral account.

- "The OEB approves WPLP's request to transfer approximately $54 million in development costs to a CWIP Account. The transferred development costs will be the opening balance for WPLP's CWIP account 2055 related to this Project." See Exhibit H, Tab 2, Schedule 1 of WPLP's prior rate applications for additional details.

- "Article 410 of the OEB's Accounting Procedures Handbook for Electricity Distributors requires that where incurred debt is not acquired on an arm's length basis, the actual borrowing cost may be used for rate making, provided that the interest rate is no greater than the OEB's published rates. Otherwise, the OEB's published rates should be used. In this case, the actual interest rate may be lower than the prescribed rate. If so, the OEB directs WPLP to use its actual cost of debt."[5] See Exhibit G, Tab 2, Schedule 1 of the present Application.

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[4] While the language in the Decision and Order refers to WPLP's first transmission rate application, this aspect needs to be determined in each transmission rate application for WPLP.

[5] On April 18, 2019, WPLP wrote to the OEB requesting clarification of this paragraph 7 of the Order section of the April 1, 2019 Decision and Order due to the concern that it appeared inconsistent with the OEB's findings in respect of CWIP interest rates in the body of the decision. The OEB agreed and amended paragraph 7 of the Order to specify that "WPLP shall transfer the balances from its development deferral account to its CWIP account, in accordance with this Decision and Order. With respect to CWIP interest rates, WPLP shall use the lower of its actual cost of debt and the OEB's published CWIP interest rate in respect of debt that is incurred on a non-arm's-length basis, and shall use the actual cost of debt in accordance with Article 410 of the Accounting Procedures Handbook in respect of debt that is incurred on an arm's-length basis."

The OEB, on p. 23 of the LTC Decision and in Schedule 2 of WPLP's amended transmission licence (attached as Schedule C thereto), granted WPLP exemptions from certain sections of the TSC in relation to the Remote Connection Lines. In particular, WPLP was exempt from all sections relating to connection procedures and customer capital contributions in respect of connection facilities. The OEB originally granted these exemptions until the earlier of the date all Transmission System facilities are placed in service or December 31, 2023. In accordance with the OEB's Decision and Order in EB-2022-0330, described below, this was extended to December 31, 2024.

G. Licence Amendments to Provide RRR Exemptions (EB-2020-0142/0143)

On May 13, 2020, WPLP filed a combined application for amendments to its electricity transmission and distribution licenses to provide WPLP with certain exemptions from the OEB's *Electricity Reporting and Record Keeping Requirements*, on a permanent basis in respect of its distribution licence (which was in effect for a limited period to authorize operation of the Pikangikum System while operating at a distribution voltage) and on a temporary basis during the construction period in respect of its transmission licence. The OEB approved the application on August 13, 2020. In addition to the TSC related exemptions discussed above, WPLP was also exempted from certain sections of the Electricity Reporting and Record Keeping Requirements (RRR) that relate to financial disclosure obligations in respect of the 2019 to 2023 reporting periods. In accordance with the OEB's Decision and Order in EB-2022-0330, described below, this was extended by one year.

H. 2022 Transmission Revenue Requirement Application (EB-2021-0134)

On April 28, 2021, WPLP filed its first transmission rate application seeking approval of an electricity transmission revenue requirement and associated rates, effective April 1, 2022 and to charge HORCI a fixed monthly charge for transmission service, effective May 1, 2022 (the "Initial Rate Application"). The parties in the proceeding participated in a settlement conference and reached a complete settlement of all issues. A settlement proposal was filed and, on September 30, 2021, the OEB issued its decision approving the settlement proposal. The following outlines the key elements of the settlement agreement approved by the OEB:

- **Rate Base & Associated Deferral Account:** Establishment of a new deferral account to record the revenue requirement impact associated with the contingency amount removed from rate base, to the extent that such contingency is realized and does not exceed the amount removed from rate base.

- **COVID Cost Recovery:** Recovery of WPLP's audited 2020 year-end balance of COVID costs as an expense through disposition of the balance in the COVID-19 Construction Costs Deferral Account (CCCDA) over a 4-year period (i.e. 25% in each of 2022, 2023, 2024 and 2025), instead of recovering 50% of its 2020 COVID costs through revenue requirement adders in each of the 2022 and 2023 years. See Exhibit H-2-2 of the present Application.

- **Performance Monitoring and Reporting:** The timing for reporting on performance measures and specific metrics to monitor and report on with respect to reliability, including in relation to vegetation management and safety. See Exhibit D-1-1 of the present Application.

- **OM&A:** The preparation and filing by WPLP in its application for 2023 revenue requirement of benchmarking studies to compare WPLP's (a) OM&A spending levels on a per line kilometer basis and on a per station basis relative to comparable Ontario and Canadian transmitters; and (b) compensation costs relative to Hydro One's compensation costs. See Exhibit F-1-1 of the present Application.

- **Presentation of Evidence:** Future transmission rate applications, for years in which additional transmission line segments and stations will be placed into service, will include detailed information on variances and the use of contingency amounts for such line segments and stations being placed into service, relative to both the values presented in the respective application and the values that were presented in the Leave to Construct proceeding (EB-2018-0190).

I. 2023 Transmission Revenue Requirement Application (EB-2022-0149)

WPLP filed its second transmission revenue requirement application on April 28, 2022, and updated it on July 6, 2022, seeking approval for its 2023 electricity transmission revenue requirement and associated rates, and to charge HORCI a fixed charge for transmission service, effective January 1, 2023. In that proceeding, the parties reached complete settlement on all issues, which was approved by the OEB in its Decision and Order dated November 29, 2022. The following outlines the key elements of the settlement agreement approved by the OEB:

- **OM&A:** Key aspects included (i) a 5% reduction to WPLP's proposed 2023 OM&A expense on an envelope basis; (ii) establishment of a new asymmetrical Construction Period OM&A Variance Account, to the benefit of ratepayers, to be used to record the difference, if any, between the annual forecast and actual OM&A expenses, with any shortfall in actual spending relative to forecast to be returned to ratepayers in a future rate proceeding; and (iii) a commitment to file, in 2025 in respect of its application for approval of a transmission revenue requirement and rates for the period starting in 2026, an econometric benchmarking study of WPLP's OM&A costs.[6]

- **COVID Cost Recovery:** Continued recovery of WPLP's audited 2020 year-end balance of COVID costs as an expense through disposition of the balance in the CCCDA over a 4-year period (i.e. 25% in each of 2022, 2023, 2024 and 2025), in accordance with the OEB's decision in WPLP's 2022 revenue requirement proceeding (EB-2022-0149). In addition, establishment of a new 2021-2023 CCCDA to record audited year-end COVID-19 related costs from 2021 to 2023, with prudence and approach to disposition to be determined in a future rate proceeding. See Exhibit H-2-2 of the present Application.

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[6] This commitment was modified in EB-2024-0176.

- **Project/Construction Monitoring, Reporting and Coordination:** To (i) provide, in future semi-annual reports filed pursuant to EB-2018-0190, certain additional information on operational plans; (ii) provide certain notices to the OEB regarding changes to the community connection schedule, as well as to post such schedules on WPLP's website subject to alignment with other ongoing communication requirements, and (iii) on a best-efforts basis to work with HORCI on enhanced coordination of community connection processes, including with respect to the staggering of connection dates, avoidance of cold-weather outages, notices of connection and targets for asset transfers.

J. Modifications to Standard Form of Transmission Connection Agreement for Load Customers (EB-2022-0199)

In anticipation of the previously scheduled date for connecting HORCI's distribution system in Pikangikum First Nation to WPLP's Transmission System, WPLP requested approval from the OEB on June 30, 2022, for modifications to certain parts of the form of standard connection agreement set out for load customers in Appendix 1 (Version A) of the TSC (the "Standard Connection Agreement"). WPLP requested that the OEB approve such requests on an interim basis to (a) allow WPLP and HORCI to give further consideration to the modified terms that should apply in place of Schedule J of the Standard Connection Agreement, and (b) to allow WPLP to further consider the approach to such modified terms in relation to WPLP's Transmission Connection Procedures, which were under development at that time. In its Decision and Order, the OEB granted WPLP's requested modifications to the Standard Connection Agreement for its connection agreement with HORCI, on an interim basis (EB-2022-0199). The OEB required WPLP to file a final version of the modified connection agreement, including the further modifications required for Schedule J, by December 31, 2022.

K. Modifications to Standard Form of Transmission Connection Agreement, Approval of Customer Connection Procedures and Licence Amendments to Extend Code Exemptions (EB-2022-0330)

On December 16, 2022, WPLP filed an application with the OEB requesting (i) approval on a final basis for the modifications to the Standard Connection Agreement as reflected in its connection agreement with HORCI, (ii) approval of its Customer Connection Procedures (CCPs) and to amend the effective date of its CCPs as specified in WPLP's Transmission Licence to the later of September 1, 2024 and the date all facilities are placed into service, and (iii) approval to extend the period of certain TSC exemptions as specified in Schedule 2 of WPLP's Transmission Licence due to the extended project construction and in-service schedule (EB-2022-0330). On April 6, 2023, the OEB issued its Decision and Order in EB-2022-0330, granting the requested relief. In particular, the OEB approved:

- On a final basis, WPLP's proposed modifications to the Standard Connection Agreement in its connection agreement with HORCI;
- WPLP's proposed CCPs;
- an extension of the effective date for WPLP's CCPs to the later of September 1, 2024 and the date all facilities are placed into service (from the date on which all of the facilities are placed in service, or January 1, 2024, whichever is earlier);
- for the Remote Connection Lines, a one-year extension (from December 31, 2023 to December 31, 2024) to the exemptions from all sections of the TSC related to connection procedures and customer capital contributions for connection facilities and cost responsibility in relation to connecting the Listed Communities; and
- WPLP's request to extend its RRR exemption by granting a one-year extension to RRR financial disclosure obligations, which will result in the commencement of reporting in 2026, rather than 2025.

L. 2024 Transmission Revenue Requirement Application (EB-2023-0168)

WPLP filed its third transmission revenue requirement application on June 23, 2023 seeking approval for its 2024 electricity transmission revenue requirement and associated rates, and to charge HORCI a fixed charge for transmission service, effective January 1, 2024. In that proceeding, the parties reached a complete settlement on all issues, which was approved by the OEB in its Decision and Order dated November 30, 2023. The following outlines the key elements of the settlement agreement approved by the OEB:

- **OM&A:** A 5% reduction to WPLP's proposed 2024 OM&A expense on an envelope basis;
- **DVA Disposition Period:** With respect to WPLP's In-Service Date Variance Account ("ISDVA"), Construction Period Interest Costs Variance Account ("CPICVA") and Deferred Contingency Deferral Account ("DCDA"), a 1-year disposition period rather than four years as proposed in the Application;
- **Interest Rate for Long Term Debt:** With respect to the interest calculation relating to the cost rate for long-term debt, an adjustment from 5.85% to 5.76%;
- **Rate Base:** A reduction in 2024 rate base additions by $6.4 million, corresponding with WPLP's unaudited forecast of known COVID-19 costs for 2023, thereby impacting the 2024 regulated return on rate base and 2024 depreciation expense.
- **COVID Cost Recovery:** (a) the addition of WPLP's audited 2021 and 2022 known COVID-19 costs to rate base, leaving the (unaudited) 2023 amounts in the 2021-2023 CCCDA; and (b) establishment of a new EPC COVID-Related Costs Deferral Account to record costs, including applicable carrying costs, incurred and to be incurred by WPLP under its EPC Contract that relate to 2020 or later and which are in respect of anticipated claims from the EPC contractor for cost and schedule relief under the EPC Contract in relation to COVID and related access issues in the Whitefeather Forest area. Moreover, WPLP was required to establish sub-accounts for each year from 2020 to such year that all

outstanding amounts are determined and is required to record in such sub-accounts any amounts relating to such years. Furthermore, the method of recovery – as capital or as expenses – shall be subject to determination in a future application, and the carrying cost shall on an interim basis be the OEB prescribed rate but shall be recalculated on the basis of the applicable CWIP rate if and when recovery is determined to be as capital.

- **Federal Funding:** Establishment of a new Federal CIAC Variance Account, effective January 1, 2024, for the purpose of recording the revenue requirement impact of the difference, if any, between WPLP's forecasted date of the Contribution in Aid of Construction (CIAC) funds being distributed to WPLP pursuant to the Federal Funding Framework and the actual date such funds are distributed to WPLP, based on a forecast date of December 31, 2024, but the account will be asymmetrical to the benefit of ratepayers and the term of the account shall expire December 31, 2024, such that if the CIAC is not distributed to WPLP until after such date then the rate impacts thereof would be a matter for consideration in a future rate application.[7]

M. 2025 Transmission Revenue Requirement Application (EB-2024-0176)

WPLP filed its fourth transmission revenue requirement application on June 28, 2024, seeking approval for its 2025 electricity transmission revenue requirement and associated rates, and to charge HORCI a fixed charge for transmission service, effective January 1, 2025. In that proceeding, the parties reached a complete settlement on all issues, which was approved by the OEB in its Decision and Order dated December 10, 2024. The following outlines the key elements of the settlement agreement approved by the OEB:

- **OM&A:** A 6% reduction to WPLP's proposed 2025 OM&A expense on an envelope basis;
- **Multi-year filing**: Commitment to filing its first multi-year application in 2026 (for a rate period starting with the 2027 rate year) which will include a Transmission System Plan

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[7] See Exhibit I-4-1 for discussion of the Federal Funding Framework, expected CIAC timing and a proposed minor modification requested for the Federal CIAC Variance Account.

(TSP), a performance scorecard and an econometric benchmarking report based on 2025 data;

- **TSP and reporting**: Performance measurement and reporting will be addressed by filing initial TSP and initial scorecard, as part of the 2026 single test year revenue requirement application, each of which will be prepared on a best efforts basis having regard to the fact that 2025 will be the first full year of operations for the completed transmission system as well as the limited time and resources available for WPLP to develop these components of the application in time for the filing;

- **Deferral and Variance Accounts:** Continuation of what was previously referred to as the Construction Period OM&A Variance Account to allow for the recording of additional variance amounts for 2025 rather than maintaining it only for the purposes of facilitating recovery of the existing balance and applicable carrying costs as proposed in the Application, subject to changing the name of the account to remove the reference to "construction period". In addition, modifications to the timing of the Construction Period Interest Costs Variance Account and the Federal CIAC Variance Account (each as reflected in revised Accounting Orders included with the Settlement Proposal); and

COVID-Related Cost Deferral Account: In the event WPLP is not in a position to seek clearance of the balance from the EPC COVID-Related Cost Deferral Account as part of this single test year application filed in 2025 in respect of the 2026 test year or its first multi-year revenue requirement application to be filed in 2026 in respect of a rate period starting with the 2027 test year, on account of WPLP not having reached a final settlement with (or not having received a final arbitration award in respect of) its EPC contractor, OEB Staff and WPLP agreed it would be appropriate for WPLP to have the ability to seek mid-term clearance of such account during its first multi-year rate term and that OEB Staff will not object to such a proposal if included as part of WPLP's initial multi-year revenue requirement application.

Exhibit A, Tab 6, Schedule 1

Indigenous, Metis and Customer Engagement

INDIGENOUS, MÉTIS & CUSTOMER ENGAGEMENT

WPLP recognizes that the OEB's Renewed Regulatory Framework ("RRF") and Filing Requirements contemplate that transmitters take an active role in customer engagement by initiating and carrying out customer engagement activities on an ongoing basis to obtain feedback regarding customer needs and preferences. Areas for engagement include matters such as investment planning, transmission rates and charges, system performance and outages, connection procedures, regional planning, testing and inspections. Moreover, WPLP recognizes the OEB's expectation that engagement efforts should be designed to obtain feedback from regulated distributor customers served by its transmission system, end-use load customers and generator customers served directly from the transmission system (if any), and where possible from end-use customers of distribution systems served by its transmission system.

WPLP's customer engagement efforts to date have been primarily focused on issues relating to the design, development, construction and operation of the Transmission System, including routing, land access, land sharing protocols and traditional protocols, through the significant Indigenous engagement activities during the project development process and EA processes. These efforts have been undertaken by the Participating First Nations, Central Corridor Energy Group (CCEG), Tribal Councils representing member Indigenous communities, and OSLP[1] on behalf of WPLP and have been instrumental in the successful development and execution of WPLP's Transmission Project.

In its transition to being a fully operating transmitter with connected customers, WPLP continues to develop and implement customer engagement processes that address the OEB's expectations for customer engagement by transmitters in a manner that is appropriate for its circumstances including by following the expectations set out in the Guiding Principles.[2] Those processes and

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[1] OSLP is a service provider as further described in Exhibit A-4-1.

[2] See Exhibit B-1-1, Section B.1.

the customer needs and preferences identified through implementation of those processes are further described in the TSP at Exhibit B-1-1.

WPLP's extensive programs of engagement during the project development phase, and its environmental assessment processes, are described in significant detail in its leave to construct application in EB-2018-0190.[3] WPLP's subsequent engagement efforts, for the period up to its initial rate application are described in EB-2021-0134, for the period up to its second rate application are described in EB-2022-0149, for the period up to its third rate application are described in EB-2023-0168, and for the period up to its fourth rate application are described in EB-2024-0176.[4] WPLP's engagement efforts for the period subsequent to EB-2024-0176 are provided below. In total, the record of engagement shows that, from 2012 to March 31, 2025, there have been just over 3000 engagement activities with affected Indigenous and Métis communities conducted in various forms (e.g. open houses, meetings, etc.) in relation to the Transmission Project.

While WPLP's engagement efforts have been extensive, they differ from the approaches to customer engagement typically carried out and described in rate applications by operating utilities. In particular, WPLP's efforts have involved and continue to involve engagement with connecting and non-connecting First Nations, land users and private landowners that have been affected by ongoing operation of the Transmission System, as well as consultations with a wide range of potentially impacted stakeholders. These stakeholders have included a number of federal, provincial and local governments and regulatory agencies, the Independent Electricity System Operator (IESO), Hydro One Networks Inc. (HONI) and Hydro One Remote Communities Inc. (HORCI). Much of WPLP's early engagement efforts,[5] focused on identifying and supporting the need to connect remote Indigenous communities to the transmission system as an alternative to the continued use of diesel generation. Discussions of electricity supply limitations related to diesel

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[3] See Exhibit I of the revised application and evidence in EB-2018-0190, filed October 5, 2018 (http://www.rds.oeb.ca/HPECMWebDrawer/Record/611043/File/document).

[4] See Exhibits A-6-1 and B-1-2 of EB-2021-0134, EB-2022-0149, EB-2023-0168 and EB-2024-0176.

[5] Including the significant efforts of the predecessor organizations to WPLP, including CCEG.

generators and the impacts on the Indigenous communities are provided in WPLP's leave to construct application in EB-2018-0190.[6] Much of WPLP's engagement has also been carried out in the context of the project development activities and the environmental assessment processes for the Line to Pickle Lake and the Remote Connection Lines that are described and referenced above.

As construction of various transmission line segments were nearing completion in 2024, WPLP initiated community engagement activities that included, but were not limited to, engagement on permanent access for operational purposes for the project, post-construction environmental monitoring requirements, development of a transmission vegetation management plan, updates on project status, archaeology, health and safety, permitting, land access, IPA transfer, backup power, and Indigenous participation, along with community-specific questions and feedback. Discussions at each community engagement session included an update on construction status, an overview of the scope of WPLP's operational and maintenance activities and details of how WPLP proposes to access transmission right of way through a combination of a permanent access for operating purposes and temporary access methods. The engagement has provided an opportunity for Indigenous community members and land users to understand and provide input on WPLP's access plans, and for WPLP to adjust its access plans based on the input provided. The majority of engagement on permanent access concluded in 2024. Engagement on vegetation management planning is continuing for 2025 and 2026 with each of the communities and land users, prioritized based on the expected timing of vegetation work in the vicinity of each community. As discussed in Exhibit B-1-1, WPLP has also initiated engagement with First Nations following completion of the Transmission Project to reaffirm and reinvigorate the Mandate, Vision and Guiding Principles described above in consideration of the Transmission Project becoming fully operational.

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[6] See Exhibit C-1-1 of the revised application and evidence in EB-2018-0190, filed October 5, 2018 (http://www.rds.oeb.ca/HPECMWebDrawer/Record/611043/File/document)

Exhibit A, Tab 7, Schedule 1

Financial Information

FINANCIAL INFORMATION

This schedule provides the financial information specified in the OEB's Filing Requirements. Included are the following:

- Attachment 1 – WPLP Audited Financial Statements for 2024
- Attachment 2 – WPLP Audited Financial Statements for 2023
- Attachment 3 – WPLP Tax Returns for 2024
- Attachment 4 – WPLP Tax Returns for 2023
- Attachment 5 – 2024 Annual Report for Fortis Inc.[1]

A. Accounting Standard

WPLP follows the Canadian Accounting Standards for Private Enterprises (ASPE) and has used that standard as the basis for this Application. WPLP previously informed the OEB that it follows ASPE on December 19, 2016, in the proceeding to establish its Development Cost Deferral Account (EB-2016-0262).[2]

Authorization to use the ASPE is not required by a Canadian securities regulator. As a profit-oriented entity whose debt and equity instruments are not publicly traded, WPLP is eligible to apply ASPE for financial reporting and rate regulated accounting under Part II of the *CPA Canada Handbook – Accounting*. The use of ASPE for rate setting and regulatory reporting purposes results in consistency between WPLP and affiliates of FortisOntario Inc., allowing efficient implementation of accounting systems and reporting processes through a Services Agreement between WPLP and FortisOntario Inc.[3]

WPLP has had no changes to its accounting policies or accounting standards since its last revenue requirement application. WPLP's capitalization policy under ASPE is provided in Exhibit C-6-1.

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[1] First Nation LP does not prepare an equivalent annual report.

[2] EB-2016-0262; IRRs filed December 19, 2016; response to IR Board Staff – 15 a)

[3] See Exhibit F-3-1 for additional details on shared services.

B. Existing Accounting Orders

Exhibit H-1-1 provides a comprehensive summary of WPLP's existing regulatory accounts, including references to the OEB accounting orders establishing to those accounts.

C. Other Financial Information

WPLP does not engage in non-utility business and is therefore not required to segregate any portion of its fixed assets or financial results.

As described in Exhibit G of this Application, WPLP has secured project-specific debt financing. WPLP's partners, First Nation LP and Fortis (WP) LP, made equity contributions in 2022 as the initial assets went into service, and in 2023 coinciding with additional assets going in service. No contribution was required in 2024, however a 2025 contribution was completed on April 15, 2025[4] to align with the OEB deemed debt to equity structure of 60:40, as further described in Exhibits G-1-1 and G-2-1. Filing Requirements related to rating agency reports, prospectuses and information circulars are therefore not applicable.

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[4] Prior to the OEB issuing the Decision and Order for EB-2024-0176, WPLP informed the OEB on December 9, 2024, of a delay in the planned contribution of $70 million that was expected in mid-January 2025. WPLP committed to consult with OEB staff if it expected the delay would exceed WPLP's materiality threshold. On March 24, 2025, WPLP provided an update to the OEB that the equity injection was planned for April 15, 2025, and the impact of the delay was below materiality threshold. Subsequently on April 15, 2025, WPLP confirmed to the OEB that WPLP received the equity funds.

Exhibit A, Tab 7, Schedule 1

Financial Information

ATTACHMENT 1

WPLP Audited Financial Statements for 2024

Wataynikaneyap Power LP

Financial statements
December 31, 2024

Shape the future
with confidence

Independent auditor's report

To the Directors of
Wataynikaneyap Power LP

Opinion

We have audited the financial statements of **Wataynikaneyap Power LP** [the "Partnership"], which comprise the balance sheet as at December 31, 2024, and the statement of partners' equity, statement of operations and statement of cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Partnership as at December 31, 2024, and its results of operations and its cash flows for the year then ended in accordance with Canadian accounting standards for private enterprises.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial statements* section of our report. We are independent of the Partnership in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of management and those charged with governance for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with Canadian accounting standards for private enterprises, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Partnership's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Partnership or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Partnership's financial reporting process.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Partnership's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Partnership to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Ernst & Young LLP

Chartered Professional Accountants
Licensed Public Accountants

Toronto, Canada
April 17, 2025

Wataynikaneyap Power LP

Balance sheet

As at December 31

	2024 $	2023 $
Assets		
Current		
Cash *[note 7]*	**35,141,315**	4,359,869
Prepaid expenses	**584,047**	413,121
Accounts receivable *[note 1]*	**12,785,729**	7,913,725
Inventory	**6,027,718**	4,519,382
HST receivable	**—**	8,753,148
Due from related parties *[note 3]*	**23,484**	9,066
Total current assets	**54,562,293**	25,968,311
Regulatory assets *[notes 1 and 2]*	**118,360,569**	39,204,611
Property, plant and equipment, net *[note 4]*	**1,748,781,166**	1,778,328,145
	1,921,704,028	1,843,501,067
Liabilities and partners' equity		
Current		
Accounts payable and accrued liabilities	**36,244,738**	149,695,010
HST payable	**768,251**	—
Due to related parties *[note 3]*	**5,363,304**	4,929,726
Total current liabilities	**42,376,293**	154,624,736
Long-term debt *[note 5]*	**961,003,724**	1,239,942,952
Regulatory liabilities *[notes 1 and 2]*	**24,092,382**	21,913,732
Deferred contributions *[note 6]*	**476,269,823**	49,750,833
Total liabilities	**1,503,742,222**	1,466,232,253
Commitments *[note 9]*		
Partners' equity	**417,961,806**	377,268,814
	1,921,704,028	1,843,501,067

See accompanying notes

Approved by the Directors:

Director

Director

Wataynikaneyap Power LP

Statement of partners' equity

Year ended December 31

	2024				2023
	First Nation LP	Fortis (WP) LP	Wataynikaneyap Power GP Inc.		
	$	$	$	$	$
	51.00%	48.99%	0.01%	Total	Total
Partners' equity, beginning of year	**192,382,162**	**184,881,906**	**4,746**	**377,268,814**	283,440,236
Issuance of LP units	—	—	—	—	60,300,000
Net income for the year	**20,753,426**	**19,935,497**	**4,069**	**40,692,992**	33,528,578
Partners' equity, end of year	**213,135,588**	**204,817,403**	**8,815**	**417,961,806**	377,268,814

See accompanying notes

Wataynikaneyap Power LP

Statement of operations

Year ended December 31

	2024 $	**2023** $
Revenue		
Transmission	**150,095,758**	93,954,251
Pikangikum capital contribution amortization *[note 6]*	**1,211,531**	1,235,845
Trust agreement capital contribution amortization *[note 6]*	**3,656,933**	—
Regulatory interest, net	**2,654,593**	1,024,525
Interest income	**605,479**	357,701
	158,224,294	96,572,322
Expenses		
Operations	**9,752,513**	5,239,475
Maintenance	**1,270,536**	716,645
General and administration	**14,061,092**	8,578,321
Donations	**26,439**	11,688
Operating financing costs	**55,128,094**	28,585,877
Regulatory financing costs	**3,943,168**	1,485,945
Other expenses	**493,930**	423,994
Amortization	**32,855,530**	18,001,799
	117,531,302	63,043,744
Net income for the year	**40,692,992**	33,528,578

See accompanying notes

Wataynikaneyap Power LP

Statement of cash flows

Year ended December 31

	2024	2023
	$	$
Operating activities		
Net income for the year	**40,692,992**	33,528,578
Add (deduct) items not involving cash		
Non-cash regulatory interest	**(2,654,593)**	(1,024,525)
Amortization of deferred contributions	**(4,868,464)**	(1,235,845)
Amortization of property, plant and equipment	**32,855,530**	18,001,799
Changes in regulatory assets and liabilities	**(74,322,715)**	57,519,849
Changes in non-cash working capital balances related to operations		
Accounts receivable	**(4,872,004)**	(2,665,262)
Prepaid expenses	**(170,926)**	(393,083)
Inventory	**(1,508,336)**	(220,278)
HST receivable	**9,521,399**	(6,798,993)
Due from/(to) related parties	**419,160**	1,111,944
Accounts payable and accrued liabilities	**(113,450,272)**	(66,749,160)
Cash provided by (used in) operating activities	**(118,358,229)**	31,075,024
Investing activities		
Purchases of property, plant and equipment	**(77,471,036)**	(415,805,674)
Cash used in investing activities	**(77,471,036)**	(415,805,674)
Financing activities		
Increase (decrease) in deferred contributions	**505,549,939**	(984,168)
Issuance of LP units	**—**	60,300,000
Increase (decrease) in long-term debt	**(278,939,228)**	294,729,255
Cash provided by financing activities	**226,610,711**	354,045,087
Net increase (decrease) in cash during the year	**30,781,446**	(30,685,563)
Cash, beginning of year	**4,359,869**	35,045,432
Cash, end of year	**35,141,315**	4,359,869

See accompanying notes

Notes to financial statements

December 31, 2024

1. Basis of accounting and summary of significant accounting policies

Partnership

Wataynikaneyap Power LP [the "Partnership" or "WPLP"] was formed and registered under the laws of the Province of Ontario [the "Province"] by First Nation LP, Fortis (WP) LP and Wataynikaneyap Power GP Inc., through a limited partnership agreement dated July 6, 2015 and shall adhere to the following guiding principles:

[i] Our people expect that the Wataynikaneyap Power Project will be undertaken in a manner that respects our lands, rights and principles; our way of life on the land and as part of the land; and our land sharing protocols.

[ii] Our sacred responsibilities given to us by the Creator are to protect the land, which protects us in return. Therefore, the Project shall be built, operated and maintained in a way that minimizes adverse environmental impacts, as follows:

- The Wataynikaneyap Transmission Project [the "Project"] shall not poison the lands;
- No herbicides shall be used throughout the life of the transmission line to control vegetation;
- The Project shall be constructed, operated and maintained in a manner that observes and does not interfere with seasonal hunting, trapping, fishing and harvesting and keeps disturbances to a minimum;
- No new transmission lines shall be located underwater; and
- The Project will develop and implement an environmental and social management plan, which will include acceptable and effective mitigation measures for any sacred sites, gathering sites and harvesting sites.

[iii] The Project shall respect confidentiality and comply with any conditions of use for any Traditional Land and Resource Use Information provided by the communities, including intellectual property.

[iv] Our communities must maintain decision-making and ownership and receive benefits in the Project.

The Partnership ownership interests are the following:

First Nation LP – 51.0%
Fortis (WP) LP – 48.99%
Wataynikaneyap Power GP Inc. – 0.01%

Fortis (WP) LP is owned 80% by Fortis Inc. and 20% by Liberty Utilities (Wataynikaneyap Transmission) LP as at December 31, 2024. The shares of First Nation LP are held directly by 24 Participating First Nations in equal shares.

On August 1, 2015, Wataynikaneyap Power Corporation transferred the project assets of the Wataynikaneyap transmission project [the "Project"] to WPLP for $15,759,486, and WPLP assumed notes payable totalling this same amount as consideration for the transfer.

The business of WPLP is the planning, development and operation of the Project, which consists of a new transmission system in Northwestern Ontario, to reinforce transmission to Pickle Lake and to connect remote First Nation communities that are currently served by diesel generation. WPLP is a licensed Ontario electricity transmitter and is regulated by the Ontario Energy Board ["OEB"].

The Province identified the Project as a priority in the 2010 and 2013 Long-Term Energy Plans [“LTEP”]. The Province declared in the 2013 LTEP that the connection of remote First Nation communities is a key step towards providing a reliable, clean and affordable energy future for everyone in the Province. Further declaration of support was provided in the 2017 LTEP; the Project was noted as being selected as the transmitter for connecting remote First Nation communities.

On July 20, 2016, the Lieutenant Governor in Council made an Order in Council pursuant to Section 96.1 of the *Ontario Energy Board Act* [the “Act”] declaring the construction of an electricity line originating at a point between Ignace and Dryden and terminating in Pickle Lake, and the construction of electricity transmission lines extending north from Pickle Lake and Red Lake required to connect certain remote communities, to be a priority project.

On June 2, 2016, the Ontario Legislature passed the *Energy Statute Law Amendment Act, 2015* [also referred to as “Bill 135”]. Bill 135 permitted Cabinet to designate WPLP on July 20, 2016 as the electricity transmitter to connect 16 remote First Nation communities that currently rely on diesel power to the Province’s electricity grid.

The Lieutenant Governor in Council made an Order in Council on July 20, 2016 approving a directive issued by the Minister of Energy pursuant to Section 28.6.1 of the Act, which required the OEB, without holding a hearing, to amend the conditions of WPLP’s electricity transmission licence to include a requirement that WPLP proceed to develop and seek approvals for the Project.

On November 1, 2016, the Minister of Energy issued a letter to WPLP indicating that the Government of Ontario is committed to working with all First Nation communities in Ontario that are diesel reliant. The Government of Ontario has identified 21 diesel-reliant communities for whom grid connection makes economic sense, of which 16 are included in the Project. WPLP is fully supportive of improving the living conditions for all diesel-reliant First Nation communities by continuing to proceed with the Project to economically expand Ontario’s electricity grid. McDowell Lake First Nation is one of the First Nation shareholders and has expressed a desire to become connected to the Project. WPLP will pursue options, as a licensed transmitter, to provide economic means to connect McDowell Lake to the Project and has initiated discussions with the Government of Ontario in this regard.

Basis of accounting

These financial statements have been prepared in accordance with Part II of the *CPA Canada Handbook – Accounting*, “Accounting Standards for Private Enterprises” [“ASPE”], which constitutes generally accepted accounting principles for non-publicly accountable enterprises in Canada. The financial statements reflect the financial position and results of WPLP. These financial statements do not include the assets, liabilities, revenue and expenses of the partners. No provision has been made in these financial statements for any income taxes that may be assessable to the partners. Further, no provision has been made in the accounts for any salaries or interest accruing to the partners.

Notes to financial statements

Summary of significant accounting policies

Regulation

WPLP is a licensed Ontario electricity transmitter and is regulated by the OEB.

On August 26, 2016, WPLP applied to the OEB for an Accounting Order authorizing WPLP to establish a new regulatory deferral account for the purpose of recording costs in relation to the development of the Project.

On March 23, 2017, the OEB issued its Decision and Order on the deferral account proceeding. The effective date for the new deferral account was established as November 23, 2010. As part of the Decision and Order, WPLP is allowed to record carrying charges on allowable Project costs at regulated interest rates prescribed by the OEB. As a result of the Decision and Order, the OEB has denied all Project costs incurred prior to November 23, 2010, as well as any start-up and partnership formation costs from being included in the deferral account.

On November 22, 2018, the OEB issued its Decision and Order on the deferral account for recording and facilitating the future recovery of costs relating to the operation of WPLP's distribution system. As part of the Decision and Order, WPLP is allowed to record carrying charges on allowable operation, maintenance and administration costs for the distribution system, as well as any costs that may be incurred after the in-service date, which are not paid for by Indigenous Services Canada, at regulated interest rates prescribed by the OEB.

On April 1, 2019, the OEB issued its Decision and Order on the leave to construct application to construct transmission lines and associated facilities in Northwestern Ontario. As part of the Decision and Order, the OEB approved the transfer of development costs to WPLP's construction work-in-progress ["CWIP"] account, and all future project construction costs are to be recorded in the CWIP account.

Prior to April 1, 2019, costs determined to be Project development costs were deferred as regulatory assets on the balance sheet. All non-Project costs are recognized on the statement of operations. Future transmission rate proceedings will determine the proper disposition of all Project costs.

On September 30, 2021, the OEB issued its Decision and Order on the inaugural rate application filed by WPLP for the 2022 test year in April 2021. As part of the Decision and Order, the OEB approved the discontinuance of the CWIP Funding subaccount used to track funding amounts without applying the amounts recorded in that subaccount as offsets to development and construction costs. The OEB further approved the establishment of four new deferral/variance accounts: In-Service Date Variance Account ["ISDVA"], Construction Period Interest Costs Variance Account ["CPICVA"], Deferred Contingency Deferral Account ["DCDA"] and the 2020 COVID Construction Cost Deferral Account ["CCCDA"].

On November 29, 2022, the OEB issued its Decision and Order on the rate application filed by WPLP for the 2023 test year in April 2022. As part of the Decision and Order, the OEB approved the continuance of the ISDVA, CPICVA and DCDA accounts, and the establishment of two new variance accounts: Construction Period OM&A Variance Account and 2021-2023 COVID Construction Cost Deferral Account ["2021-2023 CCCDA"].

On November 30, 2023, the OEB issued its Decision and Order on the rate application filed by WPLP for the 2024 test year in June 2023. As part of the Decision and Order, the OEB approved the continuance of the existing deferral and variance accounts. The OEB further approved the establishment of two new deferral/variance accounts: EPC COVID-Related Costs Deferral Account and Federal CIAC Variance Account.

On December 10, 2024, the OEB issued its Decision and Order on the rate application filed by WPLP for the 2025 test year in June 2024. As part of the Decision and Order, the OEB required the continued use of OM&A Variance Account for 2025, the extension to the Federal CIAC Variance Account to December 2026 and the extension to the CPICVA until a time when WPLP's construction financing has transitioned to long-term debt financing.

Revenue recognition

Revenue from the transmission of electricity is recognized on the accrual basis. Transmission revenue is based on the revenue requirement that is submitted through the annual rate application and subsequently approved by the OEB. The approved revenue requirement includes a rate of return along with other cost recoveries necessary to support the Partnership's transmission system. Unbilled revenue included in accounts receivable as at December 31, 2024 is $12,782,443 [2023 – $6,979,769].

As noted above, WPLP is allowed regulatory carrying charges on the amount of deferred Project costs and thus recognizes interest income when earned on the balance of such costs. Expense recoveries are recognized as revenue in the year in which recovery is identified and collectibility is assured.

Inventory

Inventory, consisting of material and supplies, is measured at the lower of weighted average cost and net realizable value.

Property, plant and equipment

Property, plant and equipment are initially measured at cost and subsequently measured at cost less accumulated amortization.

Property, plant and equipment are amortized over the respective asset's useful life using the following method and rates:

On the straight-line method

Transmission plant	
Land rights	40 years
Station equipment – transformers and stations	50 years
Station equipment – switches and breakers	40 years
Station equipment – protection and control	20 years
Towers and fixtures	60 years
Poles and fixtures	45 years
Overhead conductors and devices	45 years

General plant	
Buildings and fixtures	50 years
Leasehold improvements	5 years
Computer hardware	5 years
Tools shop and garage equipment	10 years
Measurement and testing equipment	5 years
Transportation equipment	5–10 years

Income taxes

As a limited partnership, WPLP is not a taxable entity for federal and provincial income tax purposes. Accordingly, no income taxes are recognized in WPLP's financial statements.

Financial instruments

When WPLP becomes a party to the contractual provisions of a financial instrument, WPLP recognizes the financial asset or financial liability at its fair value, except for related party transactions, which are at the carrying or exchange amount depending on the circumstances. WPLP recognizes its transaction costs in income in the period incurred. However, financial instruments that will not be subsequently measured at fair value are adjusted by the transaction costs that are directly attributable to their origination, issuance or assumption. Subsequently, WPLP measures its financial instruments at amortized cost. WPLP does not own any equity instruments that would be subsequently measured at fair value if quoted in an active market or at cost less impairment for equity instruments not quoted in an active market. Financial assets measured at amortized cost include cash, accounts receivable and amounts due from related parties.

Use of estimates

The preparation of financial statements in conformity with ASPE and the regulatory environment in which the Company operates requires amounts to be recorded at estimated values until finalization and adjustment pursuant to subsequent regulatory decisions or other regulatory proceedings. Management makes estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as at the date of the financial statements, and the reported amounts of revenue and expenses during the reporting period. Actual results may vary from the current estimates. These estimates are reviewed periodically and, as adjustments become necessary, they are reported in income in the period in which they become known. Significant estimates and assumptions that are made by management are used for, but not limited to, the valuation of regulatory assets.

2. Regulatory assets and liabilities

Regulatory assets and liabilities arise as a result of regulatory requirements established by the OEB and consist mainly of engineering, environmental assessments and project management costs.

Notes to financial statements

The OEB has the general power to include or exclude costs, revenue, gains or losses in the rates of a specific period, resulting in the timing of revenue and expense recognition that may differ in WPLP's regulated operations from those otherwise expected in non-regulated businesses. This change in timing gives rise to the recognition of regulatory assets and liabilities. WPLP continually assesses the likelihood of recovery of its regulatory assets and believes that its regulatory assets and liabilities will be factored into the setting of future transmission rates as discussed in note 1. If future recovery through rates is no longer considered probable, the appropriate carrying amount will be written off in the period that the assessment is made.

Regulatory assets and liabilities are not subject to a regulatory return; however, the balances include an accrual for interest recovery/payable as permitted by the OEB at the quarterly approved deferral and variance prescribed interest rate [bankers' acceptances – three months plus 0.25 spread]. WPLP currently only accrues interest on regulatory costs that have been netted against third-party funding received. On September 30, 2021, the OEB approved the transfer of coronavirus disease ["COVID-19"] costs incurred to December 31, 2020 to a deferral account in the Decision and Order EB-2021-0134. On November 29, 2022, the OEB approved the establishment and transfer of COVID-19 costs incurred in 2021 to a deferral account in the Decision and Order EB-2022-0149. As a result, COVID-19 costs relating to 2021 were transferred during the year to the new deferral account.

On November 30, 2023, the OEB approved the transfer of audited COVID-19 costs incurred in 2021 and 2022 from the 2021-2023 CCCDA to rate base with an effective date of January 1, 2024.

In the 2025 rate application filing, WPLP proposed the transfer of audited 2023 COVID-19-related costs from the 2021-2023 CCCDA to rate base with an effective date of January 1, 2024 that was accepted as filed by the OEB.

Long-term regulatory assets and liabilities consist of the following:

	2024 $	**2023** $
Long-term regulatory assets		
Distribution System Deferral Account	**693,127**	2,511,723
COVID Construction Cost Deferral Account – 2020	**4,953,066**	9,646,529
COVID Construction Cost Deferral Account – 2021 to 2023	**—**	3,007,256
EPC COVID-Related Costs Deferral Account	**83,861,409**	—
Construction Period Interest Costs Variance Account	**23,064,350**	23,832,772
Deferred Contingency Deferral Account	**256,386**	206,331
In-Service Date Variance Account	**5,532,231**	—
	118,360,569	39,204,611

	2024 $	2023 $
Long-term regulatory liabilities		
OM&A Variance Account	**9,954,705**	5,330,204
Federal CIAC Variance Account	**14,137,677**	—
In-Service Date Variance Account	**—**	16,583,528
	24,092,382	21,913,732

Distribution System Deferral Account

This account records the costs incurred in relation to the Pikangikum System from the in-service date of the Pikangikum System up to the date the Pikangikum System is converted into and thereafter forms part of WPLP's transmission system. WPLP will record interest on the balance in this account using the OEB's prescribed interest rate for deferral and variance accounts. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed. The OEB approved the disposition of the audited 2023 balance as at December 31, 2023 plus forecasted carrying charges, which is being collected through revenue requirement adders in 2025.

Construction Period Interest Costs Variance Account

This account records the revenue requirement impact attributable to the difference between the effective interest rate for long-term debt approved in rate application and WPLP's actual effective interest rate on long-term debt during the construction period. WPLP will record interest on the balance in this account using the OEB's prescribed interest rate for deferral and variance accounts. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed. The OEB approved the disposition of the audited 2023 balance as at December 31, 2023 plus forecasted carrying charges, which is being collected through revenue requirement adders in 2025. The remaining balance in this account will be brought forward for disposition in a future proceeding with the OEB.

COVID Construction Cost Deferral Account – 2020

This account records all the incremental development and constructions costs that are directly attributable to the COVID-19 pandemic incurred after March 11, 2020. WPLP will record interest on the balance in this account using the OEB's prescribed interest rate for deferral and variance accounts. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed. The OEB approved the disposition of WPLP's audited CCCDA 2020 account balance as at December 31, 2020, which is being collected through revenue requirement adders over a four-year period ending December 31, 2025.

COVID Construction Cost Deferral Account – 2021 to 2023

This account records all the incremental development and construction costs that are directly attributable to the COVID-19 pandemic incurred from 2021 to 2023. In 2024, WPLP transferred the audited 2023 balance to capital as approved in OEB's decision EB-2024-0176. WPLP will record interest on the balance in this account using the OEB's prescribed interest rate for deferral and variance accounts; however, interest will ultimately be dependent on the OEB's determination as to the approach to disposition of the recorded amounts as capital or as an expense.

Deferred Contingency Deferral Account

This account records the revenue requirement impact attributable to contingency costs associated with 2022 in-service asset additions limited to a maximum of $48,075,777. WPLP will record interest on the balance in this account using the OEB's prescribed interest rate for deferral and variance accounts. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed. The OEB approved the disposition of the audited 2023 balance as at December 31, 2023 plus forecasted carrying charges, which is being collected through revenue requirement adders in 2025. The remaining balance in this account will be brought forward for prudency review and disposition in a future rate application proceeding.

In-Service Date Variance Account

This account records the difference between WPLP's approved revenue requirement based on forecasted in-service dates for the various lines/stations consisting of the transmission system and the revenue requirement if calculated based on WPLP's actual in-service dates for those lines/stations. This account shall be symmetrical. WPLP will record interest on the balance in this account using the OEB's prescribed interest rate for deferral and variance accounts. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed. The OEB approved the disposition of the audited 2023 balance as at December 31, 2023 plus forecasted carrying charges, which is being recovered through reduction to revenue requirement in 2025. The remaining balance in this account will be brought forward for disposition in a future proceeding with the OEB.

OM&A Variance Account

This account records the difference, if any, between WPLP's forecast annual OM&A expenses as approved by the OEB and its actual OM&A expenses for the corresponding year, during the period that WPLP's transmission project is under construction. This account shall be asymmetrical. WPLP will record interest on the balance in this account using the OEB's prescribed interest rate for deferral and variance accounts. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed. The OEB approved the disposition of the audited 2023 balance as at December 31, 2023 plus forecasted carrying charges, which is being recovered through reduction to revenue requirement in 2025. The remaining balance in this account will be brought forward for prudency review and disposition in a future rate application proceeding.

EPC COVID-Related Costs Deferral Account

This account records record costs incurred and to be incurred by WPLP in respect of anticipated claims for cost and schedule relief under its EPC Contract that relate to 2020 or later and which are in relation to COVID and related access issues in the Whitefeather Forest, including costs (such as legal costs) associated with WPLP's consideration, negotiation and potential settlement and/or other resolution of COVID-related costs. WPLP will record interest on the balance in this account using the OEB's prescribed interest rate for deferral and variance accounts; however, interest will ultimately be dependent on the OEB's determination as to the approach to disposition of the recorded amounts as capital or as an expense.

Federal CIAC Variance Account

This account records the revenue requirement impact of the difference between the forecasted date of the Contribution in Aid of Construction ("CIAC") funds being distributed pursuant to the Federal Funding Framework in 2024 Rate Application and the actual date the CIAC funds were distributed. This account shall be asymmetrical. WPLP will record interest on the balance in this account using the OEB's prescribed interest rate for deferral and variance accounts. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed. The balance in this account will be brought forward for prudency review and disposition in a future rate application proceeding.

Notes to financial statements

December 31, 2024

3. Related party transactions

During the year, WPLP entered into the following transactions with related parties:

	2024 $	2023 $
Project costs paid on behalf of WPLP by		
First Nation LP	**—**	(23,079)
Fortis (WP) GP Inc.	**1,779**	162
Fortis (WP) LP	**12,435**	(5)
Fortis Inc.	**382,750**	339,195
FortisOntario Inc.	**2,815,982**	2,636,348
Liberty Utilities	**98,786**	84,799
Newfoundland Power Inc.	**1,150**	19,617
Opiikapawiin Services LP	**6,877,400**	7,182,946
Wataynikaneyap Power PM Inc.	**5,864,751**	5,819,291
	16,055,033	16,059,274
Project engagement fees billed to WPLP by First Nation LP	**635,743**	614,859
Project management fees billed to WPLP by Wataynikaneyap Power PM Inc.	**635,743**	614,859

	2024 $	2023 $
Payments		
First Nation LP	**(716,423)**	(745,808)
Fortis (WP) GP Inc.	**(1,600)**	—
Fortis (WP) LP	**(9,701)**	—
FortisOntario Inc.	**(2,796,679)**	(2,658,142)
Newfoundland Power Inc.	**(1,150)**	(19,617)
Opiikapawiin Services LP	**(7,039,215)**	(6,614,760)
Wataynikaneyap Power PM Inc.	**(6,431,898)**	(6,218,260)
	(16,996,666)	(16,256,587)

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Notes to financial statements

As at December 31, the amounts due from/(to) related parties are as follows:

	2024 $	**2023** $
Current due to related parties		
First Nation LP	**59,866**	51,238
First Nation LP third-party funding	**222,424**	222,424
Fortis (WP) LP	**843**	—
Fortis Inc.	**734,337**	339,195
FortisOntario Inc.	**448,152**	424,753
Liberty Utilities	**183,585**	84,799
Opiikapawiin Services LP	**2,502,607**	2,664,421
Wataynikaneyap Power PM Inc.	**1,211,490**	1,142,896
	5,363,304	4,929,726

	2024 $	**2023** $
Current due from related parties		
Fortis (WP) GP Inc.	**1,837**	2,016
Fortis (WP) LP	**—**	1,891
Fortis Inc.	**12,392**	—
FortisOntario Inc.	**6,749**	2,653
Wataynikaneyap Power GP Inc.	**2,506**	2,506
	23,484	9,066

The amounts due from related parties are unsecured, non-interest bearing and have no specified terms of repayment.

As part of the OEB Decision and Order EB-2021-0134 on the initial rate application, WPLP was instructed to discontinue the CWIP Funding subaccount without applying the amounts recorded in that subaccount as offsets to development and construction costs. The amount due to First Nation LP of $222,424 [2023 – $222,424] represents the third-party funding removed as an offset to CWIP construction costs.

Details of the relationships with related parties are as follows:

- First Nation LP owns 51% of WPLP.
- Fortis (WP) LP owns 48.99% of WPLP.
- Fortis (WP) LP is owned 80% by Fortis Inc., who in turn owns 100% of FortisOntario Inc.
- Wataynikaneyap Power PM Inc. is owned 100% by FortisOntario Inc.
- Opiikapawiin Services LP is owned 100% by 24 Participating First Nations.

Notes to financial statements

December 31, 2024

4. Property, plant and equipment

	2024			2023
	Cost $	Accumulated amortization $	Net book value $	Net book value $
Transmission assets				
Land rights	**54,796**	**8,219**	**46,577**	47,947
Station equipment	**421,578,660**	**13,425,850**	**408,152,810**	272,629,612
Towers and fixtures	**617,215,377**	**15,022,788**	**602,192,589**	399,217,465
Poles and fixtures	**56,910,262**	**3,955,892**	**52,954,370**	52,398,602
Overhead conductors and devices	**710,440,555**	**26,229,742**	**684,210,813**	482,755,084
	1,806,199,650	**58,642,491**	**1,747,557,159**	1,207,048,710
General plant				
Buildings and fixtures	**396,999**	**—**	**396,999**	—
Leasehold improvements	**228,961**	**—**	**228,961**	—
Computer hardware	**356,556**	**12,765**	**343,791**	—
Transportation equipment	**155,392**	**77,696**	**77,696**	108,774
Tools shop and garage equipment	**168,500**	**—**	**168,500**	—
Measurement and testing equipment	**8,793**	**733**	**8,060**	—
	1,315,201	**91,194**	**1,224,007**	108,774
Construction work-in-progress	**—**	**—**	**—**	571,170,661
	1,807,514,851	**58,733,685**	**1,748,781,166**	1,778,328,145

Included in the cost of property, plant and equipment is $nil [2023 – $571,170,661] of assets not being amortized because they are under construction.

5. Long-term debt

	2024 $	2023 $
Senior banks [ii]	**494,880,204**	418,180,204
Ontario loan [i]	**466,123,520**	823,959,796
Unamortized financing costs, net of amortization of $15,604,788	**—**	(2,197,048)
	961,003,724	1,239,942,952

In October 2019, WPLP obtained two non-revolving construction facilities. The details of the facilities are as follows:

[i] The Ontario Financing Authority has provided a facility to a maximum of $1,340,000,000. The rate of interest is dependent upon when the draws are made and is otherwise based on the average three-month Ontario T-Bill rate ["cost of funds"] plus 49.9551 basis points. The cost of funds is accrued and included as a draw on the facility. The balance of the interest rate is payable on a 91-day basis. The average rate of interest for the year is 4.82% [2023 – 5.35%]. The facility is supported by a guarantee of Wataynikaneyap Power GP Inc. As of December 31, 2024, the maturity date of the facility was December 30, 2025 with principal payments required only to the extent of equity contributions from the unitholders. Subsequent to the year-end, on March 28, 2025, the maturity date of the facility was extended to December 31, 2027.

[ii] A $680,000,000 non-revolving construction facility provided by financial institutions and bears interest at the Canadian Dollar Offered Rate plus a spread of 1.5% till June 11, 2024, from June 12, 2024 the facility bears interest at the Canadian Overnight Repo Rate Average plus a spread of 1.5%. The average rate of interest for the year is 6.22% [2023 – 6.81%]. WPLP has provided a performance bond in the amount of $909,989,612 and a pledge of the unitholders' units in support of the facility. As of December 31, 2024, the maturity date of the facility was December 30, 2025 with principal payments required only to the extent of equity contributions from the unitholders. Subsequent to the year-end, on March 28, 2025, the maturity date of the facility was extended to December 31, 2027.

6. Deferred contributions

Deferred contributions relate to government funding received for the construction of transmission assets. One contribution related to the construction of a 99 km high-voltage, single-circuit, three-phase line to extend from Red Lake to a new substation near Pikangikum First Nation, which serves the community by the construction of an additional 18 km of a three-phase 25 kV line. The amount is deferred and amortized at a rate corresponding with the amortization rate of the Pikangikum project assets. The amount amortized in the year was $1,211,531 [2023 – $1,235,845] and is included under Pikangikum capital contribution amortization in the statement of operations.

A second contribution was received by WPLP as part of the Federal Funding Framework, which provided a contribution to WPLP of $509,236,276 as determined within the Amended Trust agreement dated June 6, 2024. The amount was first applied against capitalized interest included within the contribution of $77,819,418 and the remaining amount of $431,416,858 was deferred and amortized at a rate corresponding with the amortization rate of select assets of the transmission system. The amount amortized in the year was $3,656,933 [2023 – nil] and is included under Trust agreement capital contribution amortization in the statement of operations.

7. Cash and restricted cash

Bank balances are presented under cash.

8. Financial instruments and risk management

As at December 31, 2024, financial instruments recorded at amortized cost include cash, accounts receivable and due from related parties with a carrying value of $47,950,528 [2023 – $12,282,660].

Notes to financial statements

December 31, 2024

Risks and uncertainties

WPLP is exposed to risks of varying degrees of significance that could affect its ability to achieve its strategic objectives for growth. The principal financial risks are disclosed below.

Interest rate risk

Interest rate risk is the risk to the Partnership's income that arises from fluctuations in interest rates and the degree of volatility of these rates. The Partnership does not use derivative instruments to reduce its exposure to this risk. The Partnership is exposed to interest rate risk with respect to its long-term debt.

Credit risk

For cash, amounts due from related parties and accounts receivable, WPLP's credit risk is limited to the carrying values on the balance sheet.

Liquidity risk

Liquidity risk to WPLP is minimal. Financing of regulated capital and other expenditures is currently done through funds from its partners and related parties.

One of WPLP's partners, Fortis (WP) LP, is a large investor-owned utility that has had the ability to raise sufficient and cost-effective financing. However, the ability to arrange financing on a go-forward basis is subject to numerous factors, including the results of operations and financial position of Fortis Inc. and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

9. Commitments

WPLP's total future minimum lease payments under operating lease commitments over the next five years are as follows:

	$
2025	164,828
2026	172,397
2027	158,525
2028	5,594
2029	1,838
	503,182

In addition, WPLP has contractual commitments to its Engineering, Procurement and Construction contractor due to the impacts of COVID-19. Direct COVID-19 costs that can be reasonably estimated have been accrued as at December 31, 2024, the remaining cost exposure from COVID-19 is not determinable at this time.

Exhibit A, Tab 7, Schedule 1

Financial Information

ATTACHMENT 2

WPLP Audited Financial Statements for 2023

Wataynikaneyap Power LP

Financial statements
December 31, 2023

Independent auditor's report

To the Directors of
Wataynikaneyap Power LP

Opinion

We have audited the financial statements of **Wataynikaneyap Power LP** [the "Partnership"], which comprise the balance sheet as at December 31, 2023, and the statement of partners' equity, statement of operations and statement of cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Partnership as at December 31, 2023, and its results of operations and its cash flows for the year then ended in accordance with Canadian accounting standards for private enterprises.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial statements* section of our report. We are independent of the Partnership in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of management and those charged with governance for the financial statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with Canadian accounting standards for private enterprises, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Partnership's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Partnership or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Partnership's financial reporting process.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Partnership's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Partnership to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Ernst & Young LLP

Toronto, Canada
April 17, 2024

Chartered Professional Accountants
Licensed Public Accountants

Wataynikaneyap Power LP

Balance sheet

As at December 31

	2023	2022
	$	$
Assets		
Current		
Cash *[note 7]*	**4,359,869**	35,045,432
Prepaid expenses	**413,121**	20,038
Accounts receivable	**7,913,725**	5,248,463
Inventory	**4,519,382**	4,299,104
HST receivable	**8,753,148**	1,954,155
Due from related parties *[note 3]*	**9,066**	17,114
Total current assets	**25,968,311**	46,584,306
Regulatory assets *[notes 1 and 2]*	**39,204,611**	88,981,445
Property, plant and equipment, net *[note 4]*	**1,778,328,145**	1,380,524,270
	1,843,501,067	1,516,090,021
Liabilities and partners' equity		
Current		
Accounts payable and accrued liabilities	**149,695,010**	216,444,170
Due to related parties *[note 3]*	**4,929,726**	3,825,830
Total current liabilities	**154,624,736**	220,270,000
Long-term debt *[note 5]*	**1,239,942,952**	945,213,697
Regulatory liabilities *[notes 1 and 2]*	**21,913,732**	15,195,242
Deferred contributions *[note 6]*	**49,750,833**	51,970,846
Total liabilities	**1,466,232,253**	1,232,649,785
Partners' equity	**377,268,814**	283,440,236
	1,843,501,067	1,516,090,021

See accompanying notes

Approved by the Directors:

Director

Director

Wataynikaneyap Power LP

Statement of partners' equity

Year ended December 31

	2023				2022
	First Nation LP 51.00%	Fortis (WP) LP 48.99%	Wataynikaneyap Power GP Inc. 0.01%	Total	Total
	$	$	$	$	$
Partners' equity, beginning of year	**144,529,587**	**138,909,256**	**1,393**	**283,440,236**	16,940,653
Cancellation of LP units	—	—	—	—	(4,849,054)
Issuance of LP units	**30,753,000**	**29,547,000**	—	**60,300,000**	254,136,438
Contributed surplus	—	—	—	—	4,849,054
Net income for the year	**17,099,575**	**16,425,650**	**3,353**	**33,528,578**	12,363,145
Partners' equity, end of year	**192,382,162**	**184,881,906**	**4,746**	**377,268,814**	283,440,236

See accompanying notes

Wataynikaneyap Power LP

Statement of operations

Year ended December 31

	2023	**2022**
	$	$
Revenue		
Transmission	**93,954,251**	25,071,060
Pikangikum capital contribution amortization *[note 6]*	**1,235,845**	1,237,590
Regulatory interest, net	**1,024,525**	1,126,160
Interest income	**357,701**	53,933
	96,572,322	27,488,743
Expenses		
Operations	**5,239,475**	1,318,308
Maintenance	**716,645**	—
General and administration	**8,578,321**	2,638,196
Donations	**11,688**	—
Operating financing costs	**28,585,877**	4,939,252
Regulatory financing costs	**1,485,945**	1,887,789
Other expenses	**423,994**	—
Amortization	**18,001,799**	4,342,053
	63,043,744	15,125,598
Net income for the year	**33,528,578**	12,363,145

See accompanying notes

Wataynikaneyap Power LP

Statement of cash flows

Year ended December 31

	2023	2022
	$	$
Operating activities		
Net income for the year	**33,528,578**	12,363,145
Add (deduct) items not affecting cash		
Non-cash regulatory interest	**(1,024,525)**	(1,126,160)
Amortization of deferred contributions	**(1,235,845)**	(1,237,590)
Amortization of property, plant and equipment	**18,001,799**	4,342,053
Changes in regulatory assets and liabilities	**57,519,849**	(9,919,481)
Changes in non-cash working capital balances related to operations		
Accounts receivable	**(2,665,262)**	(5,020,935)
Prepaid expenses	**(393,083)**	(20,038)
Inventory	**(220,278)**	(3,915,036)
HST receivable	**(6,798,993)**	1,367,982
Due from/(to) related parties	**1,111,944**	(8,165,389)
Accounts payable and accrued liabilities	**(66,749,160)**	45,806,523
Cash provided by operating activities	**31,075,024**	34,475,074
Investing activities		
Purchases of property, plant and equipment	**(415,805,674)**	(416,338,340)
Cash used in investing activities	**(415,805,674)**	(416,338,340)
Financing activities		
Decrease in deferred contributions	**(984,168)**	(77,383)
Issuance of LP units	**60,300,000**	254,136,438
Increase in long-term debt	**294,729,255**	126,869,254
Cash provided by financing activities	**354,045,087**	380,928,309
Net decrease in cash during the year	**(30,685,563)**	(934,957)
Cash, beginning of year	**35,045,432**	35,980,389
Cash, end of year	**4,359,869**	35,045,432

See accompanying notes

Notes to financial statements

December 31, 2023

1. Basis of accounting and summary of significant accounting policies

Partnership

Wataynikaneyap Power LP [the "Partnership" or "WPLP"] was formed and registered under the laws of the Province of Ontario [the "Province"] by First Nation LP, Fortis (WP) LP and Wataynikaneyap Power GP Inc., through a limited partnership agreement dated July 6, 2015 and shall adhere to the following Guiding Principles:

[i] Our people expect that the Wataynikaneyap Power Project will be undertaken in a manner that respects our lands, rights and principles; our way of life on the land and as part of the land; and our land sharing protocols.

[ii] Our sacred responsibilities given to us by the Creator are to protect the land, which protects us in return. Therefore, the Project shall be built, operated and maintained in a way that minimizes adverse environmental impacts, as follows:

- The Project shall not poison the lands;
- No herbicides shall be used throughout the life of the transmission line to control vegetation;
- The Project shall be constructed, operated and maintained in a manner that observes and does not interfere with seasonal hunting, trapping, fishing and harvesting and keeps disturbances to a minimum;
- No new transmission lines shall be located underwater; and
- The Project will develop and implement an environmental and social management plan which will include acceptable and effective mitigation measures for any sacred sites, gathering sites and harvesting sites.

[iii] The Project shall respect confidentiality and comply with any conditions of use for any Traditional Land and Resource Use information provided by the communities, including intellectual property.

[iv] Our communities must maintain decision-making and ownership and receive benefits in the Project.

The Partnership ownership interests are the following:

First Nation LP – 51.0%
Fortis (WP) LP – 48.99%
Wataynikaneyap Power GP Inc. – 0.01%

Fortis (WP) LP is owned 80% by Fortis Inc. and 20% by Liberty Utilities (Wataynikaneyap Transmission) LP as at December 31, 2023. The shares of First Nation LP are held directly by 24 Participating First Nations in equal shares.

On August 1, 2015, Wataynikaneyap Power Corporation transferred the project assets of the Wataynikaneyap transmission project [the "Project"] to WPLP for $15,759,486, and WPLP assumed notes payable totalling this same amount as consideration for the transfer.

The business of WPLP is the planning, development and operation of the Project, which consists of a new transmission system in Northwestern Ontario, to reinforce transmission to Pickle Lake and to connect remote First Nation communities that are currently served by diesel generation. WPLP is a licensed Ontario electricity transmitter and is regulated by the Ontario Energy Board ["OEB"].

The Province identified the Project as a priority in the 2010 and 2013 Long-Term Energy Plans [“LTEP”]. The Province declared in the 2013 LTEP that the connection of remote First Nation communities is a key step towards providing a reliable, clean and affordable energy future for everyone in the province. Further declaration of support was provided in the 2017 LTEP; the Project was noted as being selected as the transmitter for connecting remote First Nation communities.

On July 20, 2016, the Lieutenant Governor in Council made an Order in Council pursuant to Section 96.1 of the *Ontario Energy Board Act* [the “Act”] declaring the construction of an electricity line originating at a point between Ignace and Dryden and terminating in Pickle Lake, and the construction of electricity transmission lines extending north from Pickle Lake and Red Lake required to connect certain remote communities, to be a priority project.

On June 2, 2016, the Ontario Legislature passed the *Energy Statute Law Amendment Act, 2015* [also referred to as “Bill 135”]. Bill 135 permitted Cabinet to designate WPLP on July 20, 2016 as the electricity transmitter to connect 16 remote First Nation communities that currently rely on diesel power to the Province’s electricity grid.

The Lieutenant Governor in Council made an Order in Council on July 20, 2016 approving a Directive issued by the Minister of Energy pursuant to Section 28.6.1 of the Act, which required the OEB, without holding a hearing, to amend the conditions of WPLP’s electricity transmission license to include a requirement that WPLP proceed to develop and seek approvals for the Project.

On November 1, 2016, the Minister of Energy issued a letter to WPLP indicating that the Government of Ontario is committed to working with all First Nation communities in Ontario that are diesel reliant. The Government of Ontario has identified 21 diesel-reliant communities for whom grid connection makes economic sense, of which 16 are included in the Project. WPLP is fully supportive of improving the living conditions for all diesel-reliant First Nation communities by continuing to proceed with the Project to economically expand Ontario’s electricity grid. McDowell Lake First Nation is one of the First Nation shareholders and has expressed a desire to become connected to the Project. WPLP will pursue options, as a licensed transmitter, to provide economic means to connect McDowell Lake to the Project and has initiated discussions with the Government of Ontario in this regard.

Basis of accounting

These financial statements have been prepared in accordance with Part II of the *CPA Canada Handbook – Accounting*, “Accounting Standards for Private Enterprises” [“ASPE”], which constitutes generally accepted accounting principles for non-publicly accountable enterprises in Canada. The financial statements reflect the financial position and results of WPLP. These financial statements do not include the assets, liabilities, revenue and expenses of the partners. No provision has been made in these financial statements for any income taxes that may be assessable to the partners. Further, no provision has been made in the accounts for any salaries or interest accruing to the partners.

Summary of significant accounting policies

Regulation

WPLP is a licensed Ontario electricity transmitter and is regulated by the OEB.

On August 26, 2016, WPLP applied to the OEB for an Accounting Order authorizing WPLP to establish a new regulatory deferral account for the purpose of recording costs in relation to the development of the Project.

On March 23, 2017, the OEB issued its Decision and Order on the deferral account proceeding. The effective date for the new deferral account was established as November 23, 2010. As part of the Decision and Order, WPLP is allowed to record carrying charges on allowable Project costs at regulated interest rates prescribed by the OEB. As a result of the Decision and Order, the OEB has denied all Project costs incurred prior to November 23, 2010, as well as any start-up and partnership formation costs from being included in the deferral account.

On November 22, 2018, the OEB issued its Decision and Order on the deferral account for recording and facilitating the future recovery of costs relating to the operation of WPLP's distribution system. As part of the Decision and Order, WPLP is allowed to record carrying charges on allowable operation, maintenance and administration costs for the distribution system, as well as any costs that may be incurred after the in-service date, which are not paid for by Indigenous Services Canada, at regulated interest rates prescribed by the OEB.

On April 1, 2019, the OEB issued its Decision and Order on the leave to construct application to construct transmission lines and associated facilities in Northwestern Ontario. As part of the Decision and Order, the OEB approved the transfer of development costs to WPLP's construction work-in-progress ["CWIP"] account, and all future project construction costs are to be recorded in the CWIP account.

Prior to April 1, 2019, costs determined to be Project development costs were deferred as regulatory assets on the balance sheet. All non-Project costs are recognized on the statement of operations. Future transmission rate proceedings will determine the proper disposition of all Project costs.

On September 30, 2021, the OEB issued its Decision and Order on the inaugural rate application filed by WPLP for the 2022 test year in April 2021. As part of the Decision and Order, the OEB approved the discontinuance of the CWIP Funding subaccount used to track funding amounts without applying the amounts recorded in that subaccount as offsets to development and construction costs. The OEB further approved the establishment of four new deferral/variance accounts: In-Service Date Variance Account ["ISDVA"], Construction Period Interest Costs Variance Account ["CPICVA"], Deferred Contingency Deferral Account ["DCDA"] and the COVID Construction Cost Deferral Account ["CCCDA"].

On November 29, 2022, the OEB issued its Decision and Order on the rate application filed by WPLP for the 2023 test year in April 2022. As part of the Decision and Order, the OEB approved the continuance of the ISDVA, CPICVA and DCDA accounts, and the establishment of two new variance accounts: Construction Period OM&A Variance Account ["CPOMAVA"] and 2021–2023 COVID Construction Cost Deferral Account ["2021–2023 CCCDA"].

On November 30, 2023, the OEB issued its Decision and Order on the rate application filed by WPLP for the 2024 test year in June 2023. As part of the Decision and Order, the OEB approved the continuance of the existing deferral and variance accounts. The OEB further approved the establishment of two new deferral/variance accounts: EPC COVID-Related Costs Deferral Account and Federal CIAC Variance Account.

Revenue recognition

Revenue from the transmission of electricity is recognized on the accrual basis. Transmission revenue is based on the revenue requirement that is submitted through the annual rate application and subsequently approved by the OEB. The approved revenue requirement includes a rate of return along with other cost recoveries necessary to support the Partnership's transmission system. Unbilled revenue included in accounts receivable as at December 31, 2023 is $6,979,769 [2022 – $5,048,410].

As noted above, WPLP is allowed regulatory carrying charges on the amount of deferred Project costs and thus recognizes interest income when earned on the balance of such costs. Expense recoveries are recognized as revenue in the year in which recovery is identified and collectibility is assured.

Inventory

Inventory, consisting of material and supplies, is measured at the lower of weighted average cost and net realizable value.

Property, plant and equipment

Property, plant and equipment are initially measured at cost and subsequently measured at cost less accumulated amortization.

Property, plant and equipment are amortized over the respective asset's useful life using the following rates:

On the straight-line method

Transmission plant	
Land rights	40 years
Station equipment – transformers and stations	50 years
Station equipment – switches and breakers	40 years
Station equipment – protection and control	20 years
Towers and fixtures	60 years
Poles and fixtures	45 years
Overhead conductors and devices	45 years
General plant	
Office furniture and equipment	10 years
Computer hardware	5 years
Transportation equipment	5–10 years

Income taxes

As a limited partnership, WPLP is not a taxable entity for federal and provincial income tax purposes. Accordingly, no income taxes are recognized in WPLP's financial statements.

Financial instruments

When WPLP becomes a party to the contractual provisions of a financial instrument, WPLP recognizes the financial asset or financial liability at its fair value, except for related party transactions, which are recorded at the carrying or exchange amount depending on the circumstances. WPLP recognizes its transaction costs in income in the period incurred. However, financial instruments that will not be subsequently measured at fair value are adjusted by the transaction costs that are directly attributable to their origination, issuance or assumption. Subsequently, WPLP measures its financial instruments at amortized cost. WPLP does not own any equity instruments that would be subsequently measured at fair value if quoted in an active market or at cost less impairment for equity instruments not quoted in an active market. Financial assets measured at amortized cost include cash, accounts receivable and due from related parties.

Use of estimates

The preparation of financial statements in conformity with ASPE and the regulatory environment in which the Company operates requires amounts to be recorded at estimated values until finalization and adjustment pursuant to subsequent regulatory decisions or other regulatory proceedings. Management makes estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as at the date of the financial statements, and the reported amounts of revenue and expenses during the reporting period. Actual results may vary from the current estimates. These estimates are reviewed periodically and, as adjustments become necessary, they are reported in income in the period in which they become known. Significant estimates and assumptions that are made by management are used for, but not limited to, the valuation of regulatory assets.

2. Regulatory assets and liabilities

Regulatory assets and liabilities arise as a result of regulatory requirements established by the OEB and consist mainly of engineering, environmental assessments and project management costs.

The OEB has the general power to include or exclude costs, revenue, gains or losses in the rates of a specific period, resulting in the timing of revenue and expense recognition that may differ in WPLP's regulated operations from those otherwise expected in non-regulated businesses. This change in timing gives rise to the recognition of regulatory assets and liabilities. WPLP continually assesses the likelihood of recovery of its regulatory assets and believes that its regulatory assets and liabilities will be factored into the setting of future transmission rates as discussed in note 1. If future recovery through rates is no longer considered probable, the appropriate carrying amount will be written off in the period that the assessment is made.

Regulatory assets and liabilities are not subject to a regulatory return; however, the balances include an accrual for interest recovery/payable as permitted by the OEB at the quarterly approved deferral and variance prescribed interest rate [bankers' acceptances – three months plus 0.25 spread]. WPLP currently only accrues interest on regulatory costs that have been netted against third-party funding received. On September 30, 2021, the OEB approved the transfer of coronavirus disease ["COVID-19"] costs incurred to December 31, 2020 to a deferral account in the Decision and Order EB-2021-0134. On November 29, 2022, the OEB approved the establishment and transfer of COVID-19 costs incurred in 2021 to a deferral account in the Decision and Order EB-2022-0149. As a result, COVID-19 costs relating to 2021 were transferred during the year to the new deferral account.

On November 30, 2023, the OEB approved the transfer of audited COVID-19 costs incurred in 2021 and 2022 from the 2021–2023 CCCDA to rate base with an effective date of January 1, 2024.

Long-term regulatory assets and liabilities consist of the following:

	2023 $	**2022** $
Long-term regulatory assets		
Distribution System Deferral Account	**2,511,723**	2,937,724
COVID Construction Cost Deferral Account – 2020	**9,646,529**	13,442,027
COVID Construction Cost Deferral Account – 2021 to 2023	**3,007,256**	69,183,830
Construction Period Interest Costs Variance Account	**23,832,772**	3,395,782
Deferred Contingency Deferral Account	**206,331**	22,082
	39,204,611	88,981,445

	2023 $	**2022** $
Long-term regulatory liabilities		
Construction Period OM&A Variance Account	**5,330,204**	—
In-Service Date Variance Account	**16,583,528**	15,195,242
	21,913,732	15,195,242

Distribution System Deferral Account

This account records the costs incurred in relation to the Pikangikum System from the in-service date of the Pikangikum System up to the date the Pikangikum System is converted into and thereafter forms part of WPLP's transmission system. WPLP will record interest on the balance in this account using the OEB's prescribed interest rate for deferral and variance accounts. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed. The OEB approved the disposition of the 2022 balance as at December 31, 2022, which is being collected through revenue requirement adders in 2024.

Construction Period Interest Costs Variance Account

This account records the revenue requirement impact attributable to the difference between the effective interest rate for long-term debt approved in rate application and WPLP's actual effective interest rate on long-term debt during the construction period. WPLP will record interest on the balance in this account using the OEB's prescribed interest rate for deferral and variance accounts. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed. The OEB approved the disposition of the 2022 balance as at December 31, 2022, which is being collected through revenue requirement adders in 2024. The remaining balance in this account will be brought forward for disposition in a future proceeding with the OEB.

Notes to financial statements

COVID Construction Cost Deferral Account – 2020

This account records all the incremental development and constructions costs that are directly attributable to the COVID-19 pandemic incurred after March 11, 2020. WPLP will record interest on the balance in this account using the OEB's prescribed interest rate for deferral and variance accounts. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed. The OEB approved the disposition of WPLP's CCCDA 2020 account balance as at December 31, 2020, which is being collected through revenue requirement adders over a four-year period ending December 31, 2025.

COVID Construction Cost Deferral Account – 2021 to 2023

This account records all the incremental development and construction costs that are directly attributable to the COVID-19 pandemic incurred from 2021 to 2023. WPLP will record interest on the balance in this account using the OEB's prescribed interest rate for deferral and variance accounts; however, interest will ultimately be dependent on the OEB's determination as to the approach to disposition of the recorded amounts as capital or as an expense. The 2023 balance in this account will be brought forward for a prudency review and disposition in future rate application proceedings.

Deferred Contingency Deferral Account

This account records the revenue requirement impact attributable to contingency costs associated with 2022 in-service asset additions limited to a maximum of $48,075,777. WPLP will record interest on the balance in this account using the OEB's prescribed interest rate for deferral and variance accounts. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed. The OEB approved the disposition of the 2022 balance as at December 31, 2022, which is being collected through revenue requirement adders in 2024. The remaining balance in this account will be brought forward for prudency review and disposition in a future rate application proceeding.

In-Service Date Variance Account

This account records the difference between WPLP's approved revenue requirement based on forecasted in-service dates for the various lines/stations consisting of the transmission system and the revenue requirement if calculated based on WPLP's actual in-service dates for those lines/stations. This account shall be symmetrical. WPLP will record interest on the balance in this account using the OEB's prescribed interest rate for deferral and variance accounts. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed. The OEB approved the disposition of the 2022 balance as at December 31, 2022, which is being recovered through reduction to revenue requirement in 2024. The remaining balance in this account will be brought forward for disposition in a future proceeding with the OEB.

Construction Period OM&A Variance Account

This account records the difference, if any, between WPLP's forecast annual OM&A expenses as approved by the OEB and its actual OM&A expenses for the corresponding year, during the period that WPLP's transmission project is under construction. This account shall be asymmetrical. WPLP will record interest on the balance in this account using the OEB's prescribed interest rate for deferral and variance accounts. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed. The balance in this account will be brought forward for disposition in a future proceeding with the OEB.

Notes to financial statements

December 31, 2023

3. Related party transactions

During the year, WPLP entered into the following transactions with related parties:

	2023 $	2022 $
Project costs paid on behalf of WPLP by		
First Nation LP	**(23,079)**	245,503
Fortis (WP) GP Inc.	**162**	—
Fortis (WP) LP	**(5)**	—
Fortis Inc.	**339,195**	—
FortisOntario Inc.	**2,636,348**	1,918,674
Liberty Utilities	**84,799**	—
Newfoundland Power Inc.	**19,617**	56,657
Opiikapawiin Services LP	**7,182,946**	6,529,746
Wataynikaneyap Power PM Inc.	**5,819,291**	5,287,262
	16,059,274	14,037,842
Project engagement fees billed to WPLP by First Nation LP	**614,859**	578,313
Project management fees billed to WPLP by Wataynikaneyap Power PM Inc.	**614,859**	578,313

	2023 $	2022 $
Payments		
First Nation LP	**(745,808)**	(594,044)
FortisOntario Inc.	**(2,658,142)**	(1,707,061)
Newfoundland Power Inc.	**(19,617)**	(56,657)
Opiikapawiin Services LP	**(6,614,760)**	(6,203,276)
Wataynikaneyap Power PM Inc.	**(6,218,260)**	(5,528,118)
	(16,256,587)	(14,089,156)

These transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

Wataynikaneyap Power LP

Notes to financial statements

December 31, 2023

As at December 31, the amounts due from (to) related parties are as follows:

	2023 $	2022 $
Current due to related parties		
First Nation LP	**51,238**	102,650
First Nation LP third-party funding	**222,424**	245,503
Fortis Inc.	**339,195**	—
FortisOntario Inc.	**424,753**	443,893
Liberty Utilities	**84,799**	—
Opiikapawiin Services LP	**2,664,421**	2,106,780
Wataynikaneyap Power PM Inc.	**1,142,896**	927,004
	4,929,726	3,825,830

	2023 $	2022 $
Current due from related parties		
Fortis (WP) GP Inc.	**2,016**	2,178
Fortis (WP) LP	**1,891**	1,885
FortisOntario Inc.	**2,653**	—
Opiikapawiin Services LP	**—**	10,545
Wataynikaneyap Power GP Inc.	**2,506**	2,506
	9,066	17,114

The amounts due from related parties are unsecured, non-interest bearing and have no specified terms of repayment.

As part of the OEB Decision and Order EB-2021-0134 on the initial rate application, WPLP was instructed to discontinue the CWIP Funding subaccount without applying the amounts recorded in that subaccount as offsets to development and construction costs. The due to First Nation LP of $222,424 [2022 – $245,503] represents the third-party funding removed as an offset to CWIP construction costs.

Details of the relationships with related parties are as follows:

- First Nation LP owns 51% of WPLP.
- Fortis (WP) LP owns 48.99% of WPLP.
- Fortis (WP) LP is owned 80% by Fortis Inc., who in turn owns 100% of FortisOntario Inc.
- Wataynikaneyap Power PM Inc. is owned 100% by FortisOntario Inc.
- Opiikapawiin Services LP is owned 100% by 24 Participating First Nations.

Notes to financial statements

December 31, 2023

4. Property, plant and equipment

	2023			2022
	Cost $	Accumulated amortization $	Net book value $	Net book value $
Transmission assets				
Land rights	**54,796**	**6,849**	**47,947**	49,316
Station equipment	**277,974,952**	**5,345,340**	**272,629,612**	128,218,389
Towers and fixtures	**405,125,666**	**5,908,201**	**399,217,465**	254,241,662
Poles and fixtures	**55,110,721**	**2,712,119**	**52,398,602**	21,744,049
Overhead conductors and devices	**494,618,420**	**11,863,336**	**482,755,084**	323,804,059
Transportation equipment	**155,392**	**46,618**	**108,774**	139,853
Construction work-in-progress	**571,170,661**	**—**	**571,170,661**	652,326,942
	1,804,210,608	**25,882,463**	**1,778,328,145**	1,380,524,270

Included in the cost of property, plant and equipment is $571,170,661 [2022 – $652,326,942] of assets not being amortized because they are under construction.

5. Long-term debt

	2023 $	2022 $
Senior banks [ii]	**418,180,204**	319,677,184
Ontario loan [i]	**823,959,796**	630,362,816
Unamortized financing costs, net of amortization of $13,407,740	**(2,197,048)**	(4,826,303)
	1,239,942,952	945,213,697

In October 2019, WPLP obtained two non-revolving construction facilities. The details of the facilities are as follows:

[i] The Ontario Financing Authority has provided a facility to a maximum of $1,340,000,000. The rate of interest is dependent upon when the draws are made and is otherwise based on the average three-month Ontario T-Bill rate [“cost of funds”] plus 49.9551 basis points. The cost of funds is accrued and included as a draw on the facility. The balance of the interest rate is payable on a 91-day basis. The average rate of interest for the year is 5.35% [2022 – 2.95%]. The facility is supported by a guarantee of Wataynikaneyap Power GP Inc. The maturity date of the facility is December 30, 2025 with principal payments required only to the extent of equity contributions from the unitholders.

[ii] A $680,000,000 non-revolving construction facility provided by financial institutions and bears interest at the Canadian dollar offered rate plus a spread of 1.5%. The average rate of interest for the year is 6.81% [2022 – 4.23%]. WPLP has provided a performance bond in the amount of $909,989,612 and a pledge of the unitholders' units in support of the facility. The maturity date of the facility is December 30, 2025 with principal payments required only to the extent of equity contributions from the unitholders.

6. Deferred contributions

Deferred contributions relate to government funding received for the construction of a new 99km high-voltage, single-circuit, three-phase line to extend from Red Lake to a new substation near Pikangikum First Nation, which serves the community by the construction of an additional 18km of a three-phase 25 kV line. The amount is deferred and amortized at a rate corresponding with the amortization rate of the Pikangikum project assets. The amount amortized in the year was $1,235,845 [2022 – $1,237,590] and is included under Pikangikum capital contribution amortization in the statement of operations.

7. Cash and restricted cash

Bank balances are presented under cash.

8. Financial instruments and risk management

As at December 31, 2023, financial instruments recorded at amortized cost include cash, accounts receivable and due from related parties with a carrying value of $12,282,660 [2022 – $40,311,009].

Risks and uncertainties

WPLP is exposed to risks of varying degrees of significance that could affect its ability to achieve its strategic objectives for growth. The principal financial risks are disclosed below.

Interest rate risk

Interest rate risk is the risk to the Partnership's income that arises from fluctuations in interest rates and the degree of volatility of these rates. The Partnership does not use derivative instruments to reduce its exposure to this risk. The Partnership is exposed to interest rate risk with respect to its long-term debt.

Credit risk

For cash, due from related parties and accounts receivable, WPLP's credit risk is limited to the carrying values on the balance sheet.

Liquidity risk

Liquidity risk to WPLP is minimal. Financing of regulated capital and other expenditures is currently done through funds from its partners and related parties.

One of WPLP's partners, Fortis (WP) LP, is a large investor-owned utility that has had the ability to raise sufficient and cost-effective financing. However, the ability to arrange financing on a go-forward basis is subject to numerous factors, including the results of operations and financial position of Fortis Inc. and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

Notes to financial statements

December 31, 2023

9. Commitments

WPLP's total future minimum lease payments under operating lease commitments over the next five years are as follows:

	$
2024	164,349
2025	162,990
2026	170,559
2027	156,687
2028	3,757
	658,342

In addition, WPLP has contractual commitments to its Engineering, Procurement and Construction contractor due to the impacts of COVID-19. Direct COVID-19 costs that can be reasonably estimated have been accrued as at December 31, 2023, and the remaining cost exposure from COVID-19 is not determinable at this time.

10. COVID-19

In March 2020, the World Health Organization declared the COVID-19 outbreak a pandemic. Governments and central banks have responded with monetary and fiscal interventions to stabilize economic conditions.

The extent of such adverse effects on WPLP's business and financial and operational performance are uncertain and difficult to assess. The impact of the COVID-19 pandemic, as well as the effectiveness of government and central bank responses, remain unclear at this time. It is not possible to reliably estimate the duration and severity of these consequences, as well as their impact on the financial position and results of the Partnership for future periods.

Exhibit A, Tab 7, Schedule 1

Financial Information

ATTACHMENT 3

WPLP Tax Returns for 2024

Agence du revenu du Canada | Canada Revenue Agency

Protected B when completed
T5013
Financial

Partnership Financial Return

Complete this financial return using the instructions in the T4068, Guide for the Partnership Information Return (T5013 Forms). You can file this return electronically without a web access code using the "File a return" service in My Business Account at **canada.ca/my-cra-business-account** or, for authorized representatives, in Represent a Client at **canada.ca/taxes-representatives**.

Unless otherwise stated, all legislative references are to the Income Tax Act.

055 **For internal use only.**

Identification

Partnership account number
001 78830 4327 RZ0001

Partnership name
006 Wataynikaneyap Power LP
007

Partnership operating or trading name
008
009

Location of the partnership head office
Has this location changed since the last time you filed a partnership information return? 010 ☐ Yes ☒ No
If you answered **Yes** to line 010, enter the address of the new location on lines 011 to 018.
011
012
City 015
Province, territory, or state 016
Country 017
Postal or zip code 018

Mailing address of the partnership
(if different from the head office address)
Has this address changed since the last time you filed a partnership information return? 020 ☐ Yes ☒ No
If you answered **Yes** to line 020, enter the new mailing address on lines 021 to 028.
021 c/o
023
024
City 025
Province, territory, or state 026
Country 027
Postal or zip code 028

Location of the partnership's books and records
(if different from the head office address)
Has this location changed since the last time you filed a partnership information return? 030 ☐ Yes ☒ No
If you answered **Yes** to line 030, enter the address of the new location on lines 031 to 038.
031
032
City 035
Province, territory, or state 036
Country 037
Postal or zip code 038

Is this an amended return? 040 ☐ Yes ☒ No

Fiscal period to which this information return applies
060 Fiscal period start (Year Month Day) From 2024-01-01
061 Fiscal period-end [1] (Year Month Day) To 2024-12-31

[1] If you answered **Yes** to question 078 below, enter the date when the partnership ceased to exist.

The end members of this partnership are
(tick the applicable boxes)
062 01 ☐ Individuals (including trusts)
02 ☒ Corporations

Is this the first year of filing? 070 ☐ Yes ☒ No

If you answered **Yes** to line 070, enter the date the partnership was created (Year Month Day) 071

Number of T5013 slips 073 3

Is this the partnership's final information return up to dissolution? 078 ☐ Yes ☒ No

If an election was made under section 261 by one or more partners, enter the functional currency code used for this return 079

Was the partnership a Canadian partnership throughout the fiscal period? 082 ☒ Yes ☐ No

Type of partnership at the end of the fiscal period

086

Non tax shelter	**Tax shelter**
☐ 01 General partnership	☐ 11 General partnership
☒ 02 Limited partnership	☐ 12 Limited partnership
☐ 03 Limited liability partnership	☐ 13 Co-ownership
☐ 08 Investment club	☐ 19 Other (specify below)

If the partnership is a tax shelter (TS), enter the TS identification number 087

Industry code (NAICS): 237130

Approval code: RC-24-P009

Required documents to attach to this T5013 FIN, Partnership Financial Return

- Form T5013 SUM, Summary of Partnership Income
- A copy of each T5013, Statement of Partnership Income slip issued to partners and nominees or agents
- T5013 SCH 1, Net Income (Loss) for Income Tax Purposes[2]
  [2] If you are an inactive partnership, see line 280 in Guide T4068 for more information.
- T5013 SCH 50, Partner's Ownership and Account Activity

The General Index of Financial Information (GIFI) schedules

- T5013 SCH 100, Balance Sheet Information
- T5013 SCH 125, Income Statement Information
- T5013 SCH 140, Summary Statement (located at the bottom of page 2 of T5013 SCH 125 and used when more than one T5013 SCH 125 is filed)
- T5013 SCH 141, General Index of Financial Information (GIFI) – Additional Information (not required for investment clubs)

Answer the following questions. For each **affirmative** answer, **attach** the related schedule or form to the partnership return, unless otherwise instructed.

At any time during the fiscal period, was the partnership a member of another partnership (directly or indirectly through one or more partnerships)?	**150**	☐ Yes	☒ No	T5013 SCH 9
Has the partnership had any transactions, including sections 97 and 98 transactions or subsection 85(2) transfers with its members or employees, other than transactions in the ordinary course of business? (Do not include non-arm's length transactions with non-residents.)	**162**	☐ Yes	☒ No	T2058, T2059, or T2060
Did the partnership have a total amount over $1 million of reportable transactions with non-arm's length non-residents?	**171**	☐ Yes	☒ No	T106
Does the partnership have to file Form T1134 in respect of any foreign affiliates in the fiscal period?	**172**	☐ Yes	☒ No	T1134
Has the partnership made any charitable donations, gifts of cultural or ecological property or federal, provincial, territorial or municipal political contributions?	**202**	☐ Yes	☒ No	T5013 SCH 2
Does the partnership have a permanent establishment in more than one jurisdiction?	**205**	☐ Yes	☒ No	T5013 SCH 5
Has the partnership realized any capital gains or incurred any capital losses during the fiscal period?	**206**	☐ Yes	☒ No	T5013 SCH 6
Does the partnership have any property that is eligible for capital cost allowance?	**208**	☒ Yes	☐ No	T5013 SCH 8
Does the partnership have any resource-related deductions (not including renounced expenditures)?	**212**	☐ Yes	☒ No	T5013 SCH 12
Is the partnership allocating any investment tax credits (ITCs) other than the specific ITCs mentioned below that have their own schedule? If **Yes**, attach a document to this return providing a detailed calculation of the partnership's ITCs and their allocation to one or more partners.	**231**	☐ Yes	☒ No	Calculation and allocation
Did the partnership incur any scientific research and experimental development (SR&ED) expenditures?	**232**	☐ Yes	☒ No	T661
Does the partnership have a corporation or trust as a member or deemed to be a member under subsection 18.2(12) and interest and financing expenses or interest and financing revenues in the fiscal period?	**233**	☒ Yes	☐ No	T5013 SCH 130
Did the partnership allocate renounced resource expenses to its members?	**252**	☐ Yes	☒ No	T5013 SCH 52
Did the partnership own or hold specified foreign property for which the total cost amount, at any time in the fiscal period, was more than CAN $100,000?	**259**	☐ Yes	☒ No	T1135
Is the partnership allocating any Canadian journalism labour tax credits?	**260**	☐ Yes	☒ No	T5013 SCH 58
Is the partnership allocating any return of fuel charge proceeds to farmers tax credits?	**261**	☐ Yes	☒ No	T5013 SCH 63
Is the partnership allocating any carbon capture, utilization and storage (CCUS) ITC, labour requirements addition to tax, or Part XII.7 tax?	**263**	☐ Yes	☒ No	T5013 SCH 78
Is the partnership allocating any clean technology ITC, labour requirements addition to tax, or recapture of clean technology ITC?	**264**	☐ Yes	☒ No	T5013 SCH 75

Additional information

Did the partnership use the International Financial Reporting Standards (IFRS) when it prepared its financial statements? **270** ☐ Yes ☒ No

Was a slip issued to one or more nominees or agents? **271** ☐ Yes ☒ No

Does the partnership agreement require that the nominee(s) or agent(s) complete and file any of the documents identified on page 2? **272** ☐ Yes ☒ No

Does the partnership have one or more new nominees or agents? **273** ☐ Yes ☒ No

Did the partnership allocate any amount of income tax deducted at source? **274** ☐ Yes ☒ No

Did the partnership make any other election(s) under the Act during the fiscal period? **275** ☒ Yes ☐ No

If **Yes**, attach a copy of each election form to this return.

Is this partnership the continuation of one or more predecessor partnerships since its last partnership information return was filed? **277** ☐ Yes ☒ No

If you answered **Yes** to line 277, provide the business number(s) of the predecessor partnership(s) **278**

279

Was the partnership inactive throughout the fiscal period this information return applies to? **280** ☐ Yes ☒ No

If **Yes**, see Guide T4068 to verify your filing requirements.

Did members of the partnership immigrate to Canada during the fiscal period? **291** ☐ Yes ☒ No

Did members of the partnership emigrate from Canada during the fiscal period? **292** ☐ Yes ☒ No

If the major business activity is construction, did you have any subcontractors during the fiscal period? **295** ☐ Yes ☒ No

Did the partnership report its farming or fishing income using the cash method? **296** ☐ Yes ☒ No

Is this a publicly traded partnership? **297** ☐ Yes ☒ No

If you answered **Yes** to line 297, did the partnership issue T5008 information slips to report transactions of interests in the partnership? **298** ☐ Yes ☐ No

Miscellaneous information

For tax deductions withheld at source, was an NR4 information return filed for the fiscal period? **301** ☐ Yes ☒ No

If you answered **Yes** to line 301, enter the non-resident account number **302**

If you answered **Yes** to line 301, were NR4 slips issued? **303** ☐ Yes ☐ No

Is this partnership a specified investment flow-through (SIFT) partnership? **304** ☐ Yes ☒ No

If you answered **Yes** to line 304, enter the taxable non-portfolio earnings for the fiscal period **305**

If you answered **Yes** to line 304, enter the tax payable under Part IX.1 for the fiscal period **306**

Enter the amount of the late-filing penalty from line 307 of the T5013 SCH 52, Summary Information for Partnerships that Allocated Renounced Resource Expenses to their Members **307**

Amount of payment enclosed with this return **308**

Protected B when completed

Additional information for all partnerships (including tax shelters that are partnerships)

Name and identification number of the partner designated under subsection 165(1.15)

400 Wataynikaneyap Power GP Inc. — Name of designated partner

402 815046362RC0001 — Identification number

Additional information for tax shelters only

Principal promoter

500 — Last name (print)

501 — First name (print)

502 — Identification number

Certification

950 I, Fecteau — Last name (print)

951 Duane — First name (print)

954 CFO — Position or title

certify that the information given on this information return and in any attached document is correct and complete. I also certify that the method of calculating income, deductions and credits for this fiscal period is consistent with that of the previous fiscal period except as noted in a statement attached to this return.

955 — Year Month Day

Signature of the authorized partner

956 (905) 994-3643 — Telephone number

Language of correspondence

Indicate your language of correspondence . . . . **990** ☒ English ☐ French

Privacy notice

Personal information (including the SIN) is collected and used to administer or enforce the Income Tax Act and related programs and activities including administering tax, benefits, audit, compliance, and collection. The information collected may be disclosed to other federal, provincial, territorial, aboriginal or foreign government institutions to the extent authorized by law. Failure to provide this information may result in paying interest or penalties, or in other actions. Under the Privacy Act, individuals have a right of protection, access to and correction of their personal information, and to file a complaint with the Privacy Commissioner of Canada regarding the handling of their personal information. Refer to Personal Information Bank CRA PPU 224 on Info Source at **canada.ca/cra-info-source**.

Canada Revenue Agency Agence du revenu du Canada

PARTNERSHIP'S BALANCE SHEET INFORMATION

T5013
SCHEDULE 100

Partnership name	Partnership account Number	Fiscal period end Year Month Day	
Wataynikaneyap Power LP	78830 4327 RZ0001	2024-12-31	Original ☒ Amended ☐

Is this a NIL schedule? 999 Yes ☐ No ☒

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	54,562,293.00	25,968,311.00
	Total tangible capital assets	2008	+	1,807,460,055.00	1,804,155,812.00
	Total accumulated amortization of tangible capital assets	2009	–	58,725,466.00	25,875,614.00
	Total intangible capital assets	2178	+	54,796.00	54,796.00
	Total accumulated amortization of intangible capital assets	2179	–	8,219.00	6,849.00
	Total long-term assets	2589	+	118,360,569.00	39,204,611.00
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	1,921,704,028.00	1,843,501,067.00
	Liabilities				
	Total current liabilities	3139	+	42,376,293.00	154,624,736.00
	Total long-term liabilities	3450	+	1,461,365,929.00	1,311,607,517.00
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	1,503,742,222.00	1,466,232,253.00
	Partner's capital				
	Total partners' capital (mandatory field)	3575	+	417,961,806.00	377,268,814.00
	Total liabilities and partners' capital	3585	=	1,921,704,028.00	1,843,501,067.00

* Generic item

Current Assets

SCHEDULE 100

Form Identifier 1599

Account	Description	GIFI		Current year	Prior year
	Cash and deposits				
	* Cash and deposits	1000		35,141,315.00	4,359,869.00
	Cash and deposits		+	35,141,315.00	4,359,869.00
	Accounts receivable				
	* Accounts receivable	1060		12,785,729.00	7,913,725.00
	Accounts receivable		+	12,785,729.00	7,913,725.00
	Inventories				
	* Inventories	1120		6,027,718.00	4,519,382.00
	Inventories		+	6,027,718.00	4,519,382.00
	Due from/investment in related parties				
	* Due from/investment in related parties	1400		23,484.00	9,066.00
	Due from/investment in related parties		+	23,484.00	9,066.00
	Other current assets				
	* Other current assets	1480			8,753,148.00
	Prepaid expenses	1484		584,047.00	413,121.00
	Other current assets		+	584,047.00	9,166,269.00
	Total current assets	1599	=	54,562,293.00	25,968,311.00

* Generic item

Tangible Capital Assets and Accumulated Amortization

SCHEDULE 100

Form identifier 2008/2009

Machinery, equipment, furniture and fixtures

Account	Description	GIFI	Tangible capital assets	Accumulated amortization	Prior year
	* Machinery, equipment, furniture, and fixtures	1740	+ 1,806,144,854.00		1,232,829,759.00
	*Accumulated amortization of machinery, equipment, furniture, and fixtures	1741		– 58,634,272.00	25,828,996.00
	Computer equipment/software	1774	+ 356,556.00		
	Accumulated amortization of computer equipment/software	1775		– 12,765.00	
	Transportation equipment	1783	+ 958,645.00		155,392.00
	Accumulated amortization of transportation equipment	1784		– 78,429.00	46,618.00
	Total		1,807,460,055.00	58,725,466.00	

Other tangible capital assets

Account	Description	GIFI	Tangible capital assets	Accumulated amortization	Prior year
	Other capital assets under construction	1920	+		571,170,661.00
	Total tangible capital assets	2008	= 1,807,460,055.00		1,804,155,812.00
	Total accumulated amortization of tangible capital assets	2009		= 58,725,466.00	25,875,614.00

* Generic item

Intangible Capital Assets and Accumulated Amortization

SCHEDULE 100

Form identifier 2178/2179

Account	Description	GIFI		Intangible capital assets		Accumulated amortization	Prior year
	Intangible assets						
	Rights	2024	+	54,796.00			54,796.00
	Accumulated amortization of rights	2025			–	8,219.00	6,849.00
	Total			54,796.00		8,219.00	
	Total intangible capital assets	2178	=	54,796.00			54,796.00
	Total accumulated amortization of intangible capital assets	2179			=	8,219.00	6,849.00

***** Generic item

Long-term Assets

SCHEDULE 100

Form identifier 2589

Account	Description	GIFI		Current year	Prior year
	Other long-term assets				
	* Other long-term assets	2420		118,360,569.00	39,204,611.00
	Other long-term assets		+	118,360,569.00	39,204,611.00
	Total long-term assets	2589	=	118,360,569.00	39,204,611.00

* Generic item

Current Liabilities

SCHEDULE 100

Form identifier 3139

Account	Description	GIFI		Current year	Prior year
	Amounts payable and accrued liabilities				
	* Amounts payable and accrued liabilities	2620		36,244,738.00	149,695,010.00
	Amounts payable and accrued liabilities		+	36,244,738.00	149,695,010.00
	* Taxes payable	2680	+	768,251.00	
	Due to related parties				
	* Due to related parties	2860		5,363,304.00	4,929,726.00
	Due to related parties		+	5,363,304.00	4,929,726.00
	Total current liabilities	3139	=	42,376,293.00	154,624,736.00

* Generic item

Long-term Liabilities

SCHEDULE 100

Form identifier 3450

Account	Description	GIFI		Current year	Prior year
	Long-term debt				
	* Long-term debt	3140		961,003,724.00	1,239,942,952.00
	Long-term debt		+	961,003,724.00	1,239,942,952.00
	Other long-term liabilities				
	* Other long-term liabilities	3320		500,362,205.00	71,664,565.00
	Other long-term liabilities		+	500,362,205.00	71,664,565.00
	Total long-term liabilities	3450	=	1,461,365,929.00	1,311,607,517.00

* Generic item

Partner's capital

SCHEDULE 100

GIFI Code 3575

Account	Description	GIFI		Current year	Prior year
Total net income/loss					
	Net income/loss	3545	+	40,692,992.00	33,528,578.00
	Total net income/loss	3550	=	40,692,992.00	33,528,578.00
General partners' capital					
	General partners' capital beginning balance	3551	+	4,746.00	1,393.00
	General partners' net income (loss)	3552	+	4,069.00	3,353.00
	General partners' capital ending balance	3560	=	8,815.00	4,746.00
Limited partners' capital					
	Limited partners' capital beginning balance	3561	+	377,264,068.00	283,438,843.00
	Limited partners' net income (loss)	3562	+	40,688,923.00	33,525,225.00
	Limited partners' contributions during the fiscal period	3564	+		60,300,000.00
	Limited partners' capital ending balance	3571	+	417,952,991.00	377,264,068.00
	Total partners' capital	3575	=	417,961,806.00	377,268,814.00

* Generic item

Canada Revenue Agency Agence du revenu du Canada

T5013
SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Partnership name	Partnership account number	Fiscal period end Year Month Day	
Wataynikaneyap Power LP	78830 4327 RZ0001	2024-12-31	Original ☒ Amended ☐

Income statement information

Description **GIFI**

Is this a NIL schedule? . . . . **999** ☐ Yes ☒ No

Operating Business Name **0001**

Description of the operation **0002**

Sequence Number **0003** 01

Account	Description	GIFI	Current year	Prior year
	Income statement information			
	Total sales of goods and services	8089 +	150,095,758.00	93,954,251.00
	Cost of sales	8518 –		
	Gross profit/loss	8519 =	150,095,758.00	93,954,251.00
	Cost of sales	8518 +		
	Total operating expenses	9367 +	117,531,302.00	63,043,744.00
	Total expenses (mandatory field)	9368 =	117,531,302.00	63,043,744.00
	Total revenue (mandatory field)	8299 +	158,224,294.00	96,572,322.00
	Total expenses (mandatory field)	9368 –	117,531,302.00	63,043,744.00
	Net non-farming income	9369 =	40,692,992.00	33,528,578.00
	Farming income statement information			
	Total farm revenue (mandatory field)	9659 +		
	Total farm expenses (mandatory field)	9898 –		
	Net farm income	9899 =		
	Net income/loss before extraordinary items – all operations	9970 =	40,692,992.00	33,528,578.00
	Total other comprehensive income	9998 =		
	Extraordinary items and income (linked to Schedule 140)			
	Extraordinary item(s)	9975 –		
	Legal settlements	9976 –		
	Unrealized gains/losses	9980 +		
	Unusual items	9985 –		
	Current income taxes	9990 –		
	Deferred income tax provision	9995 –		
	Total – Other comprehensive income	9998 +		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999 =	40,692,992.00	33,528,578.00

Revenue

SCHEDULE 125

Form identifier 8299

Account	Description	GIFI		Current year	Prior year
	* Trade sales of goods and services	8000	+	150,095,758.00	93,954,251.00
	Total sales of goods and services	8089	=	150,095,758.00	93,954,251.00
	Investment revenue				
	* Investment revenue	8090		2,654,593.00	1,024,525.00
	Interest from other Canadian sources	8094		605,479.00	357,701.00
	Investment revenue		+	3,260,072.00	1,382,226.00
	Other revenue				
	* Other revenue	8230		4,868,464.00	1,235,845.00
	Other revenue		+	4,868,464.00	1,235,845.00
	Total revenue	8299	=	158,224,294.00	96,572,322.00

* Generic item

Operating Expenses

SCHEDULE 125

Form identifier 9367

Account	Description	GIFI		Current year	Prior year
	Advertising and promotion				
	* Advertising and promotion	8520		26,439.00	11,688.00
	Meals and entertainment	8523		86,933.00	34,190.00
	Advertising and promotion		+	113,372.00	45,878.00
	* Amortization of tangible assets	8670	+	32,855,530.00	18,001,799.00
	Interest and bank charges				
	* Interest and bank charges	8710		55,128,094.00	28,585,877.00
	Interest and bank charges		+	55,128,094.00	28,585,877.00
	Office expenses				
	* Office expenses	8810		9,752,513.00	5,239,475.00
	Office expenses		+	9,752,513.00	5,239,475.00
	Repairs and maintenance				
	* Repairs and maintenance	8960		1,270,536.00	716,645.00
	Repairs and maintenance		+	1,270,536.00	716,645.00
	Other expenses				
	* Other expenses	9270		4,350,165.00	1,909,939.00
	General and administrative expenses	9284		14,061,092.00	8,544,131.00
	Other expenses		+	18,411,257.00	10,454,070.00
	Total operating expenses	9367	=	117,531,302.00	63,043,744.00

* Generic item

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T5013
Schedule 141
Protected B when completed

General Index of Financial Information (GIFI) – Additional Information

Partnership name	Partnership account number	Fiscal period-end Year Month Day	
Wataynikaneyap Power LP	78830 4327 RZ0001	2024-12-31	☒ Original ☐ Amended

- A partnership needs to complete all parts of this schedule that apply and include it with their partnership information return along with the other GIFI schedules.
- For more information, see Guide RC4088, General Index of Financial Information (GIFI), and Guide T4068, Guide for the Partnership Information Return (T5013 forms).

Part 1 – Information on the person primarily involved with the financial information

Can you identify the person* specified in the heading of Part 1? . . . **111** Yes ☒ No ☐

If you answered **no**, go to Part 2.

Does that person have a professional designation in accounting? . . . **095** Yes ☒ No ☐

Is that person connected** with the partnership? . . . **097** Yes ☐ No ☒

* A person primarily involved with the financial information is a person who has more than a 50% involvement in preparing the financial information that the partnership information return is based on. For example, if three persons prepared the financial information by doing respectively 30%, 30%, and 40% of the work, answer **no** at line 111. If they did respectively 10%, 20%, and 70% of the work, answer **yes** at line 111 and complete Part 1 by referring only to the third person.

** A person connected with a partnership can be: (i) a member of the partnership who owns more than 10% of the partnership units; (ii) an employee of the partnership; or (iii) a person not dealing at arm's length with the partnership.

Part 2 – Type of involvement

Choose one or more of the following options that represent your involvement and that of the person referred to in Part 1:

Completed an auditor's report . . . **300** ☒

Completed a review engagement report . . . **301** ☐

Conducted a compilation engagement . . . **302** ☐

Provided accounting services . . . **303** ☐

Provided bookkeeping services . . . **304** ☐

Other . . . **305** ☐

If other, please specify . . . **306** ____________________

Part 3 – Reservations

If you selected option **300** or **301** in Part 2 above, answer the following question:

Has the person referred to in Part 1 expressed a reservation? . . . **099** Yes ☐ No ☒

Part 4 – Other information

Were notes to the financial statements prepared? . . . **101** Yes ☒ No ☐

Did the partnership have any subsequent events? . . . **104** Yes ☐ No ☒

Did the partnership re-evaluate its assets during the fiscal period? . . . **105** Yes ☐ No ☒

Did the partnership have any contingent liabilities during the fiscal period? . . . **106** Yes ☐ No ☒

Did the partnership have any commitments during the fiscal period? . . . **107** Yes ☒ No ☐

Does the partnership have investments in joint ventures? If **yes**, complete question 109 below . . . **108** Yes ☐ No ☒

Is the partnership filing joint venture(s) financial statements? . . . **109** Yes ☐ No ☐

Approval code: RC-24-P009

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income as a result of an impairment loss in the fiscal period, a reversal of an impairment loss recognized in a previous fiscal period, or a change in fair value during the fiscal period? **200** Yes ☐ No ☒

If **yes**, enter the amount recognized:

In net income Increase (decrease)

Property, plant, and equipment	**210**	
Intangible assets	**215**	
Investment property	**220**	
Biological assets	**225**	
Financial instruments	**230**	
Other	**235**	

In other comprehensive income Increase (decrease)

Property, plant, and equipment	**211**	
Intangible assets	**216**	
Financial instruments	**231**	
Other	**236**	

Financial instruments

Did the partnership derecognize any financial instrument(s) during the fiscal period (other than trade receivables)? **250** Yes ☐ No ☒

Did the partnership apply hedge accounting during the fiscal period? **255** Yes ☐ No ☒

Did the partnership discontinue hedge accounting during the fiscal period? **260** Yes ☐ No ☒

Adjustments to opening partners' capital

Was an amount included in the opening balance of partners' capital, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current fiscal period? **265** Yes ☐ No ☒

If **yes**, you have to maintain a separate reconciliation.

Part 5 – Information on the person who prepared the partnership information return

If the person who prepared the partnership information return has a professional designation in accounting but is not the person identified in Part 1, choose all of the following options that apply:

Prepared the partnership information return and the financial information contained therein	**310**	☐
The client provided the financial statements	**311**	☒
The client provided a trial balance	**312**	☐
The client provided a general ledger	**313**	☐
Other	**314**	☐

If other, please specify **315** ____________________

See the privacy notice on your return.

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Partnership name	Partnership account number	**Fiscal period end** Year Month Day
Wataynikaneyap Power LP	78830 4327 RZ0001	2024-12-31

Is this a NIL schedule? . . . . **999** Yes ☐ No ☒

Assets – lines 1000 to 2599

1000	35,141,315.00	**1060**	12,785,729.00	**1120**	6,027,718.00
1400	23,484.00	**1484**	584,047.00	**1599**	54,562,293.00
1740	1,806,144,854.00	**1741**	-58,634,272.00	**1774**	356,556.00
1775	-12,765.00	**1783**	958,645.00	**1784**	-78,429.00
2008	1,807,460,055.00	**2009**	-58,725,466.00	**2024**	54,796.00
2025	-8,219.00	**2178**	54,796.00	**2179**	-8,219.00
2420	118,360,569.00	**2589**	118,360,569.00	**2599**	1,921,704,028.00

Liabilities – lines 2600 to 3499

2620	36,244,738.00	**2680**	768,251.00	**2860**	5,363,304.00
3139	42,376,293.00	**3140**	961,003,724.00	**3320**	500,362,205.00
3450	1,461,365,929.00	**3499**	1,503,742,222.00		

Partner's capital – lines 3540 to 3575

3545	40,692,992.00	**3550**	40,692,992.00	**3551**	4,746.00
3552	4,069.00	**3560**	8,815.00	**3561**	377,264,068.00
3562	40,688,923.00	**3571**	417,952,991.00	**3575**	417,961,806.00
3585	1,921,704,028.00				

Approval code: RC-24-P009

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Partnership name	Partnership account number	**Fiscal period end** Year Month Day
Wataynikaneyap Power LP	78830 4327 RZ0001	2024-12-31

Is this a NIL schedule? . . . . **999** ☐ Yes ☒ No

Description

Sequence number **0003** 01

Revenue – lines 8000 to 8299

8000	150,095,758.00	**8089**	150,095,758.00	**8090**	2,654,593.00
8094	605,479.00	**8230**	4,868,464.00	**8299**	158,224,294.00

Cost of sales – lines 8300 to 8519

8519	150,095,758.00

Operating expenses – lines 8520 to 9369

8520	26,439.00	**8523**	86,933.00	**8670**	32,855,530.00
8710	55,128,094.00	**8810**	9,752,513.00	**8960**	1,270,536.00
9270	4,350,165.00	**9284**	14,061,092.00	**9367**	117,531,302.00
9368	117,531,302.00	**9369**	40,692,992.00		

Farming revenue – lines 9370 to 9659

9659	0.00

Farming expenses – lines 9660 to 9899

9898	0.00

Extraordinary items and taxes – lines 9970 to 9999

9970	40,692,992.00	**9999**	40,692,992.00

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Net Income (Loss) for Income Tax Purposes

Protected B when completed

T5013
Schedule 1

Partnership name	**Partnership account number**	**Fiscal period end** Year Month Day	
Wataynikaneyap Power LP	78830 4327 RZ0001	2024-12-31	☒ Original ☐ Amended

- Fill out this schedule to reconcile the partnership's net income (loss) reported on the financial statements and its net income (loss) for income tax purposes.
- All the information requested in this form and in the documents supporting your information return is "prescribed information".
- Fill out this schedule using the instructions in Guide T4068, Guide for the Partnership Information Return (T5013 forms).
- Fill out a worksheet to identify the source of all the amounts reported on the T5013 information slips.
- Attach the original copy of this completed schedule to Form T5013 FIN, Partnership Financial Return.

Is this a NIL schedule? 999 ☐ Yes ☒ No

(If **yes**, do not use zeroes (000 00), dashes (-), nil, or N/A on the lines.)

Amount calculated on line 9999 from Schedule 125 or Schedule 140			500	40,692,992.00
Add:				
Provision for Part IX.1 specified investment flow through (SIFT) taxes	101			
Amortization/depreciation of tangible assets	104	32,855,530.00		
Amortization of natural resource assets	105			
Amortization of intangible assets	106			
Recapture of capital cost allowance from Schedule 8	107			
Income or loss for tax purposes from partnerships	109			
Loss in equity of affiliates	110			
Loss on disposal of assets per financial statements	111			
Charitable donations and gifts from Schedule 2	112			
Political contributions from Schedule 2	114			
Current fiscal period's holdbacks	115			
Deferred and prepaid expenses	116			
Depreciation in inventory – end of fiscal period	117			
Scientific research and experimental development (SR&ED) expenditures deducted per financial statements	118			
Capitalized interest and property taxes on vacant land	119			
Non-deductible club dues and fees	120			
Non-deductible meals and entertainment expenses	121	43,466.50		
Non-deductible automobile expenses	122			
Non-deductible life insurance premiums	123			
Non-deductible company pension plans	124			
Reserves from financial statements – balance at the end of the fiscal period	126			
Soft costs on construction and renovation of buildings	127			
Salaries and wages paid to partners deducted on financial statements	150			
Cost of products available for sale that were consumed	151			
Personal expenses of the partners paid by the partnership	152			
Dividend rental arrangement compensation payment deductions	154			
Renounced exploration, development and resource property expenses deducted per financial statements from Schedule 52	155			
Certain fines and penalties	156			
Amount from line 508 on page 2 of this schedule	199	118,172.23		
Total (**Add** lines 101 to 199. Enter this amount on line 501)		33,017,168.73 ▶	501	+ 33,017,168.73
Deduct: Amount from line 511 on page 3 of this schedule			502	– 73,710,160.73
Net income (loss) for income tax purposes – (line 500 **plus** line 501 **minus** line 502)			503	=
Deduct: Net income (loss) for general partners			504	–
Net income (loss) for income tax purposes for limited and non-active partners (line 503 **minus** line 504)			505	=

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Canada

Partnership account number	78830 4327 RZ0001
Fiscal period end Year Month Day	2024-12-31

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Add:

Accounts payable and accruals for cash basis – closing	201			
Accounts receivable and prepaid for cash basis – opening	202			
Accrual inventory – opening	203			
Accrued dividends – prior fiscal period	204			
Book loss on joint ventures or partnerships	205			
Capital items expensed	206	84,460.12		
Debt issue expense	208			
Deemed dividend income	209			
Deemed interest on loans to non-residents	210			
Deemed interest received	211			
Development expenses claimed in current fiscal period	212			
Dividend stop-loss adjustment	213			
Dividends credited to the investment account	214			
Exploration expenses claimed in current fiscal period	215			
Financing fees deducted in books	216			
Foreign accrual property income	217			
Foreign affiliate property income	218			
Foreign exchange included in retained earnings	219			
Gain on settlement of debt – income inclusion under subsection 80(13)	220			
Interest paid on income debentures	221			
Limited partnership losses	222			
Loss from international banking centres	223			
Mandatory inventory adjustment – included in current fiscal period	224			
Non-deductible advertising	226			
Non-deductible interest	227			
Non-deductible legal and accounting fees	228			
Optional value of inventory – included in current fiscal period	229			
Other expenses from financial statements	230			
Recapture of SR&ED expenditures from Form T661	231			
Resource amounts deducted	232			
Sales tax assessments	234			
Write-down of capital property	236			
Amounts received in respect of qualifying environmental trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			
Contractors' completion method adjustment: revenue net of costs on contracts under 2 years – previous fiscal period	238			
Taxable/Non-deductible other comprehensive income items	239			
Total (**Add** lines 201 to 239. Enter this amount on line 506)		84,460.12 ▶	506	+ 84,460.12

Other additions:

600	Asset Retirement	290	33,712.11		
601		291			
602		292			
603		293			
604		294			
	Total (**Add** lines 290 to 294. Enter this amount on line 507)		33,712.11 ▶	507	+ 33,712.11

Total (**Add** lines 506 and 507) 508 = 118,172.23

Enter the amount from line 508 on line 199 on page 1 of this schedule.

Partnership account number
78830 4327 RZ0001

Fiscal period end
Year Month Day
2024-12-31

Protected B when completed

Deduct:

Accounts payable and accruals for cash basis – opening	300	
Accounts receivable and prepaid for cash basis – closing	301	
Accrual inventory – closing	302	
Accrued dividends – current fiscal period	303	
Bad debt	304	
Book income of joint venture or partnership	305	
Equity in income from affiliates	306	
Exempt income under section 81	307	
Income from international banking centres	308	
Mandatory inventory adjustment – included in prior fiscal period	309	
Contributions to a qualifying environmental trust	310	
Non-Canadian advertising expenses – broadcasting	311	
Non-Canadian advertising expenses – printed materials	312	
Optional value of inventory – included in prior fiscal period	313	
Other income from financial statements	314	
Payments made for allocations in proportion to borrowing and bonus interest payments	315	
Contractors' completion method adjustment: revenue net of costs on contracts under 2 years – current fiscal period	316	
Non-taxable/Deductible other comprehensive income items	347	

Other less common deductions:

700	Amortization of deferred contribution	390	4,868,464.00
701		391	
702	Gain on Disposal	392	33,712.00
703		393	
704		394	

Total (**Add** lines 300 to 394. Enter this amount on line 509) 4,902,176.00 ▶ 509 + 4,902,176.00

Other deductions:

Gain on disposal of assets per financial statements	401	
Non-taxable dividends under section 83	402	
Capital cost allowance from Schedule 8	403	68,807,984.73
Terminal loss from Schedule 8	404	
Foreign non-business tax deduction under subsection 20(12)	407	
Prior fiscal period's holdbacks	408	
Deferred and prepaid expenses	409	
Depreciation in inventory – end of prior fiscal period	410	
SR&ED expenditures claimed in the fiscal period from Form T661 (line 460)	411	
Reserves from financial statements – balance at the beginning of the fiscal period	414	
Patronage dividends	416	
Contributions to deferred income plans	417	

Total (**Add** lines 401 to 417. Enter this amount on line 510) 68,807,984.73 ▶ 510 + 68,807,984.73

Total (**Add** lines 509 and 510) 511 = 73,710,160.73
Enter this amount on line 502 on page 1 of this schedule.

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T5013
Schedule 8

Protected B when completed

Capital Cost Allowance (CCA)

Partnership name	Partnership account number	Fiscal period end Year Month Day	
Wataynikaneyap Power LP	78830 4327 RZ0001	2024-12-31	☒ Original ☐ Amended

- Fill out this schedule to calculate the amount of capital cost allowance (CCA) the partnership is claiming for the fiscal period, or to account for acquisitions or dispositions of depreciable property, or both.
- Fill out this schedule to designate immediate expensing property.
- Fill out this schedule using the instructions in the T4068, Guide for the Partnership Information Return (T5013 forms).
- If you do not have enough space to list all the information, use an additional T5013 Schedule 8.
- Attach the original copy of this completed schedule to Form T5013 FIN, Partnership Financial Return.

Part 1 – Agreement between associated eligible persons or partnerships (EPOPs)

Are you associated in the fiscal period with one or more EPOPs with which you have entered into an agreement under subsection 1104(3.3) of the Regulations? . . . . **105** Yes ☐ No ☐

If you answered **yes**, complete Part 1. Otherwise, go to Part 2.

Enter a percentage assigned to each associated EPOP (including your partnership) as determined in the agreement.

This percentage will be used to allocate the immediate expensing limit. The total of all the percentages assigned under the agreement should not exceed 100%. If the total is more than 100%, then the associated group has an immediate expensing limit of nil. For more information about the immediate expensing limit, see note 12 in Part 3.

	1 Name of EPOP **110**	2 Identification number See **note 1** **115**	3 Percentage assigned under the agreement **120**
1			%
2			%
3			%
4			%
5			%
6			%
7			%
8			%
		Total	%

Immediate expensing limit allocated to the partnership (see **note 2**) . . . . **125** ______

Note 1: The identification number is the social insurance number, business number, or partnership account number of the EPOP.

Note 2: Multiply 1.5 million by the percentage assigned to your partnership in column 3.

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Part 2 – Income earned from the source in which the designated immediate expensing property (DIEP) is used

The source refers to the business or property from which the income was earned and in which the DIEP is used. For more information about DIEP, see note 5 in Part 3.

Are you a Canadian partnership of which all of the members were, throughout the fiscal period, Canadian-controlled private corporations (CCPC), individuals (other than trusts) resident in Canada or a combination thereof? . . . . . **150** Yes ☐ No ☒

If you answered **yes**, complete Part 2. Otherwise, go to Part 3.

Is there more than one source of income? . . . . . **155** Yes ☐ No ☐

If you answered **no**, enter the income of that source of income (net income for income tax purposes before any CCA deductions) . . . . . **156** ______

If the answer is **yes**, complete the table below.

	1 Source of income **160**	2 Income before any CCA deductions from each source (if the income is a loss or nil, enter "0") **165**	3 Aggregate amount of DIEP used for each source **170**
1			
2			
3			
4			
5			
6			
7			
8			

Protected B when completed

Part 3 – CCA calculation

	1 Class number See **note 3** **200**	2 Undepreciated capital cost (UCC) at the beginning of the fiscal period **201**	3 Cost of acquisitions during the fiscal period (new property must be available for use) See **note 4** **203**	4 Cost of acquisitions from column 3 that are designated immediate expensing property (DIEP) See **note 5** **232**	5 Adjustments and transfers (show amounts that will reduce the UCC in brackets) See **note 6** **205**	6 Amount from column 5 that is assistance received or receivable during the fiscal period for a property, subsequent to its disposition See **note 7** **221**	7 Amount from column 5 that is repaid during the fiscal period for a property, subsequent to its disposition See **note 8** **222**	8 Proceeds of dispositions See **note 9** **207**
1	14.1	40,315.54						
2	99	571,170,661.00	2,178,146.00		-573,348,807.00			
3	47	1,112,822,402.50	573,348,807.00		-427,226,515.46			
4	10	59,825.92						
5	50		356,556.00					
6	8		261,753.12					
7	2		396,999.00					
8	13		228,961.00					

	9 Proceeds of dispositions of the DIEP (enter amount from column 8 that relates to the DIEP reported in column 4) **234**	10 UCC (column 2 **plus** column 3 **plus** or **minus** column 5 **minus** column 8) See **note 10**	11 UCC of the DIEP (enter the UCC amount that relates to the DIEP reported in column 4) See **note 11** **236**	12 Immediate expensing See **note 12** **238**	13 Cost of acquisitions on remainder of Class (column 3 **minus** column 12)	14 Cost of acquisitions from column 13 that are accelerated investment incentive properties (AIIP) or properties included in Classes 54 to 56 See **note 13** **225**	15 Remaining UCC (column 10 **minus** column 12)	16 Proceeds of disposition available to reduce the UCC of AIIP and property included in Classes 54 to 56 (column 8 **plus** column 6 **minus** column 13 **plus** column 14 **minus** column 7) (if negative, enter "0") See **note 14**
1		40,315.54					40,315.54	
2					2,178,146.00	2,178,146.00		
3		1,258,944,694.04			573,348,807.00	573,348,807.00	1,258,944,694.04	
4		59,825.92					59,825.92	
5		356,556.00			356,556.00	356,556.00	356,556.00	
6		261,753.12			261,753.12	261,753.12	261,753.12	
7		396,999.00			396,999.00	396,999.00	396,999.00	
8		228,961.00			228,961.00		228,961.00	
		Totals						

Protected B when completed

Part 3 – CCA calculation (continued)

	17 Net capital cost additions of AIIP and property included in Classes 54 to 56 acquired during the fiscal period (column 14 **minus** column 16) (if negative, enter "0")	18 UCC adjustment for AIIP and property included in Classes 54 to 56 acquired during the fiscal period (column 17 **multiplied** by the relevant factor) See **note 15**	19 UCC adjustment for property acquired during the fiscal period other than AIIP and property included in Classes 54 to 56 (0.5 **multiplied** by the result of column 13 **minus** column 14 **minus** column 6 **plus** column 7 **minus** column 8) (if negative, enter "0") See **note 16** **224**	20 CCA rate % See **note 17** **212**	21 Recapture of CCA See **note 18** **213**	22 Terminal loss See **note 19** **215**	23 CCA (for declining balance method, the result of column 15 **plus** column 18 **minus** column 19, **multiplied** by column 20, or a lower amount, **plus** column 12) See **note 20** **217**	24 UCC at the end of the fiscal period (column 10 **minus** column 23) **220**
1				5.00			2,822.09	37,493.45
2	2,178,146.00							
3	573,348,807.00			8.00			68,492,042.40	1,190,452,651.64
4				30.00			17,947.78	41,878.14
5	356,556.00			55.00			196,105.80	160,450.20
6	261,753.12			20.00			52,350.62	209,402.50
7	396,999.00			6.00			23,819.94	373,179.06
8			22,896.10				22,896.10	206,064.90
					230	**240**	**250**	
				Totals			68,807,984.73	

Enter the amount from line 230 on line 107 of T5013 Schedule 1.
Enter the amount from line 240 on line 404 of T5013 Schedule 1.
Enter the amount from line 250 on line 403 of T5013 Schedule 1.

Note 3: If a class number has not been provided in Schedule II of the Income Tax Regulations for a particular class of property, use the subsection provided in Regulation 1101.

Note 4: Include any property acquired in previous fiscal periods that has now become available for use, net of any assistance received or entitled to be received in the fiscal period from a government, municipality or other public authority, or a reduction of capital cost after the application of section 80. This property would have been previously excluded from column 3. List separately any acquisitions of property in the class that are not subject to the 50% rule. See Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance, for exceptions to the 50% rule. Do not include any amount in column 3 in respect of property included in column 5 (see note 6).

Note 5: A DIEP reported in column 4 is a property acquired after December 31, 2021, by a Canadian partnership (all of the members of which were, throughout the period, Canadian-controlled private corporations, individuals (other than trusts) resident in Canada or a combination thereof) that becomes available for use before 2025 (if all the members are individuals throughout the fiscal period), or before 2024 in any other case. The property is designated as such on or before the day that is 12 months after the filing due date of an information return under section 229 of the Regulations by any member of the partnership for the fiscal period to which the designation relates. It includes all capital property subject to the CCA rules, if certain conditions are met, other than property included in Classes 1 to 6, 14.1, 17, 47, 49, and 51. A property can only qualify as DIEP in the fiscal period in which it becomes available for use. See subsection 1104(3.1) of the Regulations for more information.

If there is more than one source of income, the total amount of DIEP reported in Part 2 (total of column 3) should be equal to the total amount of DIEP reported in Part 3 (total of column 4).

Part 3 – CCA calculation (continued)

Note 6: Enter in column 5, "Adjustments and transfers", amounts that increase or reduce the UCC (column 10). Items that increase the UCC include amounts transferred under subsection 97(2). Items that reduce the UCC (show amounts that reduce the UCC in brackets) include assistance received or receivable during the fiscal period for a property, subsequent to its disposition, if such assistance would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f). See the Guide T4068 for other examples of adjustments and transfers to include in column 5.

Also include property acquired in a non-arm's length transaction (other than by virtue of a right referred to in paragraph 251(5)(b) of the Act) if the property was a depreciable property acquired by the transferor at least 364 days before the end of your fiscal period and continuously owned by the transferor until it was acquired by you.

Note 7: Include all amounts of assistance you received (or were entitled to receive) after the disposition of a depreciable property that would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f) if received before the disposition.

Note 8: Include all amounts you have repaid during the fiscal period for any legally required repayment, made after the disposition of a corresponding property, of:

- assistance that would have otherwise increased the capital cost of the property under paragraph 13(7.1)(d) and
- an inducement, assistance, or any other amount contemplated in paragraph 12(1)(x) received, that otherwise would have increased the capital cost of the property under paragraph 13(7.4)(b)

Also include property acquired in a non-arm's length transaction (other than by virtue of a right referred to in paragraph 251(5)(b) of the Act) if the property was a depreciable property acquired by the transferor less than 364 days before the end of your fiscal period and continuously owned by the transferor until it was acquired by you.

Note 9: For each property disposed of during the fiscal period, deduct from the proceeds of disposition any outlays and expenses to the extent that they were made or incurred for the purpose of making the disposition(s). The amount reported in respect of the property cannot exceed the property's capital cost, unless that property is a timber resource property as defined in subsection 13(21).

If the cost of a zero-emission passenger vehicle (or a passenger vehicle that was, at any time, a DIEP) exceeds the prescribed amount and it is disposed of to a person or partnership with which you deal at arm's length, the proceeds of disposition will be adjusted based on a factor equal to the prescribed amount as a proportion of the actual cost of the vehicle. The actual cost of the vehicle will be adjusted for payment or repayment of government assistance.

Note 10: If the amount in column 5 (as shown in brackets) reduces the UCC, you must subtract it for the purposes of the calculation. Otherwise, add the amount in column 5 for the purpose of the calculation.

Note 11: The amount to enter in column 11 must not exceed the amount in column 10. If it does, enter in column 11 the amount from column 10. If the amount determined in column 10 is zero or a negative amount, enter zero. The only amounts incurred before 2022, to be included in this column are certain inventory purchases from arm's length persons or partnerships where the conditions in paragraphs 1100(0.3)(a) to (c) are met.

Note 12: Immediate expensing applies to a DIEP included in column 11. The total immediate expensing for the fiscal period (total of column 12) is limited to the lesser of:

1. Immediate expensing limit: it is equal to one of the following five amounts, whichever is applicable:
   - $1.5 million, if you are not associated with any other EPOP in the fiscal period
   - amount from line 125, if you are associated in the fiscal period with one or more EPOPs
   - nil, if the total of the percentages assigned in Part 1 is more than 100% or you are associated in the fiscal period with one or more EPOPs and have not filed an agreement in prescribed form as required under subsection 1104(3.3) of the Regulations
   - the amount determined under subsection 1104(3.5) of the Regulations for any second or subsequent fiscal periods ending in a calendar year, if you have two or more fiscal periods ending in the calendar year in which you are associated with another EPOP that has a tax year ending in that calendar year
   - any amount allocated by the minister under subsection 1104(3.4) of the Regulations

   The immediate expensing limit has to be prorated if your fiscal period is less than 51 weeks. You cannot carry forward any unused amount of the immediate expensing limit.
2. UCC of the DIEP: total of column 11
3. Income earned from the source in which the DIEP is used: amount from line 156 or relevant source of income from line 165

Note 13: An AIIP is a property (other than property included in Classes 54 to 56) that you acquired after November 20, 2018, and that became available for use before 2028.

Classes 54 and 55 include zero-emission vehicles that you acquired after March 18, 2019, and that became available for use before 2028.

Class 56 applies to eligible zero-emission automotive equipment and vehicles (other than motor vehicles) that are acquired after March 1, 2020, and that became available for use before 2028.

See Guide T4068 for more information.

Note 14: Include only elements from columns 6 and 7 that are not related to the DIEP.

Part 3 – CCA calculation (continued)

Note 15: The relevant factors for property of a class in Schedule II, that is an AIIP or included in Classes 54 to 56, available for use before 2024 are:

- 2 1/3 for property in Classes 43.1, 54, and 56
- 1 1/2 for property in Class 55
- 1 for property in Classes 43.2 and 53
- 0 for property in Classes 12, 13, 14, and 15, as well as properties that are Canadian vessels included in paragraph 1100(1)(v) of the Regulations (see note 20 for additional information) and
- 0.5 for all other property that is an AIIP

Note 16: The UCC adjustment for property acquired during the fiscal period (also known as the half-year rule or 50% rule) does not apply to certain property (including AIIP and property included in Classes 54 to 56). Include only elements from columns 6 and 7 that are not related to the DIEP.

For special rules and exceptions, see Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance.

Note 17: Enter a rate only if you are using the declining balance method. For any other method (for example, the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 23.

Note 18: If the amount in column 10 is negative, you have a recapture of CCA. If applicable, enter the negative amount from column 10 in column 21 as a positive. The recapture rules do not apply to passenger vehicles in Class 10.1. However, they do apply to a passenger vehicle that was, at any time, a DIEP.

Note 19: If no property is left in the class at the end of the fiscal period and there is still a positive amount in the column 10, you have a terminal loss. If applicable, enter the positive amount from column 10 in column 22. The terminal loss rules do not apply to:

- passenger vehicles in Class 10.1
- property in Class 14.1, unless you have ceased carrying on the business to which it relates
- limited-period franchises, concessions, or licences in Class 14 if, at the time of acquisition, the property was a former property of the transferor or any similar property attributable to the same fixed place of business, and you had jointly elected with the transferor to have the replacement property rules apply, unless certain conditions are met

Note 20: If the fiscal period is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See Guide T4068 for more information.

For property in class 10.1 disposed of during the fiscal period, deduct a maximum of 50% of the regular CCA deduction if you owned the property at the beginning of the fiscal period.

For AIIP listed below, the maximum first fiscal period allowance you can claim is determined as follows:

- Class 13: the lesser of 150% of the amount calculated in Schedule III of the Regulations and the UCC at the end of the fiscal period (before any CCA deduction)
- Class 14: the lesser of 150% of the allocation for the fiscal period of the capital cost of the property apportioned over the remaining life of the property (at the time the cost was incurred) and the UCC at the end of the fiscal period (before any CCA deduction)
- Class 15: the lesser of 150% of an amount computed on the basis of a rate per cord, board foot, or cubic metre cut in the fiscal period and the UCC at the end of the fiscal period (before any CCA deduction)
- Canadian vessels described under paragraph 1100(1)(v) of the Regulations: the lesser of 50% of the capital cost of the property and the UCC at the end of the fiscal period (before any CCA deduction)
- Class 41.2: use a 25% CCA rate. The additional allowance under paragraphs 1100(1)(y.2) (for single mine properties) and 1100(1)(ya.2) (for multiple mine properties) of the Regulations is not eligible for the accelerated investment incentive. The additional allowance in respect of natural gas liquefaction under paragraph 1100(1)(yb) of the Regulations is eligible for the accelerated investment incentive

The AIIP also applies to property (other than a timber resource property) that is a timber limit or a right to cut timber from a limit as well as to industrial mineral mine or a right to remove minerals from an industrial mineral mine. See the Income Tax Regulations for more detail.

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Partnership information return

Additions for tax purposes – regular classes (T5013 Schedule 8)		576,542,261 12		
Additions for tax purposes – leasehold improvements (T5013 Schedule 8)	+	228,961 00		
Operating leases capitalized for book purposes	+			
Capital gain deferred	+			
Recapture deferred	+			
Deductible expenses capitalized for book purposes (T5013 Schedule 1)	+			
Other (specify):				
CWIP Additions	+	-573,348,807 00		
Total additions per partnership information return	=	3,422,415 12	▶	3,422,415 12
Proceeds up to original cost – regular classes (T5013 Schedule 8)				
Proceeds up to original cost – leasehold improvements (T5013 Schedule 8)	+			
Proceeds in excess of original cost – capital gain	+			
Recapture deferred – as above	+			
Capital gain deferred – as above	+			
Pre V-day appreciation	+			
Other (specify):				
PPE write off	+	-4,307 66		
Rounding	+	-0 45		
Capitalized Expenses	+	84,460 12		
Total proceeds per partnership information return	=	80,152 01	▶ –	80,152 01
Depreciation and amortization per financial statements (T5013 Schedule 1)			–	32,855,530 00
Loss on disposal of fixed assets per financial statements			–	33,712 11
Gain on disposal of fixed assets per financial statements			+	
Net change per partnership information return			=	-29,546,979 00

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		1,748,781,166 00
Opening net book value	–	1,778,328,145 00
Net change per financial statements	=	-29,546,979 00

If the amounts from the tax return and the financial statements differ, explain why below.

Canada Revenue Agency / Agence du revenu du Canada

Partner's Ownership and Account Activity

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T5013
Schedule 50

Partnership name	**Partnership account number**	**Fiscal period end** Year Month Day	
Wataynikaneyap Power LP	788304327RZ0001	2024-12-31	☒ Original ☐ Amended

- Fill out this schedule to reconcile each partner's interest in the partnership (including partners who retired during the fiscal period).
- All the information requested in this form and in the documents supporting your information return is "prescribed information".
- Fill out this schedule using the instructions in Guide T4068, *Guide for the Partnership Information Return (T5013 forms)*.
- If you do not have enough space to list all the information, use an additional Schedule 50.
- Attach the original copy of this completed schedule to Form T5013 FIN, *Partnership Financial Return*.

Number of partners	**010**	3
Number of partners who disposed of all, or part of, their partnership interest	**011**	
Number of nominees or agents	**012**	
Total of all amounts from line 220	**015**	

Partner 1

Ownership						Fiscal period's income (loss) allocation	Account activity
100 Partner name	**101** Partner identification number	**105** Type of partner	**106** Partner code	**107** Percentage (%) of partner's interest	**110** Did the partner dispose of an interest during the fiscal period?	**220** Partner's share of the net income (loss)	**300** Cost base
First Nation LP	722558525RZ0001	3	0	51.0000	☐ Yes ☒ No	0.00	140338371.00

Account activity (continued)					**At-risk amount (ARA)** (for limited partners only)		
310 Cost of units acquired during the fiscal period	**320** Partner's share of the previous fiscal period's net income (loss)	**330** Capital contributions in the fiscal period	**340** Withdrawals in the fiscal period	**350** Other adjustment	**410** Partner's share of the fiscal period's net income	**420** Partner's share in certain reductions of resource expenses for the fiscal period	**430** Non-arm's length debt owing and/or benefits receivable

Partner 2

Ownership						Fiscal period's income (loss) allocation	Account activity
100 Partner name	**101** Partner identification number	**105** Type of partner	**106** Partner code	**107** Percentage (%) of partner's interest	**110** Did the partner dispose of an interest during the fiscal period?	**220** Partner's share of the net income (loss)	**300** Cost base
Fortis (WP) LP	749436499RZ0001	3	0	48.9900	☐ Yes ☒ No	0.00	134009205.00

Account activity (continued)					**At-risk amount (ARA)** (for limited partners only)		
310 Cost of units acquired during the fiscal period	**320** Partner's share of the previous fiscal period's net income (loss)	**330** Capital contributions in the fiscal period	**340** Withdrawals in the fiscal period	**350** Other adjustment	**410** Partner's share of the fiscal period's net income	**420** Partner's share in certain reductions of resource expenses for the fiscal period	**430** Non-arm's length debt owing and/or benefits receivable

Approval code: RC-24-P009

Canada

Partner 3	**Ownership**					**Fiscal period's income (loss) allocation**	**Account activity**
100	101	105	106	107	110	220	300
Partner name	Partner identification number	Type of partner	Partner code	Percentage (%) of partner's interest	Did the partner dispose of an interest during the fiscal period?	Partner's share of the net income (loss)	Cost base
Wataynikaneyap Power GP Inc.	815046362RC0001	2	2	0.0100	☐ Yes ☒ No	0.00	N/A

Account activity (continued)					**At-risk amount (ARA)** (for limited partners only)		
310	320	330	340	350	410	420	430
Cost of units acquired during the fiscal period	Partner's share of the previous fiscal period's net income (loss)	Capital contributions in the fiscal period	Withdrawals in the fiscal period	Other adjustment	Partner's share of the fiscal period's net income	Partner's share in certain reductions of resource expenses for the fiscal period	Non-arm's length debt owing and/or benefits receivable

Partner 4	**Ownership**					**Fiscal period's income (loss) allocation**	**Account activity**
100	101	105	106	107	110	220	300
Partner name	Partner identification number	Type of partner	Partner code	Percentage (%) of partner's interest	Did the partner dispose of an interest during the fiscal period?	Partner's share of the net income (loss)	Cost base
					☐ Yes ☐ No		

Account activity (continued)					**At-risk amount (ARA)** (for limited partners only)		
310	320	330	340	350	410	420	430
Cost of units acquired during the fiscal period	Partner's share of the previous fiscal period's net income (loss)	Capital contributions in the fiscal period	Withdrawals in the fiscal period	Other adjustment	Partner's share of the fiscal period's net income	Partner's share in certain reductions of resource expenses for the fiscal period	Non-arm's length debt owing and/or benefits receivable

Partner 5	**Ownership**					**Fiscal period's income (loss) allocation**	**Account activity**
100	101	105	106	107	110	220	300
Partner name	Partner identification number	Type of partner	Partner code	Percentage (%) of partner's interest	Did the partner dispose of an interest during the fiscal period?	Partner's share of the net income (loss)	Cost base
					☐ Yes ☐ No		

Account activity (continued)					**At-risk amount (ARA)** (for limited partners only)		
310	320	330	340	350	410	420	430
Cost of units acquired during the fiscal period	Partner's share of the previous fiscal period's net income (loss)	Capital contributions in the fiscal period	Withdrawals in the fiscal period	Other adjustment	Partner's share of the fiscal period's net income	Partner's share in certain reductions of resource expenses for the fiscal period	Non-arm's length debt owing and/or benefits receivable

See the privacy notice on your return.

List Detailing the Partner's Ownership and Account Activity

Partnership Wataynikaneyap Power LP

Partner		Partner code	Percentage (%) of partner's interest	Line		Line		Line		Line		Line		Line	
1	First Nation LP	0	51.0000												
2	Fortis (WP) LP	0	48.9900												
3	Wataynikaneyap Power GP Inc.	2	0.0100												
			Total												

Canada Revenue Agency　Agence du revenu du Canada

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Summary of Partnership Income

T5013 Summary

Do not use this area.

50 ☐☐☐☐ 1616

Fill out this summary and the related slips using the instructions in Guide T4068, Guide for the Partnership Information Return (T5013 Forms).

The **partnership information return** is made up of three parts:

- T5013 FIN, Partnership Financial Return
- All the T5013 schedules the partnership has to file, depending on its fiscal situation
- T5013, Statement of Partnership Income, slips and this summary

If you make certain payments to a non-resident of Canada, the amounts must be reported on an NR4 return. For more information, see Guide T4061, NR4 – Non-Resident Tax Withholding, Remitting and Reporting.

For more information on filing the partnership information return, go to **canada.ca/t5013-filing-requirements**.

Part 1 – Identification

Partnership's account number: 78830 4327 RZ0001

Fiscal period-start (Year Month Day): 2024-01-01

Fiscal period-end (Year Month Day): 2024-12-31

Name of the partnership: Wataynikaneyap Power LP

Postal or ZIP code: L2A 5Y2

Are you a nominee or an agent? (If yes, provide the following information) ☐ Yes ☐ No

Nominee or agent's account number:

Name of the nominee or agent:

Postal or ZIP code:

Is the partnership a tax shelter? ☐ Yes ☒ No

If yes, enter the tax shelter identification number (TS):

Part 2 – Totals from T5013 slips

Total number of T5013 information slips attached	009	3
Total limited partner's business income (loss)	010	
Total business income (loss)	020	
Total capital gains (losses)	030	
Capital cost allowance	040	68,807,984.73

Fill out the six boxes below using the information found on the T5013 slips

Canadian and foreign net rental income (loss)	110	
Professional income (loss)	120	
Renounced Canadian exploration expenses	190	
Renounced Canadian development expenses	191	
Expenses qualifying for an ITC *	194	
Total carrying charges	210	

* Line 194 is the total of all the amounts in boxes 194 and 239 of all the T5013 slips.

Part 3 – Contact information

076 Person to contact about this summary: Fecteau, Duane

078 Telephone number: (905) 994-3643

Part 4 – Certification

I certify that the information given in this summary and the related slips is correct and complete.

Year Month Day	Signature of authorized person	Position or office
		CFO

Prepared by: Ernst & Young LLP

Year Month Day: 2025-05-29

Part 5 – Privacy notice

Personal information is collected to administer or enforce the Income Tax Act and related programs and activities including administering tax, benefits, audit, compliance, and collection. The information collected may be used or disclosed for the purposes of other federal acts that provide for the imposition and collection of a tax or duty. It may also be disclosed to other federal, provincial, territorial, or foreign government institutions to the extent authorized by law. Failure to provide this information may result in paying interest or penalties, or in other actions. Under the Privacy Act, individuals have a right of protection, access to and correction of their personal information, or to file a complaint with the Privacy Commissioner of Canada regarding the handling of their personal information. Refer to Personal Information Bank CRA PPU 224 on Information about Programs and Information Holdings at **canada.ca/cra-information-about-programs**.

Canada

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Fiscal period-end / Exercice se terminant le: YYYY-MM-DD 2024-12-31 AAAA-MM-JJ

T5013

Statement of Partnership Income
État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

Wataynikaneyap Power LP
1130 Bertie Street
Fort Erie ON L2A 5Y2

Tax shelter identification number (see **statement** on back *) / Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *):

Partner code – Code de l'associé **002**	0
Country code – Code du pays **003**	CAN
Recipient type – Genre de bénéficiaire **004**	4
Partnership account number (15 characters) – Numéro de compte de la société de personnes (15 caractères) **001**	788304327RZ0001
Total limited partner's business income (loss) – Total du revenu (de la perte) d'entreprise du commanditaire **010**	
Total business income (loss) – Total du revenu (de la perte) d'entreprise **020**	
Partner's identification number – Numéro d'identification de l'associé **006**	722558525RZ0001
Partner's share (%) of partnership – Part de l'associé (%) dans la société de personnes **005**	51.000000
Total capital gains (losses) – Total des gains (pertes) en capital **030**	
Capital cost allowance – Déduction pour amortissement **040**	35,092,072 21

Partner's name and address – Nom et adresse de l'associé

Last name (print) – Nom de famille (en lettres moulées) | First name – Prénom | Initials – Initiales

► First Nation LP
300 Anemki Place, Suite C
Fort William First Nation ON P7J 1H9

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
105		163,909,013 51	106		163,909,013 51
118		80,694,389 94	247		30,541,838 29
248		283,385 58	254		415,494 81

Box – Case	Code	Other information – Autres renseignements

See the privacy notice on your return
Consultez l'avis de confidentialité dans votre déclaration

For Partnership 4
Pour la société de personnes 4

Canada Revenue Agency / Agence du revenu du Canada

Fiscal period-end / Exercice se terminant le: YYYY-MM-DD 2024-12-31 AAAA-MM-JJ

T5013

Statement of Partnership Income
État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

Wataynikaneyap Power LP
1130 Bertie Street
Fort Erie ON L2A 5Y2

Tax shelter identification number (see **statement** on back *) / Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *):

Partner code / Code de l'associé: **002** 0

Country code / Code du pays: **003** CAN

Recipient type / Genre de bénéficiaire: **004** 4

Partnership account number (15 characters) / Numéro de compte de la société de personnes (15 caractères): **001** 788304327RZ0001

Total limited partner's business income (loss) / Total du revenu (de la perte) d'entreprise du commanditaire: **010**

Total business income (loss) / Total du revenu (de la perte) d'entreprise: **020**

Partner's identification number / Numéro d'identification de l'associé: **006** 749436499RZ0001

Partner's share (%) of partnership / Part de l'associé (%) dans la société de personnes: **005** 48.990000

Total capital gains (losses) / Total des gains (pertes) en capital: **030**

Capital cost allowance / Déduction pour amortissement: **040** 33,709,031 72

Partner's name and address – Nom et adresse de l'associé

Last name (print) – Nom de famille (en lettres moulées) / First name – Prénom / Initials – Initiales

► Fortis (WP) LP
1130 Bertie Street
PO BOX 1218
Fort Erie ON L2A 5Y2

Box – Case	Code	Other information – Autres renseignements	Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
			105		157,530,935 65	106		157,530,935 65
			118		77,514,081 63	247		29,338,130 54
			248		272,216 85	254		399,119 43

See the privacy notice on your return
Consultez l'avis de confidentialité dans votre déclaration

For Partnership 4
Pour la société de personnes 4

Canada Revenue Agency | Agence du revenu du Canada

Fiscal period-end / Exercice se terminant le: YYYY-MM-DD / AAAA-MM-JJ: 2024-12-31

T5013

Statement of Partnership Income
État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

Wataynikaneyap Power LP
1130 Bertie Street
Fort Erie ON L2A 5Y2

Tax shelter identification number (see **statement** on back *) / Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *):

Partner code / Code de l'associé: **002** 2

Country code / Code du pays: **003** CAN

Recipient type / Genre de bénéficiaire: **004** 3

Partnership account number (15 characters) / Numéro de compte de la société de personnes (15 caractères): **001** 788304327RZ0001

Total limited partner's business income (loss) / Total du revenu (de la perte) d'entreprise du commanditaire: **010**

Total business income (loss) / Total du revenu (de la perte) d'entreprise: **020**

Partner's identification number / Numéro d'identification de l'associé: **006** 815046362RC0001

Partner's share (%) of partnership / Part de l'associé (%) dans la société de personnes: **005** 0.010000

Total capital gains (losses) / Total des gains (pertes) en capital: **030**

Capital cost allowance / Déduction pour amortissement: **040** 6,880 80

Partner's name and address – Nom et adresse de l'associé

Last name (print) – Nom de famille (en lettres moulées) | First name – Prénom | Initials – Initiales

► Wataynikaneyap Power GP Inc.

1130 Bertie Street
P.O. Box 1218
Fort Erie ON L2A 5Y2

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
118		15,822 43	247		5,988 60
248		55 57	254		81 47

Box – Case	Code	Other information – Autres renseignements

See the privacy notice on your return
Consultez l'avis de confidentialité dans votre déclaration

For Partnership 4
Pour la société de personnes 4

Protected B when completed – **Protégé B** une fois rempli

Exhibit A, Tab 7, Schedule 1

Financial Information

ATTACHMENT 4

WPLP Tax Returns for 2023

Agence du revenu du Canada Canada Revenue Agency

T5013
Financial
Protected B when completed

Partnership Financial Return

Complete this financial return using the instructions in the T4068, Guide for the Partnership Information Return (T5013 Forms). You can file this return electronically without a web access code using the "File a return" service in My Business Account at **canada.ca/my-cra-business-account** or, for authorized representatives, in Represent a Client at **canada.ca/taxes-representatives**.

Unless otherwise stated, all legislative references are to the Income Tax Act or, where appropriate, the Income Tax Regulations.

055 For internal use only

Identification

Partnership account number
001 78830 4327 RZ0001

Partnership name
006 Wataynikaneyap Power LP
007

Partnership operating or trading name
008
009

Location of the partnership head office
Has this location changed since the last time you filed a partnership information return? . . . 010 ☐ Yes ☒ No
If you answered **Yes** to line 010, enter the address of the new location on lines 011 to 018.
011
012
City 015
Province, territory or state 016
Country 017
Postal or zip code 018

Mailing address of the partnership
(if different from the head office address)
Has this address changed since the last time you filed a partnership information return? . . . 020 ☐ Yes ☒ No
If you answered **Yes** to line 020, enter the new mailing address on lines 021 to 028.
021 c/o
023
024
City 025
Province, territory or state 026
Country 027
Postal or zip code 028

Location of the partnership's books and records
(if different from the head office address)
Has this location changed since the last time you filed a partnership information return? . . . 030 ☐ Yes ☒ No
If you answered **Yes** to line 030, enter the address of the new location on lines 031 to 038.
031
032
City 035
Province, territory or state 036
Country 037
Postal or zip code 038

Is this an amended return? . . . 040 ☐ Yes ☒ No

Fiscal period to which this information return applies

060 Fiscal period start Year Month Day From 2023-01-01
061 Fiscal period-end* Year Month Day To 2023-12-31

*If you answered **Yes** to question 078 below, enter the date when the partnership ceased to exist.

The end members of this partnership are
(tick the applicable boxes)
062
01 ☐ Individuals (including trusts)
02 ☒ Corporations

Is this the first year of filing? . . . 070 ☐ Yes ☒ No

If you answered **Yes** to line 070, enter the date the partnership was created . . . 071 Year Month Day

Number of T5013 slips . . . 073 3

Is this the partnership's final information return up to dissolution? . . . 078 ☐ Yes ☒ No

If an election was made under section 261 by one or more partners, enter the functional currency code used for this return . . . 079

Was the partnership a Canadian partnership throughout the fiscal period? . . . 082 ☒ Yes ☐ No

Type of partnership at the end of the fiscal period

086

Non tax shelter	**Tax shelter**
☐ 01 General partnership	☐ 11 General partnership
☒ 02 Limited partnership	☐ 12 Limited partnership
☐ 03 Limited liability partnership	☐ 13 Co-ownership
☐ 08 Investment club	☐ 19 Other (specify below)

If the partnership is a tax shelter (TS), enter the TS identification number . . . 087

Industry code (NAICS): 237130

Approval code: RC-23-P009

Canada

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Required documents to attach to this T5013 FIN, Partnership Financial Return

- Form T5013 SUM, Summary of Partnership Income
- a copy of each T5013, Statement of Partnership Income, slip issued to partners and nominees or agents
- T5013 SCH 1, Net Income (Loss) for Income Tax Purposes **
  ** If you are an inactive partnership, see line 280 in Guide T4068 for more information.
- T5013 SCH 50, Partner's Ownership and Account Activity

The General Index of Financial Information (GIFI) schedules

- T5013 SCH 100, Balance Sheet Information
- T5013 SCH 125, Income Statement Information
- T5013 SCH 140, Summary Statement (when more than one schedule 125 is filed)
- T5013 SCH 141, General Index of Financial Information (GIFI) – Additional Information (not required for investment clubs)

Answer the following questions. For each **affirmative** answer, **attach** the related schedule or form to the partnership return, unless otherwise instructed.

At any time during the fiscal period, was the partnership a member of another partnership (directly or indirectly through one or more partnerships)?	**150**	☐ Yes	☒ No	T5013 SCH 9
Has the partnership had any transactions, including sections 97 and 98 transactions or subsection 85(2) transfers with its members or employees, other than transactions in the ordinary course of business? (Do not include non-arm's length transactions with non-residents.)	**162**	☐ Yes	☒ No	T2058, T2059 or T2060
Did the partnership have a total amount over $1 million of reportable transactions with non-arm's length non-residents?	**171**	☐ Yes	☒ No	T106
Does the partnership have to file Form T1134 in respect of any foreign affiliates in the fiscal period?	**172**	☐ Yes	☒ No	T1134
Has the partnership made any charitable donations, gifts of cultural or ecological property or federal, provincial, territorial or municipal political contributions?	**202**	☐ Yes	☒ No	T5013 SCH 2
Does the partnership have a permanent establishment in more than one jurisdiction?	**205**	☐ Yes	☒ No	T5013 SCH 5
Has the partnership realized any capital gains or incurred any capital losses during the fiscal period?	**206**	☐ Yes	☒ No	T5013 SCH 6
Does the partnership have any property that is eligible for capital cost allowance?	**208**	☒ Yes	☐ No	T5013 SCH 8
Does the partnership have any resource-related deductions (not including renounced expenditures)?	**212**	☐ Yes	☒ No	T5013 SCH 12
Is the partnership allocating any investment tax credits (ITCs)? If **Yes**, attach a document to this return providing a detailed calculation of the partnership's ITCs and their allocation to one or more partners.	**231**	☐ Yes	☒ No	Calculation and allocation
Did the partnership incur any scientific research and experimental development (SR&ED) expenditures?	**232**	☐ Yes	☒ No	T661
Did the partnership allocate renounced resource expenses to its members?	**252**	☐ Yes	☒ No	T5013 SCH 52
Did the partnership own or hold specified foreign property for which the total cost amount, at any time in the fiscal period, was more than CAN $100,000?	**259**	☐ Yes	☒ No	T1135
Is the partnership allocating any Canadian journalism labour tax credits?	**260**	☐ Yes	☒ No	T5013 SCH 58
Is the partnership allocating any return of fuel charge proceeds to farmers tax credits?	**261**	☐ Yes	☒ No	T5013 SCH 63
Is the partnership allocating any air quality improvement tax credits?	**262**	☐ Yes	☒ No	T5013 SCH 65

Protected B when completed

Additional information

Did the partnership use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	**270**	☐ Yes	☒ No
Was a slip issued to one or more nominees or agents?	**271**	☐ Yes	☒ No
Does the partnership agreement require that the nominee(s) or agent(s) complete and file any of the documents identified on page 2?	**272**	☐ Yes	☒ No
Does the partnership have one or more new nominees or agents?	**273**	☐ Yes	☒ No
Did the partnership allocate any amount of income tax deducted at source?	**274**	☐ Yes	☒ No
Did the partnership make any other election(s) under the Act during the fiscal period?	**275**	☐ Yes	☒ No
If **Yes**, attach a copy of each election form to this return. Is this partnership the continuation of one or more predecessor partnerships since its last partnership information return was filed?	**277**	☐ Yes	☒ No
If you answered **Yes** to line 277, provide the business number(s) of the predecessor partnership(s)	**278**		
	279		
Was the partnership inactive throughout the fiscal period this information return applies to?	**280**	☐ Yes	☒ No
If **Yes**, see Guide T4068 to verify your filing requirements.			
Did members of the partnership immigrate to Canada during the fiscal period?	**291**	☐ Yes	☒ No
Did members of the partnership emigrate from Canada during the fiscal period?	**292**	☐ Yes	☒ No
If the major business activity is construction, did you have any subcontractors during the fiscal period?	**295**	☐ Yes	☒ No
Did the partnership report its farming or fishing income using the cash method?	**296**	☐ Yes	☒ No
Is this a publicly traded partnership?	**297**	☐ Yes	☒ No
If you answered **Yes** to line 297, did the partnership issue T5008 information slips to report transactions of interests in the partnership?	**298**	☐ Yes	☐ No

Miscellaneous information

For tax deductions withheld at the source, was an NR4 information return filed for the fiscal period?	**301**	☐ Yes	☒ No
If you answered **Yes** to line 301, enter the non-resident account number	**302**		
If you answered **Yes** to line 301, were NR4 slips issued?	**303**	☐ Yes	☐ No
Is this partnership a specified investment flow-through (SIFT) partnership?	**304**	☐ Yes	☒ No
If you answered **Yes** to line 304, enter the taxable non-portfolio earnings for the fiscal period	**305**		
If you answered **Yes** to line 304, enter the tax payable under Part IX.1 for the fiscal period	**306**		
Enter the amount of the late-filing penalty from line 307 of Schedule 52	**307**		
Amount of payment enclosed with this return	**308**		

Protected B when completed

Additional information for all partnerships (including tax shelters that are partnerships)

Name and identification number of the partner designated under subsection 165(1.15) of the Act

400 ______ Name of designated partner

402 ______ Identification number

Additional information for tax shelters only

Principal promoter

500 ______ Last name (print)

501 ______ First name (print)

502 ______ Identification number

Certification

950 I, Fecteau (Last name (print))

951 Duane (First name (print))

954 CFO (Position or title)

certify that the information given on this information return and in any attached document is correct and complete. I also certify that the method of calculating income, deductions and credits for this fiscal period is consistent with that of the previous fiscal period except as noted in a statement attached to this return.

955 2024-05-30 (Year Month Day)

______ Signature of the authorized partner

956 (905) 994-3643 (Telephone number)

Language of correspondence

Indicate your language of correspondence . . . . 990 ☒ English ☐ French

Privacy notice

Personal information (including the SIN) is collected to administer or enforce the Income Tax Act and related programs and activities including administering tax, benefits, audit, compliance, and collection. The information collected may be used or disclosed for the purposes of other federal acts that provide for the imposition and collection of a tax or duty. It may also be disclosed to other federal, provincial, territorial, or foreign government institutions to the extent authorized by law. Failure to provide this information may result in paying interest or penalties, or in other actions. Under the Privacy Act, individuals have a right of protection, access to and correction of their personal information, or to file a complaint with the Privacy Commissioner of Canada regarding the handling of their personal information. Refer to Personal Information Bank CRA PPU 224 on Information about Programs and Information Holdings at **canada.ca/cra-information-about-programs**.

Canada Revenue Agency Agence du revenu du Canada

T5013
SCHEDULE 100

PARTNERSHIP'S BALANCE SHEET INFORMATION

Partnership name	Partnership account Number	Fiscal period end Year Month Day	
Wataynikaneyap Power LP	78830 4327 RZ0001	2023-12-31	Original ☒ Amended ☐

Is this a NIL schedule? **999** Yes ☐ No ☒

Balance sheet information

Account	Description	GIFI		Current year	Prior year
Assets					
	Total current assets	1599	+	25,968,311.00	46,584,306.00
	Total tangible capital assets	2008	+	1,804,155,812.00	1,388,472,631.00
	Total accumulated amortization of tangible capital assets	2009	–	25,875,614.00	7,997,677.00
	Total intangible capital assets	2178	+	54,796.00	54,796.00
	Total accumulated amortization of intangible capital assets	2179	–	6,849.00	5,480.00
	Total long-term assets	2589	+	39,204,611.00	88,981,445.00
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	1,843,501,067.00	1,516,090,021.00
Liabilities					
	Total current liabilities	3139	+	154,624,736.00	220,270,000.00
	Total long-term liabilities	3450	+	1,311,607,517.00	1,012,379,785.00
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	1,466,232,253.00	1,232,649,785.00
Partner's capital					
	Total partners' capital (mandatory field)	3575	+	377,268,814.00	283,440,236.00
	Total liabilities and partners' capital	3585	=	1,843,501,067.00	1,516,090,021.00

* Generic item

Current Assets

SCHEDULE 100

Form Identifier 1599

Account	Description	GIFI	Current year	Prior year
Cash and deposits				
	* Cash and deposits	1000	4,359,869.00	35,045,432.00
	Cash and deposits	+	4,359,869.00	35,045,432.00
Accounts receivable				
	* Accounts receivable	1060	7,913,725.00	5,248,463.00
	Accounts receivable	+	7,913,725.00	5,248,463.00
Inventories				
	* Inventories	1120	4,519,382.00	4,299,104.00
	Inventories	+	4,519,382.00	4,299,104.00
Due from/investment in related parties				
	* Due from/investment in related parties	1400	9,066.00	17,114.00
	Due from/investment in related parties	+	9,066.00	17,114.00
Other current assets				
	* Other current assets	1480	8,753,148.00	1,954,155.00
	Prepaid expenses	1484	413,121.00	20,038.00
	Other current assets	+	9,166,269.00	1,974,193.00
	Total current assets	1599 =	25,968,311.00	46,584,306.00

* Generic item

Tangible Capital Assets and Accumulated Amortization

SCHEDULE 100

Form identifier 2008/2009

Account	Description	GIFI	Tangible capital assets	Accumulated amortization	Prior year
	Machinery, equipment, furniture and fixtures				
	* Machinery, equipment, furniture, and fixtures	1740	+ 1,232,829,759.00		735,990,297.00
	*Accumulated amortization of machinery, equipment, furniture, and fixtures	1741		– 25,828,996.00	7,982,138.00
	Transportation equipment	1783	+ 155,392.00		155,392.00
	Accumulated amortization of transportation equipment	1784		– 46,618.00	15,539.00
	Total		1,232,985,151.00	25,875,614.00	
	Other tangible capital assets				
	Other capital assets under construction	1920	+ 571,170,661.00		652,326,942.00
	Total		571,170,661.00		
	Total tangible capital assets	2008	= 1,804,155,812.00		1,388,472,631.00
	Total accumulated amortization of tangible capital assets	2009		= 25,875,614.00	7,997,677.00

* Generic item

Intangible Capital Assets and Accumulated Amortization

SCHEDULE 100

Form identifier 2178/2179

Account	Description	GIFI		Intangible capital assets		Accumulated amortization	Prior year
	Intangible assets						
	Rights	2024	+	54,796.00			54,796.00
	Accumulated amortization of rights	2025			–	6,849.00	5,480.00
	Total			54,796.00		6,849.00	
	Total intangible capital assets	2178	=	54,796.00			54,796.00
	Total accumulated amortization of intangible capital assets	2179			=	6,849.00	5,480.00

***** Generic item

Long-term Assets

SCHEDULE 100

Form identifier 2589

Account	Description	GIFI		Current year	Prior year

Other long-term assets

Account	Description	GIFI		Current year	Prior year
	* Other long-term assets	2420		39,204,611.00	88,981,445.00
	Other long-term assets		+	39,204,611.00	88,981,445.00
	Total long-term assets	2589	=	39,204,611.00	88,981,445.00

* Generic item

Current Liabilities

SCHEDULE 100

Form identifier 3139

Account	Description	GIFI		Current year	Prior year
Amounts payable and accrued liabilities					
	* Amounts payable and accrued liabilities	2620		149,695,010.00	216,444,170.00
	Amounts payable and accrued liabilities		+	149,695,010.00	216,444,170.00
Due to related parties					
	* Due to related parties	2860		4,929,726.00	3,825,830.00
	Due to related parties		+	4,929,726.00	3,825,830.00
	Total current liabilities	3139	=	154,624,736.00	220,270,000.00

* Generic item

Long-term Liabilities

SCHEDULE 100

Form identifier 3450

Account	Description	GIFI		Current year	Prior year
Long-term debt					
	* Long-term debt	3140		1,239,942,952.00	945,213,697.00
	Long-term debt		+	1,239,942,952.00	945,213,697.00
Other long-term liabilities					
	* Other long-term liabilities	3320		71,664,565.00	67,166,088.00
	Other long-term liabilities		+	71,664,565.00	67,166,088.00
	Total long-term liabilities	3450	=	1,311,607,517.00	1,012,379,785.00

* Generic item

Partner's capital

SCHEDULE 100

GIFI Code 3575

Account	Description	GIFI		Current year	Prior year
	Total net income/loss				
	Net income/loss	3545	+	33,528,578.00	12,363,145.00
	Total net income/loss	3550	=	33,528,578.00	12,363,145.00
	General partners' capital				
	General partners' capital beginning balance	3551	+	1,393.00	-327.00
	General partners' net income (loss)	3552	+	3,353.00	1,236.00
	General partners' contributions during the fiscal period	3554	+		484.00
	General partners' capital ending balance	3560	=	4,746.00	1,393.00
	Limited partners' capital				
	Limited partners' capital beginning balance	3561	+	283,438,843.00	16,940,980.00
	Limited partners' net income (loss)	3562	+	33,525,225.00	12,361,909.00
	Limited partners' contributions during the fiscal period	3564	+	60,300,000.00	254,135,954.00
	Limited partners' capital ending balance	3571	+	377,264,068.00	283,438,843.00
	Total partners' capital	3575	=	377,268,814.00	283,440,236.00

* Generic item

Canada Revenue Agency / Agence du revenu du Canada

T5013
SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Partnership name	Partnership account number	Fiscal period end Year Month Day	
Wataynikaneyap Power LP	78830 4327 RZ0001	2023-12-31	Original ☒ Amended ☐

Income statement information

Description **GIFI**

Is this a NIL schedule? . . . . **999** ☐ Yes ☒ No

Operating Business Name **0001**

Description of the operation **0002**

Sequence Number **0003** 01

Income statement information

Account	Description	GIFI		Current year	Prior year
	Total sales of goods and services	8089	+	93,954,251.00	25,071,060.00
	Cost of sales	8518	–		
	Gross profit/loss	8519	=	93,954,251.00	25,071,060.00
	Cost of sales	8518	+		
	Total operating expenses	9367	+	63,043,744.00	15,125,598.00
	Total expenses (mandatory field)	9368	=	63,043,744.00	15,125,598.00
	Total revenue (mandatory field)	8299	+	96,572,322.00	27,488,743.00
	Total expenses (mandatory field)	9368	–	63,043,744.00	15,125,598.00
	Net non-farming income	9369	=	33,528,578.00	12,363,145.00

Farming income statement information

Account	Description	GIFI		Current year	Prior year
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		

Account	Description	GIFI		Current year	Prior year
	Net income/loss before extraordinary items – all operations	9970	=	33,528,578.00	12,363,145.00
	Total other comprehensive income	9998	=		

Extraordinary items and income (linked to Schedule 140)

Account	Description	GIFI		Current year	Prior year
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–		
	Deferred income tax provision	9995	–		
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	33,528,578.00	12,363,145.00

Revenue

SCHEDULE 125

Form identifier 8299

Account	Description	GIFI		Current year	Prior year
	* Trade sales of goods and services	8000	+	93,954,251.00	25,071,060.00
	Total sales of goods and services	8089	=	93,954,251.00	25,071,060.00
	Investment revenue				
	* Investment revenue	8090		1,024,525.00	1,126,160.00
	Interest from other Canadian sources	8094		357,701.00	53,933.00
	Investment revenue		+	1,382,226.00	1,180,093.00
	Other revenue				
	* Other revenue	8230		1,235,845.00	1,237,590.00
	Other revenue		+	1,235,845.00	1,237,590.00
	Total revenue	8299	=	96,572,322.00	27,488,743.00

* Generic item

Operating Expenses

SCHEDULE 125

Form identifier 9367

Account	Description	GIFI		Current year	Prior year
	Advertising and promotion				
	* Advertising and promotion	8520		11,688.00	
	Meals and entertainment	8523		34,190.00	29,529.00
	Advertising and promotion		+	45,878.00	29,529.00
	* Amortization of tangible assets	8670	+	18,001,799.00	4,342,053.00
	Interest and bank charges				
	* Interest and bank charges	8710		28,585,877.00	4,939,252.00
	Interest and bank charges		+	28,585,877.00	4,939,252.00
	Office expenses				
	* Office expenses	8810		5,239,475.00	1,318,308.00
	Office expenses		+	5,239,475.00	1,318,308.00
	Repairs and maintenance				
	* Repairs and maintenance	8960		716,645.00	
	Repairs and maintenance		+	716,645.00	
	Other expenses				
	* Other expenses	9270		1,909,939.00	1,887,789.00
	General and administrative expenses	9284		8,544,131.00	2,608,667.00
	Other expenses		+	10,454,070.00	4,496,456.00
	Total operating expenses	9367	=	63,043,744.00	15,125,598.00

* Generic item

Canada Revenue Agency Agence du revenu du Canada

T5013
Schedule 141
Protected B when completed

General Index of Financial Information (GIFI) – Additional Information

Partnership name	Partnership account number	Fiscal period-end Year Month Day	
Wataynikaneyap Power LP	78830 4327 RZ0001	2023-12-31	☒ Original ☐ Amended

- A partnership needs to complete all parts of this schedule that apply and include it with their partnership information return along with the other GIFI schedules.
- For more information, see Guide RC4088, General Index of Financial Information (GIFI), and Guide T4068, Guide for the Partnership Information Return (T5013 forms).

Part 1 – Information on the person primarily involved with the financial information

Can you identify the person* specified in the heading of Part 1? . . . . . **111** Yes ☒ No ☐

If you answered **no**, go to Part 2.

Does that person have a professional designation in accounting? . . . . . **095** Yes ☒ No ☐

Is that person connected** with the partnership? . . . . . **097** Yes ☐ No ☒

* A person primarily involved with the financial information is a person who has more than a 50% involvement in preparing the financial information that the partnership information return is based on. For example, if three persons prepared the financial information by doing respectively 30%, 30%, and 40% of the work, answer **no** at line 111. If they did respectively 10%, 20%, and 70% of the work, answer **yes** at line 111 and complete Part 1 by referring only to the third person.

** A person connected with a partnership can be: (i) a member of the partnership who owns more than 10% of the partnership units; (ii) an employee of the partnership; or (iii) a person not dealing at arm's length with the partnership.

Part 2 – Type of involvement

Choose one or more of the following options that represent your involvement and that of the person referred to in Part 1:

Completed an auditor's report . . . . . **300** ☒

Completed a review engagement report . . . . . **301** ☐

Conducted a compilation engagement . . . . . **302** ☐

Provided accounting services . . . . . **303** ☐

Provided bookkeeping services . . . . . **304** ☐

Other . . . . . **305** ☐

If other, please specify . . . . . **306** ____________

Part 3 – Reservations

If you selected option **300** or **301** in Part 2 above, answer the following question:

Has the person referred to in Part 1 expressed a reservation? . . . . . **099** Yes ☐ No ☒

Part 4 – Other information

Were notes to the financial statements prepared? . . . . . **101** Yes ☒ No ☐

Did the partnership have any subsequent events? . . . . . **104** Yes ☐ No ☒

Did the partnership re-evaluate its assets during the fiscal period? . . . . . **105** Yes ☐ No ☒

Did the partnership have any contingent liabilities during the fiscal period? . . . . . **106** Yes ☐ No ☒

Did the partnership have any commitments during the fiscal period? . . . . . **107** Yes ☒ No ☐

Does the partnership have investments in joint ventures? If **yes**, complete question 109 below . . . . . **108** Yes ☐ No ☒

Is the partnership filing joint venture(s) financial statements? . . . . . **109** Yes ☐ No ☐

Approval code: RC-23-P009

Protected B when completed

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income as a result of an impairment loss in the fiscal period, a reversal of an impairment loss recognized in a previous fiscal period, or a change in fair value during the fiscal period? **200** Yes ☐ No ☒

If **yes**, enter the amount recognized:

In net income Increase (decrease)

Property, plant, and equipment **210** ______

Intangible assets **215** ______

Investment property **220** ______

Biological assets **225** ______

Financial instruments **230** ______

Other **235** ______

In other comprehensive income Increase (decrease)

Property, plant, and equipment **211** ______

Intangible assets **216** ______

Financial instruments **231** ______

Other **236** ______

Financial instruments

Did the partnership derecognize any financial instrument(s) during the fiscal period (other than trade receivables)? **250** Yes ☐ No ☒

Did the partnership apply hedge accounting during the fiscal period? **255** Yes ☐ No ☒

Did the partnership discontinue hedge accounting during the fiscal period? **260** Yes ☐ No ☒

Adjustments to opening partners' capital

Was an amount included in the opening balance of partners' capital, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current fiscal period? **265** Yes ☐ No ☒

If **yes**, you have to maintain a separate reconciliation.

Part 5 – Information on the person who prepared the partnership information return

If the person who prepared the partnership information return has a professional designation in accounting but is not the person identified in Part 1, choose all of the following options that apply:

Prepared the partnership information return and the financial information contained therein **310** ☐

The client provided the financial statements **311** ☒

The client provided a trial balance **312** ☐

The client provided a general ledger **313** ☐

Other **314** ☐

If other, please specify **315** ______

See the privacy notice on your return.

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Partnership name	Partnership account number	**Fiscal period end** Year Month Day
Wataynikaneyap Power LP	78830 4327 RZ0001	2023-12-31

Is this a NIL schedule? . . . . **999** Yes ☐ No ☒

Assets – lines 1000 to 2599

1000	4,359,869.00	**1060**	7,913,725.00	**1120**	4,519,382.00
1400	9,066.00	**1480**	8,753,148.00	**1484**	413,121.00
1599	25,968,311.00	**1740**	1,232,829,759.00	**1741**	-25,828,996.00
1783	155,392.00	**1784**	-46,618.00	**1920**	571,170,661.00
2008	1,804,155,812.00	**2009**	-25,875,614.00	**2024**	54,796.00
2025	-6,849.00	**2178**	54,796.00	**2179**	-6,849.00
2420	39,204,611.00	**2589**	39,204,611.00	**2599**	1,843,501,067.00

Liabilities – lines 2600 to 3499

2620	149,695,010.00	**2860**	4,929,726.00	**3139**	154,624,736.00
3140	1,239,942,952.00	**3320**	71,664,565.00	**3450**	1,311,607,517.00
3499	1,466,232,253.00				

Partner's capital – lines 3540 to 3575

3545	33,528,578.00	**3550**	33,528,578.00	**3551**	1,393.00
3552	3,353.00	**3560**	4,746.00	**3561**	283,438,843.00
3562	33,525,225.00	**3564**	60,300,000.00	**3571**	377,264,068.00
3575	377,268,814.00	**3585**	1,843,501,067.00		

Approval code: RC-23-P009

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Partnership name	Partnership account number	**Fiscal period end** Year Month Day
Wataynikaneyap Power LP	78830 4327 RZ0001	2023-12-31

Is this a NIL schedule? . . . . **999** ☐ Yes ☒ No

Description

Sequence number **0003** 01

Revenue – lines 8000 to 8299

8000	93,954,251.00	**8089**	93,954,251.00	**8090**	1,024,525.00
8094	357,701.00	**8230**	1,235,845.00	**8299**	96,572,322.00

Cost of sales – lines 8300 to 8519

8519	93,954,251.00

Operating expenses – lines 8520 to 9369

8520	11,688.00	**8523**	34,190.00	**8670**	18,001,799.00
8710	28,585,877.00	**8810**	5,239,475.00	**8960**	716,645.00
9270	1,909,939.00	**9284**	8,544,131.00	**9367**	63,043,744.00
9368	63,043,744.00	**9369**	33,528,578.00		

Farming revenue – lines 9370 to 9659

9659	0.00

Farming expenses – lines 9660 to 9899

9898	0.00

Extraordinary items and taxes – lines 9970 to 9999

9970	33,528,578.00	**9999**	33,528,578.00

Approval code: RC-23-P009

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

Protected B when completed

T5013
Schedule 1

Partnership name	**Partnership account number**	**Fiscal period end** Year Month Day	
Wataynikaneyap Power LP	78830 4327 RZ0001	2023-12-31	☒ Original ☐ Amended

- Fill out this schedule to reconcile the partnership's net income (loss) reported on the financial statements and its net income (loss) for income tax purposes.
- All the information requested in this form and in the documents supporting your information return is "prescribed information".
- Fill out this schedule using the instructions in Guide T4068, Guide for the Partnership Information Return (T5013 forms).
- Fill out a worksheet to identify the source of all the amounts reported on the T5013 information slips.
- Attach the original copy of this completed schedule to Form T5013 FIN, Partnership Financial Return.

Is this a NIL schedule? **999** ☐ Yes ☒ No

(If **yes**, do not use zeroes (000 00), dashes (-), nil, or N/A on the lines.)

Amount calculated on line 9999 from Schedule 125 or Schedule 140			500	33,528,578.00
Add:				
Provision for Part IX.1 specified investment flow through (SIFT) taxes	101			
Amortization/depreciation of tangible assets	104	18,001,799.00		
Amortization of natural resource assets	105			
Amortization of intangible assets	106			
Recapture of capital cost allowance from Schedule 8	107			
Income or loss for tax purposes from partnerships	109			
Loss in equity of affiliates	110			
Loss on disposal of assets per financial statements	111			
Charitable donations and gifts from Schedule 2	112			
Political contributions from Schedule 2	114			
Current fiscal period's holdbacks	115			
Deferred and prepaid expenses	116			
Depreciation in inventory – end of fiscal period	117			
Scientific research and experimental development (SR&ED) expenditures deducted per financial statements	118			
Capitalized interest and property taxes on vacant land	119			
Non-deductible club dues and fees	120			
Non-deductible meals and entertainment expenses	121	17,095.00		
Non-deductible automobile expenses	122			
Non-deductible life insurance premiums	123			
Non-deductible company pension plans	124			
Reserves from financial statements – balance at the end of the fiscal period	126			
Soft costs on construction and renovation of buildings	127			
Salaries and wages paid to partners deducted on financial statements	150			
Cost of products available for sale that were consumed	151			
Personal expenses of the partners paid by the partnership	152			
Dividend rental arrangement compensation payment deductions	154			
Renounced exploration, development and resource property expenses deducted per financial statements from Schedule 52	155			
Certain fines and penalties	156			
Amount from line 508 on page 2 of this schedule	199	1,106,660.64		
Total (**Add** lines 101 to 199. Enter this amount on line 501)		19,125,554.64 ▶	501	+ 19,125,554.64
Deduct: Amount from line 511 on page 3 of this schedule			502	– 52,654,132.64
Net income (loss) for income tax purposes – (line 500 **plus** line 501 **minus** line 502)			503	=
Deduct: Net income (loss) for general partners			504	–
Net income (loss) for income tax purposes for limited and non-active partners (line 503 **minus** line 504)			505	=

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Canada

Partnership account number 78830 4327 RZ0001

Fiscal period end Year Month Day 2023-12-31

Protected B when completed

Add:

Accounts payable and accruals for cash basis – closing	**201**	
Accounts receivable and prepaid for cash basis – opening	**202**	
Accrual inventory – opening	**203**	
Accrued dividends – prior fiscal period	**204**	
Book loss on joint ventures or partnerships	**205**	
Capital items expensed	**206**	
Debt issue expense	**208**	
Deemed dividend income	**209**	
Deemed interest on loans to non-residents	**210**	
Deemed interest received	**211**	
Development expenses claimed in current fiscal period	**212**	
Dividend stop-loss adjustment	**213**	
Dividends credited to the investment account	**214**	
Exploration expenses claimed in current fiscal period	**215**	
Financing fees deducted in books	**216**	
Foreign accrual property income	**217**	
Foreign affiliate property income	**218**	
Foreign exchange included in retained earnings	**219**	
Gain on settlement of debt – income inclusion under subsection 80(13)	**220**	
Interest paid on income debentures	**221**	
Limited partnership losses	**222**	
Loss from international banking centres	**223**	
Mandatory inventory adjustment – included in current fiscal period	**224**	
Non-deductible advertising	**226**	
Non-deductible interest	**227**	
Non-deductible legal and accounting fees	**228**	
Optional value of inventory – included in current fiscal period	**229**	
Other expenses from financial statements	**230**	
Recapture of SR&ED expenditures from Form T661	**231**	
Resource amounts deducted	**232**	
Sales tax assessments	**234**	
Write-down of capital property	**236**	
Amounts received in respect of qualifying environmental trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	**237**	
Contractors' completion method adjustment: revenue net of costs on contracts under 2 years – previous fiscal period	**238**	
Taxable/Non-deductible other comprehensive income items	**239**	

Total (**Add** lines 201 to 239. Enter this amount on line 506) ▶ **506** +

Other additions:

600	Asset Retirement	**290**	1,106,660.64		
601		**291**			
602		**292**			
603		**293**			
604		**294**			
	Total (**Add** lines 290 to 294. Enter this amount on line 507)		1,106,660.64	▶ **507**	+ 1,106,660.64

Total (**Add** lines 506 and 507) **508** = 1,106,660.64

Enter the amount from line 508 on line 199 on page 1 of this schedule.

Partnership account number
78830 4327 RZ0001

Fiscal period end
Year Month Day
2023-12-31

Protected B when completed

Deduct:

Accounts payable and accruals for cash basis – opening	300	
Accounts receivable and prepaid for cash basis – closing	301	
Accrual inventory – closing	302	
Accrued dividends – current fiscal period	303	
Bad debt	304	
Book income of joint venture or partnership	305	
Equity in income from affiliates	306	
Exempt income under section 81	307	
Income from international banking centres	308	
Mandatory inventory adjustment – included in prior fiscal period	309	
Contributions to a qualifying environmental trust	310	
Non-Canadian advertising expenses – broadcasting	311	
Non-Canadian advertising expenses – printed materials	312	
Optional value of inventory – included in prior fiscal period	313	
Other income from financial statements	314	
Payments made for allocations in proportion to borrowing and bonus interest payments	315	
Contractors' completion method adjustment: revenue net of costs on contracts under 2 years – current fiscal period	316	
Non-taxable/Deductible other comprehensive income items	347	

Other less common deductions:

700	Amortization of deferred contribution	390	1,235,845.00
701	20(1)(e) Financing fees	391	3,120,958.00
702	Gain on Disposal	392	1,106,660.64
703		393	
704		394	

Total (**Add** lines 300 to 394. Enter this amount on line 509) 5,463,463.64 ▶ **509** + 5,463,463.64

Other deductions:

Gain on disposal of assets per financial statements	401	
Non-taxable dividends under section 83	402	
Capital cost allowance from Schedule 8	403	47,190,669.00
Terminal loss from Schedule 8	404	
Foreign non-business tax deduction under subsection 20(12)	407	
Prior fiscal period's holdbacks	408	
Deferred and prepaid expenses	409	
Depreciation in inventory – end of prior fiscal period	410	
SR&ED expenditures claimed in the fiscal period from Form T661 (line 460)	411	
Reserves from financial statements – balance at the beginning of the fiscal period	414	
Patronage dividends	416	
Contributions to deferred income plans	417	

Total (**Add** lines 401 to 417. Enter this amount on line 510) 47,190,669.00 ▶ **510** + 47,190,669.00

Total (**Add** lines 509 and 510) **511** = 52,654,132.64
Enter this amount on line 502 on page 1 of this schedule.

See the privacy notice on your return.

Agence du revenu du Canada Canada Revenue Agency

T5013
Schedule 8

Protected B when completed

Capital Cost Allowance (CCA)

Partnership name	Partnership account number	Fiscal period end Year Month Day	
Wataynikaneyap Power LP	78830 4327 RZ0001	2023-12-31	☒ Original ☐ Amended

- Fill out this schedule to calculate the amount of capital cost allowance (CCA) the partnership is claiming for the fiscal period, or to account for acquisitions or dispositions of depreciable property, or both.
- Fill out this schedule to designate immediate expensing property.
- Fill out this schedule using the instructions in the T4068, Guide for the Partnership Information Return (T5013 forms).
- If you do not have enough space to list all the information, use an additional T5013 Schedule 8.
- Attach the original copy of this completed schedule to Form T5013 FIN, Partnership Financial Return.

Part 1 – Agreement between associated eligible persons or partnerships (EPOPs)

Are you associated in the fiscal period with one or more EPOPs with which you have entered into an agreement under subsection 1104(3.3) of the Regulations? . . . . **105** Yes ☐ No ☐

If you answered **yes**, complete Part 1. Otherwise, go to Part 2.

Enter a percentage assigned to each associated EPOP (including your partnership) as determined in the agreement.

This percentage will be used to allocate the immediate expensing limit. The total of all the percentages assigned under the agreement should not exceed 100%. If the total is more than 100%, then the associated group has an immediate expensing limit of nil. For more information about the immediate expensing limit, see note 12 in Part 3.

	1 Name of EPOP **110**	2 Identification number See **note 1** **115**	3 Percentage assigned under the agreement **120**
1			%
2			%
3			%
4			%
5			%
6			%
7			%
8			%
		Total	%

Immediate expensing limit allocated to the partnership (see **note 2**) . . . . **125** ______

Note 1: The identification number is the social insurance number, business number, or partnership account number of the EPOP.

Note 2: Multiply 1.5 million by the percentage assigned to your partnership in column 3.

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Protected B when completed

Part 2 – Income earned from the source in which the designated immediate expensing property (DIEP) is used

The source refers to the business or property from which the income was earned and in which the DIEP is used. For more information about DIEP, see note 5 in Part 3.

Are you a Canadian partnership of which all of the members were, throughout the fiscal period, Canadian-controlled private corporations (CCPC), individuals (other than trusts) resident in Canada or a combination thereof? . . . . . **150** Yes ☐ No ☒

If you answered **yes**, complete Part 2. Otherwise, go to Part 3.

Is there more than one source of income? . . . . . **155** Yes ☐ No ☐

If you answered **no**, enter the income of that source of income (net income for income tax purposes before any CCA deductions) . . . . . **156** ____________

If the answer is **yes**, complete the table below.

	1 Source of income **160**	2 Income before any CCA deductions from each source (if the income is a loss or nil, enter "0") **165**	3 Aggregate amount of DIEP used for each source **170**
1			
2			
3			
4			
5			
6			
7			
8			

Protected B when completed

Part 3 – CCA calculation

	1 Class number See **note 3** 200	2 Undepreciated capital cost (UCC) at the beginning of the fiscal period 201	3 Cost of acquisitions during the fiscal period (new property must be available for use) See **note 4** 203	4 Cost of acquisitions from column 3 that are designated immediate expensing property (DIEP) See **note 5** 232	5 Adjustments and transfers (show amounts that will reduce the UCC in brackets) See **note 6** 205	6 Amount from column 5 that is assistance received or receivable during the fiscal period for a property, subsequent to its disposition See **note 7** 221	7 Amount from column 5 that is repaid during the fiscal period for a property, subsequent to its disposition See **note 8** 222	8 Proceeds of dispositions See **note 9** 207
1	14.1	43,350.04						
2	99	652,326,942.00	416,789,842.00		-497,946,123.00			
3	47	662,038,274.32	497,946,123.00					
4	10	85,465.60						
5								
6								
7								
8								

	9 Proceeds of dispositions of the DIEP (enter amount from column 8 that relates to the DIEP reported in column 4) 234	10 UCC (column 2 **plus** column 3 **plus** or **minus** column 5 **minus** column 8) See **note 10**	11 UCC of the DIEP (enter the UCC amount that relates to the DIEP reported in column 4) See **note 11** 236	12 Immediate expensing See **note 12** 238	13 Cost of acquisitions on remainder of Class (column 3 **minus** column 12)	14 Cost of acquisitions from column 13 that are accelerated investment incentive properties (AIIP) or properties included in Classes 54 to 56 See **note 13** 225	15 Remaining UCC (column 10 **minus** column 12)	16 Proceeds of disposition available to reduce the UCC of AIIP and property included in Classes 54 to 56 (column 8 **plus** column 6 **minus** column 13 **plus** column 14 **minus** column 7) (if negative, enter "0") See **note 14**
1		43,350.04					43,350.04	
2		571,170,661.00			416,789,842.00	416,789,842.00	571,170,661.00	
3		1,159,984,397.32			497,946,123.00	497,946,123.00	1,159,984,397.32	
4		85,465.60					85,465.60	
5								
6								
7								
8								
		Totals						

Part 3 – CCA calculation (continued)

	17 Net capital cost additions of AIIP and property included in Classes 54 to 56 acquired during the fiscal period (column 14 **minus** column 16) (if negative, enter "0")	18 UCC adjustment for AIIP and property included in Classes 54 to 56 acquired during the fiscal period (column 17 **multiplied** by the relevant factor) See **note 15**	19 UCC adjustment for property acquired during the fiscal period other than AIIP and property included in Classes 54 to 56 (0.5 **multiplied** by the result of column 13 **minus** column 14 **minus** column 6 **plus** column 7 **minus** column 8) (if negative, enter "0") See **note 16** **224**	20 CCA rate % See **note 17** **212**	21 Recapture of CCA See **note 18** **213**	22 Terminal loss See **note 19** **215**	23 CCA (for declining balance method, the result of column 15 **plus** column 18 **minus** column 19, **multiplied** by column 20, or a lower amount, **plus** column 12) See **note 20** **217**	24 UCC at the end of the fiscal period (column 10 **minus** column 23) **220**
1				5.00			3,034.50	40,315.54
2	416,789,842.00	208,394,921.00						571,170,661.00
3	497,946,123.00	248,973,061.50		8.00			47,161,994.82	1,112,822,402.50
4				30.00			25,639.68	59,825.92
5								
6								
7								
8								
				Totals	**230**	**240**	**250** 47,190,669.00	

Enter the amount from line 230 on line 107 of T5013 Schedule 1.
Enter the amount from line 240 on line 404 of T5013 Schedule 1.
Enter the amount from line 250 on line 403 of T5013 Schedule 1.

Note 3: If a class number has not been provided in Schedule II of the Income Tax Regulations for a particular class of property, use the subsection provided in Regulation 1101.

Note 4: Include any property acquired in previous fiscal periods that has now become available for use, net of any assistance received or entitled to be received in the fiscal period from a government, municipality or other public authority, or a reduction of capital cost after the application of section 80. This property would have been previously excluded from column 3. List separately any acquisitions of property in the class that are not subject to the 50% rule. See Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance, for exceptions to the 50% rule. Do not include any amount in column 3 in respect of property included in column 5 (see note 6).

Note 5: A DIEP reported in column 4 is a property acquired after December 31, 2021, by a Canadian partnership (all of the members of which were, throughout the period, Canadian-controlled private corporations, individuals (other than trusts) resident in Canada or a combination thereof) that becomes available for use before 2025 (if all the members are individuals throughout the fiscal period), or before 2024 in any other case. The property is designated as such on or before the day that is 12 months after the filing due date of an information return under section 229 of the Regulations by any member of the partnership for the fiscal period to which the designation relates. It includes all capital property subject to the CCA rules, if certain conditions are met, other than property included in Classes 1 to 6, 14.1, 17, 47, 49, and 51. A property can only qualify as DIEP in the fiscal period in which it becomes available for use. See subsection 1104(3.1) of the Regulations for more information.

If there is more than one source of income, the total amount of DIEP reported in Part 2 (total of column 3) should be equal to the total amount of DIEP reported in Part 3 (total of column 4).

Part 3 – CCA calculation (continued)

Note 6: Enter in column 5, "Adjustments and transfers", amounts that increase or reduce the UCC (column 10). Items that increase the UCC include amounts transferred under subsection 97(2). Items that reduce the UCC (show amounts that reduce the UCC in brackets) include assistance received or receivable during the fiscal period for a property, subsequent to its disposition, if such assistance would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f). See the Guide T4068 for other examples of adjustments and transfers to include in column 5.

Also include property acquired in a non-arm's length transaction (other than by virtue of a right referred to in paragraph 251(5)(b) of the Act) if the property was a depreciable property acquired by the transferor at least 364 days before the end of your fiscal period and continuously owned by the transferor until it was acquired by you.

Note 7: Include all amounts of assistance you received (or were entitled to receive) after the disposition of a depreciable property that would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f) if received before the disposition.

Note 8: Include all amounts you have repaid during the fiscal period for any legally required repayment, made after the disposition of a corresponding property, of:

- assistance that would have otherwise increased the capital cost of the property under paragraph 13(7.1)(d) and
- an inducement, assistance, or any other amount contemplated in paragraph 12(1)(x) received, that otherwise would have increased the capital cost of the property under paragraph 13(7.4)(b)

Also include property acquired in a non-arm's length transaction (other than by virtue of a right referred to in paragraph 251(5)(b) of the Act) if the property was a depreciable property acquired by the transferor less than 364 days before the end of your fiscal period and continuously owned by the transferor until it was acquired by you.

Note 9: For each property disposed of during the fiscal period, deduct from the proceeds of disposition any outlays and expenses to the extent that they were made or incurred for the purpose of making the disposition(s). The amount reported in respect of the property cannot exceed the property's capital cost, unless that property is a timber resource property as defined in subsection 13(21).

If the cost of a zero-emission passenger vehicle (or a passenger vehicle that was, at any time, a DIEP) exceeds the prescribed amount and it is disposed of to a person or partnership with which you deal at arm's length, the proceeds of disposition will be adjusted based on a factor equal to the prescribed amount as a proportion of the actual cost of the vehicle. The actual cost of the vehicle will be adjusted for payment or repayment of government assistance.

Note 10: If the amount in column 5 (as shown in brackets) reduces the UCC, you must subtract it for the purposes of the calculation. Otherwise, add the amount in column 5 for the purpose of the calculation.

Note 11: The amount to enter in column 11 must not exceed the amount in column 10. If it does, enter in column 11 the amount from column 10. If the amount determined in column 10 is zero or a negative amount, enter zero. The only amounts incurred before 2022, to be included in this column are certain inventory purchases from arm's length persons or partnerships where the conditions in paragraphs 1100(0.3)(a) to (c) are met.

Note 12: Immediate expensing applies to a DIEP included in column 11. The total immediate expensing for the fiscal period (total of column 12) is limited to the lesser of:

1. Immediate expensing limit: it is equal to one of the following five amounts, whichever is applicable:
   - $1.5 million, if you are not associated with any other EPOP in the fiscal period
   - amount from line 125, if you are associated in the fiscal period with one or more EPOPs
   - nil, if the total of the percentages assigned in Part 1 is more than 100% or you are associated in the fiscal period with one or more EPOPs and have not filed an agreement in prescribed form as required under subsection 1104(3.3) of the Regulations
   - the amount determined under subsection 1104(3.5) of the Regulations for any second or subsequent fiscal periods ending in a calendar year, if you have two or more fiscal periods ending in the calendar year in which you are associated with another EPOP that has a tax year ending in that calendar year
   - any amount allocated by the minister under subsection 1104(3.4) of the Regulations

   The immediate expensing limit has to be prorated if your fiscal period is less than 51 weeks. You cannot carry forward any unused amount of the immediate expensing limit.
2. UCC of the DIEP: total of column 11
3. Income earned from the source in which the DIEP is used: amount from line 156 or relevant source of income from line 165

Note 13: An AIIP is a property (other than property included in Classes 54 to 56) that you acquired after November 20, 2018, and that became available for use before 2028.

Classes 54 and 55 include zero-emission vehicles that you acquired after March 18, 2019, and that became available for use before 2028.

Class 56 applies to eligible zero-emission automotive equipment and vehicles (other than motor vehicles) that are acquired after March 1, 2020, and that became available for use before 2028.

See Guide T4068 for more information.

Note 14: Include only elements from columns 6 and 7 that are not related to the DIEP.

Part 3 – CCA calculation (continued)

Note 15: The relevant factors for property of a class in Schedule II, that is an AIIP or included in Classes 54 to 56, available for use before 2024 are:

- 2 1/3 for property in Classes 43.1, 54, and 56
- 1 1/2 for property in Class 55
- 1 for property in Classes 43.2 and 53
- 0 for property in Classes 12, 13, 14, and 15, as well as properties that are Canadian vessels included in paragraph 1100(1)(v) of the Regulations (see note 20 for additional information) and
- 0.5 for all other property that is an AIIP

Note 16: The UCC adjustment for property acquired during the fiscal period (also known as the half-year rule or 50% rule) does not apply to certain property (including AIIP and property included in Classes 54 to 56). Include only elements from columns 6 and 7 that are not related to the DIEP.

For special rules and exceptions, see Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance.

Note 17: Enter a rate only if you are using the declining balance method. For any other method (for example, the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 23.

Note 18: If the amount in column 10 is negative, you have a recapture of CCA. If applicable, enter the negative amount from column 10 in column 21 as a positive. The recapture rules do not apply to passenger vehicles in Class 10.1. However, they do apply to a passenger vehicle that was, at any time, a DIEP.

Note 19: If no property is left in the class at the end of the fiscal period and there is still a positive amount in the column 10, you have a terminal loss. If applicable, enter the positive amount from column 10 in column 22. The terminal loss rules do not apply to:

- passenger vehicles in Class 10.1
- property in Class 14.1, unless you have ceased carrying on the business to which it relates
- limited-period franchises, concessions, or licences in Class 14 if, at the time of acquisition, the property was a former property of the transferor or any similar property attributable to the same fixed place of business, and you had jointly elected with the transferor to have the replacement property rules apply, unless certain conditions are met

Note 20: If the fiscal period is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See Guide T4068 for more information.

For property in class 10.1 disposed of during the fiscal period, deduct a maximum of 50% of the regular CCA deduction if you owned the property at the beginning of the fiscal period.

For AIIP listed below, the maximum first fiscal period allowance you can claim is determined as follows:

- Class 13: the lesser of 150% of the amount calculated in Schedule III of the Regulations and the UCC at the end of the fiscal period (before any CCA deduction)
- Class 14: the lesser of 150% of the allocation for the fiscal period of the capital cost of the property apportioned over the remaining life of the property (at the time the cost was incurred) and the UCC at the end of the fiscal period (before any CCA deduction)
- Class 15: the lesser of 150% of an amount computed on the basis of a rate per cord, board foot, or cubic metre cut in the fiscal period and the UCC at the end of the fiscal period (before any CCA deduction)
- Canadian vessels described under paragraph 1100(1)(v) of the Regulations: the lesser of 50% of the capital cost of the property and the UCC at the end of the fiscal period (before any CCA deduction)
- Class 41.2: use a 25% CCA rate. The additional allowance under paragraphs 1100(1)(y.2) (for single mine properties) and 1100(1)(ya.2) (for multiple mine properties) of the Regulations is not eligible for the accelerated investment incentive. The additional allowance in respect of natural gas liquefaction under paragraph 1100(1)(yb) of the Regulations is eligible for the accelerated investment incentive

The AIIP also applies to property (other than a timber resource property) that is a timber limit or a right to cut timber from a limit as well as to industrial mineral mine or a right to remove minerals from an industrial mineral mine. See the Income Tax Regulations for more detail.

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Partnership information return

Additions for tax purposes – regular classes (T5013 Schedule 8)		914,735,965	00			
Additions for tax purposes – leasehold improvements (T5013 Schedule 8)	+					
Operating leases capitalized for book purposes	+					
Capital gain deferred	+					
Recapture deferred	+					
Deductible expenses capitalized for book purposes (T5013 Schedule 1)	+					
Other (specify):						
CWIP Additions	+	-497,946,123	00			
Total additions per partnership information return	=	416,789,842	00	▶	416,789,842	00
Proceeds up to original cost – regular classes (T5013 Schedule 8)						
Proceeds up to original cost – leasehold improvements (T5013 Schedule 8)	+					
Proceeds in excess of original cost – capital gain	+					
Recapture deferred – as above	+					
Capital gain deferred – as above	+					
Pre V-day appreciation	+					
Other (specify):						
PPE write off	+	-122,492	55			
Rounding	+	-0	45			
Total proceeds per partnership information return	=	-122,493	00	▶ –	-122,493	00
Depreciation and amortization per financial statements (T5013 Schedule 1)				–	18,001,799	00
Loss on disposal of fixed assets per financial statements				–	1,106,661	00
Gain on disposal of fixed assets per financial statements				+		
Net change per partnership information return				=	397,803,875	00

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		1,778,328,145	00
Opening net book value	–	1,380,524,270	00
Net change per financial statements	=	397,803,875	00

If the amounts from the tax return and the financial statements differ, explain why below.

Canada Revenue Agency   Agence du revenu du Canada

Partner's Ownership and Account Activity

Protected B when completed

T5013
Schedule 50

Partnership name	**Partnership account number**	**Fiscal period end** Year Month Day	
Wataynikaneyap Power LP	788304327RZ0001	2023-12-31	☒ Original ☐ Amended

- Fill out this schedule to reconcile each partner's interest in the partnership (including partners who retired during the fiscal period).
- All the information requested in this form and in the documents supporting your information return is "prescribed information".
- Fill out this schedule using the instructions in Guide T4068, *Guide for the Partnership Information Return (T5013 forms)*.
- If you do not have enough space to list all the information, use an additional Schedule 50.
- Attach the original copy of this completed schedule to Form T5013 FIN, *Partnership Financial Return*.

Number of partners	**010**	3
Number of partners who disposed of all, or part of, their partnership interest	**011**	
Number of nominees or agents	**012**	
Total of all amounts from line 220	**015**	

Partner 1	**Ownership**					**Fiscal period's income (loss) allocation**	**Account activity**
100 Partner name	**101** Partner identification number	**105** Type of partner	**106** Partner code	**107** Percentage (%) of partner's interest	**110** Did the partner dispose of an interest during the fiscal period?	**220** Partner's share of the net income (loss)	**300** Cost base
First Nation LP	722558525RZ0001	3	0	51.0000	☐ Yes ☒ No	0.00	140338371.00

Account activity (continued)					**At-risk amount (ARA)** (for limited partners only)		
310 Cost of units acquired during the fiscal period	**320** Partner's share of the previous fiscal period's net income (loss)	**330** Capital contributions in the fiscal period	**340** Withdrawals in the fiscal period	**350** Other adjustment	**410** Partner's share of the fiscal period's net income	**420** Partner's share in certain reductions of resource expenses for the fiscal period	**430** Non-arm's length debt owing and/or benefits receivable
		30,753,000.00					

Partner 2	**Ownership**					**Fiscal period's income (loss) allocation**	**Account activity**
100 Partner name	**101** Partner identification number	**105** Type of partner	**106** Partner code	**107** Percentage (%) of partner's interest	**110** Did the partner dispose of an interest during the fiscal period?	**220** Partner's share of the net income (loss)	**300** Cost base
Fortis (WP) LP	749436499RZ0001	3	0	48.9900	☐ Yes ☒ No	0.00	134009205.00

Account activity (continued)					**At-risk amount (ARA)** (for limited partners only)		
310 Cost of units acquired during the fiscal period	**320** Partner's share of the previous fiscal period's net income (loss)	**330** Capital contributions in the fiscal period	**340** Withdrawals in the fiscal period	**350** Other adjustment	**410** Partner's share of the fiscal period's net income	**420** Partner's share in certain reductions of resource expenses for the fiscal period	**430** Non-arm's length debt owing and/or benefits receivable
		29,547,000.00					

Approval code: RC-23-P009

T5013 SCH 50 E (17)

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Partner 3	**Ownership**					**Fiscal period's income (loss) allocation**	**Account activity**
100 Partner name	**101** Partner identification number	**105** Type of partner	**106** Partner code	**107** Percentage (%) of partner's interest	**110** Did the partner dispose of an interest during the fiscal period?	**220** Partner's share of the net income (loss)	**300** Cost base
Wataynikaneyap Power GP Inc.	815046362RC0001	2	2	0.0100	☐ Yes ☒ No	0.00	N/A

Account activity (continued)					**At-risk amount (ARA)** (for limited partners only)		
310 Cost of units acquired during the fiscal period	**320** Partner's share of the previous fiscal period's net income (loss)	**330** Capital contributions in the fiscal period	**340** Withdrawals in the fiscal period	**350** Other adjustment	**410** Partner's share of the fiscal period's net income	**420** Partner's share in certain reductions of resource expenses for the fiscal period	**430** Non-arm's length debt owing and/or benefits receivable

Partner 4	**Ownership**					**Fiscal period's income (loss) allocation**	**Account activity**
100 Partner name	**101** Partner identification number	**105** Type of partner	**106** Partner code	**107** Percentage (%) of partner's interest	**110** Did the partner dispose of an interest during the fiscal period?	**220** Partner's share of the net income (loss)	**300** Cost base
					☐ Yes ☐ No		

Account activity (continued)					**At-risk amount (ARA)** (for limited partners only)		
310 Cost of units acquired during the fiscal period	**320** Partner's share of the previous fiscal period's net income (loss)	**330** Capital contributions in the fiscal period	**340** Withdrawals in the fiscal period	**350** Other adjustment	**410** Partner's share of the fiscal period's net income	**420** Partner's share in certain reductions of resource expenses for the fiscal period	**430** Non-arm's length debt owing and/or benefits receivable

Partner 5	**Ownership**					**Fiscal period's income (loss) allocation**	**Account activity**
100 Partner name	**101** Partner identification number	**105** Type of partner	**106** Partner code	**107** Percentage (%) of partner's interest	**110** Did the partner dispose of an interest during the fiscal period?	**220** Partner's share of the net income (loss)	**300** Cost base
					☐ Yes ☐ No		

Account activity (continued)					**At-risk amount (ARA)** (for limited partners only)		
310 Cost of units acquired during the fiscal period	**320** Partner's share of the previous fiscal period's net income (loss)	**330** Capital contributions in the fiscal period	**340** Withdrawals in the fiscal period	**350** Other adjustment	**410** Partner's share of the fiscal period's net income	**420** Partner's share in certain reductions of resource expenses for the fiscal period	**430** Non-arm's length debt owing and/or benefits receivable

See the privacy notice on your return.

List Detailing the Partner's Ownership and Account Activity

Partnership Wataynikaneyap Power LP

Partner		Partner code	Percentage (%) of partner's interest	Line		Line		Line		Line		Line		Line	
1	First Nation LP	0	51.0000												
2	Fortis (WP) LP	0	48.9900												
3	Wataynikaneyap Power GP Inc.	2	0.0100												
			Total												

Canada Revenue Agency / Agence du revenu du Canada

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Summary of Partnership Income

T5013 Summary

Fill out this summary and the related slips using the instructions in Guide T4068, Guide for the Partnership Information Return (T5013 Forms).

The **partnership information return** is made up of three parts:

- T5013 FIN, Partnership Financial Return
- All the T5013 schedules the partnership has to file, depending on its fiscal situation
- T5013, Statement of Partnership Income, slips and this summary

If you make certain payments to a non-resident of Canada, the amounts must be reported on an NR4 return. For more information, see Guide T4061, NR4 – Non-Resident Tax Withholding, Remitting and Reporting.

For more information on filing the partnership information return, go to **canada.ca/t5013-filing-requirements**.

Do not use this area.

50 ☐☐☐☐ 1616

Part 1 – Identification

Partnership's account number: 78830 4327 RZ0001

Fiscal period-start (Year Month Day): 2023-01-01

Fiscal period-end (Year Month Day): 2023-12-31

Name of the partnership: Wataynikaneyap Power LP

Postal or ZIP code: L2A 5Y2

Are you a nominee or an agent? (If yes, provide the following information) ☐ Yes ☐ No

Nominee or agent's account number:

Name of the nominee or agent:

Postal or ZIP code:

Is the partnership a tax shelter? ☐ Yes ☒ No

If yes, enter the tax shelter identification number (TS):

Part 2 – Totals from T5013 slips

Total number of T5013 information slips attached	009	3
Total limited partner's business income (loss)	010	
Total business income (loss)	020	
Total capital gains (losses)	030	
Capital cost allowance	040	47,190,669.00

Fill out the six boxes below using the information found on the T5013 slips

Canadian and foreign net rental income (loss)	110	
Professional income (loss)	120	
Renounced Canadian exploration expenses	190	
Renounced Canadian development expenses	191	
Expenses qualifying for an ITC *	194	
Total carrying charges	210	

* Line 194 is the total of all the amounts in boxes 194 and 239 of all the T5013 slips.

Part 3 – Contact information

076 Person to contact about this summary: Ernst & Young LLP

078 Telephone number: (416) 864-1234

Part 4 – Certification

I certify that the information given in this summary and the related slips is correct and complete.

Year Month Day: 2024-05-30

Signature of authorized person:

Position or office: CFO

Prepared by: Ernst & Young LLP

Year Month Day: 2024-05-30

Part 5 – Privacy notice

Personal information is collected to administer or enforce the Income Tax Act and related programs and activities including administering tax, benefits, audit, compliance, and collection. The information collected may be used or disclosed for the purposes of other federal acts that provide for the imposition and collection of a tax or duty. It may also be disclosed to other federal, provincial, territorial, or foreign government institutions to the extent authorized by law. Failure to provide this information may result in paying interest or penalties, or in other actions. Under the Privacy Act, individuals have a right of protection, access to and correction of their personal information, or to file a complaint with the Privacy Commissioner of Canada regarding the handling of their personal information. Refer to Personal Information Bank CRA PPU 224 on Information about Programs and Information Holdings at **canada.ca/cra-information-about-programs**.

Canada

Canada Revenue Agency   Agence du revenu du Canada

Fiscal period-end
Exercice se terminant le
YYYY-MM-DD
2023-12-31
AAAA-MM-JJ

T5013

Statement of Partnership Income
État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

Wataynikaneyap Power LP
1130 Bertie Street
Fort Erie ON L2A 5Y2

Tax shelter identification number (see **statement** on back *)
Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *)

Partner code Code de l'associé	Country code Code du pays	Recipient type Genre de bénéficiaire
002 0	003 CAN	004 4

Partnership account number (15 characters) Numéro de compte de la société de personnes (15 caractères)	Total limited partner's business income (loss) Total du revenu (de la perte) d'entreprise du commanditaire	Total business income (loss) Total du revenu (de la perte) d'entreprise
001 788304327RZ0001	010	020

Partner's identification number Numéro d'identification de l'associé	Partner's share (%) of partnership Part de l'associé (%) dans la société de personnes	Total capital gains (losses) Total des gains (pertes) en capital	Capital cost allowance Déduction pour amortissement
006 722558525RZ0001	005 51.000000	030	040 24,067,241 19

Partner's name and address – Nom et adresse de l'associé

Last name (print) – Nom de famille (en lettres moulées)   First name – Prénom   Initials – Initiales

► First Nation LP

300 Anemki Place, Suite C
Fort William First Nation ON P7J 1H9

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
105		163,909,013 51	106		163,909,013 51
118		49,251,884 22			

Box – Case	Code	Other information – Autres renseignements

See the privacy notice on your return
Consultez l'avis de confidentialité dans votre déclaration

For Partnership 4
Pour la société de personnes 4

Canada Revenue Agency / Agence du revenu du Canada

Fiscal period-end / Exercice se terminant le: YYYY-MM-DD 2023-12-31 AAAA-MM-JJ

T5013

Statement of Partnership Income
État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

Wataynikaneyap Power LP
1130 Bertie Street
Fort Erie ON L2A 5Y2

Tax shelter identification number (see **statement** on back *)
Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *):

Partner code / Code de l'associé: 002 0

Country code / Code du pays: 003 CAN

Recipient type / Genre de bénéficiaire: 004 4

Partnership account number (15 characters) / Numéro de compte de la société de personnes (15 caractères): 001 788304327RZ0001

Total limited partner's business income (loss) / Total du revenu (de la perte) d'entreprise du commanditaire: 010

Total business income (loss) / Total du revenu (de la perte) d'entreprise: 020

Partner's identification number / Numéro d'identification de l'associé: 006 749436499RZ0001

Partner's share (%) of partnership / Part de l'associé (%) dans la société de personnes: 005 48.990000

Total capital gains (losses) / Total des gains (pertes) en capital: 030

Capital cost allowance / Déduction pour amortissement: 040 23,118,708 74

Partner's name and address – Nom et adresse de l'associé

Last name (print) – Nom de famille (en lettres moulées) First name – Prénom Initials – Initiales

Fortis (WP) LP
1130 Bertie Street
PO BOX 1218
Fort Erie ON L2A 5Y2

Box Case	Code	Amount – Montant		Box Case	Code	Amount – Montant	
105		157,530,935	65	106		157,530,935	65
118		47,310,780	55				

Box – Case	Code	Other information – Autres renseignements

See the privacy notice on your return
Consultez l'avis de confidentialité dans votre déclaration

For Partnership 4
Pour la société de personnes 4

Canada Revenue Agency | Agence du revenu du Canada

Fiscal period-end / Exercice se terminant le: YYYY-MM-DD 2023-12-31 AAAA-MM-JJ

T5013

Statement of Partnership Income
État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

Wataynikaneyap Power LP
1130 Bertie Street
Fort Erie ON L2A 5Y2

Tax shelter identification number (see **statement** on back *) / Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *):

Partner code / Code de l'associé: **002** 2

Country code / Code du pays: **003** CAN

Recipient type / Genre de bénéficiaire: **004** 3

Partnership account number (15 characters) / Numéro de compte de la société de personnes (15 caractères): **001** 788304327RZ0001

Total limited partner's business income (loss) / Total du revenu (de la perte) d'entreprise du commanditaire: **010**

Total business income (loss) / Total du revenu (de la perte) d'entreprise: **020**

Partner's identification number / Numéro d'identification de l'associé: **006** 815046362RC0001

Partner's share (%) of partnership / Part de l'associé (%) dans la société de personnes: **005** 0.010000

Total capital gains (losses) / Total des gains (pertes) en capital: **030**

Capital cost allowance / Déduction pour amortissement: **040** 4,719 07

Partner's name and address – Nom et adresse de l'associé

Last name (print) – Nom de famille (en lettres moulées) | First name – Prénom | Initials – Initiales

► Wataynikaneyap Power GP Inc.

1130 Bertie Street
P.O. Box 1218
Fort Erie ON L2A 5Y2

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
118		9,657 23			

Box – Case	Code	Other information – Autres renseignements

See the privacy notice on your return
Consultez l'avis de confidentialité dans votre déclaration

For Partnership 4
Pour la société de personnes 4

Protected B when completed – **Protégé B** une fois rempli

Exhibit A, Tab 7, Schedule 1

Financial Information

ATTACHMENT 5

2024 Annual Report for Fortis Inc.

St. John's, NL - February 14, 2025

FORTIS INC. REPORTS FOURTH QUARTER & ANNUAL 2024 RESULTS

This news release constitutes a "Designated News Release" incorporated by reference in the prospectus supplement dated December 9, 2024 to Fortis' short form base shelf prospectus dated December 9, 2024.

Fortis Inc. ("Fortis" or the "Corporation") (TSX/NYSE: FTS), a well-diversified leader in the North American regulated electric and gas utility industry, released its 2024 fourth quarter and annual financial results.[1]

Highlights

- Annual net earnings of $1.6 billion, or $3.24 per common share for 2024
- Annual adjusted net earnings per common share[2] of $3.28, up from $3.09 for 2023, representing 6% growth[3]
- Capital expenditures[2] of $5.2 billion, yielding 6% annual rate base growth[3]
- Tranche 2.1 projects approved by MISO; ITC now estimates US$3.7-$4.2 billion in investments, with majority expected post-2029
- 4.2% increase in fourth quarter common share dividend achieving 51 years of common share dividend increases

"In 2024, Fortis extended its track record of strong EPS and rate base growth," said David Hutchens, President and Chief Executive Officer, Fortis Inc. "We executed a $5.2 billion capital program, outperformed industry averages for safety and reliability performance, and continued to be recognized as a leader for our governance practices."

"We remain focused on extending our track record as we execute our $26 billion five-year capital plan in support of our annual dividend growth guidance of 4-6% through 2029," said Mr. Hutchens. "Fortis' strength comes from the dedication and hard work of our people, and we appreciate their efforts in making 2024 another successful year."

Net Earnings

The Corporation reported net earnings attributable to common shareholders ("Net Earnings") of $1.6 billion, or $3.24 per common share for 2024, compared to $1.5 billion, or $3.10 per common share for 2023. Growth in earnings was primarily driven by rate base growth across our utilities. New customer rates at Tucson Electric Power ("TEP") effective September 1, 2023 and Central Hudson effective July 1, 2024, and an unfavourable deferred income tax adjustment recognized by ITC in 2023, also contributed to earnings growth. The increase was partially offset by higher holding company finance costs, unrealized losses on derivative contracts, and a $10 million gain realized upon the disposition of Aitken Creek in 2023. The recognition of a refund liability at ITC in 2024 associated with a reduction in the Midcontinent Independent System Operator ("MISO") base rate of return on common equity ("ROE"), largely reflecting the retroactive impact to prior periods, also unfavourably impacted earnings. An increase in the weighted average number of common shares outstanding related to the Corporation's dividend reinvestment plan, also impacted earnings per common share.

For the fourth quarter of 2024, Net Earnings were $396 million, or $0.79 per common share, compared to $381 million or $0.78 per common share for the same period in 2023. The increase was due to rate base growth as well as new customer rates at Central Hudson effective July 1, 2024. The implementation of new customer rates at Central Hudson shifted the timing of quarterly rate recovery in comparison to related costs, resulting in higher revenue and earnings in the fourth quarter of 2024. The increase in earnings was tempered by the refund liability recognized at ITC, unrealized losses on derivative contracts, and the gain on disposition of Aitken Creek in 2023, as discussed above. Lower earnings in Arizona, driven by higher operating expenses, also unfavourably impacted fourth quarter earnings in comparison to the prior year. Net earnings per common share was also impacted by an increase in the weighted average number of common shares.

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[1] Financial information is presented in Canadian dollars unless otherwise specified.

[2] Non-U.S. GAAP Measures - Fortis uses financial measures that do not have a standardized meaning under generally accepted accounting principles in the United States of America ("U.S. GAAP") and may not be comparable to similar measures presented by other entities. Fortis presents these non-U.S. GAAP measures because management and external stakeholders use them in evaluating the Corporation's financial performance and prospects. Refer to the Non-U.S. GAAP Reconciliation provided herein.

[3] Growth rates calculated using a constant U.S. dollar-to-Canadian dollar exchange rate.

Adjusted Net Earnings[2]

Adjusted net earnings attributable to common equity shareholders ("Adjusted Net Earnings") of $1.6 billion for 2024, or $3.28 per common share, were $124 million, or $0.19 per common share higher than 2023. Adjusted Net Earnings reflects the removal of items that management excludes in its key decision-making processes and evaluation of operating results. For 2024, Net Earnings was adjusted to remove the $20 million unfavourable prior period impact associated with the reduction in the MISO base ROE. For 2023, Net Earnings was adjusted to exclude the $4 million net favourable impact associated with the disposition of Aitken Creek and the revaluation of deferred income tax assets at ITC. The increase in Adjusted Net Earnings in 2024 reflects these items, as well as the other factors discussed in Net Earnings.[4]

For the fourth quarter of 2024, Adjusted Net Earnings of $416 million, or $0.83 per common share, were $66 million, or $0.11 per common share higher than the same period in 2023. Net Earnings for the fourth quarter of 2024 was adjusted to remove the $20 million prior period impact associated with the MISO base ROE, as discussed above. For the fourth quarter of 2023, Net Earnings was adjusted to exclude the disposition of Aitken Creek, including timing impacts associated with the March 31, 2023 effective date of disposition. The increase in fourth quarter Adjusted Net Earnings largely reflects these items, as well as the other factors discussed in Net Earnings.

Capital Expenditures[2]

Capital expenditures were $5.2 billion for 2024. Growth in capital was due to investments associated with the Eagle Mountain Pipeline project at FortisBC Energy, transmission reliability projects at ITC, and construction of the Roadrunner Reserve battery storage projects at TEP. Capital expenditures increased midyear rate base to $39.0 billion, representing 6% growth over 2023.[3]

In 2024, construction of the Wataynikaneyap Transmission Power project was completed. This project enables the connection of 17 First Nations communities to the Ontario power grid. Previously these communities had inefficient and unreliable access to electricity based on diesel generation, which compromised their economic and social well-being and limited opportunities for growth. The transmission line is majority-owned by 24 First Nations, while Fortis has a 39% ownership interest.

The Corporation's 2025-2029 capital plan of $26.0 billion is $1.0 billion higher than the previous five-year plan. The increase is driven by projects associated with the MISO long-range transmission plan ("LRTP") and resiliency investments at ITC, as well as distribution investments largely due to customer growth at FortisAlberta.

The five-year capital plan is expected to be funded primarily by cash from operations and regulated utility debt. Common equity proceeds are expected to be provided by the Corporation's dividend reinvestment plan, assuming current participation levels. The Corporation's $500 million at-the-market common equity program remains available and provides funding flexibility as required.

Progress continues with respect to the MISO LRTP projects. Total tranche 1 investments expected for ITC remain in the range of US$1.4-$1.8 billion through 2030, of which US$1.2 billion are included in the 2025-2029 capital plan. In December 2024, MISO approved the tranche 2.1 projects. ITC now estimates US$3.7-$4.2 billion in capital expenditures for tranche 2.1 projects located in Michigan and Minnesota where rights of first refusal are in effect and for projects requiring system upgrades in Iowa which are not subject to a competitive bidding process. A majority of the tranche 2.1 investment is expected beyond 2029.

Regulatory Updates

In October 2024, the Federal Energy Regulatory Commission ("FERC") issued an order setting the base ROE for transmission owners operating in the MISO region, including ITC. The order revised the base ROE of ITC's MISO utilities from 10.02% to 9.98% and also directed the payment of certain refunds, with interest, by December 1, 2025. Fortis' 80.1% share of the related after-tax earnings impact was approximately $22 million, of which $20 million related to periods prior to January 1, 2024.

In December 2024, the Arizona Corporation Commission ("ACC") approved a formula rate plan policy statement which allows utilities to propose formula rates with an annual true-up mechanism in future rate cases. A formula rate plan is expected to improve rate stability for customers, while also reducing regulatory lag and the number of existing rate adjusters. In January 2025, UNS Gas filed supplemental material to its general rate application proposing an annual rate adjustment mechanism as a result of the ACC's formula rate policy statement. The timing and outcome of this proceeding are unknown.

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[4] The disposition of Aitken Creek was neutral to Adjusted Net Earnings and EPS for the year.

Outlook

Fortis continues to enhance shareholder value through the execution of its capital plan, the balance and strength of its diversified portfolio of regulated utility businesses, and growth opportunities within and proximate to its service territories. The Corporation's $26.0 billion five-year capital plan is expected to increase midyear rate base from $39.0 billion in 2024 to $53.0 billion by 2029, translating into a five-year compound annual growth rate of 6.5%.[3]

Beyond the five-year capital plan, opportunities to expand and extend growth include: further expansion of the electric transmission grid in the U.S. to support load growth and facilitate the interconnection of cleaner energy; transmission investments associated with the MISO LRTP tranches 1, 2.1 and 2.2 as well as regional transmission in New York; grid resiliency and climate adaptation investments; renewable gas solutions and liquefied natural gas infrastructure in British Columbia; and the acceleration of load growth and cleaner energy infrastructure investments across our jurisdictions.

Fortis expects its long-term growth in rate base will drive earnings that support dividend growth guidance of 4-6% annually through 2029, and is premised on the assumptions and material factors listed under "Forward-Looking Information".

Fortis has reduced its corporate-wide direct greenhouse gas ("GHG") emissions by 34% from a 2019 base year, and has targets to further reduce such GHG emissions by 50% by 2030 and 75% by 2035. The Corporation's additional 2050 net-zero direct GHG emissions target reinforces Fortis' commitment to further decarbonize over the long-term, while continuing our focus on reliability and affordability. The Corporation's ability to achieve the GHG targets may be impacted by federal, state and provincial energy policies, as well as external factors, including significant customer and load growth and the development of clean energy technology.

Non-U.S. GAAP Reconciliation

Periods ended December 31	Quarter			Annual		
($ millions, except earnings per share)	**2024**	2023	Variance	**2024**	2023	Variance
Adjusted Net Earnings						
Net Earnings	**396**	381	15	**1,606**	1,506	100
Adjusting items:						
October 2024 MISO base ROE decision[5]	**20**	—	20	**20**	—	20
Disposition of Aitken Creek[6]	**—**	(31)	31	**—**	(15)	15
Unrealized loss on mark-to-market of derivatives[7]	**—**	—	—	**—**	2	(2)
Revaluation of deferred income tax assets[8]	**—**	—	—	**—**	9	(9)
Adjusted Net Earnings	**416**	350	66	**1,626**	1,502	124
Adjusted Basic EPS *($)*	**0.83**	0.72	0.11	**3.28**	3.09	0.19
Capital Expenditures						
Additions to property, plant and equipment	**1,629**	1,189	440	**5,012**	3,986	1,026
Additions to intangible assets	**64**	61	3	**206**	183	23
Adjusting item:						
Wataynikaneyap Transmission Power Project[9]	**—**	51	(51)	**29**	160	(131)
Capital Expenditures	**1,693**	1,301	392	**5,247**	4,329	918

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[5] Represents the prior period impact of FERC's October 2024 MISO base ROE decision, net of income tax recovery of $7 million.

[6] Aitken Creek was sold on November 1, 2023, with a March 31, 2023 effective date. For the year ended December 31, 2023, the adjustment represents: (i) the $10 million gain on disposition, net of income tax expense of $13 million; and (ii) $5 million of net earnings at Aitken Creek, recognized in accordance with U.S. GAAP, during the March 31, 2023 to November 1, 2023 stub period, net of income tax expense of $2 million. For the three-month period ended December 31, 2023, this adjustment represents: (i) the $10 million gain on disposition; and (ii) $21 million of stub period earnings at Aitken Creek, net of income tax expense of $9 million, including amounts initially included in Adjusted Net Earnings in the second and third quarters of 2023 prior to the close of the transaction.

[7] Represents the impact of mark-to-market accounting of natural gas derivatives at Aitken Creek through the March 31, 2023 effective date of disposition, net of income tax recovery of $1 million.

[8] Represents the revaluation of deferred income tax assets resulting from the reduction in the corporate income tax rate in the state of Iowa.

[9] Represents Fortis' 39% share of capital spending for the Wataynikaneyap Transmission Power Project. Construction was completed in the second quarter of 2024.

About Fortis

Fortis is a well-diversified leader in the North American regulated electric and gas utility industry with 2024 revenue of $12 billion and total assets of $73 billion as at December 31, 2024. The Corporation's 9,800 employees serve utility customers in five Canadian provinces, ten U.S. states and three Caribbean countries.

Forward-Looking Information

Fortis includes forward-looking information in this media release within the meaning of applicable Canadian securities laws and forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995 (collectively referred to as "forward-looking information"). Forward-looking information reflects expectations of Fortis management regarding future growth, results of operations, performance and business prospects and opportunities. Wherever possible, words such as anticipates, believes, budgets, could, estimates, expects, forecasts, intends, may, might, plans, projects, schedule, should, target, will, would, and the negative of these terms, and other similar terminology or expressions, have been used to identify the forward-looking information, which includes, without limitation: forecast capital expenditures for 2025 through 2029; the expected sources of funding for the capital plan, including the source of common equity proceeds; the nature, timing, benefits and expected costs of certain capital projects, including ITC's investments associated with tranches 1 and 2.1 of the MISO LRTP; the expected timing, outcome and impact of legal and regulatory proceedings and decisions; forecast rate base and rate base growth through 2029; the expected nature, timing and benefits of additional opportunities beyond the capital plan, including further expansion of the electric transmission grid in the U.S. to support load growth and facilitate the interconnection of cleaner energy, transmission investments associated with the MISO LRTP tranches 1, 2.1 and 2.2 as well as regional transmission in New York, grid resiliency and climate adaptation investments, renewable gas solutions and liquefied natural gas infrastructure in British Columbia, and the acceleration of load growth and cleaner energy infrastructure investments; the expectation that long-term growth in rate base will drive earnings that support dividend growth guidance of 4-6% annually through 2029; the 2050 net-zero direct GHG emissions target; the 2030 and 2035 direct GHG emissions reduction targets; and the potential impact of federal, state and provincial energy policies and other factors, including significant customer and load growth and the development of clean energy technology, on the Corporation's ability to achieve its GHG emissions reduction targets.

Forward-looking information involves significant risks, uncertainties and assumptions. Certain material factors or assumptions have been applied in drawing the conclusions contained in the forward-looking information, including, without limitation: reasonable outcomes for legal and regulatory proceedings and the expectation of regulatory stability; the successful execution of the capital plan; no material capital project and financing cost overrun; sufficient human resources to deliver service and execute the capital plan; the realization of additional opportunities beyond the capital plan; no significant variability in interest rates; no material changes in the assumed U.S. dollar-to-Canadian dollar exchange rate; the continuation of current participation levels in the Corporation's dividend reinvestment plan; and the Board of Directors of the Corporation exercising its discretion to declare dividends, taking into account the business performance and financial condition of the Corporation. Fortis cautions readers that a number of factors could cause actual results, performance or achievements to differ materially from the results discussed or implied in the forward-looking information. For additional information with respect to certain risk factors, reference should be made to the continuous disclosure materials filed from time to time by the Corporation with Canadian securities regulatory authorities and the Securities and Exchange Commission. All forward-looking information herein is given as of the date of this media release. Fortis disclaims any intention or obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise.

Teleconference to Discuss 2024 Annual Results

A teleconference and webcast will be held on February 14, 2025 at 8:30 a.m. (Eastern). David Hutchens, President and Chief Executive Officer and Jocelyn Perry, Executive Vice President and Chief Financial Officer, will discuss the Corporation's 2024 annual results.

Shareholders, analysts, members of the media and other interested parties are invited to listen to the teleconference via the live webcast on the Corporation's website, www.fortisinc.com/investors/events-and-presentations.

Those members of the financial community in Canada and the United States wishing to ask questions during the call are invited to participate toll free by calling 1.844.763.8274. Individuals in other international locations can participate by calling 1.647.484.8814. Please dial in 10 minutes prior to the start of the call. No access code is required.

An archived audio webcast of the teleconference will be available on the Corporation's website two hours after the conclusion of the call until March 14, 2025. Please call 1.855.669.9658 or 1.412.317.0088 and enter access code 9850557#.

Additional Information

This news release should be read in conjunction with the Corporation's Management Discussion and Analysis and Consolidated Financial Statements. This and additional information can be accessed at www.fortisinc.com, www.sedarplus.ca, or www.sec.gov.

For more information, please contact:

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Management Discussion and Analysis

Contents

Dated February 13, 2025

This MD&A has been prepared in accordance with National Instrument 51-102 - *Continuous Disclosure Obligations*. It should be read in conjunction with the 2024 Annual Financial Statements and is subject to the cautionary statement and disclaimer provided under "Forward-Looking Information" on page 40. Further information about Fortis, including its Annual Information Form, can be accessed at www.fortisinc.com, www.sedarplus.ca, or www.sec.gov.

Financial information herein has been prepared in accordance with U.S. GAAP (except for indicated Non-U.S. GAAP Financial Measures) and, unless otherwise specified, is presented in Canadian dollars based, as applicable, on the following U.S. dollar-to-Canadian dollar exchange rates: (i) average of 1.37 and 1.35 for the years ended December 31, 2024 and 2023, respectively; (ii) 1.44 and 1.32 as at December 31, 2024 and 2023, respectively; (iii) average of 1.40 and 1.36 for the quarters ended December 31, 2024 and 2023, respectively; and (iv) 1.30 for all forecast periods. Certain terms used in this MD&A are defined in the "Glossary" on page 41.

ABOUT FORTIS

Fortis (TSX/NYSE: FTS) is a well-diversified leader in the North American regulated electric and gas utility industry, with revenue of $12 billion in 2024 and total assets of $73 billion as at December 31, 2024.

Regulated utilities account for virtually all of the Corporation's assets. The Corporation's 9,800 employees serve 3.5 million utility customers in five Canadian provinces, ten U.S. states and three Caribbean countries. As at December 31, 2024, 66% of the Corporation's assets were located in the U.S., 31% in Canada and the remaining 3% in the Caribbean. Operations in the U.S. accounted for 57% of the Corporation's 2024 revenue, with the remaining 38% in Canada, and 5% in the Caribbean.

Fortis is principally an energy delivery company, with 93% of its assets related to transmission and distribution. The business is characterized by low-risk, stable and predictable earnings and cash flows. Earnings, EPS and TSR are the primary measures of financial performance.

Fortis' regulated utility businesses are: ITC (electric transmission - Michigan, Iowa, Minnesota, Illinois, Missouri, Kansas, Oklahoma and Wisconsin); UNS Energy (integrated electric and natural gas distribution - Arizona); Central Hudson (electric transmission and distribution, and natural gas distribution - New York State); FortisBC Energy (natural gas transmission and distribution - British Columbia); FortisAlberta (electric distribution - Alberta); FortisBC Electric (integrated electric - British Columbia); Newfoundland Power (integrated electric - Newfoundland and Labrador); Maritime Electric (integrated electric - Prince Edward Island); FortisOntario (integrated electric - Ontario); Caribbean Utilities (integrated electric - Grand Cayman); and FortisTCI (integrated electric - Turks and Caicos Islands). Fortis also holds equity investments in Wataynikaneyap Power (electric transmission - Ontario) and Belize Electricity (integrated electric - Belize).

The Corporation's non-regulated business is limited to Fortis Belize (three hydroelectric generation facilities - Belize). The Aitken Creek natural gas storage facility in British Columbia was sold on November 1, 2023 with a March 31, 2023 effective date.

Fortis has a unique operating model with a small corporate office in St. John's, Newfoundland and Labrador and business units that operate on a substantially autonomous basis. Each utility has its own management team and board of directors, with most having a majority of independent board members, which provides effective oversight within the broad parameters of Fortis policies and best practices. Subsidiary autonomy supports constructive relationships with regulators, policy makers, customers and communities. Fortis believes this model enhances accountability, opportunity and performance across the Corporation's businesses, and positions Fortis well for future investment opportunities.

Fortis is focused on providing safe, reliable and cost-effective service to customers. Delivering a cleaner energy future is the Corporation's core purpose. In addition, management is focused on delivering long-term profitable growth for shareholders through the execution of its capital plan and the pursuit of investment opportunities within and proximate to its service territories.

Additional information about the Corporation's business and reporting units is provided in Note 1 in the 2024 Annual Financial Statements.

PERFORMANCE AT A GLANCE

Key Financial Metrics

($ millions, except as indicated)	**2024**	2023	Variance
Common Equity Earnings			
Actual	**1,606**	1,506	100
Adjusted [(1)]	**1,626**	1,502	124
Basic EPS *($)*			
Actual	**3.24**	3.10	0.14
Adjusted [(1)]	**3.28**	3.09	0.19
Dividends			
Paid per common share *($)*	**2.39**	2.29	0.10
Actual Payout Ratio *(%)*	**73.6**	73.7	(0.1)
Adjusted Payout Ratio *(%)* [(1)]	**72.7**	73.9	(1.2)
Weighted average number of common shares outstanding *(# millions)*	**495.0**	486.3	8.7
Operating Cash Flow	**3,882**	3,545	337
Capital Expenditures [(1)]	**5,247**	4,329	918

[(1)] *See "Non-U.S. GAAP Financial Measures" on page 10*

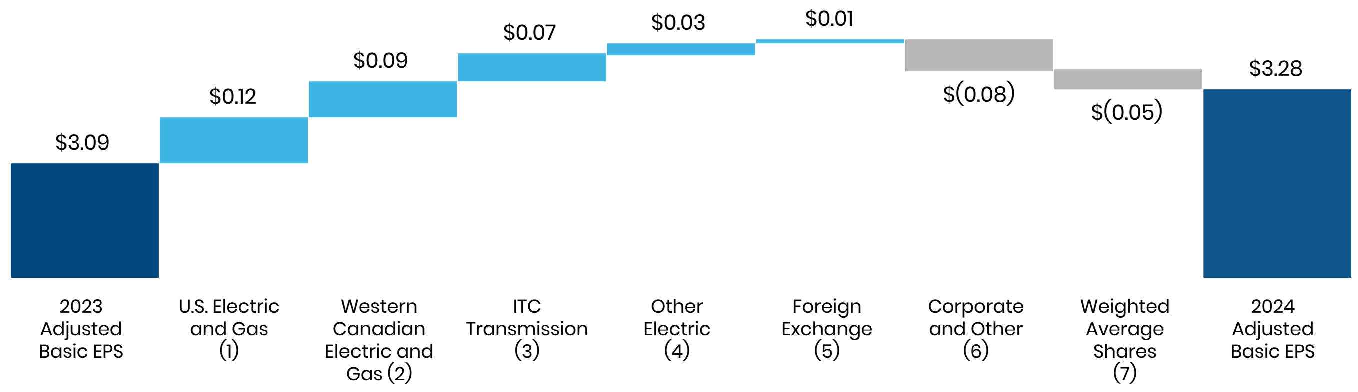
Earnings and EPS

Common Equity Earnings increased by $100 million in comparison to 2023. The increase was due to: (i) Rate Base growth; (ii) higher earnings in Arizona, largely reflecting new customer rates at TEP effective September 1, 2023 and higher production tax credits; (iii) new customer rates and a higher allowed ROE at Central Hudson effective July 1, 2024; and (iv) an unfavourable deferred income tax adjustment recognized by ITC in 2023. The increase was partially offset by higher holding company finance costs, unrealized losses on derivative contracts, and a $10 million gain realized upon the disposition of Aitken Creek in 2023. The recognition of a refund liability at ITC in 2024, due to the reduction in the MISO base ROE as approved by FERC and largely reflecting the retroactive impact to prior periods, also unfavourably impacted earnings.

In addition to the above-noted items impacting earnings, the change in EPS also reflected an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's DRIP.

Adjusted Common Equity Earnings and Adjusted Basic EPS increased by $124 million and $0.19, respectively. Refer to "Non-U.S. GAAP Financial Measures" on page 10 for a reconciliation of these measures. The change in Adjusted Basic EPS is illustrated in the following chart.

CHANGE IN ADJUSTED BASIC EPS



(1) *Includes UNS Energy and Central Hudson. Reflects higher earnings at UNS Energy due to new customer rates at TEP effective September 1, 2023, higher production tax credits, and favourable margins on wholesale sales, partially offset by higher operating costs. Also reflects higher earnings at Central Hudson due to Rate Base growth as well as new customer rates and a higher allowed ROE effective July 1, 2024, partially offset by favourable regulatory adjustments recognized in 2023*

(2) *Includes FortisBC Energy, FortisAlberta and FortisBC Electric. Primarily reflects Rate Base growth, as well as higher earnings at FortisAlberta due to an increase in the allowed ROE, higher demand charges and customer growth, partially offset by higher operating expenses*

(3) *Primarily reflects Rate Base growth, partially offset by higher holding company finance costs*

(4) *Primarily reflects Rate Base growth and higher electricity sales*

(5) *Reflects average foreign exchange rate of 1.37 in 2024 compared to 1.35 in 2023, partially offset by a foreign exchange loss associated with the revaluation of U.S. dollar denominated liabilities at a rate of 1.44 at December 31, 2024*

(6) *Reflects higher holding company finance costs and unrealized losses on derivative contracts, partially offset by higher hydroelectric production in Belize*

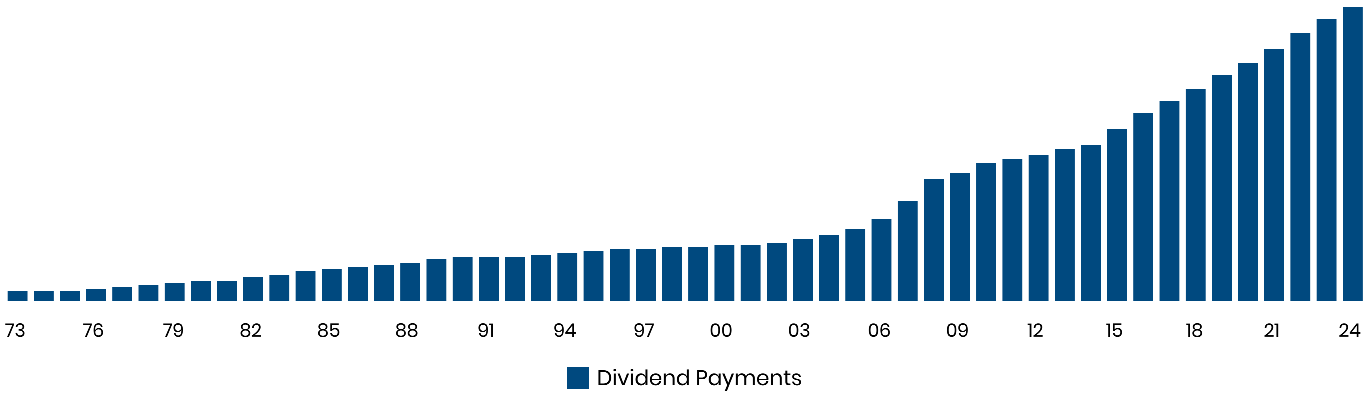
(7) *Weighted average shares of 495.0 million in 2024 compared to 486.3 million in 2023*

Dividends

Fortis paid a dividend of $0.615 per common share in the fourth quarter of 2024, up 4.2% from $0.59 paid in each of the previous four quarters. This marked the Corporation's 51st consecutive year of increases in dividends paid. The Adjusted Payout Ratio was 73% in 2024 and an average of 76% over the five-year period of 2020 through 2024.

Fortis is targeting annual dividend growth of approximately 4-6% through 2029. See "Outlook" on page 40.

51 CONSECUTIVE YEARS OF INCREASES IN DIVIDENDS PAID



Growth in dividends and changes in the market price of the Corporation's common shares have yielded the following TSRs.

TSR (1) *(%)*	**1-Year**	**5-Year**	**10-Year**	**20-Year**
Fortis	**14.1**	**6.1**	**8.4**	**10.3**

(1) *Annualized TSR per Bloomberg, as at December 31, 2024*

Operating Cash Flow

The $337 million increase in Operating Cash Flow was due to: (i) higher cash earnings, reflecting Rate Base growth, as well as new customer rates and higher sales at TEP; and (ii) the higher collection of flow-through costs at UNS Energy. Deposits received related to the construction of the Eagle Mountain Pipeline project and the receipt of an income tax refund at FortisBC Energy also favourably impacted Operating Cash Flow. The increase was partially offset by: (i) the timing of flow-through costs in customer rates as well as other changes in working capital balances at FortisBC Energy; (ii) the timing of flow-through transmission costs at FortisAlberta; (iii) higher interest payments; and (iv) the disposition of Aitken Creek in November 2023, which contributed approximately $110 million of operating cash flow in 2023.

Capital Expenditures

Capital Expenditures in 2024 were $5.2 billion, consistent with expectations and $0.9 billion higher than 2023. The increase compared to 2023 was primarily due to investments associated with the Eagle Mountain Pipeline project at FortisBC Energy, expenditures on various transmission reliability projects at ITC, and construction of the Roadrunner Reserve battery storage projects at UNS Energy.

Capital Expenditures is a Non-U.S. GAAP financial measure. Refer to "Non-U.S. GAAP Financial Measures" on page 10.

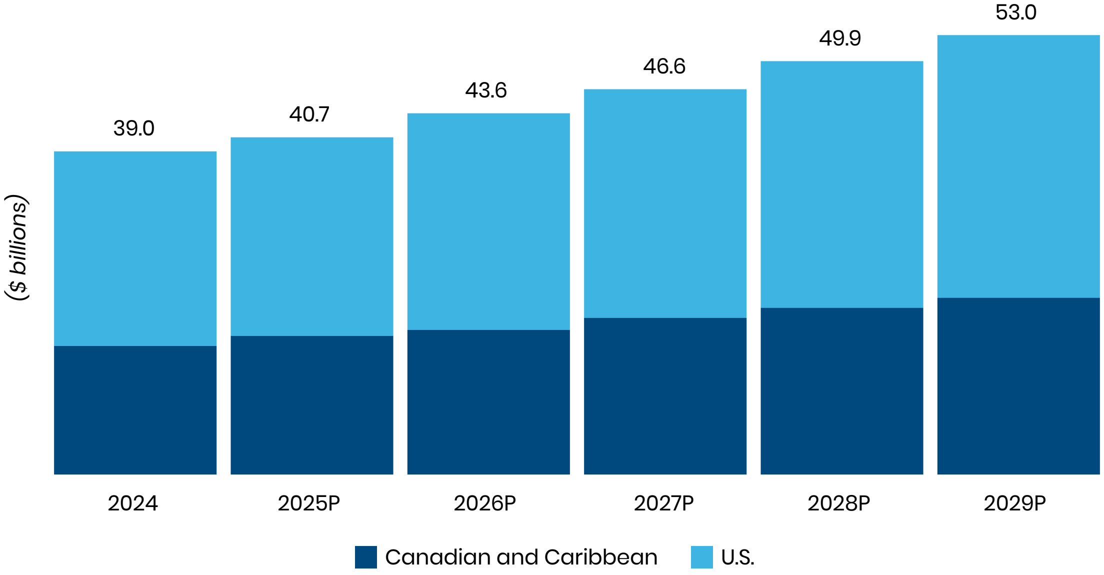
New Five-Year Capital Plan

The Corporation's 2025-2029 capital plan of $26.0 billion is the largest in the Corporation's history and is $1.0 billion higher than the previous five-year plan. The increase is driven by projects associated with the MISO LRTP and resiliency investments at ITC, as well as distribution investments largely due to customer growth at FortisAlberta. For a detailed discussion of the Corporation's capital expenditure program, see "Capital Plan" on page 19.

Funding of the capital plan is expected to be primarily through Operating Cash Flow and debt issued at the regulated utilities. Common equity proceeds are expected to be sourced from the Corporation's DRIP assuming current participation levels. The Corporation's $500 million ATM Program remains available and provides funding flexibility as required.

The five-year capital plan is expected to increase midyear Rate Base from $39.0 billion in 2024 to $53.0 billion by 2029, translating into a five-year CAGR of 6.5%.

PROJECTED RATE BASE (1)



(1) *Reflects average exchange rate of 1.37 for 2024 and exchange rate of 1.30 for 2025-2029. On average, Fortis estimates that a five-cent increase or decrease in the U.S. dollar relative to the Canadian dollar would increase or decrease Rate Base by approximately $1.1 billion over the five-year planning period*

Beyond the five-year capital plan, opportunities to expand and extend growth include: further expansion of the electric transmission grid in the U.S. to support load growth and facilitate the interconnection of cleaner energy; transmission investments associated with the MISO LRTP tranches 1, 2.1 and 2.2 as well as regional transmission in New York; grid resiliency and climate adaptation investments; renewable gas solutions and LNG infrastructure in British Columbia; and the acceleration of load growth and cleaner energy infrastructure investments across our jurisdictions.

THE INDUSTRY

The North American utility industry is undergoing significant transformation due to the need for energy security, the impacts of climate change, the transition to cleaner energy, and projected growth in load driven by data centers, manufacturing and electrification. These factors are creating significant investment opportunities for the sector.

Policy makers and regulators at the federal, state, and provincial levels are increasingly prioritizing matters of energy security, with many continuing to support the transition to cleaner energy. The conjunction of policy and forecasted load growth has resulted in opportunities to invest in renewable and natural gas generation, energy storage systems and transmission infrastructure. Electrification of transportation and heating continues to grow and represents another opportunity to reduce carbon emissions while increasing the output and efficiency of the grid.

Grid resilience continues to grow in importance with the increasing frequency and intensity of weather events such as extreme heat and cold, hurricanes, wildfires, floods and storms. With electricity expected to represent a larger portion of society's energy mix, investments in resiliency are necessary to improve the grid's ability to withstand and recover from climate events.

Diversity of energy supply and enhanced integration of energy systems are vital to deliver the resilience, energy, and capacity needed to support economic growth and energy demand. Electric transmission is a critical enabler of load growth, interconnecting large-scale generation while improving system resilience. Natural gas generation provides a reliable source of energy and capacity that will be an essential resource to meet growing energy needs. Natural gas investments, as well as energy storage solutions, will enable the adoption of additional renewable energy. Increased adoption of RNG and, in the longer-term, hydrogen will further contribute to carbon emissions reduction. The Corporation's utilities are well positioned and actively involved in pursuing these opportunities, which will drive significant capital investment, particularly at ITC, UNS Energy and in Western Canada.

New technology is stimulating change across the Corporation's service territories. Energy delivery systems are becoming more intelligent, with advanced meters, remote sensing, and grid automation. More capable operational technology provides utilities with detailed usage data, enhanced inspection capabilities, and predictive maintenance information, contributing to increased efficiency and more reliable energy delivery. Energy management capabilities are expanding through emerging storage, demand response, and distributed energy management systems.

Fortis' culture of innovation underlies a continuous drive to find better ways to safely, reliably and affordably deliver the energy and services that customers need. Fortis is a partner in Energy Impact Partners, a strategic private venture fund that invests in emerging technologies, products, services and business models that are transforming the industry. The Corporation is also involved in the Low Carbon Resources Initiative, a collaboration between EPRI and GTI Energy, along with other major utilities, to develop and demonstrate the low- and zero-carbon energy technologies needed to enable pathways to decarbonization. Fortis is also a member of EPRI's Climate READi, an initiative involving major North American utilities, regulators, policy makers, and other stakeholders focused on developing an industry-wide best practice framework for managing physical climate risk.

Meaningful customer engagement is important for utilities as customer expectations change. Customers want to make informed energy choices and become active participants in the delivery of their energy. They also expect personalized service, customized self-service offerings, and more real-time, digital communication. To respond to these changes, Fortis' utilities are enhancing customer information systems, adopting digital technologies including AI, and advancing new and modern approaches to customer engagement. At the same time, increased investment in cybersecurity is an ongoing priority in the context of an ever-changing threat landscape. Upgrades to the physical security environment are also required to keep pace with evolving challenges. These technological advancements and challenges offer strategic investment opportunities for Fortis' utilities.

The Corporation's culture and decentralized structure support our utilities' efforts to meet changing customer expectations, and to work constructively with regulators and all stakeholders on policy, energy and service solutions. Fortis is well positioned to support energy security, load growth and the clean energy transition across the Corporation's footprint.

OPERATING RESULTS

($ millions)	**2024**	2023	Variance FX	 Other
Revenue	**11,508**	11,517	108	(117)
Energy supply costs	**3,249**	3,771	32	(554)
Operating expenses	**3,040**	2,889	29	122
Depreciation and amortization	**1,927**	1,773	16	138
Other income, net	**288**	291	(10)	7
Finance charges	**1,406**	1,305	13	88
Income tax expense	**346**	360	1	(15)
Net earnings	**1,828**	1,710	7	111
Net earnings attributable to:				
Non-controlling interests	**148**	137	2	9
Preference equity shareholders	**74**	67	—	7
Common equity shareholders	**1,606**	1,506	5	95
Net earnings	**1,828**	1,710	7	111

Revenue

The decrease in revenue, net of foreign exchange, was due to lower flow-through commodity costs in customer rates at FortisBC Energy and Central Hudson. The decrease was also due to a reduction in the MISO base ROE at ITC, approved by FERC in October 2024, including retroactive application to prior periods (see "Regulatory Highlights - Significant Regulatory Matters" on page 12), and lower short-term wholesale sales revenue at UNS Energy. The decrease was partially offset by Rate Base growth and new customer rates at TEP and Central Hudson, effective September 1, 2023 and July 1, 2024, respectively.

Energy Supply Costs

The decrease in energy supply costs, net of foreign exchange, was due primarily to lower commodity costs, mainly at FortisBC Energy, Central Hudson, and UNS Energy.

Operating Expenses

The increase in operating expenses, net of foreign exchange, was due primarily to general inflationary and employee-related cost increases.

Depreciation and Amortization

The increase in depreciation and amortization, net of foreign exchange, was due to continued investment in energy infrastructure at the Corporation's regulated utilities, and new depreciation rates approved for TEP in September 2023 as part of its general rate application.

Other Income, Net

Other Income, net of foreign exchange, was relatively consistent with 2023. An increase in other income associated with higher AFUDC at UNS Energy and FortisBC Energy was largely offset by the pre-tax gain recognized in 2023 on the sale of Aitken Creek and net unrealized losses on derivative contracts.

Finance Charges

The increase in finance charges, net of foreign exchange, was due to higher debt levels to support the Corporation's capital plan, as well as higher interest rates on new debt issuances.

Income Tax Expense

The decrease in income tax expense, net of foreign exchange, was driven by higher production tax credits at UNS Energy, and the unfavourable $9 million deferred income tax adjustment recognized at ITC in 2023 following a reduction in the corporate income tax rate in the state of Iowa. The decrease was partially offset by higher earnings before taxes.

Net Earnings

See "Performance at a Glance - Earnings and EPS" on page 2.

BUSINESS UNIT PERFORMANCE

Common Equity Earnings

($ millions)	**2024**	2023	Variance FX [1]	Variance Other
Regulated Utilities				
ITC	**542**	508	8	26
UNS Energy	**448**	400	6	42
Central Hudson	**128**	105	3	20
FortisBC Energy	**293**	274	—	19
FortisAlberta	**181**	162	—	19
FortisBC Electric	**72**	68	—	4
Other Electric [2]	**163**	146	—	17
	1,827	1,663	17	147
Non-Regulated				
Corporate and Other [3]	**(221)**	(157)	(12)	(52)
Common Equity Earnings	**1,606**	1,506	5	95

[1] *The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, FortisTCI and Fortis Belize is the U.S. dollar. The reporting currency of Belize Electricity is the Belizean dollar, which is pegged to the U.S. dollar at BZ$2.00=US$1.00. Certain corporate and non-regulated holding company transactions, included in the Corporate and Other segment, are denominated in U.S. dollars*

[2] *Consists of the utility operations in eastern Canada and the Caribbean: Newfoundland Power; Maritime Electric; FortisOntario; Wataynikaneyap Power; Caribbean Utilities; FortisTCI; and Belize Electricity*

[3] *Consists of non-regulated holding company expenses, as well as earnings from long-term contracted generation assets in Belize. Also includes earnings from Aitken Creek up to the November 1, 2023 date of disposition*

ITC

($ millions)	**2024**	2023	Variance FX	Variance Other
Revenue [1]	**2,229**	2,085	33	111
Earnings [1]	**542**	508	8	26

[1] *Revenue represents 100% of ITC. Earnings represent the Corporation's 80.1% controlling ownership interest in ITC and reflect consolidated purchase price accounting adjustments.*

Revenue

The increase in revenue, net of foreign exchange, was due primarily to Rate Base growth and higher flow-through costs in customer rates. The increase was partially offset by a decrease in the MISO base ROE from 10.02% to 9.98%, as approved by FERC in October 2024, for the 15-month period from November 2013 through February 2015 and prospectively from September 2016 (See "Regulatory Highlights - Significant Regulatory Matters" on page 12).

Earnings

The increase in earnings, net of foreign exchange, was due primarily to Rate Base growth as well as an unfavourable $9 million deferred income tax adjustment recognized in 2023 following a reduction in the corporate income tax rate in the state of Iowa. The increase was partially offset by: (i) a decrease in the MISO base ROE from 10.02% to 9.98% as discussed above, which resulted in a $22 million reduction in earnings in 2024, including $20 million associated with the retroactive impact to prior periods; and (ii) higher holding company finance costs.

UNS Energy

($ millions, except as indicated)	**2024**	2023	Variance FX	Variance Other
Retail electricity sales *(GWh)*	**10,870**	10,786	—	84
Wholesale electricity sales *(GWh)* [1]	**5,810**	5,387	—	423
Gas sales *(PJ)*	**17**	17	—	—
Revenue	**3,007**	3,006	45	(44)
Earnings	**448**	400	6	42

[1] *Primarily short-term wholesale sales*

Sales

The increase in retail electricity sales was due primarily to warmer weather and customer additions.

The increase in wholesale electricity sales was driven by higher short-term wholesale sales, due to market conditions, partially offset by lower long-term wholesale sales due to the expiration of certain contracts. Revenue from short-term wholesale sales, which relate to contracts that are less than one-year in duration, is primarily credited to customers through the PPFAC mechanism and, therefore, does not materially impact earnings.

Gas sales were consistent with 2023.

Revenue

The decrease in revenue, net of foreign exchange, was due primarily to: (i) lower wholesale sales revenue, largely driven by unfavourable pricing on short-term wholesale sales; (ii) the recovery of overall lower fuel and non-fuel costs through the normal operation of regulatory mechanisms; and (iii) lower transmission revenue. The decrease was partially offset by new customer rates at TEP effective September 1, 2023.

Earnings

The increase in earnings, net of foreign exchange, was due primarily to: (i) new customer rates at TEP effective September 1, 2023, following the conclusion of the general rate application; (ii) higher production tax credits related to the Oso Grande generating facility; and (iii) higher margins on long-term wholesale sales. The increase was partially offset by: (i) higher depreciation expense, due to new depreciation rates also approved as part of the rate application; (ii) higher operating expenses, reflecting labour costs as well as an increase in planned generation maintenance in 2024; and (iii) lower transmission revenue.

Central Hudson

			Variance	
($ millions, except as indicated)	**2024**	2023	FX	Other
Electricity sales *(GWh)*	**5,060**	4,921	—	139
Gas sales *(PJ)*	**25**	24	—	1
Revenue	**1,372**	1,360	22	(10)
Earnings	**128**	105	3	20

Sales

The increase in electricity sales was due primarily to higher average consumption by residential and commercial customers due to warmer weather.

Gas sales were relatively consistent with 2023.

Changes in electricity and gas sales at Central Hudson are subject to regulatory revenue decoupling mechanisms and, therefore, do not materially impact earnings.

Revenue

The decrease in revenue, net of foreign exchange, was due primarily to the flow-through of lower energy supply costs driven by commodity prices, partially offset by the conclusion of Central Hudson's 2024 general rate application and related rebasing of customer rates effective July 1, 2024. Favourable regulatory adjustments recognized in 2023 that did not reoccur in 2024 also contributed to the decrease in revenue.

Earnings

The increase in earnings, net of foreign exchange, was due to Rate Base growth, as well as new customer rates reflecting the rebasing of costs and a higher allowed ROE effective July 1, 2024. The increase was partially offset by favourable regulatory adjustments recognized in 2023 that did not reoccur in 2024.

FortisBC Energy

($ millions, except as indicated)	**2024**	2023	Variance
Gas sales *(PJ)*	**220**	213	7
Revenue	**1,665**	1,955	(290)
Earnings	**293**	274	19

Sales

The increase in gas sales was due primarily to higher average consumption by industrial, residential and commercial customers.

Revenue

The decrease in revenue was due primarily to the recovery of lower flow-through commodity costs and the normal operation of regulatory mechanisms.

Earnings

The increase in earnings was due primarily to higher net investments in regulated assets.

FortisBC Energy earns approximately the same margin regardless of whether a customer contracts for the purchase and delivery of natural gas or only for delivery. Due to regulatory deferral mechanisms, changes in consumption levels and commodity costs do not materially impact earnings.

FortisAlberta

($ millions, except as indicated)	**2024**	2023	Variance
Electricity deliveries *(GWh)*	**17,324**	16,976	348
Revenue	**817**	738	79
Earnings	**181**	162	19

Deliveries

The increase in electricity deliveries was due primarily to customer additions and higher average consumption by industrial customers.

As approximately 85% of FortisAlberta's revenue is derived from fixed or largely fixed billing determinants, changes in quantities of energy delivered are not entirely correlated with changes in revenue. Revenue is a function of numerous variables, many of which are independent of actual energy deliveries. Significant variations in weather conditions, however, can impact revenue and earnings.

Revenue

The increase in revenue was due to: (i) Rate Base growth, including changes associated with the third PBR term beginning January 1, 2024; (ii) an increase in the allowed ROE from 8.50% to 9.28%, as approved by the AUC, effective January 1, 2024; and (iii) higher industrial and commercial demand charges, as well as customer additions.

Earnings

The increase in earnings was due to the higher allowed ROE, Rate Base growth, higher demand charges and customer additions, as discussed above. The increase was partially offset by higher operating expenses, primarily reflecting operational requirements driven by customer growth, including higher labour costs.

FortisBC Electric

($ millions, except as indicated)	**2024**	2023	Variance
Electricity sales *(GWh)*	**3,513**	3,478	35
Revenue	**545**	528	17
Earnings	**72**	68	4

Sales

The increase in electricity sales was due to higher average consumption by industrial customers, partially offset by lower average consumption by commercial customers.

Revenue

The increase in revenue was due primarily to higher electricity sales and Rate Base growth, as well as higher energy supply costs recovered from customers. The increase was partially offset by the normal operation of regulatory mechanisms.

Earnings

The increase in earnings was due primarily to Rate Base growth.

Due to regulatory deferral mechanisms, changes in consumption levels do not materially impact earnings.

Other Electric

			Variance	
($ millions, except as indicated)	**2024**	2023	FX	Other
Electricity sales *(GWh)*	**9,879**	9,753	—	126
Revenue	**1,838**	1,761	8	69
Earnings	**163**	146	—	17

Sales

The increase in electricity sales was mainly due to higher average consumption by residential and commercial customers, as well as customer additions. Higher average consumption was largely due to the conversion of home heating systems from oil to electric in Eastern Canada and increased tourism-related activities in the Caribbean.

Revenue

The increase in revenue, net of foreign exchange, was due to Rate Base growth, higher electricity sales and the flow-through of higher energy supply costs.

Earnings

The increase in earnings, net of foreign exchange, was due primarily to Rate Base growth and higher electricity sales.

Corporate and Other

			Variance	
($ millions)	**2024**	2023	FX	Other
Electricity sales *(GWh)* (1)	**215**	164	—	51
Revenue (2)	**35**	84	—	(49)
Net loss (3)	**(221)**	(157)	(12)	(52)

(1) *Reflects electricity sales at Fortis Belize*

(2) *Includes revenue for Fortis Belize as well as revenue for Aitken Creek up to the November 1, 2023 date of disposition*

(3) *Includes non-regulated holding company expenses, earnings for Fortis Belize, as well as earnings for Aitken Creek up to the November 1, 2023 date of disposition*

Sales

The increase in electricity sales reflected higher hydroelectric production in Belize associated with rainfall levels.

Revenue

The decrease in revenue reflected the disposition of Aitken Creek in November 2023, partially offset by higher hydroelectric production in Belize.

Net Loss

The increase in net loss was due to: (i) higher holding company finance costs; (ii) net unrealized losses on derivative contracts, reflecting losses on foreign exchange contracts partially offset by gains on total return swaps; and (iii) the $10 million gain on disposition of Aitken Creek recognized in 2023. The increase in net loss was partially offset by higher hydroelectric production in Belize.

The $12 million foreign exchange impact was largely due to the revaluation of U.S. dollar denominated liabilities following the significant depreciation in the Canadian dollar relative to the U.S. dollar in the fourth quarter of 2024.

NON-U.S. GAAP FINANCIAL MEASURES

Adjusted Common Equity Earnings, Adjusted Basic EPS, Adjusted Payout Ratio and Capital Expenditures are Non-U.S. GAAP Financial Measures and may not be comparable with similar measures used by other entities. They are presented because management and external stakeholders use them in evaluating the Corporation's financial performance and prospects.

Net earnings attributable to common equity shareholders (i.e., Common Equity Earnings) and basic EPS are the most directly comparable U.S. GAAP measures to Adjusted Common Equity Earnings and Adjusted Basic EPS, respectively. The Actual Payout Ratio calculated using Common Equity Earnings is the most comparable U.S. GAAP measure to the Adjusted Payout Ratio. These adjusted measures reflect the removal of items that management excludes in its key decision-making processes and evaluation of operating results.

Capital Expenditures include additions to property, plant and equipment and additions to intangible assets, as shown on the consolidated statements of cash flows. It also included Fortis' 39% share of capital spending for the Wataynikaneyap Transmission Power Project, consistent with Fortis' evaluation of operating results and its role as project manager during the construction of the project.

Non-U.S. GAAP Reconciliation

($ millions, except as indicated)	**2024**	2023	Variance
Adjusted Common Equity Earnings, Adjusted Basic EPS and Adjusted Payout Ratio			
Common Equity Earnings	**1,606**	1,506	100
Adjusting items:			
October 2024 MISO base ROE decision [(1)]	**20**	—	20
Disposition of Aitken Creek [(2)]	**—**	(15)	15
Unrealized loss on mark-to-market of derivatives [(3)]	**—**	2	(2)
Revaluation of deferred income tax assets [(4)]	**—**	9	(9)
Adjusted Common Equity Earnings	**1,626**	1,502	124
Adjusted Basic EPS [(5)] *($)*	**3.28**	3.09	0.19
Adjusted Payout Ratio [(6)] *(%)*	**72.7**	73.9	(1.2)
Capital Expenditures			
Additions to property, plant and equipment	**5,012**	3,986	1,026
Additions to intangible assets	**206**	183	23
Adjusting item:			
Wataynikaneyap Transmission Power Project [(7)]	**29**	160	(131)
Capital Expenditures	**5,247**	4,329	918

(1) Represents the prior period impact of FERC's October 2024 MISO base ROE decision (see "Regulatory Highlights - Significant Regulatory Matters" on page 12), net of income tax recovery of $7 million, included in the ITC segment

(2) Aitken Creek was sold on November 1, 2023, with a March 31, 2023 effective date. For the year ended December 31, 2023, the adjustment represents: (i) the $10 million gain on disposition, net of income tax expense of $13 million; and (ii) $5 million of net earnings at Aitken Creek, recognized in accordance with U.S. GAAP, during the March 31, 2023 to November 1, 2023 stub period, net of income tax expense of $2 million, included in the Corporate and Other segment

(3) Represents the impact of mark-to-market accounting of natural gas derivatives at Aitken Creek through the March 31, 2023 effective date of disposition, net of income tax recovery $1 million, included in the Corporate and Other segment

(4) Represents the revaluation of deferred income tax assets resulting from the reduction in the corporate income tax rate in the state of Iowa, included in the ITC segment

(5) Calculated using Adjusted Common Equity Earnings divided by weighted average common shares of 495.0 million in 2024 (2023 - 486.3 million)

(6) Calculated using dividends paid per common share of $2.39 in 2024 (2023 - $2.29) divided by Adjusted Basic EPS

(7) Represents Fortis' 39% share of capital spending for the Wataynikaneyap Transmission Power Project, included in the Other Electric segment. Construction was completed in the second quarter of 2024

REGULATORY HIGHLIGHTS

General

The earnings of the Corporation's regulated utilities are determined under COS regulation, with some using PBR mechanisms.

Under COS regulation, the regulator sets customer rates to permit a reasonable opportunity for the timely recovery of the estimated costs of providing service, including a fair rate of return on a deemed or targeted capital structure applied to an approved Rate Base. PBR mechanisms generally apply a formula that incorporates inflation and assumed productivity improvements for a set term.

The ability to recover prudently incurred costs of providing service and earn the regulator-approved ROE or ROA may depend on achieving the forecasts established in the rate-setting process. There can be varying degrees of regulatory lag between when costs are incurred and when they are recovered in customer rates. As well, the Corporation's regulated utilities, where applicable, are permitted by their respective regulators to flow through to customers, without markup, the cost of natural gas, fuel and/or purchased power through base customer rates and/or the use of rate stabilization and other mechanisms.

Transmission operations in the U.S. are regulated federally by FERC. Remaining utility operations in the U.S. and Canada are regulated by state or provincial regulators. Utility operations in the Caribbean are regulated by regulatory and governmental authorities.

Additional information about regulation and the regulatory matters discussed below is provided in Note 2 in the 2024 Annual Financial Statements. Also refer to "Business Risks - Utility Regulation" on page 22.

Significant Regulatory Matters

ITC

MISO Base ROE: In 2022, the D.C. Circuit Court issued a decision vacating certain FERC orders that had established the methodology for setting the base ROE for transmission owners operating in the MISO region, including ITC, and remanded the matter to FERC for further process. This matter dates back to complaints filed at FERC in 2013 and 2015 challenging the MISO base ROE then in effect.

In October 2024, FERC issued an order that removed the use of the risk premium model from the calculation of the base ROE, while maintaining other modifications to the methodology. The updated methodology revised the base ROE from 10.02% to 9.98%, with a maximum ROE inclusive of incentives not to exceed 12.58%. The order also directed the payment of certain refunds, with interest, by December 2025, for the 15-month period from November 2013 through February 2015, and prospectively from September 2016. A regulatory liability of $39 million (US$27 million) associated with the refunds has been recognized by ITC as of December 31, 2024. Fortis' 80.1% share of the related after-tax earnings impact was approximately $22 million, of which $20 million related to periods prior to January 1, 2024.

Certain MISO transmission owners, including ITC, filed a request for rehearing with FERC in November 2024, and filed an appeal of the order with the D.C. Circuit Court in January 2025. The requests for rehearing and appeal primarily focus on the refund period and the related interest. The timing and outcome of these filings are unknown.

Transmission Incentives: In 2021, FERC issued a supplemental NOPR on transmission incentives modifying the proposal in the initial NOPR released by FERC in 2020. The supplemental NOPR proposes to eliminate the 50-basis point RTO ROE incentive adder for RTO members that have been members for longer than three years. Although the timing and outcome of this proceeding remain unknown, every 10-basis point change in ROE at ITC impacts Fortis' annual EPS by approximately $0.01.

Transmission ROFR: In December 2023, the Iowa District Court ruled that the manner in which Iowa's ROFR statute was passed was unconstitutional. The statute granted incumbent electric transmission owners, including ITC, a ROFR to construct, own and maintain certain electric transmission assets in the state. The District Court did not make any determination on the merits of the ROFR itself, but did issue a permanent injunction preventing ITC and others from taking further action to construct the MISO LRTP tranche 1 Iowa projects in reliance on the ROFR.

MISO's decision with respect to the assignment of the tranche 1 LRTP projects was finalized on July 25, 2022. MISO is the only entity charged with determining what projects are to be competitively bid pursuant to its tariff. In May 2024, MISO commenced a variance analysis process as a result of the inability to construct a portion of the tranche 1 LRTP projects in Iowa due to the injunction imposed by the District Court. In August 2024, MISO concluded the variance analysis, which reaffirmed the original allocation of projects to ITC and other incumbent transmission owners. Approximately US$800 million of capital expenditures associated with the first tranche of MISO's LRTP in Iowa is reflected in Fortis' 2025-2029 capital plan. While the results of MISO's variance analysis process allow ITC to move forward with the development of its portion of tranche 1 LRTP projects in Iowa, various legal proceedings with respect to this matter are ongoing for which the timing and outcome are unknown.

UNS Energy

Generic Regulatory Lag Docket: In December 2024, the ACC approved a formula rate plan policy statement which allows utilities to propose formula rates in future rate cases. A formula rate plan, if approved by the ACC, would adjust rates annually based on a predetermined formula. A formula rate plan is expected to improve rate stability for customers, while also reducing regulatory lag and the number of existing rate adjusters.

UNS Gas General Rate Application: In November 2024, UNS Gas filed a general rate application with the ACC requesting an increase in gas delivery rates effective February 1, 2026. The application includes a request to set its ROE at 10.25% and a 56% common equity component of capital structure. In January 2025, UNS Gas filed supplemental material proposing an annual rate adjustment mechanism as a result of the ACC's formula rate policy statement discussed above. The timing and outcome of this proceeding are unknown.

Central Hudson

2025 General Rate Application: In August 2024, Central Hudson filed a general rate application with the PSC requesting an increase in electric and gas delivery rates effective July 1, 2025. The application includes a request to set Central Hudson's allowed ROE at 10% and a 48% common equity component of capital structure. The timing and outcome of this proceeding are unknown.

Show Cause Order: In October 2024, the PSC issued a Show Cause Order which directed Central Hudson to explain why the PSC should not initiate an enforcement proceeding in connection with a gas-related explosion that occurred in November 2023. Central Hudson filed its response in November 2024. The timing and outcome of the Show Cause Order are unknown.

FortisBC Energy and FortisBC Electric

2025-2027 Rate Framework: In April 2024, FortisBC filed an application with the BCUC requesting approval of a rate framework for the period 2025 through 2027. The rate framework builds upon the current multi-year rate plan and includes, amongst other items, updates to depreciation and capitalized overhead rates, a revised level of operation and maintenance expense per customer indexed for inflation less a fixed productivity adjustment factor, a similar approach to growth capital, a forecast approach to sustaining and other capital, continued collection of an innovation fund recognizing the need to accelerate investment in clean energy innovation, and the continued sharing with customers of variances from the allowed ROE. The rate framework also proposes the continuation of deferral mechanisms currently in place. A decision from the BCUC is expected in mid-2025.

FortisAlberta

GCOC Decision: In October 2023, the AUC issued a decision on the 2024 GCOC proceeding. In November 2023, FortisAlberta sought permission to appeal the GCOC decision to the Court of Appeal on the basis that the AUC erred in its decision to not adjust FortisAlberta's ROE and common equity component of capital structure to address incremental business risk associated with competition from REAs located in FortisAlberta's service area, as well as heightened regulatory risk due to the non-recovery of costs attributable to REAs. In April 2024, the Court of Appeal granted FortisAlberta permission to appeal, and a decision is expected in the first quarter of 2025.

Third PBR Term Decision: In October 2023, the AUC issued a decision establishing the parameters for the third PBR term for the period of 2024 through 2028. In November 2023, FortisAlberta sought permission to appeal the decision to the Court of Appeal on the basis that the AUC erred in its decision to determine capital funding using 2018-2022 historical capital investments without consideration for funding of new capital programs included in the company's 2023 cost of service revenue requirement as approved by the AUC. FortisAlberta's application for permission to appeal the decision was heard by the Court of Appeal in December 2024 and a decision is expected in the first quarter of 2025.

FINANCIAL POSITION

Significant Changes between December 31, 2024 and 2023

Balance Sheet Account	**Variance**		
($ millions)	**FX**	**Other**	**Explanation**
Cash and cash equivalents	**44**	**(449)**	Reflects the timing of a debt issuance at ITC in 2023, with proceeds reinvested in operating and capital requirements in 2024.
Other assets	**87**	**268**	Due primarily to an increase in employee future benefit assets, driven by higher discount rates as well as investment returns on DBP and OPEB plans.
Regulatory assets (current and long-term)	**126**	**121**	Due to changes associated with various regulatory mechanisms, including an increase in deferred income taxes and deferred energy management costs.
Property, plant and equipment, net	**2,423**	**3,648**	Reflects capital investments, partially offset by depreciation.
Accounts payable & other current liabilities	**119**	**262**	Due to an increase in trade accounts payable related to the Corporation's capital program, and an increase in customer deposits for the Eagle Mountain Pipeline project.
Regulatory liabilities (current and long-term)	**214**	**119**	Due to changes associated with various regulatory mechanisms including employee future benefit and future cost of removal deferrals, partially offset by the normal operation of rate stabilization accounts.
Deferred income taxes	**238**	**383**	Primarily due to higher temporary differences associated with ongoing capital investments.
Long-term debt (including current portion)	**1,655**	**2,028**	Reflects debt issuances, partially offset by debt repayments, as well as higher borrowings under committed credit facilities, in support of the Corporation's capital plan.
Shareholders' equity	**1,405**	**898**	Due primarily to: (i) Common Equity Earnings for 2024, less dividends declared on common shares; and (ii) the issuance of common shares, largely under the DRIP.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flow Requirements

At the subsidiary level, it is expected that operating expenses and interest costs will be paid from Operating Cash Flow, with varying levels of residual cash flow available for capital expenditures and/or dividend payments to Fortis. Remaining capital expenditures are expected to be financed primarily from borrowings under credit facilities, long-term debt offerings and equity injections from Fortis. Borrowings under credit facilities may be required periodically to support seasonal working capital requirements.

Cash required of Fortis to support subsidiary growth is generally derived from borrowings under the Corporation's credit facilities, the operation of the DRIP, as well as issuances of long-term debt, preference equity, and common shares including those issued through the ATM Program. The subsidiaries pay dividends to Fortis and receive equity injections from Fortis when required. Both Fortis and its subsidiaries initially borrow through their credit facilities and periodically replace these borrowings with long-term financing. Financing needs also arise to refinance maturing debt.

Credit facilities are syndicated primarily with large banks in Canada and the U.S., with no one bank holding more than approximately 20% of the Corporation's total revolving credit facilities. Approximately $5.8 billion of the total credit facilities are committed with maturities ranging from 2025 through 2029. Available credit facilities are summarized in the following table.

Credit Facilities

As at December 31 *($ millions)*	Regulated Utilities	Corporate and Other	**2024**	2023
Total credit facilities [(1)]	4,396	1,946	**6,342**	6,176
Credit facilities utilized:				
Short-term borrowings	(98)	—	**(98)**	(119)
Long-term debt (including current portion)	(1,335)	(881)	**(2,216)**	(1,572)
Letters of credit outstanding	(81)	(21)	**(102)**	(101)
Credit facilities unutilized	2,882	1,044	**3,926**	4,384

[(1)] *Additional information about the Corporation's credit facilities is provided in Note 14 in the 2024 Annual Financial Statements*

In April 2024, FortisBC Energy increased its operating credit facility from $700 million to $900 million and extended the maturity to July 2028. In May 2024, FortisBC Electric increased its operating credit facility from $150 million to $200 million and extended the maturity to April 2028.

In May 2024, the Corporation extended the maturity on its unsecured US$500 million non-revolving term credit facility to May 2025. Half of the term credit facility was repaid in the third quarter of 2024 and the remaining US$250 million has been fully utilized as at December 31, 2024. The facility is repayable at any time without penalty. In June 2024, the Corporation amended its $1.3 billion revolving term committed credit facility to extend the maturity to July 2029.

In August 2024, Newfoundland Power increased its operating credit facility from $100 million to $130 million and extended the maturity to August 2029.

The Corporation's ability to service debt and pay dividends is dependent on the financial results of, and the related cash payments from, its subsidiaries. Certain regulated subsidiaries are subject to restrictions that limit their ability to distribute cash to Fortis, including restrictions by certain regulators limiting annual dividends and restrictions by certain lenders limiting debt to total capitalization. There are also practical limitations on using the net assets of the regulated subsidiaries to pay dividends, based on management's intent to maintain the subsidiaries' regulator-approved capital structures. Fortis does not expect that maintaining such capital structures will impact its ability to pay dividends in the foreseeable future.

As at December 31, 2024, consolidated fixed-term debt maturities/repayments are expected to average $1,484 million annually over the next five years and approximately 76% of the Corporation's consolidated long-term debt, excluding credit facility borrowings, had maturities beyond five years.

In December 2024, Fortis filed a short-form base shelf prospectus with a 25-month life under which it may issue common or preference shares, subscription receipts, or debt securities in an aggregate principal amount of up to $2.0 billion. Fortis also reestablished the ATM Program pursuant to the short-form base shelf prospectus, which allows the Corporation to issue up to $500 million of common shares from treasury to the public from time to time, at the Corporation's discretion, effective until January 10, 2027. As at December 31, 2024, $500 million remained available under the ATM Program and $1.5 billion remained available under the short-form base shelf prospectus.

Fortis is well positioned with strong liquidity. This combination of available credit facilities and manageable annual debt maturities/repayments provides flexibility in the timing of access to capital markets. Given current credit ratings and capital structures, the Corporation and its subsidiaries currently expect to continue to have reasonable access to long-term capital in 2025.

Fortis and its subsidiaries were in compliance with debt covenants as at December 31, 2024 and are expected to remain compliant in 2025.

Cash Flow Summary

Summary of Cash Flows

Years ended December 31

($ millions)	**2024**	2023	Variance
Cash and cash equivalents, beginning of year	**625**	209	416
Cash from (used in):			
Operating activities	**3,882**	3,545	337
Investing activities	**(5,395)**	(3,742)	(1,653)
Financing activities	**1,064**	613	451
Effect of exchange rate changes on cash and cash equivalents	**44**	—	44
Cash and cash equivalents, end of year	**220**	625	(405)

Operating Activities

See "Performance at a Glance - Operating Cash Flow" on page 4.

Investing Activities

The increase in cash used in investing activities primarily reflects higher capital expenditures in 2024, as well as the proceeds received in 2023 related to the disposition of Aitken Creek. See "Capital Plan" on page 19. Lower customer contributions in aid of construction also contributed to the year over year variance.

Financing Activities

Cash flows related to financing activities will fluctuate largely as a result of changes in the subsidiaries' capital expenditures and the amount of Operating Cash Flow available to fund those capital expenditures, which together impact the amount of funding required from debt and common equity issuances. See "Cash Flow Requirements" on page 14. The year over year increase in cash from financing activities also reflects the repayment of credit facility borrowings in 2023 with the proceeds received from the sale of Aitken Creek.

Debt Financing

Significant Long-Term Debt Issuances

Year ended December 31, 2024	Month Issued	Interest Rate (%)	Maturity		**Amount** *($ millions)*	Use of Proceeds
ITC						
Secured senior notes	January	5.98	2034	**US**	**85**	(1) (2) (3)
First mortgage bonds	January	5.11	2029	**US**	**75**	(1) (2) (3)
First mortgage bonds	January	5.38	2034	**US**	**75**	(1) (2) (3)
Unsecured senior notes	May	5.65	2034	**US**	**400**	(3) (4)
First mortgage bonds	December	4.88	2035	**US**	**125**	(1) (2) (3)
First mortgage bonds	December	5.25	2043	**US**	**125**	(1) (2) (3)
UNS Energy						
Unsecured senior notes	May	5.60	2036	**US**	**30**	(1) (3)
Unsecured senior notes	August	5.20	2034	**US**	**400**	(3) (4)
Central Hudson						
Senior notes	April	5.59	2031	**US**	**25**	(1) (3)
Senior notes	April	5.69	2034	**US**	**35**	(1) (3)
Senior notes	October	4.88	2029	**US**	**25**	(3) (4)
Senior notes	October	5.30	2034	**US**	**44**	(3) (4)
Senior notes	October	5.40	2036	**US**	**35**	(3) (4)
FortisBC Electric						
Unsecured debentures	August	4.92	2054		**100**	(1)
FortisAlberta						
Unsecured debentures	May	4.90	2054		**300**	(1) (2) (3) (4)
Caribbean Utilities						
Unsecured senior notes	May	6.17	2039	**US**	**40**	(1) (2) (3)
Unsecured senior notes	May	6.37	2049	**US**	**40**	(1) (2) (3)
FortisOntario						
Unsecured senior notes	August	5.05	2054		**55**	(1)
Fortis						
Unsecured senior notes	September	4.17	2031		**500**	(1) (3) (4)

(1) *Repay short-term and/or credit facility borrowings*
(2) *Fund capital expenditures*
(3) *General corporate purposes*
(4) *Repay maturing long-term debt*

Common Equity Financing

Common Equity Issuances and Dividends Paid

Years ended December 31 *($ millions, except as indicated)*	**2024**	2023	Variance
Common shares issued:			
Cash (1)	**46**	43	3
Non-cash (2)	**435**	409	26
Total common shares issued	**481**	452	29
Number of common shares issued *(# millions)*	**8.7**	8.4	0.3
Common share dividends paid:			
Cash	**(744)**	(701)	(43)
Non-cash (3)	**(434)**	(408)	(26)
Total common share dividends paid	**(1,178)**	(1,109)	(69)
Dividends paid per common share *($)*	**2.39**	2.29	0.10

(1) *Includes common shares issued under stock option and employee share purchase plans*
(2) *Common shares issued under the DRIP and stock option plan*
(3) *Common share dividends reinvested under the DRIP*

On December 4, 2024 and February 13, 2025, Fortis declared a dividend of $0.615 per common share payable on March 1, 2025 and June 1, 2025, respectively. The payment of dividends is at the discretion of the Board and depends on the Corporation's financial condition and other factors.

On March 1, 2024, the annual fixed dividend per share for the First Preference Shares, Series K was reset from $0.9823 to $1.3673 for the five-year period up to but excluding March 1, 2029.

On December 1, 2024, the annual fixed dividend per share for the First Preference Shares, Series M was reset from $0.9783 to $1.3733 for the five-year period up to but excluding December 1, 2029.

Contractual Obligations

Contractual Obligations

As at December 31, 2024

($ millions)	**Total**	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Long-term debt:							
Principal (1)	**33,405**	1,990	2,585	2,541	1,499	1,024	23,766
Interest	**19,630**	1,371	1,343	1,252	1,162	1,116	13,386
Finance leases (2)	**1,139**	37	37	37	37	37	954
Other obligations (3)	**464**	127	110	100	22	21	84
Other commitments: (4)							
Gas and fuel purchase obligations	**6,299**	763	571	520	465	393	3,587
Renewable power purchase agreements	**2,628**	139	166	182	182	173	1,786
Waneta Expansion capacity agreement	**2,362**	56	58	59	60	61	2,068
Power purchase obligations	**1,335**	302	217	131	124	122	439
ITC easement agreement	**370**	14	14	14	14	14	300
TEP EPC agreements	**308**	307	1	—	—	—	—
Debt collection agreement	**99**	3	3	3	3	3	84
Renewable energy credit purchase agreements	**58**	18	7	6	6	6	15
Other	**140**	32	11	11	12	10	64
	68,237	5,159	5,123	4,856	3,586	2,980	46,533

(1) *Amounts not reduced by unamortized deferred financing and discount costs of $191 million. Additional information is provided in Note 14 of the 2024 Annual Financial Statements*

(2) *Additional information is provided in Note 15 of the 2024 Annual Financial Statements*

(3) *Primarily includes commitments with respect to long-term compensation and employee future benefit arrangements*

(4) *Represents unrecorded commitments. Additional information is provided in Note 27 of the 2024 Annual Financial Statements*

Other Contractual Obligations

The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. Capital Expenditures are forecast to be approximately $5.2 billion for 2025 and approximately $26.0 billion for the five-year 2025-2029 capital plan. See "Capital Plan" on page 19.

Under a funding framework with the Governments of Ontario and Canada, Fortis will contribute a minimum of approximately $165 million of equity capital to Wataynikaneyap Power, based on Fortis' proportionate 39% ownership interest and the final regulatory-approved capital cost of the related project. Wataynikaneyap Power has construction financing loan agreements in place and it is expected that long-term operating financing will replace the construction financing. In the event a lender under the loan agreements realizes security on the loans, Fortis may be required to accelerate its equity capital contributions, which may be in excess of the amount otherwise required of Fortis under the funding framework, to a maximum total funding of $235 million. Equity of $137 million has been contributed as of December 31, 2024.

UNS Energy has joint generation performance guarantees with participants at Four Corners and Luna, with agreements expiring in 2041 and 2046 respectively, and at San Juan and Navajo through decommissioning. The participants have guaranteed that in the event of payment default, each non-defaulting participant will bear its proportionate share of expenses otherwise payable by the defaulting participant. In exchange, the non-defaulting participants are entitled to receive their proportionate share of the generation capacity of the defaulting participant. In the case of San Juan and Navajo, participants would seek financial recovery from the defaulting party. There is no maximum amount under these guarantees, except for a maximum of $360 million for Four Corners. As at December 31, 2024, there was no obligation under these guarantees.

Off-Balance Sheet Arrangements

With the exception of letters of credit outstanding of $102 million as at December 31, 2024 and the unrecorded commitments in the table above, the Corporation had no off-balance sheet arrangements.

Capital Structure and Credit Ratings

Fortis requires ongoing access to capital and, therefore, targets a consolidated long-term capital structure that will enable it to maintain investment-grade credit ratings. The regulated utilities maintain their own capital structures in line with those reflected in customer rates.

Consolidated Capital Structure

	2024		2023	
As at December 31	*($ millions)*	*(%)*	*($ millions)*	*(%)*
Debt [(1)]	**33,435**	**56.4**	29,364	55.7
Preference shares	**1,623**	**2.7**	1,623	3.1
Common shareholders' equity and non-controlling interests [(2)]	**24,230**	**40.9**	21,709	41.2
	59,288	**100.0**	52,696	100.0

(1) *Includes long-term debt and finance leases, including current portion, and short-term borrowings, net of cash*

(2) *Includes shareholders' equity, excluding preference shares, and non-controlling interests. Non-controlling interests represented 3.4% as at December 31, 2024 (December 31, 2023 - 3.5%)*

Outstanding Share Data

As at February 13, 2025, the Corporation had issued and outstanding 499.3 million common shares and the following First Preference Shares: 5.0 million Series F; 9.2 million Series G; 7.7 million Series H; 2.3 million Series I; 8.0 million Series J; 10.0 million Series K; and 24.0 million Series M.

The common shares of the Corporation have voting rights. The Corporation's first preference shares do not have voting rights unless and until Fortis fails to pay eight quarterly dividends, whether or not consecutive or declared.

If all outstanding stock options were converted as at February 13, 2025, an additional 1.5 million common shares would be issued and outstanding.

Credit Ratings

The Corporation's credit ratings shown below reflect its low business risk profile, diversity of operations, the stand-alone nature and financial separation of each regulated subsidiary, and the level of holding company debt.

As at December 31, 2024	**Rating**	Type	Outlook
S&P	A-	Issuer	Negative
	BBB+	Unsecured debt	
Morningstar DBRS	A (low)	Issuer	Stable
	A (low)	Unsecured debt	Stable
Moody's	Baa3	Issuer	Stable
	Baa3	Unsecured debt	

Capital Plan

Capital investment in energy infrastructure is required to ensure the continued and enhanced performance, reliability and safety of the electricity and gas systems, to meet customer growth, and to deliver cleaner energy.

Capital Expenditures in 2024 were $5.2 billion, consistent with expectations and $0.9 billion higher than 2023. The increase compared to 2023 was primarily due to investments associated with the Eagle Mountain Pipeline project at FortisBC Energy, expenditures on various transmission reliability projects at ITC, and construction of the Roadrunner Reserve battery storage projects at UNS Energy.

2024 Capital Expenditures (1)(2)

	Regulated Utilities									
($ millions, except as indicated)	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	**Total Regulated Utilities**	**Non-Regulated Corporate and Other**	**Total**
Total	1,456	1,151	431	1,035	554	132	483	**5,242**	**5**	**5,247**

Forecast 2025 Capital Expenditures (2)

	Regulated Utilities									
($ millions, except as indicated)	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	**Total Regulated Utilities**	**Non-Regulated Corporate and Other**	**Total (3)**
Total	1,403	1,276	462	687	624	179	540	**5,171**	**7**	**5,178**

2025-2029 Capital Plan (2)

($ billions)	2025	2026	2027	2028	2029	**Total (3)**
Five-year capital plan	5.2	5.2	5.6	5.4	4.6	**26.0**

(1) *See "Non-U.S. GAAP Financial Measures" on page 10. Reflects a U.S. dollar-to-Canadian dollar exchange rate of 1.37 for 2024*
(2) *Excludes the non-cash equity component of AFUDC*
(3) *Reflects an assumed U.S. dollar-to-Canadian dollar exchange rate of 1.30. On average, Fortis estimates that a five-cent increase or decrease in the U.S. dollar relative to the Canadian dollar would increase or decrease Capital Expenditures by approximately $600 million over the five-year planning period*

The Corporation's 2025-2029 capital plan of $26.0 billion is $1.0 billion higher than the previous five-year plan. The increase is driven by projects associated with the MISO LRTP and resiliency investments at ITC, as well as distribution investments largely due to customer growth at FortisAlberta.

The five-year capital plan is low risk and highly executable, with nearly all investments being regulated and only 23% relating to Major Capital Projects. Geographically, 58% of planned expenditures are expected in the U.S., including 29% at ITC, with 38% in Canada and the remaining 4% in the Caribbean.

The five-year capital plan is expected to be funded primarily by cash from operations and regulated utility debt. Common equity proceeds are expected to be provided by the Corporation's DRIP, assuming current participation levels. The Corporation's $500 million ATM Program remains available and provides funding flexibility as required.

Planned capital expenditures are based on detailed forecasts of energy demand as well as labour and material costs, including inflation, supply chain availability, general economic conditions, foreign exchange rates and other factors. These factors, including potential new or revised tariffs, could change and cause actual expenditures to differ from forecast. Fortis remains focused on maintaining customer affordability by controlling costs, investing in cleaner energy resulting in fuel savings for customers, utilizing available tax credits, and implementing innovative practices, among other initiatives.

Midyear Rate Base [1]

($ billions)	**2024[2]**	2025[2]	2029[2]
ITC	**12.5**	12.8	16.5
UNS Energy	**7.6**	7.7	10.7
Central Hudson	**3.2**	3.4	4.3
FortisBC Energy	**5.8**	6.3	8.7
FortisAlberta	**4.4**	4.7	5.7
FortisBC Electric	**1.7**	1.8	2.1
Other Electric	**3.8**	4.0	5.0
Total	**39.0**	40.7	53.0

[1] *Simple average of Rate Base at beginning and end of the year*

[2] *Reflects a U.S. dollar-to-Canadian dollar average exchange rate of 1.37 for 2024. 2025 and 2029 reflect an assumed U.S. dollar-to-Canadian dollar exchange rate of 1.30 consistent with the Corporation's 2025-2029 capital plan. On average, Fortis estimates that a five-cent increase or decrease in the U.S. dollar relative to the Canadian dollar would increase or decrease Rate Base by approximately $1.1 billion over the five-year planning period*

Total midyear Rate Base is forecast to grow to $53.0 billion by 2029 underpinned by the five-year capital plan, translating to a CAGR of 6.5%.

Major Capital Projects

($ millions)	Pre-2024	**Actual 2024**	Plan 2025-2029	Expected Completion
ITC				
MISO LRTP	25	**64**	1,704	Post-2029
UNS Energy				
IRP Related Generation	—	**1**	1,620	Various
Roadrunner Reserve Battery Storage Project 1	137	**286**	51	2025
Roadrunner Reserve Battery Storage Project 2	1	**115**	325	2026
Vail-to-Tortolita Transmission Project	152	**47**	253	2027
FortisBC Energy				
Eagle Mountain Pipeline Project [1]	50	**386**	314	2027
Tilbury LNG Storage Expansion	29	**6**	585	2029
AMI Project	7	**30**	733	2028
Tilbury 1B Project	44	**5**	339	2029
Total		**940**	5,924	

[1] *Net of customer contributions*

MISO LRTP

Reflects investments associated with two tranches of the MISO LRTP. In 2022, the MISO board approved the first tranche of projects representing 18 transmission projects across the MISO Midwest subregion with total associated costs estimated at US$10 billion. Six of these projects run through ITC's MISO operating companies' service territories. ITC estimates transmission investments of US$1.4 billion to US$1.8 billion through 2030 associated with six of the 18 projects, with investments of approximately $1.6 billion (US$1.2 billion) included in the Corporation's 2025-2029 capital plan.

Investments of approximately $0.2 billion (US$0.1 billion) have been included in the Corporation's 2025-2029 capital plan associated with tranche 2.1. Significant additional investment opportunities remain for tranche 2.1 (see "Additional Investment Opportunities" on page 21).

IRP Related Generation

Includes capital expenditures supporting the energy transition as outlined in the 2023 IRPs for TEP and UNS Electric including renewable generation, energy storage systems and natural gas generation. Investments support approximately 950 MW of generation, subject to all-source requests for proposals.

Roadrunner Reserve Battery Storage Projects

Consists of two, 200 MW, battery energy storage systems which will facilitate the integration of renewable energy into the electric grid. Each system is capable of storing 800 MW hours of energy, enough to serve approximately 42,000 homes for four hours when deployed at full capacity. TEP will own and operate the systems.

Construction of Roadrunner Reserve 1 has commenced and is scheduled for completion in 2025. In October 2024, TEP filed an application with the ACC requesting approval to defer certain costs associated with owning and operating Roadrunner Reserve 1 for future recovery. TEP cannot predict the timing or outcome of this application.

In August 2024, TEP entered into an EPC agreement to develop Roadrunner Reserve 2, which is scheduled for completion in 2026.

Vail-to-Tortolita Transmission Project
Includes investment in one circuit of a new double circuit 230 kilovolt transmission line to tie infrastructure into the TEP system, improving service and reliability to customers. Construction commenced in late 2023, and is scheduled for completion in 2027.

Eagle Mountain Pipeline Project
The project consists of a 50-km pipeline expansion to a small-scale LNG facility owned by Woodfibre LNG near Squamish, British Columbia. FortisBC Energy commenced construction of the project in 2023 which is scheduled for completion in 2027.

Tilbury LNG Storage Expansion Project
This project replaces the original LNG storage tank at the Tilbury site and increases the available regasification capacity to provide backup gas supply for lower mainland customers. The regulatory process was adjourned in 2023 in order for FortisBC Energy to prepare further information in support of the CPCN application. In October 2024, FortisBC Energy filed the additional information requested. A decision from the BCUC is expected in late 2025.

AMI Project
The project includes replacement of residential, commercial and industrial meters with advanced gas meters to support the safety, resiliency, and efficient operation of FortisBC Energy's gas distribution system. The project will enable remote meter reading and remote shutoff of gas. The CPCN application was approved by the BCUC in 2023, and installation of the advanced meters is expected to commence in 2025 and be substantially complete in 2028.

Tilbury 1B Project
Construction of additional liquefaction and dispensing, including on-shore piping, in support of marine bunkering and to further optimize the Tilbury Phase 1A Expansion Project. This FortisBC Energy project received an Order in Council from the Government of British Columbia in 2017. An initial project scope has been filed with regulators to support the federal impact assessment and provincial environmental assessment required to further expand the Tilbury site.

Additional Investment Opportunities

Fortis is pursuing additional investment opportunities within existing service territories that are not yet included in the five-year capital plan.

ITC
The MISO LRTP is expected to consist of several tranches. The opportunity associated with the first tranche of projects is outlined above. In December 2024, the MISO board of directors approved a portfolio of tranche 2.1 LRTP projects with estimated transmission costs of approximately US$22 billion. ITC now estimates a range of US$3.7 billion to US$4.2 billion in capital expenditures for the MISO tranche 2.1 projects located in Michigan and Minnesota where ROFRs are in effect and for projects requiring system upgrades in Iowa which are not subject to a competitive bidding process. A majority of the tranche 2.1 investment is expected beyond 2029.

In October 2024, ITC in collaboration with another Midwest U.S. energy company, received MISO approval for the Big Cedar Load Expansion Project in Iowa. The project will consist of two phases and includes transmission upgrades to serve up to 1,600 MW of new data center load at the Big Cedar Industrial Center. The first phase of the project requires transmission upgrades to support 800 MW of new load with a targeted in-service date of 2027, and phase two requires an additional 800 MW with an expected in-service date of 2028. The project requires franchise approvals from the Iowa Utilities Commission prior to construction. The project has a potential investment of up to US$400 million.

UNS Energy
TEP is experiencing significant interest from potential new large retail customers in the manufacturing, data center, and mining sectors with energy demands that could create substantial new energy needs. TEP continues to work with the potential companies to assess capital requirements and associated timelines.

FortisBC Energy - LNG
During 2024, provincial and federal environmental assessment certificates were issued for the Tilbury Marine Jetty project. The construction of the jetty supports further expansion of FortisBC's Tilbury LNG facility, which is uniquely positioned to meet customer demand for LNG. The site is scalable, can accommodate additional storage and liquefaction equipment and is close to international shipping lanes. Once constructed, the jetty would utilize FortisBC Energy's assets at the Tilbury site, including the Tilbury Phase 1B Project yet to be constructed, to service marine bunkering.

Other Opportunities
Includes incremental transmission investment and grid modernization projects at ITC; projects related to the 2023 IRPs as well as transmission investments at UNS Energy; regional transmission in New York; further renewable gas and LNG infrastructure opportunities in British Columbia; grid resiliency and climate adaptation investments; and the acceleration of load growth and cleaner energy infrastructure investments across our jurisdictions.

GHG Emissions Reduction Targets

Fortis is primarily an energy delivery company with 93% of its assets related to transmission and distribution. This limits the impact of the Corporation's utilities on the environment when compared to more generation-intensive businesses. Fortis has a relatively small amount of fossil-fuel generation in its portfolio and plans to transition to more renewable sources of energy for its customers.

Fortis continues to lower its already low emissions profile, and has set a 2050 net-zero direct GHG emissions target. This goal is in addition to the Corporation's interim targets to reduce direct GHG emissions 50% by 2030 and 75% by 2035 from a 2019 base year. Fortis expects to achieve its targets primarily through TEP's plan to exit from coal, as well as clean energy initiatives across the Corporation's other utilities. The Corporation's ability to achieve the GHG targets may be impacted by federal, state and provincial energy policies, as well as external factors, including significant customer and load growth and the development of clean energy technology. Reliability and affordability will remain key priorities as Fortis works to meet its emissions reduction targets.

Through 2024, Fortis has made significant progress on its emissions reduction targets with the Corporation's Scope 1 emissions 34% lower compared to 2019 levels. The retirement of certain coal generating stations, the commencement of seasonal operations at other generating stations, and the introduction of renewable wind and solar energy in Arizona, have supported our carbon emissions reduction to date.

Climate-Related Disclosure Standards

In December 2024, the CSSB issued CSDS S1, *General Requirements for Disclosure of Sustainability-Related Financial Information*, and CSDS S2, *Climate-Related Disclosures*, which require an entity to disclose information about its sustainability-related and climate-related risks and opportunities, including the disclosure of material Scope 1, 2 and 3 GHG emissions. The CSSB standards are voluntary and must be adopted by the CSA to become mandatory for Canadian reporting issuers, including Fortis. The CSA continues to work towards a revised climate-related disclosure rule that will consider the CSSB standards and may include modifications considered appropriate for Canadian capital markets. The content and timing of the CSA's revised climate-related disclosure rule are unknown. Fortis will continue to monitor updates from the CSA to assess any potential impact on the Corporation's disclosures.

In March 2024, the SEC released Rule No. 33-11275, *The Enhancement and Standardization of Climate-Related Disclosures for Investors*, which outlines climate-related disclosure requirements. The rule requires disclosure of the financial effects of severe weather events and other natural conditions, as well as other climate-related financial information, in the notes to the financial statements. In addition, the rule requires disclosure of risk management, governance and oversight activities, the impact of material climate-related risks on a company's strategy, business model and outlook, and details of material climate-related targets or goals. Disclosure of material Scope 1 and 2 GHG emissions is also required for certain filers. The SEC subsequently voluntarily stayed the rule pending completion of judicial review by the Court of Appeals for the Eighth Circuit. While the rule does not apply to Fortis as a foreign private issuer filing in the U.S. using Form 40-F, management is reviewing the standard to assess the potential impact on the Corporation's disclosures.

BUSINESS RISKS

Fortis has an ERM program that identifies and evaluates the severity and probability of risks to its business. The Fortis Board, through its audit committee, oversees Fortis' ERM program ensuring that management has an effective risk management system to support strategic planning. The ERM program at the subsidiary level is overseen by each subsidiary's board of directors and any material risks identified form part of Fortis' ERM program. Materiality thresholds are reviewed annually. Systems of internal controls are used by management to monitor and manage identified risks. A summary of the Corporation's significant business risks follows.

Utility Regulation

Regulated utility assets represented virtually all of the Corporation's total assets as at December 31, 2024. Regulatory jurisdictions include five Canadian provinces, ten U.S. states and three Caribbean countries, as well FERC regulation for transmission assets in the U.S.

Regulators administer legislation covering material aspects of the utilities' business including: customer rates, allowed ROEs and deemed capital structures; capital expenditures; the terms and conditions for the provision of energy and capacity, ancillary services and affiliate services; securities issuances; and certain accounting matters. Regulatory or legislative changes and decisions, and delays in the recovery of costs in rates due to regulatory lag, could have a Material Adverse Effect. The risk of regulatory lag may be significant for UNS Energy given the past practice of its regulator to use historical test years in setting customer rates.

The ability to recover the actual cost of service and earn the approved ROE or ROA typically depends upon achieving the forecasts established in the rate-setting process. For those utilities subject to PBR mechanisms, rates reflect assumed inflation rates and productivity improvement factors, and variances therefrom could adversely affect rates of return. Failure to recover costs and/or earn a return could have a Material Adverse Effect.

For transmission operations, the underlying elements of FERC-established formula rates can be challenged by third parties which could result in rate reductions and customer refunds. These underlying elements include the ROE, ROE adders and deemed capital structure, as well as operating and capital expenditures.

In addition, the U.S. Congress periodically considers enacting energy legislation that could assign new responsibilities to FERC, modify provisions of the U.S. *Federal Power Act* or the *Natural Gas Act*, or provide FERC or another entity with increased authority to regulate U.S. federal energy matters.

While Fortis is well-positioned to maintain constructive regulatory relationships through local management teams and subsidiary boards of directors comprised mostly of independent local members, it cannot predict future legislative or regulatory changes, whether caused by economic, political or other factors. The Corporation and its utilities may experience challenges and compliance costs in responding to such regulatory changes in an effective and timely manner. Any such regulatory changes or operational impacts could have a Material Adverse Effect.

Physical Risks

The provision of electric and gas service is subject to physical risks, including impacts from severe weather and natural disasters, wars, terrorism, vandalism, critical equipment failure and other catastrophic events, including wildfires, within and outside the Corporation's service territories.

Electric utilities face risk of loss or damage from wildfires, floods, hurricanes, storm surges, washouts, landslides, earthquakes, avalanches, snow or ice storms, and other acts of nature. Further, certain utilities operate in remote or mountainous terrain that can be difficult to access for timely repairs and maintenance.

Gas utilities are exposed to operational risks associated with natural gas, including fires, explosions, pipeline corrosion and leaks, accidental damage to mains and service lines, equipment failure, damage and destruction from earthquakes, fires, floods and other natural disasters.

Accidents or natural disasters affecting any of the Corporation's electricity or gas utilities can lead to service disruption, spills and commensurate environmental or other liability.

In addition, the operation of electric and gas systems has the potential to cause fires, including wildfires as a result of equipment failure, falling trees, lightning strikes to lines or equipment, or otherwise. The risks associated with fire damage vary depending on weather, forestation, the proximity of habitation and third-party facilities to utility facilities, and other factors. Failure to adequately address the risk of fire and wildfires could result in civil actions and government enforcement proceedings and utilities may become liable for fire-suppression costs, regeneration and timber value costs, and third-party losses if their facilities are determined to have been responsible for, or contributed to, a fire or wildfire.

Generating equipment and facilities are subject to physical risks, including equipment breakdown or damage from fire, floods or other natural disasters, that may result in the uncontrolled release of water, interruption of fuel supply, lower-than-expected operational efficiency or performance, and service disruption.

Electricity and gas systems require ongoing maintenance, improvement and replacement. The utilities are responsible for operating and maintaining their assets in a safe manner, including the development and application of appropriate standards, system processes and/or procedures to ensure the safety of employees, contractors and the general public.

If service disruption, or damage arising from, or caused by, the failure to properly implement or complete approved maintenance and capital expenditures, severe weather or other physical risks, is not mitigated through insurance policies or the recovery of such costs in customer rates, such service disruption or damage could result in loss.

Any of the foregoing potential impacts of physical risk could have a Material Adverse Effect.

The foregoing physical risks can be exacerbated by the "Climate Change" risks discussed below.

Climate Change

Climate-Related Physical Risk

Climate change may negatively impact the ability to provide reliable and safe electric and gas service. A changing climate that leads to higher temperatures and more frequent and severe weather events may impact or disrupt the reliability of electric or gas systems. The physical risks associated with a changing climate requires the Corporation’s utilities to adapt and respond to continue delivering reliable service to customers.

Severe weather and events related to severe weather impact the Corporation's service territories, primarily in the form of thunderstorms, flooding, drought, extreme heat, wildfires, hurricanes, storm surges, atmospheric rivers and snow, or ice storms. Increased frequency of such events could increase the cost of providing service through increased repairs and use of contingency plans. Extreme weather conditions and changes in air temperature require system backup and can result in system stress, including service disruptions, and decreased efficiency of operating facilities over time. Changes in precipitation that impact soil moisture and water levels, or result in droughts, could increase the risk of wildfire caused by the Corporation's electricity assets or may cause water shortages that could adversely affect operations.

Longer-term climate change impacts, such as sustained higher temperatures, higher sea levels, larger storm surges and floods, could result in service disruption, shortened asset life, increased repair and replacement costs, and costs associated with strengthened design standards and systems. The impacts of climate change can intensify the "Physical Risks" (see "Physical Risks" on page 23).

The physical risks posed by the impacts of climate change and resultant damage to assets, service disruption repair and replacement costs, and liability for third party damages could have a Material Adverse Effect if not resolved in a timely and effective manner and/or mitigated through insurance policies or regulatory cost recovery. An increase in business risk associated with climate change can also impact credit ratings, which could affect credit risk spreads on new long-term debt and credit facilities, as well as their availability (see "Access to Capital" on page 28).

Climate-Related Transition Risk

A transition towards decarbonization and further renewable energy use elevates risks associated with policy, legal, technological and market changes which may have capital and financial implications for the Corporation and its utilities.

The transition to cleaner energy will require the Corporation's utilities to effectively manage, among other things, evolving regulatory and legislative requirements, new resiliency standards, the integration of new technologies and impacts on customer demand and rates. Failure to appropriately respond to climate change and decarbonize may disrupt the ability of the utilities to provide safe and cost-effective service, which could cause reputational harm and other impacts.

Fortis expects changes to government policy and regulation to continue in the coming years (see "Environmental Regulation" on page 25). Further, the emergence of initiatives designed to reduce GHG emissions, increase renewable energy use, and control or limit the effects of climate change has increased the incentive for the development of new technologies that produce renewable energy, enable more efficient storage of energy and reduce energy consumption. As new technologies become widely available, infrastructure design risks and time delays may emerge. Utility energy delivery systems will require technological changes and updates in order to effectively deliver increasing amounts of renewable energy to customers (see "Technology Developments and AI" on page 25).

The availability of regulatory mechanisms or the ability of the Corporation's utilities to pass related costs on to customers remains uncertain. Regulatory lag in relation to the adoption of climate change initiatives and/or the availability of regulatory recovery mechanisms in certain jurisdictions could contribute to financial harm to Fortis and its utilities (see "Utility Regulation" on page 22).

Technological advancements will be required in order for the Corporation to achieve its net-zero target while preserving system reliability and customer affordability. In addition to the development and implementation of relevant energy technologies, the Corporation's ability to achieve its GHG targets depends upon many factors, including the impact of federal, provincial and state energy policies, significant load and customer growth, the size of the Corporation's service territory, or the adoption of alternative energy products by the public, any of which could cause actual results and the ability to achieve such targets to materially differ from expectations. The ultimate impact of achieving or failing to achieve such targets could cause reputational damage which could result in a Material Adverse Effect.

Cybersecurity and Information and Operations Technology

As operators of critical energy infrastructure, the Corporation's utilities are at risk of cybercrime, including cyberattacks, data breaches, cyber extortion, and similar compromises. As with other businesses, our information systems and the information systems of our third-party vendors are targeted by malware, phishing efforts, and other cyberattacks. Certain of the information systems of the Corporation's utilities have been subjected to direct and/or third-party cybersecurity breaches, including unauthorized access, none of which have been material. We expect to be targeted by similar attacks in the future. The ability of the Corporation's utilities to operate effectively is dependent upon using and maintaining complex information systems and infrastructure that: (i) support the operation of generation, transmission and distribution facilities, including electric and gas facilities; (ii) provide customers with billing, consumption and load settlement information, where applicable; and (iii) support financial and general operations.

Information and operations technology systems, including those of the Corporation's third-party service providers, may be vulnerable to unauthorized access or disruption due to cyber and other attacks, including hacking, malware, acts of war or terrorism, and acts of vandalism, among others. Further, geopolitical conflicts and the advancement of AI and generative AI may further increase the scale, sophistication or frequency of cyberattacks from malicious actors, some of which actions may even be initiated by or connected with nation-state actors.

Any such event could result in the disruption of energy service and other business operations, including safety disruptions, disruption of internal control processes, property damage, reputational damage, corruption or unavailability of critical data, loss of assets, and the theft, loss, misappropriation and/or disclosure of sensitive, confidential and proprietary business information, intellectual property, or personal information of customers and/or employees. The Corporation's exposure to these risks increases as the Corporation continues to partner with third-party providers (see "Reliance on Supply Chain and Third Parties" on page 28).

A material cybersecurity breach of the Corporation's information security systems or those of a third-party service provider, or any delay or failure in assessing the materiality of such breach and related reporting/disclosure, could expose the Corporation to significant remediation costs and/or adversely affect the operations and financial performance of the Corporation, its reputation and standing with customers, regulators and financial markets, and expose it to claims for third-party damages or regulatory penalties. The resultant financial impacts may not be fully covered by insurance policies or, in the case of utilities, through regulatory cost recovery, and could have a Material Adverse Effect.

Growth

Fortis has a history of both growth through acquisitions and organic growth from capital investment in existing service territories. The Corporation's dividend growth guidance is significantly dependent upon achieving the Rate Base growth expected from the execution of the five-year capital plan as described under "Capital Plan" on page 19. Projects, particularly Major Capital Projects, are subject to risks of delay and cost overruns during construction caused by commodity price fluctuations, supply and labour costs, potential new or revised tariffs, supply chain constraints, supplier non-performance, weather, geologic conditions or other factors beyond the Corporation's control. There is no assurance that regulators will approve: (i) all of the planned projects or their amounts or timing; (ii) permits in a timely manner, or with reasonable terms and conditions; or (iii) the recovery of cost overruns in customer rates, which may have a Material Adverse Effect.

Health and Safety

The operations of the Corporation's utilities inherently involve risk to the health and safety of both employees and the public. Personal injury or loss of life could result from failure to implement or observe appropriate health and safety procedures and gives rise to operational, reputational or financial impacts, any of which could have a Material Adverse Effect. In addition, failure to comply with health and safety regulations could result in fines, penalties, reputational damage, litigation, increased capital and operating costs or adverse regulatory outcomes.

Political Environment

The political environment, at the local, national or global level, may impact energy laws, governmental energy policies or regulatory decisions. For example, political pressure or intervention to address energy prices and customer affordability concerns may impact regulatory decisions, as well as the period over which the Corporation’s utilities recover allowed costs.

The business is further exposed to risks associated with international relations and geopolitical events. Political, economic or social instability or events, trade disputes, new or revised tariffs, changes in laws or the imposition of onerous regulations applicable to existing operations, currency restrictions, and the impacts of changes in political leadership could lead to an increase in commodity prices, impact the availability and cost of energy or generally affect global economic conditions, any of which could have a Material Adverse Effect (see "Environmental Regulation" below and "General Economic Conditions" on page 27).

Technology Developments and AI

New technology developments in distributed generation, particularly solar, and energy efficiency products and services, as well as the implementation of renewable energy and energy efficiency standards, will continue to impact retail sales. Heightened awareness of energy costs and environmental concerns have increased demand for products that reduce energy consumption. The Corporation's utilities are also promoting demand-side management programs. New technologies available to customers include energy derived from renewable sources, customer-owned generation, energy-efficient appliances, battery storage and control systems. Advances in these or other technologies could have a significant impact on retail sales with a potential Material Adverse Effect. Additionally, advances in AI or generative AI could cause disruption to our business and, if we are unable to acquire, develop, implement or adopt new technology, we may suffer a competitive disadvantage, which could also have an adverse effect on our results of operations, financial condition and/or liquidity.

Further, the implementation of new information technology systems and emerging technologies, such as cloud computing, AI and generative AI into the business, including those impacting utility operations, customer billing systems and cybersecurity threat monitoring, carries risk that any such technology or system will not operate as expected. Failure to maintain, upgrade, replace or properly implement such new technology or systems could result in increased risk of a cybersecurity incident and have an adverse effect on operational efficiency, revenue or reputation (see "Cybersecurity and Information and Operations Technology" on page 24).

Environmental Regulation

The Corporation's businesses are subject to environmental laws and regulations, including those which concern emissions into the air, discharges into water or soil, use of water, hazardous waste disposal and containment, and the investigation and remediation of contamination, among others.

The risk of contamination of air, soil and water associated with electricity operations primarily relates to: (i) the transportation, handling, storage and combustion of fuel; (ii) the use of petroleum-based products, mainly transformer and lubricating oil; (iii) the management and disposal of coal combustion residuals and other wastes; and (iv) accidents resulting in hazardous release at or from coal mines that supply generating facilities. Contamination risks at gas operations primarily relate to leaks and other accidents involving gas systems. The key environmental risks for hydroelectric generation operations include dam failures and the creation of artificial water flows that may disrupt natural habitats.

Failure to comply with environmental laws and regulations, or to obtain or comply with any necessary environmental permits pursuant to such laws and regulations, could result in injunctions, fines or other penalties. Further, liabilities relating to contamination investigation and remediation, and related claims for personal injury or property damage, may arise at many locations, including formerly and currently owned/operated properties and waste treatment or disposal sites, regardless of whether such contamination was caused by the business at the time it owned the property, whether it resulted from non-compliance with applicable environmental laws and regulations, or whether it resulted from any act or omission of the business. These liabilities could result in substantial monetary judgments for clean-up costs, damages, fines and/or penalties. To the extent not fully covered by insurance or through regulatory mechanisms, these foregoing costs could have a Material Adverse Effect.

Environmental laws and regulations continue to develop and may result in significant additional expense. In particular, the management of GHG emissions and related decarbonization requirements is a concern due to new and emerging federal, state and provincial GHG laws, regulations and guidelines. Regulation and the pace of regulatory change to address reliability, resiliency, resource planning and safety is expected to increase. Future legislation could impact generation assets, operations, energy supply, operational costs, reporting obligations and other material aspects of the Corporation's business. Increased compliance costs or additional operating restrictions from revised or additional regulation could have a Material Adverse Effect (see "Climate Change" at page 23).

Natural Gas Competitiveness

Approximately 18% of the Corporation's revenue is derived from the delivery of natural gas. In British Columbia, which accounts for 79% of the Corporation's natural gas revenue, natural gas primarily competes with electricity for space and hot water heating load. Upfront capital costs for gas service continue to present competitive challenges for natural gas compared to electricity service. If gas becomes less competitive due to price or other factors, such as government policy or public perception of natural gas or its carbon intensity relative to other energy sources, the ability to add new customers could be impaired. Existing customers could also reduce their consumption or switch to electricity, placing further pressure on rates and, in the extreme, could ultimately lead to an inability to recover the utility's cost of service through customer rates.

Government policy could further impact the competitiveness of natural gas in British Columbia. As governments develop policies to address climate change, any resultant changes to energy policy may impact the competitiveness of natural gas relative to other energy sources.

Additionally, there are other competitive challenges that are impacting the penetration of natural gas into new housing stock such as the carbon intensity of the energy source and the type of housing stock being built. As part of their own climate change policy plans, local governments may use various tools at their disposal such as franchise agreements, permits, building codes and zoning bylaws to impose limitations on energy sources permitted in new and existing developments. Municipalities can also provide incentives, such as higher density allowance, to builders to adopt carbon free energy options for their developments. These actions and policies may hinder the Corporation's ability to attract new natural gas customers or retain existing customers.

A decrease in the competitiveness of natural gas due to pricing, government policy or other factors could have a Material Adverse Effect.

Weather Variability and Seasonality

Electricity consumption varies significantly in response to seasonal weather changes which have been and will continue to be impacted by climate change (see "Climate Change" on page 23). Cool summers may reduce the use of air conditioning and other cooling equipment, while warmer and less severe winters may reduce heating load. Alternatively, severe weather could unexpectedly increase heating and cooling loads, negatively impacting system reliability. Hydroelectric generation is sensitive to rainfall levels and unexpected variations in seasonal rainfall levels can negatively impact operations.

Weather and seasonality have a significant impact on gas distribution volumes as a major portion of natural gas is used for space heating by residential customers. The earnings of the Corporation's gas utilities are typically highest in the first and fourth quarters. Regulatory deferral and revenue decoupling mechanisms are in place at certain of the Corporation's utilities to minimize the volatility in earnings that would otherwise be caused by variations in weather conditions. The absence or the discontinuance of key regulatory mechanisms could result in significant and prolonged weather variations from seasonal norms having a Material Adverse Effect.

Required Approvals

The acquisition, ownership and operation of electric and gas businesses require numerous licences, permits, agreements, orders, certificates, consultations, and other approvals from various levels of government, regulators, government agencies and/or other third parties. There is no assurance that: (i) such approvals will be obtained, continuously maintained or renewed without delay; and (ii) the terms and conditions thereof will be fully complied with at all times and will not change in a material adverse manner. Significant failures in these regards could prevent the operation of the businesses and have a Material Adverse Effect.

Reliability Standards

The Energy Policy Act of 2005 provides for a regulatory framework which requires owners, operators and users of the bulk electric system in the U.S. to meet mandatory reliability standards developed by the North American Electric Reliability Corporation and its regional entities, which are approved and enforced by FERC. Many of these, or similar, standards have been adopted in certain Canadian provinces including British Columbia and Alberta. The failure to develop, implement and maintain appropriate operating practices/systems and capital plans to address reliability obligations could lead to compliance violations and a Material Adverse Effect, including as a result of the exclusion of related costs from customer rates and other potentially significant penalties.

Indigenous Peoples' Land Claims

In British Columbia, the Corporation's utilities provide service to customers on Indigenous Peoples' lands and maintain facilities on lands that are subject to Indigenous Peoples' land claims. Various treaty negotiation processes involving Indigenous Peoples and the Governments of British Columbia and Canada are underway, but the basis for potential settlements is unclear and not all Indigenous Peoples are participating in such processes. To date, the policy of the Government of British Columbia has been to structure settlements without prejudicing existing third-party rights; however, there is no assurance that the settlement processes will not have a Material Adverse Effect.

FortisAlberta has distribution assets on Indigenous Peoples' lands in Alberta with access permits held by a third party. Some of these permits require approvals from First Nations and Crown-Indigenous Relations and Northern Affairs Canada. FortisAlberta may be unable to obtain such approvals or negotiate land-use agreements with reasonable terms. Significant failures in these regards could have a Material Adverse Effect.

Certain jointly owned facilities and portions of TEP's transmission lines are located on tribal lands pursuant to leases, land easements and other rights-of-way that are effective for specified time periods. The inability to receive future approvals for continued access to the facilities and land could have a Material Adverse Effect.

Joint-Ownership Interests and Third-Party Operators

Certain generating facilities from which TEP receives power are jointly owned with, or are operated by, third parties. TEP may not have sole discretion or any ability to affect the management or operations of such facilities, including how to best address changing economic conditions or environmental requirements. A divergence in the interests of TEP and those of the joint owners or operators could have a Material Adverse Effect.

General Economic Conditions

Fluctuations in general economic conditions, inflation, energy prices, employment levels, personal disposable incomes, housing starts, industrial activity and other factors, including potential new or revised tariffs, may lower energy demand and sales and reduce capital spending, particularly to the extent that related customer and Rate Base growth are impacted. A severe and prolonged economic downturn could also impair customers' ability to pay their bills in a timely manner. Each of these factors could lead to the impairment of goodwill or other long-term assets, and could have a Material Adverse Effect. Further, the impact of macroeconomic factors, including, but not limited to, international relations and geopolitical events, could cause weaker economic conditions or increase the volatility of the equity capital markets, which could impact the business and financial condition of the Corporation or adversely impact the Corporation's share price.

Commodity Price Volatility

Purchased power and gas, and generation fuel costs are subject to commodity price volatility, which is managed through regulator-approved: (i) mechanisms that permit the flow through in customer rates of commodity price changes and/or that provide for rate-stabilization and other deferral accounts; and (ii) price-risk management strategies such as the use of derivative contracts that effectively fix costs (see "Financial Instruments - Derivatives" on page 33).

There is no assurance that current regulator-approved mechanisms or strategies will continue to exist in the future. Additionally, despite these mechanisms and strategies, severe and prolonged commodity price increases could result in rates that customers are unable to pay and/or could affect consumption and sales growth, which could have a Material Adverse Effect.

Purchased Power Supply

A significant portion of electricity and gas sold by the Corporation's utilities is purchased through the wholesale energy markets or pursuant to contracts with energy suppliers and is not being produced by the Corporation's utilities. A disruption in the wholesale energy markets, or a failure on the part of energy or fuel suppliers or operators of energy delivery systems that connect to the Corporation's utilities, could result in a loss and/or increase in the cost of purchased power and gas, which could have a Material Adverse Effect. The cost and availability of purchased power and gas may be adversely impacted by factors discussed under "Climate Change" on page 23, "Environmental Regulation" on page 25 and "Commodity Price Volatility" above.

Counterparty Credit Risk

ITC has a concentration of credit risk as approximately 70% of its revenue is derived from three customers. These customers have investment-grade credit ratings and credit risk is further managed by MISO by requiring a letter of credit or cash deposit equal to the credit exposure, which is determined by a credit-scoring model and other factors.

FortisAlberta has a concentration of credit risk as its distribution service billings are to a relatively small group of retailers. Credit risk is managed by obtaining from the retailers either a cash deposit, letter of credit, an investment-grade credit rating, or a financial guarantee from an entity with an investment-grade credit rating.

Central Hudson has seen an increase in accounts receivable since the suspension of collection efforts initially required in response to the COVID-19 pandemic. Central Hudson continues to contact customers regarding past-due balances and collection efforts continue to expand. Under its regulatory framework, Central Hudson can defer uncollectible write-offs above the amounts collected in customer rates for future recovery.

UNS Energy, Central Hudson, FortisBC Energy, and Fortis may be exposed to credit risk from non-performance by counterparties to derivative contracts. Credit risk is managed by net settling payments, when possible, and dealing only with counterparties that have investment-grade credit ratings. At UNS Energy, Central Hudson and FortisBC Energy, certain contractual arrangements require counterparties to post collateral.

There is no assurance that credit risk management strategies will continue to be effective. Significant counterparty defaults could have a Material Adverse Effect.

Reliance on Supply Chain and Third Parties

Domestic and global supply chain disruptions, as a result of either physical or cyberattacks or geopolitical issues, may delay the delivery or result in shortages of certain materials, equipment and other resources that are critical to the operation of the Corporation's utilities, or impact the services and performance of the operation of the Corporation's utilities. Failure to eliminate or manage constraints in, or performance of, the supply chain may impact the availability of items or service that are necessary to support operations as well as materials that are required for continued infrastructure growth and could have a Material Adverse Effect. Further, cybersecurity incidents in the Corporation's supply chain or cyberattacks originating from the Corporation's supply chain may further result in disruption of energy service and other business operations which could have a Material Adverse Effect.

Interest Rates

Generally, the market price of the Corporation's common shares is inversely correlated to interest rate changes. Additionally, allowed ROEs are exposed to changes in long-term interest rates, such that a decreasing interest rate environment can result in lower allowed ROEs over time. While a rising interest rate environment could result in higher allowed ROEs, such ROE changes tend to lag as a result of regulatory timelines. Borrowings under variable-rate credit facilities and long-term debt, as well as new debt issuances, are also exposed to interest rate changes. Although interest costs at the regulated utilities are generally recovered through customer rates, the discontinuance of regulatory mechanisms that permit the flow-through of actual interest costs, the impact of regulatory lag at UNS Energy, and higher finance costs on holding company debt could have a Material Adverse Effect.

Foreign Exchange Exposure

As at December 31, 2024, 69% of the Corporation's assets were located outside Canada and 62% of 2024 revenue was derived from foreign operations. The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, FortisTCI, Fortis Belize and Belize Electricity is, or is pegged to, the U.S. dollar. The earnings and cash flow from, and net investments in, these entities are exposed to fluctuations in the U.S. dollar-to-Canadian dollar exchange rate. The Corporation’s $26.0 billion five-year capital plan for 2025 through 2029 also includes exposure to foreign exchange.

Fortis has reduced its U.S. dollar currency exposure through hedging. The Corporation has issued and designated U.S. dollar-denominated long-term debt as an effective hedge of foreign net investments. Fortis has also entered into foreign exchange contracts and cross-currency swaps to manage a portion of its exposure to foreign currency risk.

Given only partial hedging, earnings and cash flow continue to be impacted by exchange rate fluctuations. In addition, there is no assurance that existing hedging strategies will continue to be effective, and therefore a significant, prolonged decrease in the U.S dollar-to-Canadian dollar exchange rate could have a Material Adverse Effect.

Access to Capital

The Corporation and certain of its subsidiaries have incurred material amounts of indebtedness. Ongoing access to cost-effective capital is required to fund, among other things, capital expenditures and the repayment of maturing debt.

Operating Cash Flow may not be sufficient to fund the repayment of all outstanding liabilities when due or fund anticipated capital expenditures.

The ability to meet long-term debt repayments is dependent upon obtaining sufficient and cost-effective financing to replace maturing indebtedness. The ability to arrange financing is subject to numerous factors, including the results of operations and financial condition of Fortis and its subsidiaries, the regulatory environments including decisions regarding capital structure and allowed ROEs, capital market conditions, general economic conditions, credit ratings, and the environmental, social and governance profile of Fortis and its subsidiaries. Changes in credit ratings could affect credit risk spreads on new long-term debt and credit facilities, as well as their availability.

Fortis is a holding company and, as such, has no revenue-generating operations of its own. The Corporation's subsidiaries are separate legal entities and have no independent obligation to pay dividends to Fortis. Prior to paying dividends to the Corporation, the subsidiaries have financial obligations that must be satisfied, including, among others, their operating expenses and obligations to creditors. Furthermore, the Corporation's utilities are required by regulation to maintain a minimum equity-to-total capital ratio that may restrict their ability to pay dividends to the Corporation or may require the Corporation to contribute capital to such subsidiaries. The future enactment of laws or regulations may prohibit or further restrict the ability of the Corporation's subsidiaries to pay dividends or to repay intercorporate indebtedness. In addition, in the event of a subsidiary's liquidation or reorganization, the Corporation's right to participate in a distribution of assets is subject to the prior claims of the subsidiary's creditors. As a result, the Corporation's ability to generate cash flow to service its debt obligations and pay dividends is reliant on the ability of its subsidiaries to generate sustained earnings and cash flows and to pay dividends and repay loans.

There is no assurance that sufficient capital will continue to be available on acceptable terms. For further information see "Liquidity and Capital Resources" on page 14.

Taxation

Earnings at Fortis and its subsidiaries could be impacted by changes in income tax rates and other tax legislation in Canada, the U.S. and other international jurisdictions. The nature, timing or impact of changes in tax laws cannot be predicted and could have a Material Adverse Effect. Although income taxes at the regulated utilities are generally recovered in customer rates, tax-related regulatory lag can result in recovery delays or non-recovery for certain periods. At the non-regulated level, changes in income tax rates and other tax legislation could materially affect the after-tax cost of existing and future debt which is not recoverable in customer rates.

Insurance

Insurance is maintained with reputable industry insurers for property damage, potential liabilities and business interruption for coverage considered appropriate and in accordance with industry practice.

A significant portion of transmission and distribution assets is uninsured, as is customary in North America, as the cost to insure such assets is prohibitive. Insurance is subject to coverage limits and deductibles, as well as time-sensitive claims discovery and reporting provisions. There is no assurance that: (i) the amounts and types of losses from actual damage, liabilities or business interruption will be fully covered by insurance; (ii) regulatory relief would be obtained for coverage shortfalls; (iii) adequate insurance at reasonable rates will continue to be available; or (iv) insurers will fulfill their obligations. Significant actual shortfalls in insurance coverage or claims payment could have a Material Adverse Effect. The availability and cost of certain types of insurance may be adversely impacted by the risks described under "Climate Change" on page 23.

Pandemics and Public Health Crises

The Corporation could be negatively impacted by widespread outbreaks of communicable diseases or other public health crises that cause economic and/or other disruptions. Outbreaks of communicable diseases, as well as efforts to reduce the health impacts and control disease spread, can lead to restrictions on business operations, including business closures and the potential impacts of reduced labour availability and productivity, supply chain disruptions, project construction delays, disruptions to capital markets, governmental and regulatory action, and a prolonged reduction in economic activity. An extended economic slowdown could reduce energy sales and adversely impact the ability of customers, contractors and suppliers to fulfill their obligations and could disrupt operations and capital expenditure programs or cause impairment of goodwill (see "General Economic Conditions" on page 27).

The Corporation's utilities provide essential services and must be operational and maintained throughout any pandemic or other public health crisis, though such events can challenge operations and increase operating costs. The duration and severity of a pandemic or other public health crisis could have a Material Adverse Effect.

Talent Management

The delivery of safe, reliable and cost-effective service depends on the attraction, development and retention of a skilled workforce as well as filling strategic positions. Like its peers, Fortis faces demographic challenges and competitive markets relating to trades, technical and professional staff, particularly considering its significant capital plan. ITC relies heavily on agreements with third parties to provide services for the construction, maintenance and operation of certain aspects of its business. Significant failures in attracting or retaining a skilled workforce or filling strategic positions within the Corporation or its utilities could have a Material Adverse Effect.

Labour Relations

Most of the Corporation's utilities employ members of labour unions or associations under collective bargaining agreements. Fortis considers its labour relationships to be satisfactory, but there is no assurance that this will continue or that existing collective bargaining agreements will be renewed on reasonable terms without work disruption or other job action. Significant failures in these regards could cause service interruptions and/or labour cost increases for which regulators may not allow full recovery in customer rates, and could have a Material Adverse Effect.

Post-Retirement Obligations

Fortis and most of its subsidiaries maintain a combination of DBP and/or OPEB plans for certain employees and retirees. The most significant cost drivers for these plans are investment performance and interest rates, which are affected by global financial markets. Regulatory deferral mechanisms are in place at many of the Corporation's utilities that permit the flow through in customer rates of certain impacts associated with market fluctuations. Severe and prolonged market disruptions, significant declines in the market values of investments held to meet plan obligations, discount rate changes, participant demographics, changes in laws and regulations, as well as changes in existing regulatory treatment of post-retirement benefit costs, may increase plan expenses or require additional plan funding and could have a Material Adverse Effect.

Reputation, Relationships and Stakeholder Activism

There can be no assurance that internal processes, controls or audits, including those related to the preparation and presentation of financial statements, will ensure compliance with the Corporation's internal policies, including its Code of Conduct, or anti-bribery and anti-corruption laws. Employees, affiliates, independent contractors or agents may violate such policies and laws, which may potentially lead to reputational damage, in addition to potential fines, penalties or litigation, any of which could have a Material Adverse Effect.

The Corporation's operations and growth prospects require strong relationships with key stakeholders, including regulators, governments and agencies, Indigenous communities, landowners, and environmental organizations. Inadequately managing expectations and issues important to stakeholders, including those arising during construction of Major Capital Projects, could affect the Corporation's reputation as well as have a significant impact on its operations and infrastructure development. See "Required Approvals" and "Indigenous Peoples' Land Claims" on page 27.

External stakeholders have been challenging companies regarding climate change, sustainability, diversity, returns (including ROEs and ROAs), executive compensation, and other matters. Public opposition to larger infrastructure projects is becoming increasingly common, which can challenge capital plans and resultant organic growth. While the Corporation actively monitors such activism and is committed to developing stronger relationships with its external stakeholders, failure to effectively manage or respond to stakeholder activism could have a Material Adverse Effect.

Legal, Administrative and Other Proceedings

Legal, administrative and other proceedings arise in the ordinary course of business and may include environmental claims, employment-related claims, securities-based litigation, contractual disputes, personal injury or property damage claims, actions by regulatory or tax authorities, and other matters. Unfavourable outcomes such as judgments or settlements for monetary or other damages, injunctions, denial or revocation of permits, reputational harm, and other results could have a Material Adverse Effect.

ACCOUNTING MATTERS

New Accounting Policies

Segment Reporting: The Corporation adopted ASU No. 2023-07, *Improvements to Reportable Segment Disclosures*, for the year ended December 31, 2024 and will adopt it for interim periods beginning in 2025. This update requires disclosure of incremental segment information, including significant segment expenses and other items that are included in segment profit or loss. This adoption of this standard did not materially impact Fortis' disclosures.

Future Accounting Pronouncements

Income Taxes: ASU No. 2023-09, *Improvements to Income Tax Disclosures*, is effective for Fortis on January 1, 2025 on a prospective basis, with retrospective application and early adoption permitted. The ASU requires additional disclosure of income tax information by jurisdiction to reflect an entity's exposure to potential changes in tax legislation, and associated risks and opportunities. Fortis does not expect the ASU to materially impact its disclosures.

Expense Disaggregation: ASU No. 2024-03, *Disaggregation of Income Statement Expenses*, is effective for Fortis on January 1, 2027 for annual periods and on January 1, 2028 for interim periods, on a prospective basis, with retrospective application and early adoption permitted. The ASU requires detailed disclosure of certain expense categories included on the consolidated statements of earnings, including energy supply costs, operating expenses, and depreciation and amortization expense. Fortis is assessing the impact on its disclosures.

Critical Accounting Estimates

General

The preparation of the 2024 Annual Financial Statements required management to make estimates and judgments that affect the reported amounts of, and disclosures related to, assets, liabilities, revenues, expenses, gains, losses and contingencies. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time they are made, with any adjustments recognized in the period they become known. Actual results may differ significantly from these estimates.

Regulatory Assets and Liabilities

As at December 31, 2024, Fortis recognized regulatory assets of $4.6 billion (2023 - $4.4 billion) and regulatory liabilities of $4.3 billion (2023 - $4.0 billion).

Regulatory assets represent future revenues and/or receivables associated with certain costs incurred that will be, or are expected to be, recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent: (i) future reductions or limitations of increases in revenue associated with amounts that will be, or are expected to be, refunded to customers through the rate-setting process; or (ii) obligations to provide future service that customers have paid for in advance.

The recognition of regulatory assets and liabilities and the period(s) of settlement are often estimates based on past, existing or expected regulatory orders in relation to the nature of the underlying amounts, and are subject to regulatory approval. There is no assurance that actual settlement amounts and the related settlement periods will not be materially different from those estimated. Differences arising from the regulator's orders would be recognized in accordance with those orders, whereby any amounts disallowed would be immediately recognized in earnings with the remainder recognized in earnings in accordance with their inclusion in customer rates.

Employee Future Benefits

Key Estimates and Assumptions

Years ended December 31	**DBP Plans**		**OPEB Plans**	
($ millions, except as indicated)	**2024**	2023	**2024**	2023
Funded status: (1)				
Benefit obligation (2)	**(3,440)**	(3,347)	**(603)**	(596)
Plan assets	**3,613**	3,313	**506**	430
	173	(34)	**(97)**	(166)
Net benefit cost (2)	**11**	21	**12**	15
Key assumptions: *(weighted average %)*				
Discount rate as at December 31 (3)	**5.25**	4.84	**5.43**	4.94
Expected long-term rate of return on plan assets (4)	**6.51**	6.58	**6.05**	5.92
Rate of compensation increase	**3.52**	3.37	**—**	—
Health care cost trend increase rate (5)	**—**	—	**4.53**	4.52

(1) *Periodic actuarial valuations determine funding contributions for the DBP plans and U.S. OPEB plans, while Canadian OPEB plans are unfunded*

(2) *Actuarially determined using the projected benefits method prorated on service and management's best estimate of expected plan investment performance, salary escalation, average remaining service life of employees, mortality rates and, for OPEB plans, expected health care costs*

(3) *Reflects market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments. The discount rate used during the year for DBP plans is 4.84% (2023 - 5.36%) and 4.96% (2023 - 5.39%) for OPEB plans*

(4) *Developed using best estimates of expected returns, volatilities and correlations for each class of asset. Estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes*

(5) *Actuarially determined, the projected 2025 rate is 6.51% and is assumed to decrease over the next 10 years to the ultimate rate of 4.53% in 2034 and thereafter*

Sensitivity Analysis	**Rate of Return**		**Discount Rate**		**Health Care Costs Trend Rate**	
Year ended December 31, 2024	**1% change**		**1% change**		**1% change**	
($ millions)	**Increase**	**Decrease**	**Increase**	**Decrease**	**Increase**	**Decrease**
DBP plans:						
Net benefit cost	**(33)**	**29**	**(24)**	**41**	**n/a**	**n/a**
Projected benefit obligation	**(2)**	**(66)**	**(378)**	**453**	**n/a**	**n/a**
OPEB plans:						
Net benefit cost	**(4)**	**4**	**(9)**	**11**	**14**	**(11)**
Accumulated benefit obligation	**—**	**—**	**(68)**	**84**	**62**	**(52)**

At the regulated utilities, changes in net benefit cost are generally expected to be reflected in customer rates, subject to regulatory lag and forecast risk at certain utilities.

ITC, Central Hudson, FortisBC Energy, FortisBC Electric and Newfoundland Power have regulator-approved mechanisms to defer variations between actual net pension cost and that forecast and reflected in customer rates. There is no assurance that these deferral mechanisms will continue in the future.

Depreciation and Amortization

As at December 31, 2024, Fortis recognized property, plant and equipment and intangible assets of $51.1 billion (2023 - $44.9 billion) representing 70% of total assets (2023 - 68%). Depreciation and amortization of these assets totalled $1.8 billion for 2024 (2023 - $1.7 billion).

Depreciation and amortization reflect the estimated useful lives of the underlying assets, which considers historical experience, manufacturers' ratings and specifications, the past and expected future pattern and nature of usage, and other factors.

At the regulated utilities, depreciation rates require regulatory approval and include a provision for estimated future removal costs, not identified as a legal obligation. Estimates primarily reflect historical experience and expected cost trends. The provision is recognized as a long-term regulatory liability against which actual removal costs are netted when incurred. As at December 31, 2024, this regulatory liability was $1.7 billion (2023 - $1.5 billion).

Depreciation rates at the regulated utilities are typically determined through periodic depreciation studies performed by external experts. Where actual experience differs from previous estimates, resultant differences are generally reflected in future depreciation rates and thereby recovered or refunded through customer rates in the manner prescribed by the regulator.

Goodwill Impairment

As at December 31, 2024, Fortis recognized goodwill of $13.1 billion (2023 - $12.2 billion), representing 18% of total assets (2023 - 18%). The increase in goodwill was due to a higher U.S. dollar-to-Canadian dollar exchange rate at December 31, 2024 in comparison to December 31, 2023, and the associated impact on the translation of U.S. dollar-denominated goodwill.

Goodwill at each of the Corporation's reporting units is tested for impairment annually and whenever an event or change in circumstances indicates that fair value may be below carrying value. If so determined, goodwill is written down to estimated fair value and an impairment loss is recognized.

The Corporation performs a qualitative assessment on each reporting unit and if it is determined that it is not likely that fair value is less than carrying value, then a quantitative estimate of fair value is not required. When a quantitative assessment is performed, the primary method for estimating fair value of the reporting units is the income approach, whereby net cash flow projections are discounted. Underlying estimates and assumptions, with varying degrees of uncertainty, include the amount and timing of expected future cash flows, growth rates, and discount rates. A secondary valuation, the market approach along with a reconciliation of the total estimated fair value of all the reporting units to the Corporation's market capitalization, is also performed and evaluated.

The recognition of impairment losses could have a Material Adverse Effect. Such losses are not recoverable in regulated utility rates. To the extent impairment losses signal lower expected future cash flows to support interest payments on unregulated holding company debt and dividends on common shares, they could adversely affect the future cost of such capital, expressed as higher interest rates on such debt, which is not recoverable in regulated utility rates, and lower common share market prices.

Income Tax

As at December 31, 2024, deferred income tax liabilities, income tax receivable, deferred income taxes included in regulatory assets, income tax payable, and deferred income taxes included in regulatory liabilities totalled $5.0 billion, $nil, $2.2 billion, $33 million and $1.3 billion, respectively (2023 - $4.4 billion, $78 million, $2.1 billion, $nil, and $1.3 billion, respectively). Income tax expense was $346 million in 2024 (2023 - $360 million).

Current income taxes reflect the estimated taxes payable/receivable in the current year based on enacted tax rates and laws, and the estimated proportion of taxable earnings/loss attributable to various jurisdictions.

Deferred income tax assets and liabilities reflect temporary differences between the tax and accounting basis of assets and liabilities. A deferred income tax asset or liability is determined for each temporary difference based on enacted income tax rates and laws in effect when the temporary differences are expected to be recovered or settled. A valuation allowance is recognized in earnings to the extent that future tax recovery is not assessed as "more likely than not".

At the regulated utilities, differences between the income tax expense or recovery recognized under U.S. GAAP and reflected in customer rates, which is expected to be recovered from, or refunded to, customers in future rates, are recognized as regulatory assets or liabilities. These are subsequently amortized to earnings in accordance with their inclusion in customer rates pursuant to the regulator's orders. Otherwise, changes in expectations and resultant estimates arising from changes in tax rates, tax laws, jurisdictional earnings allocations and other factors are recognized in earnings upon occurrence.

The Corporation and certain of its subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which the Corporation is subject to potential income tax compliance examinations include the United States (Federal, Arizona, Kansas, Iowa, Michigan, Minnesota and New York) and Canada (Federal, British Columbia and Alberta). The Corporation's 2020 to 2024 taxation years are still open for audit in Canadian jurisdictions, and its 2020 to 2024 taxation years are still open for audit in U.S. jurisdictions. The impact of such income tax compliance examinations could be material to the Corporation (see "Business Risks - Taxation" on page 29).

In June 2024, the Government of Canada enacted legislation with respect to interest deductibility limitations and global minimum tax, both of which were applicable to Fortis as of January 1, 2024. There was no material impact to Fortis in 2024 and the Corporation does not expect a material impact on its financial results, Operating Cash Flow or credit metrics over the five-year planning period.

Derivatives
The fair values of derivatives are based on estimates that cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting future earnings or cash flows.

Contingencies
The Corporation and its subsidiaries are subject to various legal proceedings and claims arising in the ordinary course of business, including those generally described under "Business Risks - Legal, Administrative and Other Proceedings" on page 30, for which no amounts have been accrued because the outcomes currently cannot be reasonably determined. Further information is provided in Note 27 in the 2024 Annual Financial Statements.

FINANCIAL INSTRUMENTS

Long-Term Debt and Other

As at December 31, 2024, the carrying value of long-term debt, including the current portion, was $33.4 billion (2023 - $29.7 billion) compared to an estimated fair value of $31.3 billion (2023 - $27.9 billion).

The consolidated carrying value of the remaining financial instruments, other than derivatives, approximates fair value, reflecting their short-term maturity, normal trade credit terms and/or nature.

Derivatives

The Corporation generally limits the use of derivatives to those that qualify as accounting, economic or cash flow hedges, or those that are approved for regulatory recovery. Derivatives are recorded at fair value, with certain exceptions, including those derivatives that qualify for the normal purchase and normal sale exception.

Energy contracts subject to regulatory deferral
UNS Energy holds electricity power purchase contracts, customer supply contracts and gas swap contracts to reduce its exposure to energy price risk. Fair values are measured primarily under the market approach using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships, transmission costs and line losses.

Central Hudson holds swap contracts for electricity and natural gas to minimize price volatility by fixing the effective purchase price. Fair values are measured using forward pricing provided by independent third-party information.

FortisBC Energy holds gas supply contracts to fix the effective purchase price of natural gas. Fair values reflect the present value of future cash flows based on published market prices and forward natural gas curves.

Unrealized gains or losses associated with changes in the fair value of these energy contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. As at December 31, 2024, unrealized losses of $175 million (2023 - $197 million) were recognized as regulatory assets and unrealized gains of $41 million (2023 - $37 million) were recognized as regulatory liabilities.

Energy contracts not subject to regulatory deferral
UNS Energy holds wholesale trading contracts to fix power prices and realize potential margin, of which 10% of any realized gains is shared with customers through rate stabilization accounts. Fair values are measured using a market approach incorporating, where possible, independent third-party information.

Aitken Creek, which was sold on November 1, 2023, held gas swap contracts to manage exposure to changes in natural gas prices, capture natural gas price spreads, and manage the financial risk posed by physical transactions. Fair values were measured using forward pricing from published market sources.

Gains or losses associated with changes in the fair value of these energy contracts are recognized in revenue. In 2024, gains of $48 million (2023 - losses of $28 million) were recognized in revenue.

Total return swaps
The Corporation holds total return swaps to manage the cash flow risk associated with forecast future cash and/or share settlements of certain stock-based compensation obligations. The swaps have a combined notional amount of $134 million and terms up to three years expiring at varying dates through January 2027. Fair value is measured using an income valuation approach based on forward pricing curves. Unrealized gains and losses associated with changes in fair value are recognized in other income, net. In 2024, unrealized gains of $12 million (2023 - $nil) were recognized in other income, net.

Foreign exchange contracts
The Corporation holds U.S. dollar-denominated foreign exchange contracts to help mitigate exposure to foreign exchange rate volatility. The contracts expire at varying dates through September 2026 and have a combined notional amount of $608 million. Fair value was measured using independent third-party information. Unrealized gains and losses associated with changes in fair value are recognized in other income, net. In 2024, unrealized losses of $17 million (2023 - unrealized gains of $10 million) were recognized in other income, net.

Interest rate contracts
During 2024, ITC entered into and settled interest rate locks with a combined notional value of US$300 million. These contracts were used to manage interest rate risk associated with the issuance of US$400 million unsecured senior notes in May 2024. Realized losses of US$3 million were recognized in other comprehensive income, which will be reclassified to earnings as a component of interest expense over five years.

ITC also entered into five-year interest rate swap contracts in 2024 with a combined notional value of US$135 million. The swaps will be used to manage interest rate risk associated with forecasted debt issuances. Fair value was measured using a discounted cash flow method based on SOFR. Unrealized gains and losses associated with the changes in fair value are recognized in other comprehensive income, and will be reclassified to earnings as a component of interest expense over the life of the debt. Unrealized gains of US$4 million were recorded in 2024.

In 2025, ITC entered into five-year interest rate swap contracts with a notional value of US$95 million to manage interest rate risk associated with forecasted debt issuances, increasing the total notional amount of interest rate swaps outstanding to US$230 million.

During 2024, the Corporation entered into and settled interest rate locks with a combined notional value of $250 million. These contract were used to manage interest rate risk associated with the issuance of $500 million unsecured senior notes in September 2024. Realized losses of $2 million were recognized in other comprehensive income, which will be reclassified to earnings as a component of interest expense over seven years.

Cross-Currency interest rate swaps
The Corporation holds cross-currency interest rate swaps, maturing in 2029, to effectively convert its $500 million, 4.43% unsecured senior notes to US$391 million, 4.34% debt. The Corporation has designated this notional U.S. debt as an effective hedge of its foreign net investments and unrealized gains and losses associated with exchange rate fluctuations on the notional U.S. debt are recognized in other comprehensive income, consistent with the translation adjustment related to the foreign net investments. Other changes in the fair value of the swaps are also recognized in other comprehensive income but are excluded from the assessment of hedge effectiveness. Fair value is measured using a discounted cash flow method based on SOFR. In 2024, unrealized losses of $29 million (2023 - unrealized gains of $15 million) were recorded in other comprehensive income.

Derivative Fair Values

The following table presents derivative assets and liabilities that are accounted for at fair value on a recurring basis.

($ millions)	**Level 1** (1)	**Level 2** (1)	**Level 3** (1)	**Total**
As at December 31, 2024				
Assets (2)				
Energy contracts subject to regulatory deferral	**—**	**63**	**—**	**63**
Energy contracts not subject to regulatory deferral	**—**	**7**	**—**	**7**
Total return swaps and interest rate contracts	**—**	**16**	**—**	**16**
Other investments	**150**	**—**	**—**	**150**
	150	**86**	**—**	**236**
Liabilities (3)				
Energy contracts subject to regulatory deferral	**—**	**(197)**	**—**	**(197)**
Energy contracts not subject to regulatory deferral	**—**	**(2)**	**—**	**(2)**
Foreign exchange contracts and cross-currency interest rate swaps	**—**	**(45)**	**—**	**(45)**
	—	**(244)**	**—**	**(244)**
As at December 31, 2023				
Assets (2)				
Energy contracts subject to regulatory deferral	—	49	—	49
Energy contracts not subject to regulatory deferral	—	6	—	6
Foreign exchange contracts	—	5	—	5
Other investments	145	—	—	145
	145	60	—	205
Liabilities (3)				
Energy contracts subject to regulatory deferral	—	(209)	—	(209)
Energy contracts not subject to regulatory deferral	—	(3)	—	(3)
Total return and cross-currency interest rate swaps	—	(6)	—	(6)
	—	(218)	—	(218)

(1) *Under the hierarchy, fair value is determined using: (i) Level 1 - unadjusted quoted prices in active markets; (ii) Level 2 - other pricing inputs directly or indirectly observable in the marketplace; and (iii) Level 3 - unobservable inputs, used when observable inputs are not available. Classifications reflect the lowest level of input that is significant to the fair value measurement.*

(2) *Included in cash and cash equivalents, accounts receivable and other current assets, or other assets*

(3) *Included in accounts payable and other current liabilities or other liabilities*

Derivative Volumes

As at December 31	**2024**	2023
Energy contracts subject to regulatory deferral (1)		
Electricity swap contracts *(GWh)*	**774**	628
Electricity power purchase contracts *(GWh)*	**430**	588
Gas swap contracts *(PJ)*	**236**	228
Gas supply contracts *(PJ)*	**105**	134
Energy contracts not subject to regulatory deferral (1)		
Wholesale trading contracts *(GWh)*	**1,499**	1,310
Gas swap contracts *(PJ)*	**3**	3

(1) *Energy contracts settle on various dates through 2029*

SELECTED ANNUAL FINANCIAL INFORMATION

Years ended December 31 *($ millions, except as indicated)*	**2024**	2023	2022
Revenue	**11,508**	11,517	11,043
Net earnings	**1,828**	1,710	1,514
Common Equity Earnings	**1,606**	1,506	1,330
EPS: *($)*			
Basic	**3.24**	3.10	2.78
Diluted	**3.24**	3.10	2.78
Total assets	**73,486**	65,920	64,252
Long-term debt (excluding current portion)	**31,224**	27,235	25,931
Dividends declared: *($)*			
Per common share	**2.41**	2.31	2.20
Per first preference share:			
Series F	**1.2250**	1.2250	1.2250
Series G (1)	**1.5308**	1.3145	1.0983
Series H	**0.4588**	0.4588	0.4588
Series I (2)	**1.4902**	1.5619	0.9157
Series J	**1.1875**	1.1875	1.1875
Series K (3)	**1.3673**	0.9823	0.9823
Series M (4)	**1.0770**	0.9783	0.9783

(1) *The annual dividend per share was reset to $1.5308 for the five-year period from September 1, 2023 up to but excluding September 1, 2028*

(2) *Floating quarterly dividend rate is reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus the applicable reset dividend yield*

(3) *The annual dividend per share was reset from $0.9823 to $1.3673 for the five-year period from March 1, 2024 up to but excluding March 1, 2029*

(4) *The annual dividend per share was reset from $0.9783 to $1.3733 for the five-year period from December 1, 2024 up to but excluding December 1, 2029*

2024/2023

For a discussion of the changes in revenue, Common Equity Earnings, EPS, total assets and long-term debt see "Performance at a Glance" on page 2, "Operating Results" on page 6, and "Financial Position" on page 13.

2023/2022

The increase in revenue was due primarily to: (i) a higher U.S. dollar-to-Canadian dollar exchange rate; (ii) Rate Base growth; (iii) higher retail revenue at UNS Energy driven by new customer rates effective September 1, 2023, customer additions, and warmer weather; and (iv) the recognition of a regulatory deferral at FortisBC associated with the new cost of capital parameters approved by the BCUC effective January 1, 2023. The increase was partially offset by the flow-through of lower commodity costs in customer rates.

Common Equity Earnings increased by $176 million in comparison to 2022. The increase was primarily driven by Rate Base growth across our utilities and the new cost of capital parameters approved for FortisBC effective January 1, 2023. Higher earnings in Arizona also contributed to earnings growth, reflecting higher retail electricity sales, new customer rates at TEP effective September 1, 2023, and lower depreciation expense associated with retirement of the San Juan generating station in 2022. An increase in the market value of certain investments that support retirement benefits, and the higher U.S. dollar-to-Canadian dollar exchange rate, also favourably impacted earnings year over year. The increase was partially offset by higher corporate finance costs and lower earnings from Aitken Creek.

In addition to the above-noted items impacting earnings, the change in EPS also reflected an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's DRIP.

The increase in total assets was primarily due to capital expenditures in 2023 and an increase in regulatory assets, largely due to an increase in deferred income taxes and unrealized losses on energy derivatives. The increase was partially offset by the translation of U.S. dollar-denominated assets at a lower U.S. dollar-to-Canadian dollar exchange rate.

FOURTH QUARTER RESULTS

Sales

(GWh, except as indicated)	**2024**	2023	Variance
Regulated Utilities			
UNS Energy			
Retail Electricity	**2,348**	2,302	46
Wholesale Electricity	**1,295**	1,349	(54)
Gas *(PJ)*	**5**	5	—
Central Hudson			
Electricity	**1,187**	1,196	(9)
Gas *(PJ)*	**6**	6	—
FortisBC Energy *(PJ)*	**67**	66	1
FortisAlberta	**4,428**	4,273	155
FortisBC Electric	**916**	901	15
Other Electric	**2,533**	2,525	8
Non-Regulated			
Corporate and Other	**80**	58	22

Electricity sales for the fourth quarter were largely consistent with the comparable period in 2023 for most of Fortis' utilities. The increase in retail sales at UNS Energy was due primarily to customer additions, while the decrease in wholesale sales was related to lower long-term wholesale sales due to the expiration of certain contracts. As well, the increase in sales at FortisAlberta was due to customer additions and higher average consumption from industrial and residential customers.

Gas sales for the fourth quarter were consistent with the comparable period in 2023.

Revenue and Common Equity Earnings

	Revenue			**Earnings**		
($ millions, except as indicated)	**2024**	2023	Variance	**2024**	2023	Variance
Regulated Utilities						
ITC	**567**	527	40	**127**	136	(9)
UNS Energy	**659**	706	(47)	**52**	62	(10)
Central Hudson	**356**	311	45	**66**	36	30
FortisBC Energy	**522**	544	(22)	**120**	105	15
FortisAlberta	**207**	188	19	**42**	36	6
FortisBC Electric	**149**	145	4	**18**	15	3
Other Electric	**479**	457	22	**52**	35	17
Non-regulated						
Corporate and Other	**10**	7	3	**(81)**	(44)	(37)
Total	**2,949**	2,885	64	**396**	381	15
Weighted average number of common shares outstanding *(# millions)*				**498.2**	489.4	8.8
Basic EPS *($)*				**0.79**	0.78	0.01

The increase in revenue was due primarily to Rate Base growth, a higher U.S. dollar-to-Canadian dollar exchange rate, and new customer rates at Central Hudson effective July 1, 2024. The implementation of Central Hudson's new customer rates has shifted the timing of quarterly rate recovery in comparison to related costs, resulting in higher revenue and earnings in the fourth quarter of 2024. The increase was partially offset by: (i) lower flow-through costs at UNS Energy and FortisBC Energy; and (ii) the recognition of a refund liability at ITC in 2024, largely reflecting the prior period impact of the reduction in the MISO base ROE approved by FERC (see "Regulatory Highlights - Significant Regulatory Matters" on page 12).

The increase in Common Equity Earnings was driven by Rate Base growth as well as higher earnings at Central Hudson due to new customer rates and a higher allowed ROE effective July 1, 2024. The increase was partially offset by the refund liability recognized at ITC, discussed above, and lower earnings in Arizona, largely reflecting higher operating expenses. Unrealized losses on derivative contracts and the $10 million gain on disposition of Aitken Creek recognized in 2023 also unfavourably impacted fourth quarter earnings in comparison to the prior year.

The favourable earnings impact resulting from the translation of U.S. dollar denominated earnings at the higher average U.S. dollar-to-Canadian dollar exchange rate was largely offset by foreign exchange losses associated with the revaluation of U.S. dollar denominated liabilities at a rate of US$1.00=CA$1.44 at December 31, 2024.

The increase in basic EPS reflects higher Common Equity Earnings, as discussed above, partially offset by an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's DRIP.

Cash Flows

($ millions)	**2024**	2023	Variance
Cash and cash equivalents, beginning of period	**896**	765	131
Cash from (used in):			
Operating activities	**962**	746	216
Investing activities	**(1,796)**	(748)	(1,048)
Financing activities	**125**	(134)	259
Effect of exchange rate changes on cash and cash equivalents	**33**	(13)	46
Change in cash associated with assets held for sale	**—**	9	(9)
Cash and cash equivalents, end of period	**220**	625	(405)

Operating Activities

The increase in Operating Cash Flow was largely driven by FortisBC Energy reflecting higher deposits received, net of expenditures incurred, associated with the Eagle Mountain Pipeline project, as well as other changes in working capital balances. The increase was partially offset by the timing of flow-through transmission amounts at FortisAlberta as well as higher interest payments.

Investing Activities

The increase in cash used in investing activities primarily reflects higher capital expenditures in 2024, as well as the proceeds received in 2023 related to the disposition of Aitken Creek. Lower customer contributions in aid of construction also contributed to the variance.

Financing Activities

The increase in cash from financing activities reflects changes in the subsidiaries' capital expenditures and the amount of Operating Cash Flow available to fund those capital expenditures, as well as the repayment of credit facility borrowings in the fourth quarter of 2023 associated with the proceeds received from the sale of Aitken Creek. See "Cash Flow Summary" on page 15.

SUMMARY OF QUARTERLY RESULTS

Quarter ended	**Revenue** *($ millions)*	**Common Equity Earnings** *($ millions)*	**Basic EPS** *($)*	**Diluted EPS** *($)*
December 31, 2024	**2,949**	**396**	**0.79**	**0.79**
September 30, 2024	**2,771**	**420**	**0.85**	**0.85**
June 30, 2024	**2,670**	**331**	**0.67**	**0.67**
March 31, 2024	**3,118**	**459**	**0.93**	**0.93**
December 31, 2023	2,885	381	0.78	0.78
September 30, 2023	2,719	394	0.81	0.81
June 30, 2023	2,594	294	0.61	0.61
March 31, 2023	3,319	437	0.90	0.90

Generally, within each calendar year, quarterly results fluctuate in accordance with seasonality. Given the diversified nature of the Corporation's subsidiaries, seasonality varies. Earnings of the gas utilities tend to be highest in the first and fourth quarters due to space-heating requirements. Earnings of the electric distribution utilities in the U.S. tend to be highest in the second and third quarters due to the use of air conditioning and other cooling equipment.

Generally, from one calendar year to the next, quarterly results reflect: (i) continued organic growth driven by the Corporation's capital plan; (ii) any significant temperature fluctuations from seasonal norms; (iii) the impact of market conditions, particularly with respect to long-term wholesale sales at UNS Energy; (iv) the timing and significance of any regulatory decisions; (v) changes in the U.S. dollar-to-Canadian dollar exchange rate; (vi) for revenue, the flow through in customer rates of commodity costs; and (vii) for EPS, increases in the weighted average number of common shares outstanding.

December 2024/December 2023

See "Fourth Quarter Results" on page 37.

September 2024/September 2023

Common Equity Earnings increased by $26 million and basic EPS increased by $0.04 in comparison to the third quarter of 2023. The increase was driven by: (i) Rate Base growth; and (ii) strong earnings in Arizona, reflecting new customer rates at TEP effective September 1, 2023, an increase in the market value of investments that support retirement benefits and higher production tax credits. Unrealized gains on derivative contracts recognized in the third quarter of 2024, and an unfavourable deferred income tax adjustment recognized by ITC in the third quarter of 2023, also contributed to the growth in earnings. The increase was partially offset by the timing of recognition of new cost of capital parameters approved for FortisBC in 2023, which included $26 million associated with the retroactive impact to January 1, 2023, as well as higher holding company finance costs. The change in basic EPS also reflected an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's DRIP.

June 2024/June 2023

Common Equity Earnings increased by $37 million and basic EPS increased by $0.06 in comparison to the second quarter of 2023. The increase was driven by strong earnings in Arizona, reflecting new customer rates at TEP effective September 1, 2023 and higher retail electricity sales associated with warmer weather. Rate Base growth across our utilities and the timing of recognition of new cost of capital parameters approved for FortisBC in 2023 also contributed to earnings growth. The increase was partially offset by lower earnings for Central Hudson and the Other Electric segment, largely reflecting higher operating costs. The change in basic EPS also reflected an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's DRIP.

March 2024/March 2023

Common Equity Earnings increased by $22 million and basic EPS increased by $0.03 in comparison to the first quarter of 2023. The increase was due to the timing of recognition of new cost of capital parameters approved for FortisBC in 2023 and Rate Base growth across our utilities. The increase was partially offset by higher holding company costs, including finance charges and unrealized losses on derivative contracts, and the November 1, 2023 disposition of Aitken Creek. In addition, the change in EPS reflected an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's DRIP.

RELATED-PARTY AND INTER-COMPANY TRANSACTIONS

Related-party transactions are in the normal course of operations and are measured at the amount of consideration agreed to by the related parties. There were no material related-party transactions in 2024 or 2023.

As of December 31, 2024, accounts receivable included $18 million due from Belize Electricity (December 31, 2023 - $8 million).

Fortis periodically provides short-term financing to subsidiaries to support capital expenditures and seasonal working capital requirements, the impacts of which are eliminated on consolidation. As at December 31, 2024 and 2023, there were no inter-segment loans outstanding. Interest charged on inter-segment loans was not material in 2024 and 2023.

MANAGEMENT'S EVALUATION OF CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

DCP are designed to provide reasonable assurance that information required to be disclosed in reports filed with, or submitted to, securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and U.S. securities laws. As of December 31, 2024, an evaluation was carried out under the supervision of, and with the participation of, the Corporation's management, including the CEO and CFO, of the effectiveness of the Corporation's DCP, as defined in the applicable Canadian and U.S. securities laws. Based on that evaluation, the CEO and CFO concluded that such DCP are effective as of December 31, 2024.

Internal Control over Financial Reporting

ICFR is designed by, or under the supervision of, the Corporation's CEO and CFO and effected by the Corporation's Board, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. GAAP. Because of its inherent limitations, ICFR may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Corporation's management, including the Corporation's CEO and CFO, assessed the effectiveness of the Corporation's ICFR as of December 31, 2024, based on the criteria set forth in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that, as of December 31, 2024, the Corporation's ICFR was effective.

During the year ended December 31, 2024, there have been no changes in the Corporation's ICFR that have materially affected, or are reasonably likely to materially affect, the Corporation's ICFR.

OUTLOOK

Fortis continues to enhance shareholder value through the execution of its capital plan, the balance and strength of its diversified portfolio of regulated utility businesses, and growth opportunities within and proximate to its service territories. The Corporation's $26.0 billion five-year capital plan is expected to increase midyear Rate Base from $39.0 billion in 2024 to $53.0 billion by 2029, translating into a five-year CAGR of 6.5%.

Beyond the five-year capital plan, opportunities to expand and extend growth include: further expansion of the electric transmission grid in the U.S. to support load growth and facilitate the interconnection of cleaner energy; transmission investments associated with the MISO LRTP tranches 1, 2.1, and 2.2 as well as regional transmission in New York; grid resiliency and climate adaptation investments; renewable gas solutions and LNG infrastructure in British Columbia; and the acceleration of load growth and cleaner energy infrastructure investments across our jurisdictions.

Fortis expects its long-term growth in Rate Base will drive earnings that support dividend growth guidance of 4-6% annually through 2029, and is premised on the assumptions and material factors listed under "Forward-Looking Information".

Fortis has reduced its corporate-wide direct GHG emissions by 34% from a 2019 base year, and has targets to further reduce such GHG emissions by 50% by 2030 and 75% by 2035. The Corporation's additional 2050 net-zero direct GHG emissions target reinforces Fortis' commitment to further decarbonize over the long-term, while continuing our focus on reliability and affordability. The Corporation's ability to achieve the GHG targets may be impacted by federal, state and provincial energy policies, as well as external factors, including significant customer and load growth and the development of clean energy technology.

FORWARD-LOOKING INFORMATION

Fortis includes forward-looking information in the MD&A within the meaning of applicable Canadian securities laws and forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995, (collectively referred to as "forward-looking information"). Forward-looking information reflects expectations of Fortis management regarding future growth, results of operations, performance, business prospects and opportunities. Wherever possible, words such as anticipates, believes, budgets, could, estimates, expects, forecasts, intends, may, might, plans, projects, schedule, should, target, will, would, and the negative of these terms, and other similar terminology or expressions, have been used to identify the forward-looking information, which includes, without limitation: the expectation that Fortis is well-positioned for future investment opportunities; annual dividend growth guidance through 2029; forecast Capital Expenditures for 2025 through 2029; the expected sources of funding for the capital plan, including the source of common equity proceeds; forecast midyear Rate Base for 2029 and projected Rate Base growth from 2024 through to 2029; the expected nature, timing and benefits of additional opportunities beyond the capital plan, including further expansion of the electric transmission grid in the U.S. to support load growth and facilitate the interconnection of cleaner energy, transmission investments associated with the MISO LRTP tranches 1, 2.1 and 2.2 as well as regional transmission in New York, grid resiliency and climate adaptation investments, renewable gas solutions and LNG infrastructure in British Columbia, and the acceleration of load growth and cleaner energy infrastructure investments; expected implications of utility industry trends on the utility sector and on the Corporation's capital investments; the expected timing, outcome and impact of legal and regulatory proceedings and decisions; the expected or potential funding sources for operating expenses, interest costs and capital expenditures; the expectation that maintaining the targeted capital structure of the regulated operating subsidiaries will not have an impact on the Corporation's ability to pay dividends in the foreseeable future; the expected consolidated fixed-term debt maturities and repayments over the next five years; the expectation that the Corporation and its subsidiaries will continue to have reasonable access to long-term capital and will remain compliant with debt covenants in 2025; the expected uses of proceeds from debt financings; the performance of contractual obligations to provide equity capital to Wataynikaneyap Power; the potential impact of new or revised tariffs on forecast and actual capital expenditures; forecast midyear Rate Base for 2025 and 2029 by segment; the nature, timing, benefits and expected costs of certain capital projects, including ITC's transmission projects associated with the MISO LRTP, IRP Related Generation, the Roadrunner Reserve Battery Storage Projects 1 and 2, the Vail-to-Tortolita Transmission Project, the Eagle Mountain Pipeline Project, the Tilbury LNG Storage Expansion, the AMI Project, and the Tilbury 1B Project, and additional investment opportunities; the 2050 net-zero direct GHG emissions target; the 2030 and 2035 direct GHG emissions reduction targets; how the Corporation's GHG emissions targets are expected to be achieved, including TEP's plan to exit coal; the potential impact of federal, state and provincial energy policies and other factors, including significant customer and load growth and the development of clean energy technology, on the Corporation's ability to achieve its GHG emissions reduction targets; the expected impacts of future accounting pronouncements on the Corporation's disclosures; the potential impact of the recognition of goodwill impairment losses; the potential and expected impacts of income tax compliance examinations and legislation with respect to interest deductibility limitations and global minimum tax; and the expectation that long-term growth in Rate Base will drive earnings that support dividend growth guidance of 4-6% annually through 2029.

Forward-looking information involves significant risks, uncertainties and assumptions. Certain material factors or assumptions have been applied in drawing the conclusions contained in the forward-looking information including, without limitation: reasonable legal and regulatory decisions and the expectation of regulatory stability; the successful execution of the capital plan; no material capital project or financing cost overrun; sufficient human resources to deliver service and execute the capital plan; the realization of additional opportunities beyond the capital plan; no significant variability in interest rates; no material changes in the assumed U.S. dollar- to- Canadian dollar exchange rate; the continuation of current participation levels in the Corporation's DRIP; the Board exercising its discretion to declare dividends, taking into account the financial performance and condition of the Corporation; no significant operational disruptions or environmental liability or upset; the continued ability to maintain the performance of the electricity and gas systems; no severe and prolonged economic downturn; sufficient liquidity and capital resources; the ability to hedge exposures to fluctuations in foreign exchange rates, natural gas prices and electricity prices; the continued availability of natural gas, fuel, coal and electricity supply; continuation of power supply and capacity purchase contracts; no significant changes in government energy plans, environmental laws and regulations that could have a material negative impact; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; no significant changes in tax laws and the continued tax deferred treatment of earnings from the Corporation's foreign operations; continued maintenance of information technology infrastructure and no material breach of cybersecurity; continued favourable relations with Indigenous Peoples; and favourable labour relations.

Fortis cautions readers that a number of factors could cause actual results, performance or achievements to differ materially from those discussed or implied in the forward-looking information. These factors should be considered carefully and undue reliance should not be placed on the forward-looking information. Risk factors which could cause results or events to differ from current expectations are detailed under the heading "Business Risks" in this MD&A and in other continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and the Securities and Exchange Commission. Key risk factors for 2025 include, but are not limited to: uncertainty regarding changes in utility regulation, including the outcome of regulatory proceedings at the Corporation's utilities; the physical risks associated with the provision of electric and gas service, which can be exacerbated by the impacts of climate change; risks related to environmental laws and regulations; risks associated with capital projects and the impact on the Corporation's continued growth; risks associated with cybersecurity and information and operations technology; the impact of weather variability and seasonality on heating and cooling loads, gas distribution volumes and hydroelectric generation; risks associated with commodity price volatility and supply of purchased power; and risks related to general economic conditions, including inflation, interest rate and foreign exchange risks.

All forward-looking information herein is given as of February 13, 2025. Fortis disclaims any intention or obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise.

GLOSSARY

2024 Annual Financial Statements: the Corporation's audited consolidated financial statements and notes thereto for the year ended December 31, 2024

Actual Payout Ratio: dividends paid per common share divided by basic EPS

Adjusted Basic EPS: Adjusted Common Equity Earnings divided by the basic weighted average number of common shares outstanding

Adjusted Common Equity Earnings: net earnings attributable to common equity shareholders adjusted as shown under "Non-U.S. GAAP Financial Measures" on page 10

Adjusted Payout Ratio: dividends paid per common share divided by Adjusted Basic EPS as shown under "Non-U.S. GAAP Financial Measures" on page 10

AFUDC: allowance for funds used during construction

AI: artificial intelligence

Aitken Creek: Aitken Creek Gas Storage ULC, a 93.8%-owned subsidiary of FortisBC Holdings Inc., sold on November 1, 2023

AMI: advanced metering infrastructure

ATM Program: at-the-market equity program

ACC: Arizona Corporation Commission

ASU: accounting standards update

AUC: Alberta Utilities Commission

BCUC: British Columbia Utilities Commission

Belize Electricity: Belize Electricity Limited, in which Fortis indirectly holds a 33% equity interest

Board: Board of Directors of the Corporation

CAGR(s): compound annual growth rate of a particular item. CAGR = $(EV/BV)^{(1/n)}-1$, where: (i) EV is the ending value of the item; (ii) BV is the beginning value of the item; and (iii) n is the number of periods. Calculated on a constant U.S. dollar-to-Canadian dollar exchange rate

Capital Expenditures: cash outlay for additions to property, plant and equipment and intangible assets as shown in the Annual Financial Statements, as well as Fortis' 39% share of capital spending for the Wataynikaneyap Transmission Power project. See "Non-U.S. GAAP Financial Measures" on page 10

Caribbean Utilities: Caribbean Utilities Company, Ltd., an indirect approximately 60%-owned (as at December 31, 2024) subsidiary of Fortis, together with its subsidiary

Central Hudson: CH Energy Group, Inc., an indirect wholly-owned subsidiary of Fortis, together with its subsidiaries, including Central Hudson Gas & Electric Corporation

CEO: Chief Executive Officer of Fortis

CFO: Chief Financial Officer of Fortis

Common Equity Earnings: net earnings attributable to common equity shareholders

Corporation: Fortis Inc.

COS: cost of service

Court of Appeal: Court of Appeal of Alberta

CPCN: Certificate of Public Convenience and Necessity

CSA: Canadian Securities Administrators

CSDS: Canadian Sustainability Disclosure Standard

CSSB: Canadian Sustainability Standards Board

DBP: defined benefit pension

D.C. Circuit Court: U.S. Court of Appeals for the District of Columbia Circuit

DCP: disclosure controls and procedures

DRIP: dividend reinvestment plan

EPC: engineering, procurement and construction

EPRI: Electric Power Research Institute

EPS: earnings per common share

ERM: enterprise risk management

FERC: Federal Energy Regulatory Commission

Fortis: Fortis Inc.

FortisAlberta: FortisAlberta Inc., an indirect wholly-owned subsidiary of Fortis

FortisBC: FortisBC Energy and FortisBC Electric

FortisBC Electric: FortisBC Inc., an indirect wholly-owned subsidiary of Fortis, together with its subsidiaries

FortisBC Energy: FortisBC Energy Inc., an indirect wholly-owned subsidiary of Fortis, together with its subsidiaries

FortisOntario: FortisOntario Inc., a direct wholly-owned subsidiary of Fortis, together with its subsidiaries

FortisTCI: FortisTCI Limited, an indirect wholly-owned subsidiary of Fortis, together with its subsidiary

Fortis Belize: Fortis Belize Limited, an indirect wholly-owned subsidiary of Fortis

Four Corners: Four Corners Generating Station, Units 4 and 5

FX: foreign exchange associated with the translation of U.S. dollar-denominated amounts. Foreign exchange is calculated by applying the change in the U.S. dollar-to-Canadian dollar FX rates to the prior period U.S. dollar balance

GCOC: generic cost of capital

GHG: greenhouse gas

GWh: gigawatt hour(s)

ICFR: internal control over financial reporting

IRP: integrated resource plan

ITC: ITC Investment Holdings Inc., an indirect 80.1%-owned subsidiary of Fortis, together with its subsidiaries, including International Transmission Company, Michigan Electric Transmission Company, LLC, ITC Midwest LLC, and ITC Great Plains, LLC

LNG: liquefied natural gas

LRTP: long range transmission plan

Luna: Luna Energy Facility

Major Capital Projects: projects, other than ongoing maintenance projects, individually costing $200 million or more in the forecast/planning period

Maritime Electric: Maritime Electric Company, Limited, an indirect wholly-owned subsidiary of Fortis

Material Adverse Effect: a material adverse effect on the Corporation's business, results of operations, financial position or liquidity, on a consolidated basis

MD&A: the Corporation's management discussion and analysis for the year ended December 31, 2024

MISO: Midcontinent Independent System Operator, Inc.

Moody's: Moody's Investor Services, Inc.

Morningstar DBRS: DBRS Limited

MW: megawatt(s)

Navajo: Navajo Generating Station

Newfoundland Power: Newfoundland Power Inc., a direct wholly-owned subsidiary of Fortis

Non-U.S. GAAP Financial Measures: financial measures that do not have a standardized meaning prescribed by U.S. GAAP

NOPR: notice of proposed rulemaking

NYSE: New York Stock Exchange

OPEB: other post-employment benefits

Operating Cash Flow: cash from operating activities

PBR: performance-based rate-setting

PJ: petajoule(s)

PPFAC: purchased power and fuel adjustment clause

PSC: New York State Public Service Commission

Rate Base: the stated value of property on which a regulated utility is permitted to earn a specified return in accordance with its regulatory construct

REA: Rural Electrification Association

RNG: renewable natural gas

ROA: rate of return on Rate Base

ROE: rate of return on common equity

ROFR: right of first refusal

RTO: regional transmission organization

S&P: Standard & Poor's Financial Services LLC

San Juan: San Juan Generating Station Unit 1

SEC: U.S. Securities and Exchange Commission

SEDAR+: Canadian System for Electronic Document Analysis and Retrieval

SOFR: secured overnight financing rates

TEP: Tucson Electric Power Company

TSR: total shareholder return, which is a measure of the return to common equity shareholders in the form of share price appreciation and dividends (assuming reinvestment) over a specified time period in relation to the share price at the beginning of the period.

TSX: Toronto Stock Exchange

UNS Electric: UNS Electric, Inc.

UNS Energy: UNS Energy Corporation, an indirect wholly-owned subsidiary of Fortis, together with its subsidiaries, including TEP, UNS Electric and UNS Gas

UNS Gas: UNS Gas, Inc.

U.S.: United States of America

U.S. GAAP: accounting principles generally accepted in the U.S.

Waneta Expansion: Waneta Expansion hydroelectric generation facility

Wataynikaneyap Power: Wataynikaneyap Power Limited Partnership, in which Fortis indirectly holds a 39% equity interest

FORTIS INC.

Audited Consolidated Financial Statements
As at and for the years ended December 31, 2024 and 2023

Consolidated Financial Statements

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Fortis Inc. and its subsidiaries (the "Corporation") is responsible for establishing and maintaining adequate internal control over financial reporting ("ICFR"). The Corporation's ICFR is designed by, or under the supervision of, the Corporation's President and Chief Executive Officer ("CEO") and Executive Vice President, Chief Financial Officer ("CFO") and effected by the Corporation's board of directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America. Because of its inherent limitations, ICFR may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Corporation's management, including its CEO and CFO, assessed the effectiveness of the Corporation's ICFR as of December 31, 2024, based on the criteria set forth in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that, as of December 31, 2024, the Corporation's ICFR was effective.

The Corporation's ICFR as of December 31, 2024 has been audited by Deloitte LLP, an Independent Registered Public Accounting Firm, which also audited the Corporation's consolidated financial statements for the year ended December 31, 2024. Deloitte LLP issued an unqualified opinion for both audits.

February 13, 2025

/s/ David G. Hutchens

David G. Hutchens

President and Chief Executive Officer, Fortis Inc.
St. John's, Canada

/s/ Jocelyn H. Perry

Jocelyn H. Perry

Executive Vice President, Chief Financial Officer, Fortis Inc.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of Fortis Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Fortis Inc. and subsidiaries (the "Corporation") as of December 31, 2024 and 2023, the related consolidated statements of earnings, comprehensive income, cash flows, and changes in equity, for each of the two years in the period ended December 31, 2024, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Corporation as of December 31, 2024 and 2023, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2024, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Corporation's internal control over financial reporting as of December 31, 2024, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 13, 2025, expressed an unqualified opinion on the Corporation's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the Corporation's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Corporation in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the audit committee and that (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Assessment for Impairment of Goodwill - Refer to Notes 3 and 12 to the financial statements

Critical Audit Matter Description

The Corporation assesses goodwill for impairment annually as well as whenever any event or other change indicates that the fair value of a reporting unit may be below its carrying value. Management has determined that there is no impairment based on its current annual assessment.

Management's assessment primarily utilizes the income approach which is based on underlying estimates and assumptions with varying degrees of uncertainty. Those with the highest degree of subjectivity and impact are the assumed terminal growth rates and discount rates. Auditing these estimates and assumptions required a high degree of audit judgment and effort, including the involvement of a fair value specialist.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the terminal growth rate and discount rate used by management to estimate the fair value of more recently acquired reporting units included the following, among others:

- Evaluating the effectiveness of controls over the estimated fair value of the reporting units, including the review and approval of the terminal growth rate and discount rate selected by management.
- Evaluating management's ability to accurately forecast the terminal growth rate by:
  - Assessing the methodology used in management's determination of the terminal growth rate; and
  - Comparing management's assumptions to historical data and available market projection data.
- With the assistance of a fair value specialist, evaluating the reasonableness of the discount rate by:
  - Testing the source information underlying the determination of the discount rate; and
  - Developing a range of independent estimates and comparing those to the discount rate selected by management.

Impact of Rate Regulation on the financial statements - Refer to Notes 2, 3 and 8 to the financial statements

Critical Audit Matter Description

The Corporation's regulated utilities are subject to rate regulation and annual earnings oversight by various federal, state and provincial regulatory authorities who have jurisdiction in the United States and Canada. Rates and resultant earnings of the Corporation's regulated utilities are determined under cost of service regulation, with some using performance-based rate-setting mechanisms. The regulation of rates is premised on the full recovery of prudently incurred costs and a reasonable rate of return on asset value ("ROA") or common shareholders' equity ("ROE"). Regulatory decisions can have an impact on the timely recovery of costs and the regulator-approved ROE and/or ROA. Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures, such as property, plant, and equipment; regulatory assets and liabilities; operating revenues and expenses; income taxes; and depreciation expense.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the high degree of subjectivity involved in assessing the potential impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of recovery of costs incurred or a refund to customers through the rate-setting process. While the Corporation's regulated utilities have indicated they expect to recover costs from customers through regulated rates, there is a risk that the respective regulatory authority will not approve full recovery of the costs incurred and a reasonable ROE and/or ROA. Auditing these matters required especially subjective judgment and specialized knowledge of accounting for rate regulation due to its inherent complexities across different jurisdictions.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the likelihood of recovery of costs incurred or a refund to customers through the rate-setting process, included the following, among others:

- Evaluating the effectiveness of controls over the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates.
- Assessing relevant regulatory orders, regulatory statutes and interpretations as well as procedural memorandums, utility and intervener filings, and other publicly available information to evaluate the likelihood of recovery in future rates or of a future reduction in rates and the ability to earn a reasonable ROA or ROE.
- For regulatory matters in progress, inspecting the regulated utilities' filings for any evidence that might contradict management's assertions. We obtained an analysis from management and letters from internal and external legal counsel, as appropriate, regarding cost recoveries or a future reduction in rates.
- Evaluating the Corporation's disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.

/s/ Deloitte LLP

Chartered Professional Accountants

St. John's, Canada
February 13, 2025

We have served as the Corporation's auditor since 2017.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of Fortis Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Fortis Inc. and subsidiaries (the "Corporation") as of December 31, 2024, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2024, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2024, of the Corporation and our report dated February 13, 2025, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Corporation's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Corporation in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte LLP

Chartered Professional Accountants

St. John's, Canada
February 13, 2025

CONSOLIDATED BALANCE SHEETS

FORTIS INC.

As at December 31 (in millions of Canadian dollars)		**2024**		2023
ASSETS				
Current assets				
Cash and cash equivalents	**$**	**220**	$	625
Accounts receivable and other current assets (Note 6)		**1,886**		1,818
Prepaid expenses		**182**		150
Inventories (Note 7)		**685**		566
Regulatory assets (Note 8)		**823**		866
Total current assets		**3,796**		4,025
Other assets (Note 9)		**1,653**		1,298
Regulatory assets (Note 8)		**3,808**		3,518
Property, plant and equipment, net (Note 10)		**49,456**		43,385
Intangible assets, net (Note 11)		**1,661**		1,510
Goodwill (Note 12)		**13,112**		12,184
Total assets	**$**	**73,486**	$	65,920
LIABILITIES AND EQUITY				
Current liabilities				
Short-term borrowings (Note 14)	**$**	**98**	$	119
Accounts payable and other current liabilities (Note 13)		**3,353**		2,972
Regulatory liabilities (Note 8)		**595**		577
Current installments of long-term debt (Note 14)		**1,990**		2,296
Total current liabilities		**6,036**		5,964
Regulatory liabilities (Note 8)		**3,696**		3,381
Deferred income taxes (Note 23)		**5,020**		4,399
Long-term debt (Note 14)		**31,224**		27,235
Finance leases (Note 15)		**343**		339
Other liabilities (Note 16)		**1,314**		1,270
Total liabilities		**47,633**		42,588
Commitments and contingencies (Note 27)				
Equity				
Common shares (1)		**15,589**		15,108
Preference shares (Note 18)		**1,623**		1,623
Additional paid-in capital		**8**		9
Accumulated other comprehensive income (Note 19)		**2,067**		653
Retained earnings		**4,521**		4,112
Shareholders' equity		**23,808**		21,505
Non-controlling interests		**2,045**		1,827
Total equity		**25,853**		23,332
Total liabilities and equity	**$**	**73,486**	$	65,920

(1) No par value. Unlimited authorized shares. 499.3 million and 490.6 million issued and outstanding as at December 31, 2024 and 2023, respectively

Approved on Behalf of the Board

/s/ Jo Mark Zurel	/s/ Maura J. Clark
Jo Mark Zurel,	**Maura J. Clark,**
Director	**Director**

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF EARNINGS

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except per share amounts)	**2024**	2023
Revenue (Note 5)	**$ 11,508**	$ 11,517
Expenses		
Energy supply costs	**3,249**	3,771
Operating expenses	**3,040**	2,889
Depreciation and amortization	**1,927**	1,773
Total expenses	**8,216**	8,433
Operating income	**3,292**	3,084
Other income, net (Note 22)	**288**	291
Finance charges	**1,406**	1,305
Earnings before income tax expense	**2,174**	2,070
Income tax expense (Note 23)	**346**	360
Net earnings	**$ 1,828**	$ 1,710
Net earnings attributable to:		
Non-controlling interests	**$ 148**	$ 137
Preference equity shareholders (Note 18)	**74**	67
Common equity shareholders	**1,606**	1,506
	$ 1,828	$ 1,710
Earnings per common share (Note 17)		
Basic	**$ 3.24**	$ 3.10
Diluted	**$ 3.24**	$ 3.10

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 (in millions of Canadian dollars)	**2024**	2023
Net earnings	**$ 1,828**	$ 1,710
Other comprehensive income (loss)		
Unrealized foreign currency translation gains (losses), net of hedging activities and income tax recovery (expense) of $14 million and $(3) million, respectively	**1,561**	(402)
Other, net of income tax expense of $3 million and $4 million, respectively	**9**	6
	1,570	(396)
Comprehensive income	**$ 3,398**	$ 1,314
Comprehensive income attributable to:		
Non-controlling interests	**$ 304**	$ 96
Preference equity shareholders	**74**	67
Common equity shareholders	**3,020**	1,151
	$ 3,398	$ 1,314

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)	**2024**	2023
Operating activities		
Net earnings	**$ 1,828**	$ 1,710
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation - property, plant and equipment	**1,695**	1,542
Amortization - intangible assets	**153**	150
Amortization - other	**79**	81
Deferred income tax expense (Note 23)	**154**	272
Equity component, allowance for funds used during construction (Note 22)	**(139)**	(101)
Other	**43**	72
Change in long-term regulatory assets and liabilities	**(99)**	(100)
Change in working capital (Note 25)	**168**	(81)
Cash from operating activities	**3,882**	3,545
Investing activities		
Additions to property, plant and equipment	**(5,012)**	(3,986)
Additions to intangible assets	**(206)**	(183)
Contributions in aid of construction	**106**	216
Proceeds on disposition, net (Note 21)	**—**	454
Contributions to equity-accounted investees	**—**	(24)
Other	**(283)**	(219)
Cash used in investing activities	**(5,395)**	(3,742)
Financing activities		
Proceeds from long-term debt, net of issuance costs (Note 14)	**3,124**	2,810
Repayments of long-term debt and finance leases	**(1,718)**	(1,210)
Borrowings under committed credit facilities	**8,618**	7,217
Repayments under committed credit facilities	**(8,055)**	(7,276)
Net change in short-term borrowings	**(25)**	(126)
Issue of common shares, net of costs, and dividends reinvested	**46**	43
Dividends		
Common shares, net of dividends reinvested	**(744)**	(701)
Preference shares	**(74)**	(67)
Subsidiary dividends paid to non-controlling interests	**(110)**	(83)
Other	**2**	6
Cash from financing activities	**1,064**	613
Effect of exchange rate changes on cash and cash equivalents	**44**	—
Change in cash and cash equivalents	**(405)**	416
Cash and cash equivalents, beginning of year	**625**	209
Cash and cash equivalents, end of year	**$ 220**	$ 625

Supplementary Cash Flow Information (Note 25)

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except share numbers)	**Common Shares** *(# millions)*	**Common Shares**	**Preference Shares** (Note 18)	**Additional Paid-In Capital**	**Accumulated Other Comprehensive Income (Loss)** (Note 19)	**Retained Earnings**	**Non-Controlling Interests**	**Total Equity**
As at December 31, 2023	**490.6**	**$ 15,108**	**$ 1,623**	**$ 9**	**$ 653**	**$ 4,112**	**$ 1,827**	**$ 23,332**
Net earnings	**—**	**—**	**—**	**—**	**—**	**1,680**	**148**	**1,828**
Other comprehensive income	**—**	**—**	**—**	**—**	**1,414**	**—**	**156**	**1,570**
Common shares issued	**8.7**	**481**	**—**	**—**	**—**	**—**	**—**	**481**
Advances from non-controlling interests	**—**	**—**	**—**	**—**	**—**	**—**	**21**	**21**
Subsidiary dividends paid to non-controlling interests	**—**	**—**	**—**	**—**	**—**	**—**	**(110)**	**(110)**
Dividends declared on common shares ($2.41 per share)	**—**	**—**	**—**	**—**	**—**	**(1,197)**	**—**	**(1,197)**
Dividends on preference shares	**—**	**—**	**—**	**—**	**—**	**(74)**	**—**	**(74)**
Other	**—**	**—**	**—**	**(1)**	**—**	**—**	**3**	**2**
As at December 31, 2024	**499.3**	**$ 15,589**	**$ 1,623**	**$ 8**	**$ 2,067**	**$ 4,521**	**$ 2,045**	**$ 25,853**
As at December 31, 2022	482.2	$ 14,656	$ 1,623	$ 10	$ 1,008	$ 3,733	$ 1,812	$ 22,842
Net earnings	—	—	—	—	—	1,573	137	1,710
Other comprehensive loss	—	—	—	—	(355)	—	(41)	(396)
Common shares issued	8.4	452	—	—	—	—	—	452
Subsidiary dividends paid to non-controlling interests	—	—	—	—	—	—	(83)	(83)
Dividends declared on common shares ($2.31 per share)	—	—	—	—	—	(1,127)	—	(1,127)
Dividends on preference shares	—	—	—	—	—	(67)	—	(67)
Other	—	—	—	(1)	—	—	2	1
As at December 31, 2023	490.6	$ 15,108	$ 1,623	$ 9	$ 653	$ 4,112	$ 1,827	$ 23,332

See accompanying Notes to Consolidated Financial Statements

1. DESCRIPTION OF BUSINESS

Fortis Inc. ("Fortis" or the "Corporation") is a well-diversified North American regulated electric and gas utility holding company. Entities within the reporting segments that follow operate with substantial autonomy.

Regulated Utilities

ITC: ITC Investment Holdings Inc., ITC Holdings Corp. and the electric transmission operations of its regulated operating subsidiaries, which include International Transmission Company ("ITCTransmission"), Michigan Electric Transmission Company, LLC ("METC"), ITC Midwest LLC ("ITC Midwest"), and ITC Great Plains, LLC. Fortis owns 80.1% of ITC and an affiliate of GIC Private Limited owns a 19.9% minority interest.

ITC owns and operates high-voltage transmission lines in Michigan's lower peninsula and portions of Iowa, Minnesota, Illinois, Missouri, Kansas, Oklahoma and Wisconsin.

UNS Energy: UNS Energy Corporation, which primarily includes Tucson Electric Power Company ("TEP"), UNS Electric, Inc. ("UNS Electric") and UNS Gas, Inc. ("UNS Gas").

UNS Energy's largest operating subsidiary, TEP, and UNS Electric are vertically integrated regulated electric utilities. They generate, transmit and distribute electricity to retail customers in southeastern Arizona, including the greater Tucson metropolitan area. TEP also sells wholesale electricity to other entities in the western United States. Together they own generating capacity of 3,442 megawatts ("MW"), including 68 MW of solar capacity and 250 MW of wind capacity. Several generating assets in which they have an interest are jointly owned.

UNS Gas is a regulated gas distribution utility serving retail customers in northern and southern Arizona.

Central Hudson: CH Energy Group, Inc., which primarily includes Central Hudson Gas & Electric Corporation. Central Hudson is a regulated electric and gas transmission and distribution utility that serves portions of New York State's Mid-Hudson River Valley and owns gas-fired and hydroelectric generating capacity totalling 43 MW.

FortisBC Energy: FortisBC Energy Inc., which is the largest regulated distributor of natural gas in British Columbia, providing transmission and distribution services. FortisBC Energy sources natural gas supplies primarily from northeastern British Columbia and Alberta on behalf of most customers.

FortisAlberta: FortisAlberta Inc. is a regulated electricity distribution utility operating in a substantial portion of southern and central Alberta. FortisAlberta is not involved in the direct sale of electricity.

FortisBC Electric: FortisBC Inc. is an integrated regulated electric utility operating in the southern interior of British Columbia. It owns four hydroelectric generating facilities with a combined capacity of 225 MW. It also provides operating, maintenance and management services relating to five hydroelectric generating facilities in British Columbia that are owned by third parties.

Other Electric: Eastern Canadian and Caribbean utilities, as follows: Newfoundland Power Inc. ("Newfoundland Power"); Maritime Electric Company, Limited ("Maritime Electric"); FortisOntario Inc. ("FortisOntario"); a 39% equity investment in Wataynikaneyap Power Limited Partnership ("Wataynikaneyap Power"); an approximate 60% controlling interest in Caribbean Utilities Company, Ltd. ("Caribbean Utilities"); FortisTCI Limited and Turks and Caicos Utilities Limited (collectively, "FortisTCI"); and a 33% equity investment in Belize Electricity Limited ("Belize Electricity").

Newfoundland Power is an integrated regulated electric utility and the principal distributor of electricity on the island portion of Newfoundland and Labrador with a generating capacity of 145 MW, of which 98 MW is hydroelectric. Maritime Electric is an integrated regulated electric utility and the principal distributor of electricity on Prince Edward Island ("PEI") with on-Island generating capacity of 90 MW. FortisOntario consists of three regulated electric utilities that provide service to customers in Fort Erie, Cornwall, Gananoque, Port Colborne and the District of Algoma in Ontario with a generating capacity of 3 MW. Wataynikaneyap Power is a transmission company majority-owned by 24 First Nations in which Fortis owns a 39% interest. The 1,800 kilometer Wataynikaneyap Power Transmission Line will connect 17 remote First Nations to the Ontario power grid.

Caribbean Utilities is an integrated regulated electric utility and the sole electricity provider on Grand Cayman with a diesel-powered generating capacity of 166 MW. FortisTCI consists of two integrated regulated electric utilities that provide electricity to certain Turks and Caicos Islands and has a generating capacity of 99 MW, including 95 MW of diesel-powered generating capacity and 4 MW of solar capacity. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize.

Non-Regulated

Corporate and Other: Captures expenses and revenues not specifically related to any reportable segment and those business operations that are below the required threshold for segmented reporting. Consists of non-regulated holding company expenses, as well as non-regulated long-term contracted generation assets in Belize. The generation assets include three hydroelectric generating facilities with a combined generating capacity of 51 MW, held through the Corporation's indirectly wholly owned subsidiary Fortis Belize Limited, the output of which is sold to Belize Electricity under 50-year power purchase agreements ("PPAs"). Also includes results for the Aitken Creek natural gas storage facility ("Aitken Creek") until the November 1, 2023 date of disposition (Note 21).

2. REGULATION

General

The earnings of the Corporation's regulated utilities are determined under cost of service ("COS") regulation, with some using performance-based rate setting ("PBR") mechanisms.

Under COS regulation, the regulator sets customer rates to permit a reasonable opportunity for the timely recovery of the estimated costs of providing service, including a fair rate of return on a deemed or targeted capital structure applied to an approved regulatory asset value ("rate base"). PBR mechanisms generally apply a formula that incorporates inflation and assumed productivity improvements for a set term.

The ability to recover prudently incurred costs of providing service and earn the regulator-approved rate of return on common shareholders' equity ("ROE") and/or rate of return on rate base assets ("ROA") may depend on achieving the forecasts established in the rate-setting process. As well, the Corporation's regulated utilities, where applicable, are permitted by their respective regulators to flow through to customers, without markup, the cost of natural gas, fuel and/or purchased power through base customer rates and/or the use of rate stabilization and other mechanisms (Note 8). There can be varying degrees of regulatory lag between when costs are incurred and when they are reflected in customer rates.

Nature of Regulation			**Allowed ROE** [1] *(%)*		
Regulated Utility	**Regulatory Authority**	**Allowed Common Equity** *(%)*	**2024**	**2023**	**Significant Features**
ITC	Federal Energy Regulatory Commission ("FERC")	60.0	**10.73** [2]	10.77 [2]	Cost-based formula rates, with annual true-up mechanism [3] Incentive adders
TEP	Arizona Corporation Commission ("ACC")	54.3	**9.55**	9.55 [4]	COS regulation Historical test year
	FERC	[5]	**9.79**	9.79	Formula transmission rates
UNS Electric	ACC	53.7	**9.75** [6]	9.50	
UNS Gas	ACC	50.8	**9.75** [7]	9.75	
Central Hudson	New York State Public Service Commission ("PSC")	48.0	**9.50** [8]	9.00	COS regulation Future test year
FortisBC Energy	British Columbia Utilities Commission ("BCUC")	45.0	**9.65**	9.65	COS regulation with formula components and incentives
FortisBC Electric	BCUC	41.0	**9.65**	9.65	Future test year
FortisAlberta	Alberta Utilities Commission ("AUC")	37.0	**9.28**	8.50	PBR, with formula to calculate ROE on an annual basis [9]
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities	45.0	**8.50**	8.50	COS regulation Future test year
Maritime Electric	Island Regulatory and Appeals Commission	40.0	**9.35**	9.35	COS regulation Future test year
FortisOntario [10]	Ontario Energy Board	40.0	**8.52-9.30**	8.52-9.30	COS regulation with incentive mechanisms
Caribbean Utilities [11]	Utility Regulation and Competition Office	N/A	**8.25-10.25**	7.50-9.50	COS regulation Rate-cap adjustment mechanism
FortisTCI [12]	Government of the Turks and Caicos Islands	N/A	**15.00-17.50**	15.00-17.50	COS regulation Historical test year

[1] *ROA for Caribbean Utilities and FortisTCI*

[2] *Reflects the allowed common equity and ROE for ITCTransmission, METC, and ITC Midwest. The ROE above is inclusive of the base ROE as well as incentive adders totalling 0.75%. FERC issued an order in October 2024 retroactively revising the base ROE to certain prior periods including 2023. See "Significant Regulatory Matters" below*

[3] *Annual true-up collected or refunded in rates within a two-year period*

[4] *Allowed common equity of 54.3% and ROE of 9.55% effective September 1, 2023*

[5] *The allowed common equity component for FERC transmission rates is formulaic, and is updated annually based on TEP's actual equity ratio*

[6] *Allowed common equity of 53.7% and ROE of 9.75% effective February 1, 2024*

[7] *A general rate application requesting new customer rates is ongoing. See "Significant Regulatory Matters" below*

[8] *ROE of 9.5% effective July 1, 2024. A general rate application requesting new customer rates effective July 1, 2025 is ongoing. See "Significant Regulatory Matters" below*

[9] *In 2023, FortisAlberta was subject to a COS revenue requirement. The ROE for 2025 has been set at 8.97%*

[10] *Two of FortisOntario's utilities follow COS regulation with incentive mechanisms, while the remaining utility is subject to a 35-year franchise agreement expiring in 2033*

[11] *Operates under licences from the Government of the Cayman Islands. Its exclusive transmission and distribution licence is for an initial 20-year period, expiring in April 2028, with a provision for automatic renewal. Its non-exclusive generation licence is for a 25-year term, expiring in November 2039*

[12] *Operates under 25 and 50 year licences from the Government of the Turks and Caicos Islands, which expire in 2036 and 2037, respectively*

2. REGULATION (cont'd)

Significant Regulatory Matters

ITC

MISO Base ROE: In 2022, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision vacating certain FERC orders that had established the methodology for setting the base ROE for transmission owners operating in the Midcontinent Independent System Operator, Inc. ("MISO") region, including ITC, and remanded the matter to FERC for further process. This matter dates back to complaints filed at FERC in 2013 and 2015 challenging the MISO base ROE then in effect.

In October 2024, FERC issued an order that removed the use of the risk premium model from the calculation of the base ROE, while maintaining other modifications to the methodology. The updated methodology revised the base ROE from 10.02% to 9.98%, with a maximum ROE inclusive of incentives not to exceed 12.58%. The order also directed the payment of certain refunds, with interest, by December 2025, for the 15-month period from November 2013 through February 2015, and prospectively from September 2016. A regulatory liability of $39 million (US$27 million) associated with the refunds has been recognized by ITC as of December 31, 2024.

Certain MISO transmission owners, including ITC, filed a request for rehearing with FERC in November 2024, and filed an appeal of the order with the D.C. Circuit Court in January 2025. The requests for rehearing and appeal primarily focus on the refund period and the related interest. The timing and outcome of these filings are unknown.

Transmission Incentives: In 2021, FERC issued a supplemental notice of proposed rulemaking ("NOPR") on transmission incentives modifying the proposal in the initial NOPR released by FERC in 2020. The supplemental NOPR proposes to eliminate the 50-basis point regional transmission organization ("RTO") ROE incentive adder for RTO members that have been members for longer than three years. The timing and outcome of this proceeding remain unknown.

Transmission Right of First Refusal ("ROFR"): In December 2023, the Iowa District Court ruled that the manner in which Iowa's ROFR statute was passed was unconstitutional. The statute granted incumbent electric transmission owners, including ITC, a ROFR to construct, own and maintain certain electric transmission assets in the state. The District Court did not make any determination on the merits of the ROFR itself, but did issue a permanent injunction preventing ITC and others from taking further action to construct the MISO long-range transmission plan ("LRTP") tranche 1 Iowa projects in reliance on the ROFR.

In May 2024, MISO commenced a variance analysis process as a result of the inability to construct a portion of the tranche 1 LRTP projects in Iowa due to the injunction imposed by the District Court. In August 2024, MISO concluded the variance analysis, which reaffirmed the original allocation of projects to ITC and other incumbent transmission owners. While the results of MISO's variance analysis process allow ITC to move forward with the development of its portion of tranche 1 LRTP projects in Iowa, various legal proceedings with respect to this matter are ongoing for which the timing and outcome are unknown.

UNS Energy

Generic Regulatory Lag Docket: In December 2024, the ACC approved a formula rate plan policy statement which allows utilities to propose formula rates in future rate cases. A formula rate plan, if approved by the ACC, would adjust rates annually based on a predetermined formula. A formula rate plan is expected to improve rate stability for customers, while also reducing regulatory lag and the number of existing rate adjusters.

UNS Gas General Rate Application: In November 2024, UNS Gas filed a general rate application with the ACC requesting an increase in gas delivery rates effective February 1, 2026. The application includes a request to set its ROE at 10.25% and a 56% common equity component of capital structure. In January 2025, UNS Gas filed supplemental material proposing an annual rate adjustment mechanism as a result of the ACC's formula rate policy statement discussed above. The timing and outcome of this proceeding are unknown.

Central Hudson

2025 General Rate Application: In August 2024, Central Hudson filed a general rate application with the PSC requesting an increase in electric and gas delivery rates effective July 1, 2025. The application includes a request to set Central Hudson's allowed ROE at 10% and a 48% common equity component of capital structure. The timing and outcome of this proceeding are unknown.

Show Cause Order: In October 2024, the PSC issued a Show Cause Order which directed Central Hudson to explain why the PSC should not initiate an enforcement proceeding in connection with a gas-related explosion that occurred in November 2023. Central Hudson filed its response in November 2024. The timing and outcome of the Show Cause Order are unknown.

FortisBC Energy and FortisBC Electric

2025-2027 Rate Framework: In April 2024, FortisBC filed an application with the BCUC requesting approval of a rate framework for the period 2025 through 2027. The rate framework builds upon the current multi-year rate plan and includes, amongst other items, updates to depreciation and capitalized overhead rates, a revised level of operation and maintenance expense per customer indexed for inflation less a fixed productivity adjustment factor, a similar approach to growth capital, a forecast approach to sustaining and other capital, continued collection of an innovation fund recognizing the need to accelerate investment in clean energy innovation, and the continued sharing with customers of variances from the allowed ROE. The rate framework also proposes the continuation of deferral mechanisms currently in place. A decision from the BCUC is expected in mid-2025.

2. REGULATION (cont'd)

FortisAlberta

Generic Cost of Capital ("GCOC") Decision: In October 2023, the AUC issued a decision on the 2024 GCOC proceeding. In November 2023, FortisAlberta sought permission to appeal the GCOC decision to the Court of Appeal of Alberta ("Court of Appeal") on the basis that the AUC erred in its decision to not adjust FortisAlberta's ROE and common equity component of capital structure to address incremental business risk associated with competition from Rural Electrification Associations ("REAs") located in FortisAlberta's service area, as well as heightened regulatory risk due to the non-recovery of costs attributable to REAs. In April 2024, the Court of Appeal granted FortisAlberta permission to appeal, and a decision is expected in the first quarter of 2025.

Third PBR Term Decision: In October 2023, the AUC issued a decision establishing the parameters for the third PBR setting term for the period of 2024 through 2028. In November 2023, FortisAlberta sought permission to appeal the decision to the Court of Appeal on the basis that the AUC erred in its decision to determine capital funding using 2018-2022 historical capital investments without consideration for funding of new capital programs included in the company's 2023 cost of service revenue requirement as approved by the AUC. FortisAlberta's application for permission to appeal the decision was heard by the Court of Appeal in December 2024 and a decision is expected in the first quarter of 2025.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

These consolidated financial statements have been prepared and presented in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP") for rate-regulated entities, and are in Canadian dollars unless otherwise indicated.

These consolidated financial statements include the accounts of the Corporation and its subsidiaries. They reflect the equity method of accounting for entities in which Fortis has significant influence, but not control, and proportionate consolidation for assets that are jointly owned with non-affiliated entities.

Cash and Cash Equivalents

Cash and cash equivalents include cash, cash held in margin accounts, and short-term deposits with initial maturities of three months or less from the date of deposit.

Allowance for Credit Losses

Fortis and its subsidiaries recognize an allowance for credit losses to reduce accounts receivable for amounts estimated to be uncollectible. The allowance for credit losses is estimated based on historical collection patterns, sales, and current and forecast economic and other conditions. Accounts receivable are written off in the period in which they are deemed uncollectible.

Inventories

Inventories, consisting of materials and supplies, gas, fuel and coal in storage, are measured at the lower of weighted average cost and net realizable value.

Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the utility rate-setting process and are subject to regulatory approval. Regulatory assets represent future revenues and/or receivables associated with certain costs incurred that will be, or are expected to be, recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent: (i) future reductions or limitations of increases in revenue associated with amounts that will be, or are expected to be, refunded to customers through the rate-setting process; or (ii) obligations to provide future service that customers have paid for in advance.

Certain remaining recovery and settlement periods are those expected by management and the actual periods could differ based on regulatory approval.

Investments

Investments are reviewed annually for potential impairment in value. Impairments are recognized when identified.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Property, Plant and Equipment

Property, plant and equipment ("PPE") are recognized at cost less accumulated depreciation. Contributions in aid of construction by customers and governments are recognized as a reduction in the cost of, and are amortized in a manner consistent with, the related PPE.

Depreciation rates of the Corporation's regulated utilities include a provision for estimated future removal costs not identified as a legal obligation. The provision is recognized as a long-term regulatory liability (Note 8) against which actual removal costs are netted when incurred.

The Corporation's regulated utilities derecognize PPE on disposal or when no future economic benefits are expected from their use. Upon derecognition, any difference between cost and accumulated depreciation, net of salvage proceeds, is charged to accumulated depreciation. No gain or loss is recognized.

Through methodologies established by their respective regulators, the Corporation's regulated utilities capitalize: (i) overhead costs that are not directly attributable to specific PPE but relate to the overall capital expenditure plan; and (ii) an allowance for funds used during construction ("AFUDC"). The debt component of AFUDC for 2024 totalled $74 million (2023 - $56 million) and is reported as a reduction of finance charges and the equity component is reported as other income (Note 22). Both components are recorded to earnings through depreciation expense over the estimated service lives of the applicable PPE.

Excluding UNS Energy and Central Hudson, PPE includes inventory held for the development, construction and betterment of other assets. As required by its regulators, UNS Energy and Central Hudson recognize such items as inventory until used and reclassifies them to PPE once put into service.

Repairs and maintenance costs are charged to earnings in the period incurred. Replacements and betterments that extend the useful lives of PPE are capitalized.

PPE is depreciated using the straight-line method based on the estimated service lives of the assets. Depreciation rates for regulated PPE are approved by the respective regulators and ranged from 0.5% to 33.0% for 2024 (2023 - 0.5% to 35.0%). The weighted average composite rate of depreciation, before reduction for amortization of contributions in aid of construction, was 2.7% for 2024 (2023 – 2.6%).

The service life ranges and weighted average remaining service life of PPE as at December 31 were as follows.

	2024		2023	
(years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Distribution				
Electric	**5-80**	**32**	5-80	31
Gas	**18-83**	**37**	18-95	38
Transmission				
Electric	**20-85**	**42**	20-90	41
Gas	**10-80**	**35**	10-85	36
Generation	**2-95**	**22**	2-95	23
Other	**3-80**	**13**	3-80	10

Intangible Assets

Intangible assets are recorded at cost less accumulated amortization. Their useful lives are assessed to be either indefinite or finite.

Intangible assets with indefinite useful lives are not amortized and are tested for impairment annually, either individually or, where the particular entity also has goodwill, at the reporting unit level in conjunction with goodwill impairment testing. An annual review is completed to determine whether the indefinite life assessment continues to be supportable. If not, the resultant changes are made prospectively.

Intangible assets with finite lives are amortized using the straight-line method based on the estimated service lives of the assets. Amortization rates for regulated intangible assets are approved by the respective regulators and ranged from 1.0% to 33.0% for 2024 (2023 – 1.0% to 33.0%).

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

The service life ranges and weighted average remaining service life of finite-life intangible assets as at December 31 were as follows.

	2024		2023	
(years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Computer software	**3-18**	**5**	3-18	5
Land, transmission and water rights	**30-85**	**52**	30-90	52
Other	**10-100**	**16**	10-100	14

The Corporation's regulated utilities derecognize intangible assets on disposal or when no future economic benefits are expected from their use. Upon derecognition any difference between the cost and accumulated amortization of the asset, net of salvage proceeds, is charged to accumulated amortization. No gain or loss is recognized.

Impairment of Long-Lived Assets

The Corporation reviews the valuation of PPE, intangible assets with finite lives, and other long-term assets when events or changes in circumstances indicate that the total undiscounted cash flows expected to be generated by the asset may be below carrying value. If that is determined to be the case, the asset is written down to estimated fair value and an impairment loss is recognized.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of the identifiable net assets related to business acquisitions.

Goodwill at each of the Corporation's reporting units is tested for impairment annually and whenever an event or change in circumstances indicates that fair value may be below carrying value. If so determined, goodwill is written down to estimated fair value and an impairment loss is recognized.

The Corporation performs a qualitative assessment on each reporting unit, and if it is determined that it is not likely that fair value is less than carrying value, then a quantitative estimate of fair value is not required. When a quantitative assessment is performed, the primary method for estimating fair value of the reporting units is the income approach, whereby net cash flow projections are discounted. Underlying estimates and assumptions, with varying degrees of uncertainty, include the amount and timing of expected future cash flows, growth rates, and discount rates. A secondary valuation, the market approach along with a reconciliation of the total estimated fair value of all the reporting units to the Corporation's market capitalization, is also performed and evaluated.

Deferred Financing Costs

Issue costs, discounts and premiums are recognized against, and amortized over the life of, the related long-term debt.

Employee Future Benefits

Fortis and each subsidiary maintain one or a combination of defined benefit pension ("DBP") and defined contribution pension plans, as well as other post-employment benefit ("OPEB") plans, including certain health and dental coverage and life insurance benefits, for qualifying members. The costs of defined contribution pension plans are expensed as incurred.

For DBP and OPEB plans, the projected or accumulated benefit obligation and net benefit costs are actuarially determined using the projected benefits method prorated on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and, for OPEB plans, expected health care costs. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension or OPEB payments.

DBP and OPEB plan assets are recognized at fair value. For the purpose of determining defined benefit pension cost, FortisBC Energy and Newfoundland Power use the market-related value whereby investment returns in excess of, or below, expected returns are recognized in the asset value over a period of three years.

The excess of any cumulative net actuarial gain or loss over 10% of the greater of: (i) the projected or accumulated benefit obligation; and (ii) the fair value or market-related value, as applicable, of plan assets at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

The net funded or unfunded status of DBP and OPEB plans, measured as the difference between the fair value of the plan assets and the projected or accumulated benefit obligation, is recognized on the Corporation's consolidated balance sheets.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

For most of the Corporation's regulated utilities, any difference between DBP or OPEB plan costs ordinarily recognized under U.S. GAAP and those recovered from customers in current rates is subject to deferral account treatment and is expected to be recovered from, or refunded to, customers in future rates. In addition, any unamortized balances related to net actuarial gains and losses, past service costs and transitional obligations associated with DBP or OPEB plans, as applicable, which would otherwise be recognized in accumulated other comprehensive income, are subject to deferral account treatment (Note 8).

Leases

A right-of-use asset and lease liability is recognized for leases with a lease term greater than 12 months. The right-of-use asset and liability are both measured at the present value of future lease payments, excluding variable payments that are based on usage or performance. Future lease payments include both lease components (e.g., rent, real estate taxes and insurance costs) and non-lease components (e.g., common area maintenance costs), which Fortis accounts for as a single lease component. The present value is calculated using the rate implicit in the lease or a lease-specific secured interest rate based on the remaining lease term. Renewal options are included in the lease term when it is reasonably certain that the option will be exercised.

Finance leases are depreciated over the lease term, except where: (i) ownership of the asset is transferred at the end of the lease term, in which case depreciation is over the estimated service life of the underlying asset; and (ii) the regulator has approved a different recovery methodology for rate-setting purposes, in which case the timing of the expense recognition will conform to the regulator's requirements.

Revenue Recognition

Most revenue is derived from energy sales and the provision of transmission services to customers based on regulator-approved tariff rates. Most contracts have a single performance obligation, being the delivery of energy or the provision of transmission services. No component of the transaction price is allocated to unsatisfied performance obligations. Energy sales are generally measured in kilowatt hours, gigajoules or transmission load delivered. The billing of energy sales is based on customer meter readings, which occur systematically throughout each month. The billing of transmission services at ITC is based on peak monthly load.

FortisAlberta is a distribution company and is required by its regulator to arrange and pay for transmission services with the Alberta Electric System Operator ("AESO"). This includes the collection of transmission revenue from its customers, which occurs through the transmission component of its regulator-approved rates. FortisAlberta reports transmission revenue and expenses on a net basis.

Electricity, gas and transmission service revenue includes an estimate for unbilled energy consumed or service provided since the last meter reading that has not been billed at the end of the reporting period. Sales estimates generally reflect an analysis of historical consumption in relation to key inputs, such as current energy prices, population growth, economic activity, weather conditions and system losses. Unbilled revenue accruals are adjusted in the periods actual consumption becomes known.

Generation revenue from non-regulated operations is recognized on delivery at contracted fixed or market rates.

Variable consideration is estimated at the most likely amount and reassessed at each reporting date until the amount is known. Variable consideration, including amounts subject to a future regulatory decision, is recognized as a refund liability until entitlement is probable.

Revenue excludes sales and municipal taxes collected from customers.

The Corporation has elected not to assess or account for any significant financing components associated with revenue billed in accordance with equal payment plans as the period between the transfer of energy to customers and the customers' payment is less than one year.

Stock-Based Compensation

Fortis recognizes liabilities associated with directors' deferred share units ("DSUs"), performance share units ("PSUs") and restricted share units ("RSUs"). DSUs represent cash-settled awards whereas PSUs and RSUs represent cash or share-settled awards. The fair value of these liabilities is based on the five-day volume weighted average price ("VWAP") of the Corporation's common shares at the end of each reporting period. The fair value of the PSU liability is also based on the expected payout probability, based on historical performance in accordance with the defined metrics of each grant and management's best estimate.

Compensation expense is recognized on a straight-line basis over the vesting period, which for PSUs and RSUs is over the lesser of three years or the period to retirement eligibility and for DSUs is at the time of grant. Forfeitures are accounted for as they occur.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Foreign Currency Translation

Assets and liabilities of the Corporation's foreign operations, all of which have a U.S. dollar functional currency, are translated at the exchange rate in effect at the balance sheet date and the resultant unrealized translation gains and losses are recognized in accumulated other comprehensive income. The exchange rate as at December 31, 2024 was US$1.00=CA$1.44 (2023 – US$1.00=CA$1.32).

Revenue and expenses of the Corporation's foreign operations are translated at the average exchange rate for the reporting period, which was US$1.00=CA$1.37 for 2024 (2023 - US$1.00=CA$1.35).

Monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate prevailing at the balance sheet date. Revenue and expenses denominated in foreign currencies are translated at the exchange rate prevailing at the transaction date. Translation gains and losses are recognized in earnings.

Translation gains and losses on foreign currency-denominated debt that is designated as an effective hedge of foreign net investments are recognized in other comprehensive income.

Derivatives and Hedging

Derivatives Not Designated as Hedges

Derivatives not designated as hedges are used by: (i) Fortis, to manage cash flow risk associated with forecast U.S. dollar cash inflows and forecast future cash settlements of DSU, PSU and RSU obligations; and (ii) UNS Energy, to meet forecast load and reserve requirements. Aitken Creek, to its date of disposition, utilized derivatives to manage commodity price risk, capture natural gas price spreads, and manage the financial risk of physical transactions (Note 21). Derivatives are measured at fair value with changes thereto recognized in earnings.

Derivatives not designated as hedges are also used by UNS Energy, Central Hudson and FortisBC Energy to reduce energy price risk associated with purchased power and gas requirements. The settled amounts of these derivatives are generally included in regulated rates, as permitted by the respective regulators. These derivatives are measured at fair value with changes recognized as regulatory assets or liabilities for recovery from, or refund to, customers in future rates (Note 8).

Derivatives that meet the normal purchase or normal sale scope exception are not measured at fair value and settled amounts are recognized in earnings as energy supply costs.

Derivatives Designated as Hedges

Fortis, ITC and Central Hudson use cash flow hedges, from time to time, to manage interest rate risk. Unrealized gains and losses are initially recognized in accumulated other comprehensive income and reclassified to earnings when the underlying hedged transaction affects earnings.

The Corporation's earnings from, and net investments in, foreign subsidiaries and certain equity-accounted investments are exposed to fluctuations in the U.S. dollar-to-Canadian dollar exchange rate. The Corporation has hedged a portion of this exposure through U.S. dollar-denominated debt at the corporate level. Exchange rate fluctuations associated with the translation of this debt and the foreign net investments are recognized in accumulated other comprehensive income.

Presentation of Derivatives

The fair value of derivatives is recognized as current or long-term assets and liabilities depending on the timing of settlements and resulting cash flows. Derivatives under master netting agreements and collateral positions are presented on a gross basis. Cash flows associated with the settlement of all derivatives are presented in operating activities in the consolidated statements of cash flows.

Income Taxes

The Corporation and its taxable subsidiaries follow the asset and liability method of accounting for income taxes. Current income tax expense or recovery is recognized for the estimated income taxes payable or receivable in the current year.

Deferred income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes that are "more likely than not" to be realized. They are measured using enacted income tax rates and laws in effect when the temporary differences are expected to be recovered or settled. The effect of a change in income tax rates on deferred income tax assets and liabilities is recognized in earnings in the period when the change occurs. Valuation allowances are recognized when it is "more likely than not" that all of, or a portion of, a deferred income tax asset will not be realized.

Customer rates at ITC, UNS Energy, Central Hudson and Maritime Electric reflect current and deferred income tax. Customer rates at FortisAlberta reflect current income tax. Customer rates at FortisBC Energy, FortisBC Electric, Newfoundland Power and FortisOntario reflect current income tax and, for certain regulatory balances, deferred income tax. Caribbean Utilities, FortisTCI and Fortis Belize are not subject to income tax.

Differences between the income tax expense or recovery recognized under U.S. GAAP and reflected in current customer rates, which is expected to be recovered from, or refunded to, customers in future rates, are recognized as regulatory assets or liabilities (Note 8).

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

Income Taxes (cont'd)

Fortis does not recognize deferred income taxes on temporary differences related to investments in foreign subsidiaries where it intends to indefinitely reinvest earnings. The difference between the carrying values of these foreign investments and their tax bases, resulting from unrepatriated earnings and currency translation adjustments, is approximately $8.1 billion as at December 31, 2024 (2023 - $6.3 billion). If such earnings are repatriated, the Corporation may be subject to income taxes and foreign withholding taxes. The determination of the amount of unrecognized deferred income tax liabilities on such amounts is impractical.

Tax benefits associated with actual or expected income tax positions are recognized when the "more likely than not" recognition threshold is met. The tax benefits are measured at the largest amount of benefit that is greater than 50% likely to be realized upon settlement.

Income tax interest and penalties are recognized as income tax expense when incurred.

Asset Retirement Obligations

The Corporation's subsidiaries have asset retirement obligations ("AROs") associated with certain generation, transmission, distribution and interconnection assets, including land and environmental remediation and/or asset removal. These assets and related licences, permits, rights-of-way and agreements are reasonably expected to effectively exist and operate in perpetuity due to their nature. Consequently, where the final date and cost of remediation and/or removal of the noted assets cannot be reasonably determined, AROs have not been recognized.

Otherwise, AROs are recognized at fair value in the period incurred as an increase in PPE and long-term other liabilities (Note 16) if a reasonable estimate of fair value can be determined. Fair value is estimated as the present value of expected future cash outlays, discounted at a credit-adjusted risk-free interest rate. The increase in the liability due to the passage of time is recognized through accretion and the capitalized cost is depreciated over the useful life of the asset. Accretion and depreciation expense are deferred as a regulatory asset or liability based on regulatory recovery of these costs. Actual settlement costs are recognized as a reduction in the accrued liability.

Contingencies

Fortis and its subsidiaries are subject to various legal proceedings and claims that arise in the normal course of business. Management makes judgments regarding the future outcome of contingent events and recognizes a loss based on its best estimate when it is determined that such loss, or range of loss, is probable and can be reasonably estimated. Legal fees are expensed as incurred. When a loss is recoverable in future rates, a regulatory asset is also recognized.

Management regularly reviews current information to determine whether recognized provisions should be adjusted and new provisions are required. However, estimating probable losses requires considerable judgment about potential actions by third parties and matters are often resolved over long periods of time. Actual outcomes may differ materially from the amounts recognized.

Use of Accounting Estimates

The preparation of these consolidated financial statements in accordance with U.S. GAAP requires management to make estimates and judgments, including those arising from matters dependent upon the finalization of regulatory proceedings, that affect the reported amounts of assets, liabilities, revenues, expenses, gains and losses. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time they are made, with any adjustments being recognized in the period they become known. Actual results may differ significantly from these estimates.

New Accounting Policies

Segment Reporting: The Corporation adopted ASU No. 2023-07, *Improvements to Reportable Segment Disclosures*, for the year ended December 31, 2024 and will adopt it for interim periods beginning in 2025. This update requires disclosure of incremental segment information, including significant segment expenses and other items that are included in segment profit or loss. This adoption of this standard did not materially impact Fortis' disclosures.

Future Accounting Pronouncements

The Corporation considers the applicability and impact of all Accounting Standards Updates ("ASUs") issued by the Financial Accounting Standards Board. Any ASUs not included in these consolidated financial statements were assessed and determined to be either not applicable to the Corporation or are not expected to have a material impact on the consolidated financial statements.

Income Taxes: ASU No. 2023-09, *Improvements to Income Tax Disclosures,* is effective for Fortis on January 1, 2025 on a prospective basis, with retrospective application and early adoption permitted. The ASU requires additional disclosure of income tax information by jurisdiction to reflect an entity's exposure to potential changes in tax legislation, and associated risks and opportunities. Fortis does not expect the ASU to materially impact its disclosures.

Expense Disaggregation: ASU No. 2024-03, *Disaggregation of Income Statement Expenses*, is effective for Fortis on January 1, 2027 for annual periods and on January 1, 2028 for interim periods, on a prospective basis, with retrospective application and early adoption permitted. The ASU requires detailed disclosure of certain expense categories included on the consolidated statements of earnings, including energy supply costs, operating expenses, and depreciation and amortization expense. Fortis is assessing the impact on its disclosures.

4. SEGMENTED INFORMATION

Fortis' CEO is considered the chief operating decision maker ("CODM") for purposes of reviewing segment performance. Fortis segments its business based on regulatory jurisdiction and service territory, as well as the information used by the CODM in deciding how to allocate resources. Segment performance is evaluated principally on net earnings attributable to common equity shareholders, and this measure is used consistently in the evaluation of actual segment performance as well as in the Corporation's business plan and forecasting processes.

Related-Party and Inter-Company Transactions

Related-party transactions are in the normal course of operations and are measured at the amount of consideration agreed to by the related parties. There were no material related-party transactions in 2024 or 2023.

As of December 31, 2024, accounts receivable included $18 million due from Belize Electricity (December 31, 2023 - $8 million).

Fortis periodically provides short-term financing to subsidiaries to support capital expenditures and seasonal working capital requirements, the impacts of which are eliminated on consolidation. As at December 31, 2024 and 2023, there were no inter-segment loans outstanding. Interest charged on inter-segment loans was not material in 2024 and 2023.

	Regulated								**Non-Regulated**		
($ millions)	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	**Sub-total**	**Corporate and Other**	**Inter-segment eliminations**	**Total**
Year ended December 31, 2024											
Revenue	2,229	3,007	1,372	1,665	817	545	1,838	**11,473**	**35**	**—**	**11,508**
Energy supply costs	—	1,183	393	423	—	155	1,095	**3,249**	**—**	**—**	**3,249**
Operating expenses	530	798	659	418	195	141	250	**2,991**	**49**	**—**	**3,040**
Depreciation and amortization	448	404	134	337	291	88	218	**1,920**	**7**	**—**	**1,927**
Operating income	1,251	622	186	487	331	161	275	**3,313**	**(21)**	**—**	**3,292**
Other income, net	96	51	58	45	11	6	29	**296**	**(8)**	**—**	**288**
Finance charges	483	155	79	155	135	81	93	**1,181**	**225**	**—**	**1,406**
Income tax expense	200	70	37	83	26	14	23	**453**	**(107)**	**—**	**346**
Net earnings	664	448	128	294	181	72	188	**1,975**	**(147)**	**—**	**1,828**
Non-controlling interests	122	—	—	1	—	—	25	**148**	**—**	**—**	**148**
Preference share dividends	—	—	—	—	—	—	—	**—**	**74**	**—**	**74**
Net earnings attributable to common equity shareholders	542	448	128	293	181	72	163	**1,827**	**(221)**	**—**	**1,606**
Additions to property, plant and equipment and intangible assets	1,456	1,151	431	1,035	554	132	454	**5,213**	**5**	**—**	**5,218**
As at December 31, 2024											
Goodwill	8,828	1,987	649	913	231	235	269	**13,112**	**—**	**—**	**13,112**
Total assets	27,202	14,690	6,278	10,156	6,181	2,807	5,810	**73,124**	**374**	**(12)**	**73,486**
Year ended December 31, 2023											
Revenue	2,085	3,006	1,360	1,955	738	528	1,761	11,433	84	—	11,517
Energy supply costs	—	1,290	499	760	—	153	1,069	3,771	—	—	3,771
Operating expenses	494	776	601	408	180	127	231	2,817	72	—	2,889
Depreciation and amortization	416	361	113	309	265	96	204	1,764	9	—	1,773
Operating income	1,175	579	147	478	293	152	257	3,081	3	—	3,084
Other income, net	82	49	54	34	6	4	23	252	39	—	291
Finance charges	427	145	67	163	125	79	86	1,092	213	—	1,305
Income tax expense	208	83	29	74	12	9	26	441	(81)	—	360
Net earnings	622	400	105	275	162	68	168	1,800	(90)	—	1,710
Non-controlling interests	114	—	—	1	—	—	22	137	—	—	137
Preference share dividends	—	—	—	—	—	—	—	—	67	—	67
Net earnings attributable to common equity shareholders	508	400	105	274	162	68	146	1,663	(157)	—	1,506
Additions to property, plant and equipment and intangible assets	1,103	916	341	593	608	126	466	4,153	16	—	4,169
As at December 31, 2023											
Goodwill	8,127	1,830	597	913	228	235	254	12,184	—	—	12,184
Total assets	24,269	12,784	5,371	9,225	5,962	2,715	5,227	65,553	401	(34)	65,920

5. REVENUE

The following table presents the disaggregation of the Corporation's revenue on the consolidated statements of earnings by geography and substantially autonomous utility operations.

($ millions)	**2024**	2023
Electric and gas revenue		
United States		
ITC	**2,205**	2,098
UNS Energy	**2,731**	2,707
Central Hudson	**1,366**	1,329
Canada		
FortisBC Energy	**1,538**	1,766
FortisAlberta	**770**	699
FortisBC Electric	**481**	460
Newfoundland Power	**770**	759
Maritime Electric	**277**	258
FortisOntario	**235**	217
Caribbean		
Caribbean Utilities	**402**	388
FortisTCI	**118**	108
Total electric and gas revenue	**10,893**	10,789
Other services revenue	**350**	374
Revenue from contracts with customers	**11,243**	11,163
Alternative revenue	**169**	150
Other revenue	**96**	204
Total revenue	**11,508**	11,517

Revenue from Contracts with Customers

Electric and gas revenue includes revenue from the sale and/or delivery of electricity and gas, transmission revenue, and wholesale electric revenue, all based on regulator-approved tariff rates including the flow through of commodity costs.

Other services revenue includes management fees at UNS Energy for the operation of Springerville Units 3 and 4 and revenue from other services that reflect the ordinary business activities of Fortis' utilities. Other services revenue for 2023 also includes revenue from storage optimization activities at Aitken Creek through the date of disposition (Note 21).

Alternative Revenue

Alternative revenue programs allow utilities to adjust future rates in response to past activities or completed events if certain criteria are met. Alternative revenue is recognized on an accrual basis with a corresponding regulatory asset or liability until the revenue is settled. Upon settlement, revenue is not recognized as revenue from contracts with customers but rather as settlement of the regulatory asset or liability. The significant alternative revenue programs of Fortis' utilities are summarized as follows.

ITC's formula rates include an annual true-up mechanism that compares actual revenue requirements to billed revenue, and any under- or over-collections are accrued as a regulatory asset or liability and reflected in future rates within a two year period (Note 8). The formula rates do not require annual regulatory approvals, although inputs remain subject to legal challenge.

UNS Energy's lost fixed-cost recovery mechanism ("LFCR") surcharge recovers lost fixed costs, as measured by a reduction in non-fuel revenue, associated with energy efficiency savings and distributed generation. To recover the LFCR regulatory asset, UNS Energy is required to file an annual LFCR adjustment request with the ACC for the LFCR revenue recognized in the prior year. The recovery is subject to a year-over-year cap of 2% of total retail revenue.

FortisBC Energy and FortisBC Electric have an earnings sharing mechanism that provides for a 50/50 sharing of variances from the allowed ROE. Additionally, variances between forecast and actual customer-use rates and industrial and other customer revenue are captured in a revenue stabilization account and a flow-through deferral account, respectively, to be refunded to, or received from, customers in rates within two years.

Other Revenue

Other revenue primarily includes gains or losses on energy contract derivatives, as well as regulatory deferrals at FortisBC Energy and FortisBC Electric including cost recovery variances from forecast.

6. ACCOUNTS RECEIVABLE AND OTHER CURRENT ASSETS

($ millions)	**2024**	2023
Trade accounts receivable	**1,009**	890
Unbilled accounts receivable	**738**	727
Allowance for credit losses	**(78)**	(68)
	1,669	1,549
Income tax receivable	**—**	78
Other (1)	**217**	191
	1,886	1,818

(1) *Consists mainly of customer billings for non-core services, gas mitigation costs and collateral deposits for gas purchases, and the fair value of derivative instruments (Note 26)*

Allowance for Credit Losses

The allowance for credit losses changed as follows.

($ millions)	**2024**	2023
Balance, beginning of year	**(68)**	(58)
Credit loss expensed	**(30)**	(33)
Credit loss deferral	**(31)**	(13)
Write-offs, net of recoveries	**55**	35
Foreign exchange	**(4)**	1
Balance, end of year	**(78)**	(68)

See Note 26 for disclosure on the Corporation's credit risk.

7. INVENTORIES

($ millions)	**2024**	2023
Materials and supplies	**548**	431
Gas and fuel in storage	**65**	96
Coal inventory	**72**	39
	685	566

8. REGULATORY ASSETS AND LIABILITIES

($ millions)	**2024**	2023
Regulatory assets		
Deferred income taxes (Note 3)	**2,248**	2,058
Deferred energy management costs (1)	**591**	521
Rate stabilization and related accounts (2)	**453**	521
Employee future benefits (Notes 3 and 24)	**235**	254
Derivatives (Notes 3 and 26)	**175**	197
Deferred lease costs (3)	**142**	137
Deferred restoration costs (4)	**133**	115
Manufactured gas plant site remediation deferral (Note 16)	**82**	81
Generation early retirement costs (5)	**66**	64
Renewable natural gas account (6)	**58**	47
Other regulatory assets (7)	**448**	389
Total regulatory assets	**4,631**	4,384
Less: Current portion	**(823)**	(866)
Long-term regulatory assets	**3,808**	3,518

8. REGULATORY ASSETS AND LIABILITIES (cont'd)

($ millions)	**2024**	2023
Regulatory liabilities		
Future cost of removal (Note 3)	**1,728**	1,547
Deferred income taxes (Note 3)	**1,329**	1,280
Employee future benefits (Notes 3 and 24)	**459**	294
Rate stabilization and related accounts (2)	**208**	292
Renewable energy surcharge (8)	**155**	129
Energy efficiency liability (9)	**88**	78
Electric and gas moderator account (10)	**61**	50
AESO charges deferral (11)	**58**	121
Other regulatory liabilities (7)	**205**	167
Total regulatory liabilities	**4,291**	3,958
Less: Current portion	**(595)**	(577)
Long-term regulatory liabilities	**3,696**	3,381

(1) ***Deferred Energy Management Costs:*** Certain regulated subsidiaries provide energy management services to facilitate customer energy efficiency programs where the related expenditures have been deferred as a regulatory asset and are being amortized, and recovered from customers through rates, on a straight-line basis over periods ranging from one to 10 years.

(2) ***Rate Stabilization and Related Accounts:*** Rate stabilization accounts mitigate the earnings volatility otherwise caused by variability in the cost of fuel, purchased power and natural gas above or below a forecast or predetermined level, and by weather-driven volume variability. At certain utilities, revenue decoupling mechanisms minimize the earnings impact of reduced energy consumption as energy efficiency programs are implemented. Resultant deferrals are recovered from, or refunded to, customers in future rates as approved by the respective regulators.

Related accounts include the annual true-up mechanism at ITC (Note 5).

(3) ***Deferred Lease Costs:*** Deferred lease costs at FortisBC Electric primarily relate to the Brilliant Power Purchase Agreement ("BPPA") (Note 15). The depreciation of the asset under finance lease and interest expense on the finance lease obligation are not being fully recovered in current customer rates since these rates only reflect the cash payments required under the BPPA. The annual differences are being deferred as a regulatory asset, which is expected to be recovered from customers in future rates over the term of the lease, which expires in 2056.

(4) ***Deferred Restoration Costs:*** Incremental costs incurred at Central Hudson and Maritime Electric associated with restoration activities due to significant weather events. Incremental costs incurred in excess of that collected in customer rates at Central Hudson are recovered through rate stabilization accounts. The form and recovery period for Maritime Electric will be determined by the regulator.

(5) ***Generation Early Retirement Costs:*** Includes costs at TEP associated with the retirement of the Navajo Generating Station ("Navajo"), Sundt Generating Facility Units 1 and 2, and the San Juan Generating Station ("San Juan"), as approved for recovery by its regulator.

(6) ***Renewable Natural Gas Account:*** Reflects the variance between costs incurred to procure consumable biomethane gas and the related revenue recovered in customer rates. The difference is generally refunded or recovered from customers within one year.

(7) ***Other Regulatory Assets and Liabilities:*** Comprised of regulatory assets and liabilities individually less than $50 million.

(8) ***Renewable Energy Surcharge:*** Under the ACC's Renewable Energy Standard ("RES"), UNS Energy is required to increase its use of renewable energy each year until it represents at least 15% of its total annual retail energy requirements by 2025. The cost of carrying out the plan is recovered from retail customers through a RES surcharge. Any RES surcharge collections above or below the costs incurred to implement the plans are deferred as a regulatory liability or asset.

The ACC measures RES compliance through Renewable Energy Credits ("RECs"). Each REC represents one kilowatt hour generated from renewable resources. When UNS Energy purchases renewable energy, the premium paid above the market cost of conventional power equals the REC recoverable through the RES surcharge. When RECs are purchased, UNS Energy records their cost as long-term other assets (Note 9) with a corresponding regulatory liability to reflect the obligation to use the RECs for future RES compliance. When RECs are utilized for RES compliance, energy supply costs and revenue are recognized in an equal amount.

(9) ***Energy Efficiency Liability:*** The energy efficiency liability primarily relates to Central Hudson's Energy Efficiency Program, established to fund environmental policies associated with energy conservation programs as approved by its regulator.

(10) ***Electric and Gas Moderator Account:*** As part of Central Hudson's general rate applications, certain regulatory assets and liabilities were offset and included in the electric and gas moderator account, which will be used for future customer rate moderation.

(11) ***AESO Charges Deferral:*** Relates to differences in revenue collected and amounts incurred for transmission-related items at FortisAlberta that are expected to be collected or refunded in customer rates.

8. REGULATORY ASSETS AND LIABILITIES (cont'd)

Regulatory assets not earning a return: (i) totalled $1,908 million and $1,995 million as at December 31, 2024 and 2023, respectively; (ii) are primarily related to deferred income taxes and employee future benefits; and (iii) generally do not represent a past cash outlay as they are offset by related liabilities that, likewise, do not incur a carrying cost for rate-making purposes. Recovery periods vary or are yet to be determined by the respective regulators.

9. OTHER ASSETS

($ millions)	**2024**	2023
Employee future benefits (Note 24)	**551**	355
Equity investments [(1)]	**259**	237
Other investments	**225**	180
RECs (Note 8)	**176**	155
Supplemental Executive Retirement Plan ("SERP")	**127**	117
Operating leases (Note 15)	**64**	51
Derivatives	**48**	43
Deferred compensation plan	**29**	22
Other	**174**	138
	1,653	1,298

[(1)] *Includes investments in Belize Electricity and Wataynikaneyap Power*

ITC, UNS Energy and Central Hudson provide additional post-employment benefits through SERPs and deferred compensation plans for directors and officers. The assets held to support these plans are reported separately from the related liabilities (Note 16). Most plan assets are held in trust and funded mainly through life insurance policies and mutual funds. Assets in mutual and money market funds are recorded at fair value on a recurring basis (Note 26).

10. PROPERTY, PLANT AND EQUIPMENT

($ millions)	**Cost**	**Accumulated Depreciation**	**Net Book Value**
2024			
Distribution			
Electric	**15,771**	**(4,078)**	**11,693**
Gas	**7,148**	**(1,866)**	**5,282**
Transmission			
Electric	**23,084**	**(4,865)**	**18,219**
Gas	**2,937**	**(894)**	**2,043**
Generation	**8,056**	**(3,110)**	**4,946**
Other	**5,014**	**(1,809)**	**3,205**
Assets under construction	**3,578**	**—**	**3,578**
Land	**490**	**—**	**490**
	66,078	**(16,622)**	**49,456**
2023			
Distribution			
Electric	14,352	(3,708)	10,644
Gas	6,682	(1,736)	4,946
Transmission			
Electric	19,886	(4,267)	15,619
Gas	2,751	(843)	1,908
Generation	7,192	(2,739)	4,453
Other	4,444	(1,645)	2,799
Assets under construction	2,581	—	2,581
Land	435	—	435
	58,323	(14,938)	43,385

10. PROPERTY, PLANT AND EQUIPMENT (cont'd)

Electric distribution assets are those used to distribute electricity at lower voltages (generally below 69 kilovolts ("kV")). These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment. Gas distribution assets are those used to transport natural gas at low pressures (generally below 2,070 kilopascals ("kPa")). These assets include distribution stations, telemetry, distribution pipe for mains and services, meter sets and other related equipment.

Electric transmission assets are those used to transmit electricity at higher voltages (generally at 69 kV and higher). These assets include poles, wires, switching equipment, transformers, support structures and other related equipment. Gas transmission assets are those used to transport natural gas at higher pressures (generally at 2,070 kPa and higher). These assets include transmission stations, telemetry, transmission pipe and other related equipment.

Generation assets are those used to generate electricity. These assets include hydroelectric and thermal generation stations, gas and combustion turbines, coal-fired generating stations, dams, reservoirs, photovoltaic systems, wind resources and other related equipment.

Other assets include buildings, equipment, vehicles, inventory, and information technology assets.

As at December 31, 2024, assets under construction largely reflect ongoing transmission projects at ITC and UNS Energy, as well as the Roadrunner Reserve battery storage projects at UNS Energy and the Eagle Mountain Pipeline project at FortisBC Energy.

The cost of PPE under finance lease as at December 31, 2024 was $324 million (2023 - $318 million) and related accumulated depreciation was $119 million (2023 - $113 million) (Note 15).

Jointly Owned Facilities

UNS Energy and ITC hold undivided interests in jointly owned generating facilities and transmission systems, are entitled to their pro rata share of the PPE, and are proportionately liable for the associated operating costs and liabilities. As at December 31, 2024, interests in jointly owned facilities consisted of the following.

($ millions, except as indicated)	**Ownership** *(%)*	**Cost**	**Accumulated Depreciation**	**Net Book Value**
Transmission Facilities	Various	**1,704**	**(489)**	**1,215**
Springerville Common Facilities	86.0	**580**	**(344)**	**236**
Springerville Coal Handling Facilities	83.0	**299**	**(154)**	**145**
Four Corners Units 4 and 5 ("Four Corners")	7.0	**311**	**(155)**	**156**
Gila River Common Facilities	50.0	**131**	**(52)**	**79**
Luna Energy Facility ("Luna")	33.3	**101**	**3**	**104**
		3,126	**(1,191)**	**1,935**

11. INTANGIBLE ASSETS

($ millions)	**Cost**	**Accumulated Amortization**	**Net Book Value**
2024			
Computer software	**1,035**	**(493)**	**542**
Land, transmission and water rights	**1,188**	**(210)**	**978**
Other	**143**	**(95)**	**48**
Assets under construction	**93**	**—**	**93**
	2,459	**(798)**	**1,661**
2023			
Computer software	1,040	(528)	512
Land, transmission and water rights	1,071	(182)	889
Other	132	(81)	51
Assets under construction	58	—	58
	2,301	(791)	1,510

Included in the cost of land, transmission and water rights as at December 31, 2024 was $123 million (2023 - $113 million) not subject to amortization. Amortization expense was $153 million for 2024 (2023 - $150 million). Amortization is estimated to average approximately $97 million for each of the next five years.

12. GOODWILL

($ millions)	**2024**	2023
Balance, beginning of year	**12,184**	12,464
Disposition of Aitken Creek (Note 21)	**—**	(27)
Foreign currency translation impacts [1]	**928**	(253)
Balance, end of year	**13,112**	12,184

[1] *Relates to the translation of goodwill associated with the acquisitions of ITC, UNS Energy, Central Hudson, Caribbean Utilities and FortisTCI, whose functional currency is the U.S. dollar*

No goodwill impairment was recognized by the Corporation in 2024 or 2023.

13. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

($ millions)	**2024**	2023
Trade accounts payable	**1,121**	990
Customer and other deposits	**360**	263
Dividends payable	**314**	295
Interest payable	**305**	274
Accrued taxes other than income taxes	**304**	268
Employee compensation and benefits payable	**303**	275
Gas and fuel cost payable	**221**	232
Derivatives (Note 26)	**169**	170
Income tax payable	**33**	—
Employee future benefits (Note 24)	**29**	28
Other	**194**	177
	3,353	2,972

14. LONG-TERM DEBT

($ millions)	Maturity Date	**2024**	2023
ITC			
Secured U.S. First Mortgage Bonds - 4.34% weighted average fixed rate (2023 - 4.22%)	2027-2055	**3,944**	3,268
Secured U.S. Senior Notes - 4.16% weighted average fixed rate (2023 - 4.00%)	2028-2055	**1,511**	1,278
Unsecured U.S. Senior Notes - 4.37% weighted average fixed rate (2023 - 4.16%)	2026-2043	**5,610**	5,165
Unsecured U.S. Shareholder Note - 6.00% fixed rate (2023 - 6.00%)	2028	**286**	263
UNS Energy			
Unsecured U.S. Fixed Rate Notes - 4.09% weighted average fixed rate (2023 - 3.80%)	2026-2053	**4,172**	3,668
Central Hudson			
Unsecured U.S. Promissory Notes - 4.38% weighted average fixed and variable rate (2023 - 4.27%)	2025-2060	**1,974**	1,687
FortisBC Energy			
Unsecured Debentures - 4.61% weighted average fixed rate (2023 - 4.61%)	2026-2052	**3,295**	3,295
FortisAlberta			
Unsecured Debentures - 4.63% weighted average fixed rate (2023 - 4.52%)	2034-2054	**2,835**	2,685
FortisBC Electric			
Unsecured Debentures - 4.72% weighted average fixed rate (2023 - 4.70%)	2035-2054	**960**	860
Other Electric			
Secured First Mortgage Sinking Fund Bonds - 5.24% weighted average fixed rate (2023 - 5.24%)	2026-2060	**739**	748
Secured First Mortgage Bonds - 5.29% weighted average fixed rate (2023 - 5.29%)	2025-2061	**320**	320
Unsecured Senior Notes - 4.61% weighted average fixed rate (2023 - 4.45%)	2041-2054	**207**	152
Unsecured U.S. Senior Loan Notes and Bonds - 5.03% weighted average fixed and variable rate (2023 - 4.89%)	2025-2052	**876**	702
Corporate and Other			
Unsecured U.S. Senior Notes and Promissory Notes - 3.79% weighted average fixed rate (2023 - 3.82%)	2026-2044	**2,172**	2,251
Unsecured Debentures - 6.51% fixed rate (2023 - 6.51%)	2039	**200**	200
Unsecured Senior Notes - 4.11% weighted average fixed rate (2023 - 4.10%)	2028-2033	**2,000**	1,500
Long-term classification of credit facility borrowings		**2,216**	1,572
Fair value adjustment - ITC acquisition		**88**	89
Total long-term debt (Note 26)		**33,405**	29,703
Less: Deferred financing costs and debt discounts		**(191)**	(172)
Less: Current installments of long-term debt		**(1,990)**	(2,296)
		31,224	27,235

Most long-term debt at the Corporation's regulated utilities is redeemable at the option of the respective utility at the greater of par or a specified price, together with accrued and unpaid interest. Security, if provided, is typically through a fixed or floating first charge on specific assets of the utility.

14. LONG-TERM DEBT (cont'd)

The Corporation's unsecured debentures and senior notes are redeemable at the option of Fortis at the greater of par or a specified price together with accrued and unpaid interest.

Certain long-term debt agreements have covenants that provide that the Corporation shall not declare, pay or make any restricted payments, including special or extraordinary dividends, if immediately thereafter its consolidated debt to consolidated capitalization ratio would exceed 65%.

Significant Long-Term Debt Issuances in 2024	Month Issued	Interest Rate (%)	Maturity		Amount ($ millions)	Use of Proceeds
ITC						
Secured senior notes	January	5.98	2034	**US**	**85**	(1) (2) (3)
First mortgage bonds	January	5.11	2029	**US**	**75**	(1) (2) (3)
First mortgage bonds	January	5.38	2034	**US**	**75**	(1) (2) (3)
Unsecured senior notes	May	5.65	2034	**US**	**400**	(3) (4)
First mortgage bonds	December	4.88	2035	**US**	**125**	(1) (2) (3)
First mortgage bonds	December	5.25	2043	**US**	**125**	(1) (2) (3)
UNS Energy						
Unsecured senior notes	May	5.60	2036	**US**	**30**	(1) (3)
Unsecured senior notes	August	5.20	2034	**US**	**400**	(3) (4)
Central Hudson						
Senior notes	April	5.59	2031	**US**	**25**	(1) (3)
Senior notes	April	5.69	2034	**US**	**35**	(1) (3)
Senior notes	October	4.88	2029	**US**	**25**	(3) (4)
Senior notes	October	5.30	2034	**US**	**44**	(3) (4)
Senior notes	October	5.40	2036	**US**	**35**	(3) (4)
FortisBC Electric						
Unsecured debentures	August	4.92	2054		**100**	(1)
FortisAlberta						
Unsecured debentures	May	4.90	2054		**300**	(1) (2) (3) (4)
Caribbean Utilities						
Unsecured senior notes	May	6.17	2039	**US**	**40**	(1) (2) (3)
Unsecured senior notes	May	6.37	2049	**US**	**40**	(1) (2) (3)
FortisOntario						
Unsecured senior notes	August	5.05	2054		**55**	(1)
Fortis						
Unsecured senior notes	September	4.17	2031		**500**	(1) (3) (4)

(1) *Repay short-term and/or credit facility borrowings*
(2) *Fund capital expenditures*
(3) *General corporate purposes*
(4) *Repay maturing long-term debt*

14. LONG-TERM DEBT (cont'd)

Long-Term Debt Repayments

The consolidated requirements to meet principal repayments and maturities in each of the next five years and thereafter are as follows.

($ millions)	**Total**
2025	1,990
2026	2,585
2027	2,541
2028	1,499
2029	1,024
Thereafter	23,766
	33,405

In December 2024, Fortis filed a short-form base shelf prospectus with a 25-month life under which it may issue common or preference shares, subscription receipts, or debt securities in an aggregate principal amount of up to $2.0 billion. Fortis also reestablished the at-the-market equity program ("ATM Program") pursuant to the short-form base shelf prospectus, which allows the Corporation to issue up to $500 million of common shares from treasury to the public from time to time, at the Corporation's discretion, effective until January 10, 2027. As at December 31, 2024, $500 million remained available under the ATM Program and $1.5 billion remained available under the short-form base shelf prospectus.

Credit Facilities

($ millions)	Regulated Utilities	Corporate and Other	**2024**	2023
Total credit facilities	4,396	1,946	**6,342**	6,176
Credit facilities utilized:				
Short-term borrowings [1]	(98)	—	**(98)**	(119)
Long-term debt (including current portion) [2]	(1,335)	(881)	**(2,216)**	(1,572)
Letters of credit outstanding	(81)	(21)	**(102)**	(101)
Credit facilities unutilized	2,882	1,044	**3,926**	4,384

[1] *The weighted average interest rate was approximately 6.1% (2023 - 6.9%).*

[2] *The weighted average interest rate was approximately 4.6% (2023 - 6.2%). The current portion was $1,860 million (2023 - $1,160 million).*

Credit facilities are syndicated primarily with large banks in Canada and the U.S., with no one bank holding more than approximately 20% of the Corporation's total revolving credit facilities. Approximately $5.8 billion of the total credit facilities are committed with maturities ranging from 2025 through 2029.

In April 2024, FortisBC Energy increased its operating credit facility from $700 million to $900 million and extended the maturity to July 2028. In May 2024, FortisBC Electric increased its operating credit facility from $150 million to $200 million and extended the maturity to April 2028.

In May 2024, the Corporation extended the maturity on its unsecured US$500 million non-revolving term credit facility to May 2025. Half of the term credit facility was repaid in the third quarter of 2024 and the remaining US$250 million has been fully utilized as at December 31, 2024. The facility is repayable at any time without penalty. In June 2024, the Corporation amended its $1.3 billion revolving term committed credit facility to extend the maturity to July 2029.

In August 2024, Newfoundland Power increased its operating credit facility from $100 million to $130 million and extended the maturity to August 2029.

14. LONG-TERM DEBT (cont'd)

Consolidated credit facilities of approximately $6.3 billion as at December 31, 2024 are itemized below.

($ millions)		**Amount**	Maturity
Unsecured committed revolving credit facilities			
Regulated utilities			
ITC [(1)]	**US**	**1,000**	2028
UNS Energy	**US**	**375**	2027
Central Hudson	**US**	**250**	2029
FortisBC Energy		**900**	2028
FortisAlberta		**250**	2029
FortisBC Electric		**200**	2028
Other Electric		**285**	(2)
Other Electric	**US**	**83**	2025
Corporate and Other		**1,350**	(3)
Other facilities			
Regulated utilities			
Central Hudson - uncommitted credit facility	**US**	**60**	n/a
FortisBC Energy - uncommitted credit facility		**55**	2025
FortisBC Electric - unsecured demand overdraft facility		**10**	n/a
Other Electric - unsecured demand facilities		**20**	n/a
Other Electric - unsecured demand facility and emergency standby loan	**US**	**93**	2025
Corporate and Other			
Unsecured non-revolving facility	**US**	**250**	2025
Unsecured revolving facility	**US**	**150**	2025
Unsecured non-revolving facility		**21**	n/a

(1) *ITC also has a US$400 million commercial paper program, under which $nil was outstanding as at December 31, 2024 and 2023*
(2) *$90 million in 2027, $65 million in 2027, and $130 million in 2029*
(3) *$50 million in 2026 and $1.3 billion in 2029*

15. LEASES

The Corporation and its subsidiaries lease office facilities, utility equipment, land, and communication tower space with remaining terms of up to 23 years, with optional renewal terms. Certain lease agreements include rental payments adjusted periodically for inflation or require the payment of real estate taxes, insurance, maintenance, or other operating expenses associated with the leased premises.

The Corporation's subsidiaries also have finance leases related to generating facilities with remaining terms of up to 31 years.

Leases were presented on the consolidated balance sheets as follows.

($ millions)	**2024**	2023
Operating leases		
Other assets	**64**	51
Accounts payable and other current liabilities	**(17)**	(12)
Other liabilities	**(47)**	(39)
Finance leases [(1)]		
Regulatory assets	**142**	137
PPE, net	**205**	205
Accounts payable and other current liabilities	**(4)**	(3)
Finance leases	**(343)**	(339)

(1) *FortisBC Electric has a finance lease for the BPPA (Note 8), which relates to the sale of the output of the Brilliant hydroelectric plant, and for the Brilliant Terminal Station ("BTS"), which relates to the use of the station. Both agreements expire in 2056. In exchange for the specified take-or-pay amounts of power, the BPPA requires semi-annual payments based on a return on capital, which includes the original and ongoing capital cost, and related variable power purchase costs. The BTS requires semi-annual payments based on a charge related to the recovery of the capital cost of the BTS, and related variable operating costs.*

15. LEASES (cont'd)

The components of lease expense were as follows.

($ millions)	**2024**	2023
Operating lease cost	**19**	12
Finance lease cost:		
Amortization	**2**	3
Interest	**33**	33
Variable lease cost	**21**	23
Total lease cost	**75**	71

As at December 31, 2024, the present value of minimum lease payments was as follows.

($ millions)	Operating Leases	Finance Leases	**Total**
2025	18	37	**55**
2026	15	37	**52**
2027	12	37	**49**
2028	6	37	**43**
2029	4	37	**41**
Thereafter	19	954	**973**
	74	1,139	**1,213**
Less: Imputed interest	(10)	(792)	**(802)**
Total lease obligations	64	347	**411**
Less: Current installments	(17)	(4)	**(21)**
	47	343	**390**

Supplemental lease information follows.

($ millions, except as indicated)	**2024**	2023
Weighted average remaining lease term *(years)*		
Operating leases	**7**	7
Finance leases	**31**	32
Weighted average discount rate *(%)*		
Operating leases	**4.6**	4.5
Finance leases	**5.0**	5.0

16. OTHER LIABILITIES

($ millions)	**2024**	2023
Employee future benefits (Note 24)	**446**	527
AROs (Note 3)	**249**	163
Customer and other deposits	**128**	168
Stock-based compensation plans (Note 20)	**113**	82
Manufactured gas plant site remediation *(1)*	**101**	94
Derivatives (Note 26)	**66**	48
Deferred compensation plan (Note 9)	**63**	54
Operating leases (Note 15)	**47**	39
Mine reclamation obligations *(2)*	**40**	30
Retail energy contract *(3)*	**20**	27
Other	**41**	38
	1,314	1,270

16. OTHER LIABILITIES (Cont'd)

[1] Environmental regulations require Central Hudson to investigate sites at which it or its predecessors once owned and/or operated manufactured gas plants and, if necessary, remediate those sites. Costs are accrued based on the amounts that can be reasonably estimated. Central Hudson has notified its insurers that it intends to seek reimbursement where insurance coverage exists. Differences between actual costs and the associated rate allowances are deferred as a regulatory asset for future recovery (Note 8).

[2] TEP pays ongoing reclamation costs related to two coal mines that supply generating facilities in which it has an ownership interest but does not operate. Costs are deferred as a regulatory asset and recovered from customers as permitted by the regulator. TEP's share of the reclamation costs is estimated to be $49 million. The present value of the estimated future liability in included in other liabilities.

[3] FortisAlberta has an agreement with a retail energy provider to act as its default retailer to eligible customers under the regulated retail option. As part of this agreement FortisAlberta received an upfront payment which is being amortized to revenue over the eight year agreement.

17. EARNINGS PER COMMON SHARE

Diluted earnings per share ("EPS") was calculated using the treasury stock method for stock options.

	2024			2023		
	Net Earnings to Common Shareholders *($ millions)*	**Weighted Average Shares** *(# millions)*	**EPS** *($)*	Net Earnings to Common Shareholders *($ millions)*	Weighted Average Shares *(# millions)*	EPS *($)*
Basic EPS	**1,606**	**495.0**	**3.24**	1,506	486.3	3.10
Potential dilutive effect of stock options (Note 20)	**—**	**0.2**	**—**	—	0.2	—
Diluted EPS	**1,606**	**495.2**	**3.24**	1,506	486.5	3.10

18. PREFERENCE SHARES

Authorized

An unlimited number of first preference shares and second preference shares, without nominal or par value.

Issued and Outstanding First Preference Shares	**2024**		2023	
	Number of Shares *(thousands)*	**Amount** *($ millions)*	Number of Shares *(thousands)*	Amount *($ millions)*
Series F	**5,000**	**122**	5,000	122
Series G	**9,200**	**225**	9,200	225
Series H	**7,665**	**188**	7,665	188
Series I	**2,335**	**57**	2,335	57
Series J	**8,000**	**196**	8,000	196
Series K	**10,000**	**244**	10,000	244
Series M	**24,000**	**591**	24,000	591
	66,200	**1,623**	66,200	1,623

18. PREFERENCE SHARES (Cont'd)

Characteristics of the first preference shares are as follows:

First Preference Shares [1] [2]	**Dividend Rate** *(%)*	**Annual Dividend** *($)*	**Reset Dividend Yield** *(%)*	**Redemption and/or Conversion Option Date**	**Redemption Value** *($)*	**Right to Convert on a One-For-One Basis**
Perpetual fixed rate						
Series F	4.90	1.2250	—	Currently Redeemable	25.00	—
Series J	4.75	1.1875	—	Currently Redeemable	25.00	—
Fixed rate reset [3] [4]						
Series G	6.12	1.5308	2.13	September 1, 2028	25.00	—
Series H	1.84	0.4588	1.45	June 1, 2025	25.00	Series I
Series K	5.47	1.3673	2.05	March 1, 2029	25.00	Series L
Series M	5.49	1.3733	2.48	December 1, 2029	25.00	Series N
Floating rate reset [4] [5]						
Series I	[5]	—	1.45	June 1, 2025	25.00	Series H
Series L	—	—	—	—	—	Series K
Series N	—	—	—	—	—	Series M

[1] *Holders are entitled to receive a fixed or floating cumulative quarterly cash dividend as and when declared by the Board of Directors of the Corporation, payable in equal installments on the first day of each quarter.*

[2] *On or after the specified redemption dates, the Corporation has the option to redeem for cash the outstanding first preference shares, in whole or in part, at the specified per share redemption value plus all accrued and unpaid dividends up to but excluding the dates fixed for redemption, and in the case of the first preference shares that reset, on every fifth anniversary date thereafter.*

[3] *On the redemption and/or conversion option date, and on each five-year anniversary thereafter, the reset annual dividend per share will be determined by multiplying $25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date, plus the applicable reset dividend yield.*

[4] *On each conversion option date, the holders have the option, subject to certain conditions, to convert any or all of their shares into an equal number of Cumulative Redeemable first preference shares of a specified series.*

[5] *The floating quarterly dividend rate will be reset every quarter based on the then current three-month Government of Canada Treasury Bill rate plus the applicable reset dividend yield.*

On the liquidation, dissolution or winding-up of Fortis, holders of common shares are entitled to participate ratably in any distribution of assets of Fortis, subject to the rights of holders of first and second preference shares, and any other class of shares of the Corporation entitled to receive the assets of the Corporation on such a distribution, in priority to or ratably with the holders of the common shares.

19. ACCUMULATED OTHER COMPREHENSIVE INCOME

($ millions)	Opening Balance	Net Change	Ending Balance
2024			
Unrealized foreign currency translation gains (losses)			
Net investments in foreign operations	**1,059**	**1,653**	**2,712**
Hedges of net investments in foreign operations	**(452)**	**(262)**	**(714)**
Income tax recovery	**4**	**14**	**18**
	611	**1,405**	**2,016**
Other			
Interest rate hedges (Note 26)	**62**	**10**	**72**
Unrealized employee future benefits (losses) gains (Note 24)	**(9)**	**2**	**(7)**
Income tax expense	**(11)**	**(3)**	**(14)**
	42	**9**	**51**
Accumulated other comprehensive income	**653**	**1,414**	**2,067**
2023			
Unrealized foreign currency translation gains (losses)			
Net investments in foreign operations	1,495	(436)	1,059
Hedges of net investments in foreign operations	(530)	78	(452)
Income tax recovery (expense)	7	(3)	4
	972	(361)	611
Other			
Interest rate hedges (Note 26)	49	13	62
Unrealized employee future benefits losses (Note 24)	(6)	(3)	(9)
Income tax expense	(7)	(4)	(11)
	36	6	42
Accumulated other comprehensive income	1,008	(355)	653

20. STOCK-BASED COMPENSATION PLANS

Stock Options

Beginning January 1, 2022, the Corporation no longer grants stock options. Existing options to purchase common shares of the Corporation are exercisable for a period of 10 years from the grant date, expire no later than three years after the death or retirement of the optionee, and vest evenly over a four year period on each anniversary of the grant date. Compensation expense related to stock options was measured at the grant date using the Black-Scholes fair value option-pricing model with each grant amortized to compensation expense evenly over the four year vesting period, with the offsetting entry to additional paid-in capital. Fortis satisfies stock option exercises by issuing common shares from treasury. Upon exercise, proceeds are credited to capital stock at the option prices and the fair value of the options, as previously recognized, is reclassified from additional paid-in capital to capital stock.

As at December 31, 2024, the Corporation had 1.5 million stock options outstanding (2023 - 1.9 million) with a weighted average exercise price of $48.96 (2023 - $48.12). There were 1.4 million options vested as of December 31, 2024 (2023 – 1.6 million) with a weighted average exercise price of $48.87 (2023 - $47.19).

In 2024, 0.4 million stock options were exercised (2023 - 0.3 million) for cash proceeds of $15 million (2023 - $13 million) and an intrinsic value realized by option holders of $5 million (2023 - $6 million).

DSUs

Directors of the Corporation who are not officers are eligible for grants of DSUs representing the equity portion of their annual compensation. Directors can also elect to receive credit for their quarterly cash retainer in a notional account of DSUs in lieu of cash. The Corporation may also determine that special circumstances justify the grant of additional DSUs to a director.

Beginning in 2024, in any year in which a director satisfies their share ownership target, the director may elect to receive a portion of their equity compensation in cash or common shares, with the remaining portion to be granted as DSUs. Common share elections are satisfied quarterly through purchases on the Toronto Stock Exchange or the New York Stock Exchange.

Each DSU vests at the grant date, has an underlying value equivalent to that of one common share of the Corporation, is entitled to commensurate notional common share dividends, and is settled in cash.

20. STOCK-BASED COMPENSATION PLANS (cont'd)

DSUs (cont'd)

The following table summarizes information related to DSUs.

	2024	2023
Number of units *(thousands)*		
Beginning of year	**241**	224
Granted	**29**	40
Notional dividends reinvested	**10**	10
Paid out	**(39)**	(33)
End of year	**241**	241

The accrued liability has been recognized at the respective December 31st VWAP and included in other liabilities (Note 16). The accrued liability, compensation expense and cash payout were not material for 2024 or 2023.

PSUs

Senior management of the Corporation and its subsidiaries, and all ITC employees, are eligible for grants of PSUs representing a component of their long-term compensation.

Each PSU vests over a three year period, has an underlying value equivalent to that of one common share of the Corporation, and is entitled to commensurate notional common share dividends. PSUs are generally settled in cash with cash payouts calculated at the end of the three year vesting period as the product of: (i) the number of units vested; (ii) the VWAP of the Corporation's common shares for the five trading days prior to the vesting date; and (iii) a payout percentage that may range from 0% to 200%. Effective with the 2024 grant, PSUs granted under the Corporation's Omnibus Equity Plan can be settled in cash or common shares of the Corporation. PSUs settled through common shares will be satisfied by issuing common shares from treasury.

The payout percentage is based on the Corporation's performance over the three year vesting period, mainly determined by: (i) the Corporation's total shareholder return as compared to a predefined peer group of companies; (ii) the Corporation's cumulative EPS, or for subsidiaries the company's cumulative net income, as compared to the target established at the time of the grant; and (iii) beginning with the 2022 PSU grant, the Corporation's Scope 1 carbon reduction performance as compared to target established at the time of the grant. In addition, the 2023 PSU grant included a payout modifier based on the achievement of diversity, equity and inclusion goals.

The following table summarizes information related to PSUs.

	2024	2023
Number of units *(thousands)*		
Beginning of year	**1,942**	1,790
Granted	**788**	722
Notional dividends reinvested	**78**	66
Paid out	**(609)**	(606)
Cancelled/forfeited	**(28)**	(30)
End of year	**2,171**	1,942
Additional information *($ millions)*		
Compensation expense recognized	**53**	45
Compensation expense unrecognized (1)	**34**	28
Cash payout	**44**	46
Accrued liability as at December 31 (2)	**105**	90
Aggregate intrinsic value as at December 31 (3)	**139**	118

(1) *Relates to unvested PSUs and is expected to be recognized over a weighted average period of two years*

(2) *Recognized at the respective December 31st VWAP and included in accounts payable and other current liabilities and in other liabilities (Notes 13 and 16)*

(3) *Relates to outstanding PSUs and reflects a weighted average contractual life of one year*

20. STOCK-BASED COMPENSATION PLANS (cont'd)

RSUs

Senior management of the Corporation and its subsidiaries, and all ITC employees, are eligible for grants of RSUs representing a component of their long-term compensation.

Each RSU vests over a three year period, has an underlying value equivalent to that of one common share of the Corporation, is entitled to commensurate notional common share dividends, and is settled in cash or common shares of the Corporation. Beginning with the 2024 grant, RSUs settled through common shares will be satisfied by issuing common shares from treasury.

The following table summarizes information related to RSUs.

	2024	2023
Number of units *(thousands)*		
Beginning of year	**1,079**	977
Granted	**464**	416
Notional dividends reinvested	**38**	35
Paid out	**(357)**	(323)
Cancelled/forfeited	**(23)**	(26)
End of year	**1,201**	1,079
Additional information *($ millions)*		
Compensation expense recognized	**29**	21
Compensation expense unrecognized (1)	**21**	17
Cash payout	**19**	17
Accrued liability as at December 31 (2)	**54**	42
Aggregate intrinsic value as at December 31 (3)	**75**	59

(1) Relates to unvested RSUs and is expected to be recognized over a weighted average period of two years
(2) Recognized at the respective December 31st VWAP and included in accounts payable and other current liabilities and in long-term other liabilities (Notes 13 and 16)
(3) Relates to outstanding RSUs and reflects a weighted average contractual life of one year

Share-settlements were not material for 2024 and 2023.

21. DISPOSITION

On November 1, 2023, FortisBC Holdings Inc. ("FHI") completed the sale of its Aitken Creek business to a subsidiary of Enbridge Inc. for approximately $470 million including working capital and closing adjustments, following the satisfaction of all regulatory requirements. The transaction reflected a March 31, 2023 effective date. A gain on disposition of $23 million ($10 million after tax), net of transaction costs, was recognized in the Corporate and Other segment.

For the seven-month period between the March 31, 2023 effective date and the November 1, 2023 disposition date, Aitken Creek recognized net earnings, excluding the gain as noted above, of $5 million.

From January 1, 2023 through to the November 1, 2023 disposition date, excluding the gain, Aitken Creek recognized net earnings of $20 million.

22. OTHER INCOME, NET

($ millions)	**2024**	2023
Equity component of AFUDC	**139**	101
Non-service component of net periodic benefit cost	**73**	62
Interest income [(1)]	**64**	76
Equity income	**14**	14
Gain on disposal of Aitken Creek, pre-tax (Note 21)	**—**	23
Gain on derivatives, net	**—**	9
Net foreign exchange (loss) gain	**(10)**	4
Other	**8**	2
	288	291

[(1)] *Includes interest on short-term deposits, as well as interest on regulatory deferrals, including the PPFAC at TEP and UNS Electric*

23. INCOME TAXES

Deferred Income Tax Assets and Liabilities

The significant components of deferred income tax assets and liabilities consisted of the following.

($ millions)	**2024**	2023
Gross deferred income tax assets		
Regulatory liabilities	**659**	636
Tax loss and credit carryforwards	**629**	600
Employee future benefits	**123**	136
Other	**216**	144
	1,627	1,516
Valuation allowance	**(50)**	(23)
Net deferred income tax asset	**1,577**	1,493
Gross deferred income tax liabilities		
PPE	**(5,993)**	(5,355)
Regulatory assets	**(432)**	(372)
Intangible assets	**(172)**	(165)
	(6,597)	(5,892)
Net deferred income tax liability	**(5,020)**	(4,399)

Income Tax Expense

($ millions)	**2024**	2023
Canadian		
Earnings before income tax expense	**518**	526
Current income tax	**154**	71
Deferred income tax	**(87)**	17
Total Canadian	**67**	88
Foreign		
Earnings before income tax expense	**1,656**	1,544
Current income tax	**38**	17
Deferred income tax	**241**	255
Total Foreign	**279**	272
Income tax expense	**346**	360

Income tax expense differs from the amount that would be expected to be generated by applying the enacted combined Canadian federal and provincial statutory income tax rate to earnings before income tax expense.

23. INCOME TAXES (cont'd)

The following is a reconciliation of consolidated statutory taxes to consolidated effective taxes.

($ millions, except as indicated)	**2024**	2023
Earnings before income tax expense	**2,174**	2,070
Combined Canadian federal and provincial statutory income tax rate *(%)*	**30.0**	30.0
Expected federal and provincial taxes at statutory rate	**652**	621
(Decrease)/Increase resulting from:		
Foreign and other statutory rate differentials	**(169)**	(166)
Effects of rate-regulated accounting	**(97)**	(98)
Tax credits	**(36)**	(14)
Enactment of new tax laws, change in tax rate	**2**	12
Other	**(6)**	5
Income tax expense	**346**	360
Effective tax rate *(%)*	**15.9**	17.4

Income Tax Carryforwards[1]

($ millions)	Expiring Year	**2024**
Canadian		
Non-capital loss	2028-2044	**155**
Other tax credits and restricted interest and financing expenses[2]	2026-2044	**77**
		232
Foreign		
Federal and state net operating loss[3]	2029-2044	**315**
Other tax credits	2027-2044	**82**
		397
Total income tax carryforwards recognized		**629**

[1] *Income tax carryforwards presented on an after-tax basis*

[2] *Indefinite carryforward for restricted interest and financing expenses*

[3] *Indefinite carryforward for Federal net operating losses, and for states that have adopted the Federal provisions, effective for tax years beginning after December 31, 2017*

The Corporation and certain of its subsidiaries are subject to taxation in Canada, the United States and other foreign jurisdictions. The material jurisdictions in which the Corporation is subject to potential income tax compliance examinations include the United States (Federal, Arizona, Kansas, Iowa, Michigan, Minnesota and New York) and Canada (Federal, British Columbia and Alberta). The Corporation's 2020 to 2024 taxation years are still open for audit in Canadian jurisdictions, and its 2020 to 2024 taxation years are still open for audit in United States jurisdictions.

24. EMPLOYEE FUTURE BENEFITS

For DBP and OPEB plans, the benefit obligation and fair value of plan assets are measured as at December 31.

For the Corporation's Canadian and Caribbean subsidiaries, actuarial valuations to determine funding contributions for pension plans are required at least every three years. The most recent valuations were as of December 31, 2021 for certain FortisBC Energy and FortisBC Electric plans; December 31, 2022 for the remaining FortisBC Energy and FortisBC Electric plans, Newfoundland Power, FortisAlberta and FortisOntario; December 31, 2023 for the Corporation; and December 31, 2024 for Caribbean Utilities.

ITC, UNS Energy and Central Hudson perform annual actuarial valuations as their funding requirements are based on maintaining minimum annual targets, all of which have been met.

The Corporation's investment policy is to ensure that the DBP and OPEB plan assets, together with expected contributions, are invested in a prudent and cost-effective manner to optimally meet the liabilities of the plans. The investment objective is to maximize returns in order to manage the funded status of the plans and minimize the Corporation's cost over the long term, as measured by both cash contributions and recognized expense.

24. EMPLOYEE FUTURE BENEFITS (cont'd)

Allocation of Plan Assets *(weighted average %)*	**2024 Target Allocation**	**2024**	2023
Equities	**46**	**47**	46
Fixed income	**46**	**45**	45
Real estate	**7**	**7**	8
Cash and other	**1**	**1**	1
	100	**100**	100

Fair Value of Plan Assets

($ millions)	**Level 1** [(1)]	**Level 2** [(1)]	**Level 3** [(1)]	**Total**
2024				
Equities	**773**	**1,168**	**—**	**1,941**
Fixed income	**268**	**1,561**	**—**	**1,829**
Real estate	**—**	**—**	**300**	**300**
Cash and other	**23**	**26**	**—**	**49**
	1,064	**2,755**	**300**	**4,119**
2023				
Equities	666	1,059	—	1,725
Fixed income	232	1,447	—	1,679
Real estate	—	—	291	291
Cash and other	34	14	—	48
	932	2,520	291	3,743

(1) *See Note 26 for a description of the fair value hierarchy.*

The following table reconciles the changes in the fair value of plan assets that have been measured using Level 3 inputs.

($ millions)	**2024**	2023
Balance, beginning of year	**291**	282
Return on plan assets	**5**	(9)
Foreign currency translation	**3**	(1)
Purchases, sales and settlements	**1**	19
Balance, end of year	**300**	291

24. EMPLOYEE FUTURE BENEFITS (cont'd)

Funded Status

	DBP Plans		OPEB Plans	
($ millions)	**2024**	2023	**2024**	2023
Change in benefit obligation [(1)]				
Balance, beginning of year	**3,347**	3,063	**596**	582
Service costs	**74**	62	**25**	22
Employee contributions	**17**	17	**4**	3
Interest costs	**161**	159	**29**	30
Benefits paid	**(181)**	(169)	**(35)**	(31)
Actuarial (gains) losses	**(115)**	255	**(49)**	(1)
Past service credits/plan amendments	**(3)**	—	**—**	—
Foreign currency translation	**140**	(40)	**33**	(9)
Balance, end of year [(2)]	**3,440**	3,347	**603**	596
Change in value of plan assets				
Balance, beginning of year	**3,313**	3,079	**430**	389
Actual return on plan assets	**249**	373	**50**	61
Benefits paid	**(174)**	(162)	**(31)**	(26)
Employee contributions	**17**	17	**4**	3
Employer contributions	**57**	46	**14**	13
Foreign currency translation	**151**	(40)	**39**	(10)
Balance, end of year	**3,613**	3,313	**506**	430
Funded status	**173**	(34)	**(97)**	(166)
Balance sheet presentation				
Other assets (Note 9)	**395**	236	**156**	119
Other current liabilities (Note 13)	**(16)**	(15)	**(13)**	(13)
Other liabilities (Note 16)	**(206)**	(255)	**(240)**	(272)
	173	(34)	**(97)**	(166)

(1) Amounts reflect projected benefit obligation for DBP plans and accumulated benefit obligation for OPEB plans.

(2) The accumulated benefit obligation, which excludes assumptions about future salary levels, for DBP plans was $3,144 million as at December 31, 2024 (2023 - $2,983 million).

For those DBP plans for which the projected benefit obligation exceeded the fair value of plan assets as at December 31, 2024, the obligation was $1,668 million compared to plan assets of $1,460 million (2023 - $1,940 million and $1,681 million, respectively).

For those DBP plans for which the accumulated benefit obligation exceeded the fair value of plan assets as at December 31, 2024, the obligation was $195 million compared to plan assets of $62 million (2023 - $268 million and $130 million, respectively).

For those OPEB plans for which the accumulated benefit obligation exceeded the fair value of plan assets as at December 31, 2024, the obligation was $296 million compared to plan assets of $44 million (2023 - $320 million and $36 million, respectively).

Net Benefit Cost (1)

	DBP Plans		OPEB Plans	
($ millions)	**2024**	2023	**2024**	2023
Service costs	**74**	62	**25**	22
Interest costs	**161**	159	**29**	30
Expected return on plan assets	**(221)**	(202)	**(26)**	(22)
Amortization of actuarial gains	**(1)**	(9)	**(17)**	(19)
Amortization of past service credits/plan amendments	**(1)**	(1)	**(1)**	(1)
Regulatory adjustments	**(1)**	12	**2**	5
	11	21	**12**	15

(1) The non-service benefit cost components of net periodic benefit cost are included in other income, net in the consolidated statements of earnings.

24. EMPLOYEE FUTURE BENEFITS (cont'd)

The following table summarizes the accumulated amounts of net benefit cost that have not yet been recognized in earnings or comprehensive income and shows their classification on the consolidated balance sheets.

	DBP Plans		**OPEB Plans**	
($ millions)	**2024**	2023	**2024**	2023
Unamortized net actuarial losses (gains)	**11**	12	**(11)**	(10)
Unamortized past service costs	**1**	1	**6**	6
Income tax (recovery) expense	**(3)**	(3)	**1**	1
Accumulated other comprehensive income	**9**	10	**(4)**	(3)
Net actuarial losses (gains)	**46**	189	**(283)**	(215)
Past service credits	**(1)**	(2)	**(2)**	(3)
Other regulatory deferrals	**12**	(11)	**4**	2
	57	176	**(281)**	(216)
Regulatory assets (Note 8)	**235**	254	**—**	—
Regulatory liabilities (Note 8)	**(178)**	(78)	**(281)**	(216)
Net regulatory assets (liabilities)	**57**	176	**(281)**	(216)

The following table summarizes the components of net benefit cost recognized in comprehensive income or as regulatory (liabilities) assets.

	DBP Plans		**OPEB Plans**	
($ millions)	**2024**	2023	**2024**	2023
Current year net actuarial (gains) losses	**(1)**	4	**(1)**	1
Past service credits/plan amendments	**—**	—	**—**	(1)
Foreign currency translation	**—**	(1)	**—**	—
Income tax recovery	**—**	(1)	**—**	—
Total recognized in comprehensive income	**(1)**	2	**(1)**	—
Current year net actuarial (gains) losses	**(142)**	78	**(72)**	(40)
Amortization of actuarial gains	**1**	9	**16**	18
Amortization of past service credits	**1**	2	**1**	1
Foreign currency translation	**(2)**	(1)	**(12)**	2
Regulatory adjustments	**23**	(5)	**2**	(5)
Total recognized in regulatory (liabilities) assets	**(119)**	83	**(65)**	(24)

Significant Assumptions

	DBP Plans		**OPEB Plans**	
(weighted average %)	**2024**	2023	**2024**	2023
Discount rate as at December 31 [1]	**5.25**	4.84	**5.43**	4.94
Expected long-term rate of return on plan assets [2]	**6.51**	6.58	**6.05**	5.92
Rate of compensation increase	**3.52**	3.37	**—**	—
Health care cost trend increase as at December 31 [3]	**—**	—	**4.53**	4.52

[1] *The discount rate used during the year was 4.84% for DBP plans (2023 - 5.36%) and 4.96% for OPEB plans (2023 - 5.39%). ITC and UNS Energy use the split discount rate methodology for determining current service and interest costs. All other subsidiaries use the single discount rate approach.*

[2] *Developed by management using best estimates of expected returns, volatilities and correlations for each class of asset. Best estimates are based on historical performance, future expectations and periodic portfolio rebalancing among the diversified asset classes.*

[3] *The projected 2025 health care cost trend rate is 6.51% and is assumed to decrease over the next 10 years to the ultimate health care cost trend rate of 4.53% in 2034 and thereafter.*

24. EMPLOYEE FUTURE BENEFITS (cont'd)

Expected Benefit Payments

($ millions)	DBP Plans	OPEB Plans
2025	$ 196	$ 33
2026	201	34
2027	206	34
2028	210	35
2029	218	36
2030-2034	1,155	203

During 2025, the Corporation expects to contribute $49 million for DBP plans and $12 million for OPEB plans.

In 2024, the Corporation expensed $58 million (2023 - $53 million) related to defined contribution pension plans.

25. SUPPLEMENTARY CASH FLOW INFORMATION

($ millions)	**2024**	2023
Years ended December 31		
Cash paid (received) for		
Interest	**1,361**	1,255
Income taxes	**(17)**	129
Change in working capital		
Accounts receivable and other current assets	**(2)**	142
Prepaid expenses	**(21)**	(7)
Inventories	**(73)**	(1)
Regulatory assets - current portion	**93**	104
Accounts payable and other current liabilities	**115**	(390)
Regulatory liabilities - current portion	**56**	71
	168	(81)
Non-cash financing activity		
Common share dividends reinvested	**434**	408
As at December 31		
Non-cash investing and financing activities		
Accrued capital expenditures	**722**	516
Contributions in aid of construction	**14**	15

26. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Derivatives

The Corporation generally limits the use of derivatives to those that qualify as accounting, economic or cash flow hedges, or those that are approved for regulatory recovery.

Derivatives are recorded at fair value, with certain exceptions, including those derivatives that qualify for the normal purchase and normal sale exception. Fair values reflect estimates based on current market information about the derivatives as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future consolidated earnings or cash flow.

26. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (cont'd)

Energy Contracts Subject to Regulatory Deferral

UNS Energy holds electricity power purchase contracts, customer supply contracts and gas swap contracts to reduce its exposure to energy price risk. Fair values are measured primarily under the market approach using independent third-party information, where possible. When published prices are not available, adjustments are applied based on historical price curve relationships, transmission costs and line losses.

Central Hudson holds swap contracts for electricity and natural gas to minimize price volatility by fixing the effective purchase price. Fair values are measured using forward pricing provided by independent third-party information.

FortisBC Energy holds gas supply contracts to fix the effective purchase price of natural gas. Fair values reflect the present value of future cash flows based on published market prices and forward natural gas curves.

Unrealized gains or losses associated with changes in the fair value of these energy contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulators. As at December 31, 2024, unrealized losses of $175 million (2023 - $197 million) were recognized as regulatory assets and unrealized gains of $41 million (2023 - $37 million) were recognized as regulatory liabilities.

Energy Contracts Not Subject to Regulatory Deferral

UNS Energy holds wholesale trading contracts to fix power prices and realize potential margin, of which 10% of any realized gains is shared with customers through rate stabilization accounts. Fair values are measured using a market approach incorporating, where possible, independent third-party information.

Aitken Creek, which was sold on November 1, 2023 (Note 21), held gas swap contracts to manage exposure to changes in natural gas prices, capture natural gas price spreads, and manage the financial risk posed by physical transactions. Fair values were measured using forward pricing from published market sources.

Gains or losses associated with changes in the fair value of these energy contracts are recognized in revenue. In 2024, gains of $48 million (2023 - losses of $28 million) were recognized in revenue.

Total Return Swaps

The Corporation holds total return swaps to manage the cash flow risk associated with forecast future cash and/or share settlements of certain stock-based compensation obligations. The swaps have a combined notional amount of $134 million and terms up to three years expiring at varying dates through January 2027. Fair value is measured using an income valuation approach based on forward pricing curves. Unrealized gains and losses associated with changes in fair value are recognized in other income, net. In 2024, unrealized gains of $12 million (2023 - $nil) were recognized in other income, net.

Foreign Exchange Contracts

The Corporation holds U.S. dollar-denominated foreign exchange contracts to help mitigate exposure to foreign exchange rate volatility. The contracts expire at varying dates through September 2026 and have a combined notional amount of $608 million. Fair value was measured using independent third-party information. Unrealized gains and losses associated with changes in fair value are recognized in other income, net. In 2024, unrealized losses of $17 million (2023 - unrealized gains of $10 million) were recognized in other income, net.

Interest Rate Contracts

During 2024, ITC entered into and settled interest rate locks with a combined notional value of US$300 million. These contracts were used to manage interest rate risk associated with the issuance of US$400 million unsecured senior notes in May 2024. Realized losses of US$3 million were recognized in other comprehensive income, which will be reclassified to earnings as a component of interest expense over five years.

ITC also entered into 5-year interest rate swap contracts in 2024 with a combined notional value of US$135 million. The swaps will be used to manage interest rate risk associated with forecasted debt issuances. Fair value was measured using a discounted cash flow method based on secured overnight financing rates ("SOFR"). Unrealized gains and losses associated with the changes in fair value are recognized in other comprehensive income, and will be reclassified to earnings as a component of interest expense over the life of the debt. Unrealized gains of US$4 million were recorded in 2024.

In 2025, ITC entered into 5-year interest rate swap contracts with a notional value of US$95 million to manage interest rate risk associated with forecasted debt issuances, increasing the total notional amount of interest rate swaps outstanding to US$230 million.

During 2024, the Corporation entered into and settled interest rate locks with a combined notional value of $250 million. These contract were used to manage interest rate risk associated with the issuance of $500 million unsecured senior notes in September 2024. Realized losses of $2 million were recognized in other comprehensive income, which will be reclassified to earnings as a component of interest expense over seven years.

Cross-Currency Interest Rate Swaps

The Corporation holds cross-currency interest rate swaps, maturing in 2029, to effectively convert its $500 million, 4.43% unsecured senior notes to US$391 million, 4.34% debt. The Corporation has designated this notional U.S. debt as an effective hedge of its foreign net investments and unrealized gains and losses associated with exchange rate fluctuations on the notional U.S. debt are recognized in other comprehensive income, consistent with the translation adjustment related to the foreign net investments. Other changes in the fair value of the swaps are also recognized in other comprehensive income but are excluded from the assessment of hedge effectiveness. Fair value is measured using a discounted cash flow method based on SOFR. In 2024, unrealized losses of $29 million (2023 - unrealized gains of $15 million) were recorded in other comprehensive income.

26. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (cont'd)

Recurring Fair Value Measures

The following table presents derivative assets and liabilities that are accounted for at fair value on a recurring basis.

($ millions)	**Level 1** [(1)]	**Level 2** [(1)]	**Level 3** [(1)]	**Total**
As at December 31, 2024				
Assets				
Energy contracts subject to regulatory deferral [(2)] [(3)]	**—**	**63**	**—**	**63**
Energy contracts not subject to regulatory deferral [(2)]	**—**	**7**	**—**	**7**
Total return swaps and interest rate contracts [(2)]	**—**	**16**	**—**	**16**
Other investments [(4)]	**150**	**—**	**—**	**150**
	150	**86**	**—**	**236**
Liabilities				
Energy contracts subject to regulatory deferral [(3)] [(5)]	**—**	**(197)**	**—**	**(197)**
Energy contracts not subject to regulatory deferral [(5)]	**—**	**(2)**	**—**	**(2)**
Foreign exchange contracts and cross-currency interest rate swaps [(5)]	**—**	**(45)**	**—**	**(45)**
	—	**(244)**	**—**	**(244)**
As at December 31, 2023				
Assets				
Energy contracts subject to regulatory deferral [(2)] [(3)]	—	49	—	49
Energy contracts not subject to regulatory deferral [(2)]	—	6	—	6
Foreign exchange contracts [(2)]	—	5	—	5
Other investments [(4)]	145	—	—	145
	145	60	—	205
Liabilities				
Energy contracts subject to regulatory deferral [(3)] [(5)]	—	(209)	—	(209)
Energy contracts not subject to regulatory deferral [(5)]	—	(3)	—	(3)
Total return and cross-currency interest rate swaps [(5)]	—	(6)	—	(6)
	—	(218)	—	(218)

(1) *Under the hierarchy, fair value is determined using: (i) Level 1- unadjusted quoted prices in active markets; (ii) Level 2 - other pricing inputs directly or indirectly observable in the marketplace; and (iii) Level 3 - unobservable inputs, used when observable inputs are not available. Classifications reflect the lowest level of input that is significant to the fair value measurement.*

(2) *Included in accounts receivable and other current assets or other assets*

(3) *Unrealized gains and losses arising from changes in fair value of these contracts are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates as permitted by the regulators, with the exception of long-term wholesale trading contracts and certain gas swap contracts.*

(4) *UNS Energy holds investments in money market accounts, and ITC and Central Hudson hold investments in trust associated with supplemental retirement benefit plans for select employees, which include mutual funds and money market accounts. The fair value of these investments is included in cash and cash equivalents and other assets, with gains and losses recognized in other income, net*

(5) *Included in accounts payable and other current liabilities or other liabilities*

Energy Contracts

The Corporation has elected gross presentation for its derivative contracts under master netting agreements and collateral positions, which apply only to its energy contracts. The following table presents the potential offset of counterparty netting.

($ millions)	**Gross Amount Recognized In Balance Sheet**	**Counterparty Netting of Energy Contracts**	**Cash Collateral Posted/(Received)**	**Net Amount**
As at December 31, 2024				
Derivative assets	**70**	**(30)**	**15**	**55**
Derivative liabilities	**(199)**	**30**	**—**	**(169)**
As at December 31, 2023				
Derivative assets	55	(24)	28	59
Derivative liabilities	(212)	24	(1)	(189)

26. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (cont'd)

Volume of Derivative Activity

As at December 31, 2024, the Corporation had various energy contracts that will settle on various dates through 2029. The volumes related to electricity and natural gas derivatives are outlined below.

	2024	2023
Energy contracts subject to regulatory deferral [(1)]		
Electricity swap contracts *(GWh)*	**774**	628
Electricity power purchase contracts *(GWh)*	**430**	588
Gas swap contracts *(PJ)*	**236**	228
Gas supply contracts *(PJ)*	**105**	134
Energy contracts not subject to regulatory deferral [(1)]		
Wholesale trading contracts *(GWh)*	**1,499**	1,310
Gas swap contracts *(PJ)*	**3**	3

[(1)] *GWh means gigawatt hours and PJ means petajoules*

Credit Risk

For cash equivalents, accounts receivable and other current assets, and long-term other receivables, credit risk is generally limited to the carrying value on the consolidated balance sheets. The Corporation's subsidiaries generally have a large and diversified customer base, which minimizes the concentration of credit risk. Policies in place to minimize credit risk include requiring customer deposits, prepayments and/or credit checks for certain customers, performing disconnections and/or using third-party collection agencies for overdue accounts.

ITC has a concentration of credit risk as approximately 70% of its revenue is derived from three customers. These customers have investment-grade credit ratings and credit risk is further managed by MISO by requiring a letter of credit or cash deposit equal to the credit exposure, which is determined by a credit-scoring model and other factors.

FortisAlberta has a concentration of credit risk as its distribution service billings are to a relatively small group of retailers. Credit risk is managed by obtaining from the retailers either a cash deposit, letter of credit, an investment-grade credit rating, or a financial guarantee from an entity with an investment-grade credit rating.

Central Hudson has seen an increase in accounts receivable since the suspension of collection efforts initially required in response to the COVID-19 pandemic. Central Hudson continues to contact customers regarding past-due balances and collection efforts continue to expand. Under its regulatory framework, Central Hudson can defer uncollectible write-offs above the amounts collected in customer rates for future recovery.

UNS Energy, Central Hudson, FortisBC Energy, and Fortis may be exposed to credit risk from non-performance by counterparties to derivative contracts. Credit risk is managed by net settling payments, when possible, and dealing only with counterparties that have investment-grade credit ratings. At UNS Energy, Central Hudson and FortisBC Energy, certain contractual arrangements require counterparties to post collateral.

The value of derivatives in net liability positions under contracts with credit risk-related contingent features that, if triggered, could require the posting of a like amount of collateral was $117 million as at December 31, 2024 (2023 - $117 million).

Hedge of Foreign Net Investments

The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, FortisTCI, Fortis Belize Limited and Belize Electricity is, or is pegged to, the U.S. dollar. The earnings and cash flow from, and net investments in, these entities are exposed to fluctuations in the U.S. dollar-to-Canadian dollar exchange rate. The Corporation has reduced this exposure through hedging.

As at December 31, 2024, US$2.2 billion (2023 - US$2.6 billion) of corporately issued U.S. dollar-denominated long-term debt has been designated as an effective hedge of net investments, leaving approximately US$12.6 billion (2023 - US$11.5 billion) unhedged. Exchange rate fluctuations associated with the hedged net investment in foreign subsidiaries and the debt serving as the hedge are recognized in accumulated other comprehensive income.

Financial Instruments Not Carried at Fair Value

Excluding long-term debt, the consolidated carrying value of the Corporation's remaining financial instruments approximates fair value, reflecting their short-term maturity, normal trade credit terms and/or nature.

As at December 31, 2024, the carrying value of long-term debt, including the current portion, was $33.4 billion (2023 - $29.7 billion) compared to an estimated fair value of $31.3 billion (2023 - $27.9 billion).

27. COMMITMENTS AND CONTINGENCIES

As at December 31, 2024, unconditional minimum purchase obligations were as follows.

($ millions)	**Total**	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Gas and fuel purchase obligations (1)	**6,299**	763	571	520	465	393	3,587
Renewable PPAs (2)	**2,628**	139	166	182	182	173	1,786
Waneta Expansion capacity agreement (3)	**2,362**	56	58	59	60	61	2,068
Power purchase obligations (4)	**1,335**	302	217	131	124	122	439
ITC easement agreement (5)	**370**	14	14	14	14	14	300
TEP EPC agreements (6)	**308**	307	1	—	—	—	—
Debt collection agreement (7)	**99**	3	3	3	3	3	84
Renewable energy credit purchase agreements (8)	**58**	18	7	6	6	6	15
Other (9)	**140**	32	11	11	12	10	64
	13,599	**1,634**	**1,048**	**926**	**866**	**782**	**8,343**

(1) *FortisBC Energy ($5,014 million):* includes contracts of $2,792 million for the purchase of renewable natural gas expiring in 2045 and contracts of $2,222 million for the purchase of gas, renewable gas, gas transportation and storage services, expiring in 2062. FortisBC Energy's gas purchase obligations are based on gas commodity indices that vary with market prices and the obligations are based on index prices as at December 31, 2024. The renewable gas supply obligations disclosed reflect the contracted price per gigajoule between the Corporation and the suppliers.

UNS Energy ($1,160 million): includes long-term contracts for the purchase and delivery of coal to fuel generating facilities, the purchase of gas transportation services to meet load requirements, the purchase of transmission services for purchased power, as well as natural gas commodity agreements based on projected market prices as of December 31, 2024. Amounts paid for coal depend on actual quantities purchased and delivered. Certain contracts have price adjustment clauses that will affect future costs. These contracts have various expiry dates through 2048.

(2) *TEP and UNS Electric* are party to renewable PPAs, with expiry dates from 2027 through 2051, that require TEP and UNS Electric to purchase 100% of the output of certain renewable energy generating facilities and RECs associated with the output delivered once commercial operation is achieved. The agreements include purchase commitments that are contingent upon the developers obtaining commercial operation of the generating facilities, which are expected to be placed in service in 2026 and 2027. Amounts are the estimated future payments.

(3) *FortisBC Electric* is a party to an agreement to purchase capacity from the Waneta Expansion hydroelectric generating facility for forty-years, beginning April 2015.

(4) *Maritime Electric ($563 million):* includes an energy purchase agreement and transmission capacity contract for 30 MW of capacity to PEI with New Brunswick Power, expiring December 2026 and November 2032, respectively. The agreements entitle Maritime Electric to approximately 4.55% of the output of New Brunswick Power's Point Lepreau nuclear generating station and require Maritime Electric to pay its share of the station's capital operating costs for the life of the unit.

FortisOntario ($374 million): an agreement with Hydro-Québec for the supply of up to 145 MW of capacity and a minimum of 537 GWh of associated energy annually through December 2030.

FortisBC Electric ($301 million): an agreement with BC Hydro to purchase up to 200 MW of capacity and 1,752 GWh of associated energy annually for a 20-year term beginning October 1, 2013.

(5) ITC is party to an agreement with Consumers Energy, the primary customer of METC, which provides METC with an easement for transmission purposes and rights-of-way, leasehold interests, fee interests and licenses associated with the land over which its transmission lines cross. The agreement expires in December 2050, subject to 10 potential 50-year renewals thereafter unless METC gives notice of non-renewal at least one year in advance.

(6) TEP has entered into two engineering, procurement and construction ("EPC") agreements associated with the development of energy storage projects. Roadrunner Reserve 1 is expected to be placed in service in 2025, with Roadrunner Reserve 2 to follow in 2026.

(7) Maritime Electric is party to a debt collection agreement with PEI Energy Corporation for the initial capital cost of the submarine cables and associated parts of the New Brunswick transmission system interconnection. Payments under the agreement, which expires in February 2056, are collected in customer rates.

(8) UNS Energy and Central Hudson are party to REC purchase agreements, mainly for the purchase of environmental attributions from retail customers with solar installations or other renewable generation. Payments are primarily made at contractually agreed-upon intervals based on metered energy production.

(9) Includes AROs and joint-use asset and shared service agreements.

27. COMMITMENTS AND CONTINGENCIES (cont'd)

Other Commitments

Under a funding framework with the Governments of Ontario and Canada, Fortis will contribute a minimum of approximately $165 million of equity capital to Wataynikaneyap Power, based on Fortis' proportionate 39% ownership interest and the final regulatory-approved capital cost of the related project. Wataynikaneyap Power has construction financing loan agreements in place and it is expected that long-term operating financing will replace the construction financing. In the event a lender under the loan agreements realizes security on the loans, Fortis may be required to accelerate its equity capital contributions, which may be in excess of the amount otherwise required of Fortis under the funding framework, to a maximum total funding of $235 million. Equity of $137 million has been contributed as of December 31, 2024.

UNS Energy has joint generation performance guarantees with participants at Four Corners and Luna, with agreements expiring in 2041 and 2046 respectively, and at San Juan and Navajo through decommissioning. The participants have guaranteed that in the event of payment default, each non-defaulting participant will bear its proportionate share of expenses otherwise payable by the defaulting participant. In exchange, the non-defaulting participants are entitled to receive their proportionate share of the generation capacity of the defaulting participant. In the case of San Juan and Navajo, participants would seek financial recovery from the defaulting party. There is no maximum amount under these guarantees, except for a maximum of $360 million for Four Corners. As at December 31, 2024, there was no obligation under these guarantees.

Contingency

In 2013, FHI and Fortis were named as defendants in an action in the British Columbia Supreme Court by the Coldwater Indian Band ("Band") regarding interests in a pipeline across reserve lands. The Band seeks cancellation of the right-of-way and damages for wrongful interference with the Band's use and enjoyment of reserve lands. In 2016, the Federal Court dismissed the Band's application for judicial review of the ministerial consent. In 2017, the Federal Court of Appeal set aside the minister's consent and returned the matter to the minister for redetermination. No amount has been accrued as the outcome cannot yet be reasonably determined.

Exhibit A, Tab 8, Schedule 1

Draft Issues List

DRAFT ISSUES LIST

EB-2025-0192

Wataynikaneyap Power LP (WPLP)

1. GENERAL

- Has WPLP responded appropriately to all relevant OEB directions from previous proceedings?
- Are all elements of the proposed revenue requirement and their associated total bill impacts reasonable?
- Is the proposed effective date of January 1, 2026 and proposed timing for inclusion in the UTRs and Hydro One Remotes Communities Inc. (HORCI) billings appropriate?

2. TRANSMISSION SYSTEM PLAN

- Is the proposed initial Transmission System Plan, prepared on a best efforts basis, including proposed 2026 test year capital expenditures and in-service additions arising therefrom, and the rationale for planning and pacing choices, appropriate and adequately explained?

3. RATE BASE

- Are the amounts proposed for rate base appropriate?

4. PERFORMANCE

- Is the proposed approach to monitoring and OEB reporting of WPLP's transmission system performance, including the initial performance scorecard prepared on a best efforts basis, appropriate?

5. OPERATING REVENUE

- Are the proposed load and revenue forecasts appropriate?

6. OPERATING COSTS

- Are the proposed spending levels for OM&A in 2026 appropriate, including consideration of factors such as system reliability and asset condition?

- Are the amounts proposed to be included in the revenue requirement for income taxes appropriate?
- Is the proposed depreciation expense appropriate?
- Are the services to be provided by third parties, and their associated costs, appropriate?

7. COST OF CAPITAL & CAPITAL STRUCTURE

- Is the proposed capital structure appropriate?
- Is the proposed cost of capital, including updates, appropriate?

8. DEFERRAL & VARIANCE ACCOUNTS

- Are the proposed amounts, disposition, continuance and discontinuance of existing deferral and variance accounts appropriate?
- Are the proposed modifications to existing deferral and variance accounts, if any, appropriate?
- Are the proposed new deferral and variance accounts appropriate, if any?
- Are WPLP's COVID-19 related costs and their proposed treatment appropriate?

9. COST ALLOCATION

- Is the proposed cost allocation appropriate?

Exhibit B, Tab 1, Schedule 1

Transmission System Plan

TRANSMISSION SYSTEM PLAN

A. Introduction

As WPLP's Transmission System is newly constructed, it requires minimal sustaining capital investment in the near term and the operational experience WPLP is gaining over the first full year of the entire system being in service during 2025 will help inform its capital planning going forward. WPLP has prepared, on a best-efforts basis in accordance with the OEB's decision in EB-2024-0176, a ten-year Transmission System Plan ("TSP"), comprised of the past 5 historical/bridge years from 2021-2025, and the five future years from 2026-2030. Where possible, WPLP has prepared this TSP in accordance with the relevant sections of Chapter 2 (Revenue Requirement Applications) of the OEB Filing Requirements for Electricity Transmission Applications, with further guidance from Chapter 5 of the Filing Requirements (Distribution System Plan). Some elements of the TSP remain incomplete or under development given WPLP's limited time and resources since the conclusion of EB-2024-0176 and 2025 being the first full year of actuals based on the entire Transmission System being in service. WPLP will continue to develop its TSP for inclusion as part of its first multi-year rate application, which will be filed in 2026 for a rate period starting with the 2027 rate year.

1. WPLP's Transmission System

WPLP's Transmission System is a newly built greenfield system, put into service in stages from 2022-2024, that operates as a single transmission system in northwestern Ontario. One part of the system reinforces transmission to Pickle Lake (the "Line to Pickle Lake"). The balance of the system connects the provincial power system to the distribution systems owned and operated, or to be owned and operated, by Hydro One Remote Communities Inc. ("HORCI") in 16 remote Indigenous communities that were previously served exclusively by local diesel generation (the "Remote Connection Lines").[1] These two components of WPLP's Transmission System are

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[1] One of the 16 communities, Pikangikum First Nation became grid-connected in 2018 through an interim 44 kV connection. On May 12, 2023, the Pikangikum Distribution System was converted to 115 kV supply and now forms part of WPLP's Transmission System. The future connection of a 17th community, McDowell Lake First Nation, would also be supported through the Remote Connection Lines.

depicted in the Transmission System Map provided in **Appendix 'A'** and are described further in Exhibit B-1-2.

2. Transmission System Construction and In-Servicing

Regarding the in-service schedule for the Transmission System, on August 12, 2022, WPLP placed into service the Line to Pickle Lake, including its 2 associated substations. In September 2022, WPLP placed into service the Red Lake Substation, and in October and November 2022, WPLP placed into service the segments of the Remote Connection Lines necessary for connection of North Caribou Lake First Nation and Kingfisher Lake First Nation, respectively, including 3 associated substations. In 2023, WPLP converted the Pikangikum Distribution System to form part of the Transmission System as of May 12, 2023. Also in 2023, WPLP put into service portions of the Remote Connection Lines, including associated stations, that were needed to connect eight additional communities.[2] Together, those in-service assets included 14 line segments and 8 substations.[3] In 2024, WPLP put into service the portions of the Remote Connection Lines and associated stations needed to connect the remaining five communities,[4] which consisted of 13 line segments and 8 substations.

In respect of four of the communities to be served by the Transmission System (Muskrat Dam First Nation, Poplar Hill First Nation, North Spirit Lake First Nation and Keewaywin First Nation), while all WPLP line and station facilities up to the connection points to these communities were energized and available for use by 2024, the distribution systems in the communities, over which WPLP has no control, were not yet ready to receive service at the time transmission service became available. The distribution systems in three of the four communities (Poplar Hill First Nation, North Spirit Lake First Nation and Keewaywin First Nation) were connected to WPLP's

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[2] Muskrat Dam First Nation (July 2023), Bearskin Lake First Nation (July 2023), Wawakapewin First Nation (August 2023), Wunnumin Lake First Nation (September 2023), Kasabonika Lake First Nation (September 2023), Sachigo Lake First Nation (November 2023), Kitchenuhmaykoosib Inninuwug (December 2023), and Wapekeka First Nation (December 2023).

[3] These counts include line segments and substations associated with the Pikangikum Distribution System that are already in service and transitioned to a transmission supply on May 12, 2023.

[4] Poplar Hill First Nation (March 2024), Deer Lake First Nation (April 2024), Sandy Lake First Nation (April 2024), North Spirit Lake First Nation (May 2024), Keewaywin First Nation (May 2024).

Transmission System between December 2024 and February 2025.[5] The distribution system in Muskrat Dam First Nation remains in the process of being transferred from the Independent Power Authority to HORCI, along with related system and customer information, and necessary upgrades to the system in coordination with Indigenous Services Canada are in the process of being completed. It is expected that these processes will be completed in 2025.[6]

Following completion of Transmission System construction in 2024, WPLP received a significant capital contribution from the independent Trust established under the Federal Funding Framework, as discussed in Exhibit I-4-1.[7] An amendment to the Trust Agreement under the Federal Funding Framework allows for a second capital contribution to be made to WPLP based upon the OEB's approval in a future proceeding of a rate base addition in relation to the amount of any settlement or other final resolution of the issues that are the subject of ongoing commercial discussions with WPLP's EPC Contractor, the purpose of which will be to account for COVID-19 costs for the benefit of Ontario ratepayers, as discussed in Exhibit I-4-1. WPLP also expects to refinance in 2026.[8] Finally, as noted, WPLP anticipates filing its first multi-year incentive-based rate application in 2026 for rates starting in 2027.

3. Roadmap of the TSP

WPLP's Transmission System Plan[9], which comprises Exhibit 'B', is organized as follows:

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[5] Poplar Hill First Nation on December 17, 2024, North Spirit Lake First Nation on January 28, 2025, and Keewaywin First Nation on February 21, 2025.

[6] See April 15, 2025 Semi-Annual Report, filed in connection with EB-2018-0190, for more information.

[7] The CIAC was received on July 11, 2024.

[8] Whether the refinancing will involve extending the term of or replacing project financing, or transitioning to long-term financing, will depend on the status and timing for any settlement or other final resolution of the ongoing commercial discussions with the EPC Contractor.

[9] This TSP does not include COVID-19 costs currently under commercial negotiation that are recorded or will be recorded in the EPC COVID-Related Cost Deferral Account. WPLP will request in a future rate application to transfer the balance to rate base along with the corresponding additional contribution from the Trust as described in Exhibit I-4-1.

- The balance of this Exhibit B-1-1 provides a summary of WPLP's investment planning process.

- Exhibit B-1-2 sets out WPLP's asset management plan, and includes information about the material capital assets in WPLP's transmission system.

- Exhibit B-1-3 is focused on regional considerations, including information about the regional planning processes in which WPLP is a participant, how WPLP has considered its regional context in developing its plans, and how it coordinates planning with third parties.

- Exhibit B-1-4 provides a summary of WPLP's capital expenditures over the past five historical years, including the 2025 bridge year, and its planned capital expenditures, starting with the 2026 test year.[10] WPLP also confirms that no benchmarking studies have been undertaken related to capital expenditures due to the minimal amount of sustaining capital expenditures planned.

B. WPLP's Investment Planning Process

The key components of WPLP's investment planning process are its Strategic Plan, O&M Strategy, Economic and Planning Assumptions and its Investment Strategy.

1. Strategic Plan

During the development of the Transmission Project, the leadership of the 24 Participating First Nations established the Mandate, Vision and Guiding Principles set out below, which together have guided WPLP in its development, construction and ownership of the Transmission System.

Following completion of the Transmission Project, WPLP initiated a process to engage with First Nations to reaffirm and reinvigorate the Mandate, Vision and Guiding Principles in consideration of its transition to Operations. The renewed Mandate, Vision and Guiding Principles, which are

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[10] This forecast does not include COVID-19 costs currently under commercial negotiation and recorded or to be recorded in the EPC COVID-related Cost Deferral Account that WPLP will request to transfer to rate base in a future rate filing along with the corresponding additional contribution from the Trust.

expected to be adopted by April 2026, will provide a foundation for WPLP's overall organizational strategy, which will in turn influence the progression of the transitional O&M and investment strategies, discussed in the sections below.

The Mandate, Vision and Guiding Principles that have guided the development, construction and ownership of the Transmission Project to date are as follows:

(a) Mandate

Connect First Nations to Ontario's electrical grid to provide reliable accessible energy with majority First Nations ownership and eventual 100% First Nations ownership.

(b) Vision

- The communities have a long-term vision to secure opportunities from the lands and resources, pursue economic development and energy, while protecting the environment and maintaining our Peoples' responsibilities to the land, given by the Creator.
- Any opportunities must benefit the future generation.
- Indigenous Peoples of the Homeland will continue to exercise our Aboriginal and Treaty Rights according to the spirit and intent of the Treaty passed down by our Elders.
- Indigenous Peoples will exercise our inherent rights given to us by the Creator.
- We will maintain our culture, language, and enforce our natural and spiritual laws and protocols.
- We will protect the land, as we are the stewards, and any development will require blessing from the People in order to move forward.

(c) Guiding Principles

Our people expect that the Wataynikaneyap Power Project will be undertaken in a manner that respects our lands, rights and principles; our way of life on the land and as part of the land; and our land sharing protocols.

The Project shall respect confidentiality and comply with any conditions of use for any Traditional Land and Resource Use information provided by the communities, including intellectual property.

Our communities must maintain decision-making and ownership, and receive benefits in the Project.

Our sacred responsibilities given to us by the Creator are to protect the land, which protects us in return. Therefore, the Project shall be built, operated and maintained in a way that minimizes adverse environmental impacts, as follows:

- The Project shall not poison the lands;
- No herbicides shall be used throughout the life of the transmission line to control vegetation;
- The Project shall be constructed, operated and maintained in a manner that observes and does not interfere with seasonal hunting, trapping, fishing and harvesting and keeps disturbances to a minimum;
- No new transmission lines shall be located underwater;
- The Project will develop and implement an environmental and social management plan which will include acceptable and effective mitigation measures for any sacred sites, gathering sites, and harvesting sites; and
- The Project shall respect confidentiality and comply with any conditions of use for any Traditional Land and Resource Use information provided by the communities, including

intellectual property. Our communities must maintain decision-making and ownership and receive benefits in the Project.

2. Operations and Maintenance (O&M) Strategy

As discussed below, WPLP's O&M Strategy is integrally linked to its preliminary Asset Management Plan and is therefore an important component of this initial TSP. WPLP presented an initial O&M strategy in prior rate applications that focused on the following primary components and objectives[11]:

- A third-party agreement for Inspection, Maintenance and Emergency Response ("IMER") activities, using a qualified contractor with apprentices from Participating First Nations to complete regular planned inspection and maintenance activities while also being available to respond to troubleshooting requirements, outages and emergencies as needed. 24/7 control room services provided under an agreement with Hydro One Networks Inc. also support WPLP's IMER activities.

- A focus on Indigenous Participation where WPLP strives to maximize opportunities for employment, contracting and capacity building, both internally and through its O&M service agreements. Examples include establishing contractual requirements for Indigenous recruitment, employment, support and retention, identifying contracting and sub-contracting opportunities for Indigenous businesses, and identifying pathways to employment consistent with the long-term needs of an operating utility to refocus training and outreach efforts to align with those needs.

- Evaluating emerging technologies and work methods that can facilitate efforts to tailor WPLP's overall O&M strategy to the expectations set out by the Guiding Principles, Mandate and Vision, as well as the unique operating footprint with limited access. For example, WPLP's recent trials of drone-based transmission line inspections combined with

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[11] WPLP's initial O&M strategy is summarized here to provide relevant context to this initial TSP. See EB-2024-0176, Exhibit B-1-4, Section C for detailed descriptions of each component of WPLP's initial O&M strategy.

AI analysis techniques may allow for more detailed and cost-effective inspections of its transmission line, while also introducing emerging employment opportunities such as drone operators.

- Leveraging opportunities for transitioning Transmission Project construction resources to support efficient Transmission System operations. Examples include engaging First Nations with respect to using significant portions of WPLP's construction access for permanent operational access, purchasing lift equipment from the EPC Contractor to support future maintenance and emergency response activities at WPLP's most remote substations, and transitioning certain employees from roles focused on construction into roles that support ongoing operations.
- Recruiting internal resources to lead and support the gradual ramp-up of O&M programs during the transition from construction to operations.

WPLP has implemented the initial strategy detailed in prior applications and summarized above. Additionally, in 2024, WPLP completed a competitive procurement process to select a third-party service provider to perform the majority of WPLP's environmental monitoring and reporting activities related to its Endangered Species Act exemption permit. Through this process, WPLP selected Giiwedin Environmental Services Inc. to provide services that include monitoring of permanent wildlife survey plots, seasonal surveys of caribou habitat, caribou range level surveys, vegetation restoration surveys, bat gate installation and monitoring of bat hibernacula, as well as reporting on these activities.

WPLP expects employment and contracting related to O&M programs to focus on the following key areas in 2025 and 2026:

- Ongoing recruitment of engineering and operations staff to address existing vacancies and pending retirements.

- Contracting for initial vegetation management activities, with a focus on identifying and expanding First Nations capacity to perform this work. This effort is being supported by extensive engagement with First Nations on WPLP's vegetation management program in consideration of both the potential impacts to traditional land use activities and the significant opportunity to work with First Nations to perform this work safely and efficiently.

- Identification of internal and contracted resources required to coordinate the implementation of the vegetation management program, including analysis and planning functions as well as contract management and contractor oversight functions.

Finally, as noted above, WPLP's O&M Strategy is integrally linked to its preliminary Asset Management Plan, provided in Exhibit B-1-2. WPLP is in the relatively unique position of operating and maintaining a large transmission system where its assets were procured, constructed, commissioned and placed in service in the last seven years. Further, the vast majority of WPLP's assets have been placed in service in the past three years[12] and are included in the warranty provisions of WPLP's contract with its EPC Contractor, Valard. This results in a situation where most assets are in excellent condition, limited asset health trending is available to support condition or reliability-based maintenance approaches, and any major issues with assets may be covered under warranty. In consideration of these circumstances, WPLP has focused its initial O&M efforts on establishing regular planned inspection and testing programs aimed at identifying and trending asset health and performance, as well as identifying any systemic issues with asset performance that may require resolution through the EPC warranty process.

To effectively manage the extensive data associated with in-service and commissioning records, inspection programs and diagnostic testing, and to help retrieve, sort and analyze this data to identify and prioritize maintenance needs, WPLP is in the process of implementing a software-based Asset Management Condition Monitoring Solution ("ENGIN" by Engineered Intelligence

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[12] This includes all assets apart from the portions of the Pikangikum Distribution System that were constructed in 2018 and converted to form part of WPLP's transmission system in 2023.

Inc.). WPLP's initial Asset Management Plan, in Exhibit B-1-2, provides details on WPLP's inspection and maintenance strategy by asset class, along with details on its implementation and use of ENGIN to support the evolution of this strategy.

3. Economic and Planning Assumptions

WPLP has identified three sources of economic activity planning that are directly relevant to WPLP's transmission system planning processes and related investments in the Transmission System:

- Load growth on the distribution systems within the connected First Nations;
- Requests for connection of new industrial loads, primarily from the mining sector; and,
- Outcomes of regional planning processes.

For medium to long-term transmission system planning purposes, WPLP currently forecasts an annual growth rate of 4% for load in the connected First Nations. This assumption is consistent with the assumptions included in prior planning studies and business cases developed by OPA/IESO, which were referenced during the development and design of the Transmission Project. WPLP intends to refine this assumption over time once several years of grid-connected demand data are available for analysis and trending.

As the Transmission Project was constructed and placed into service, WPLP began receiving inquiries related to connecting new industrial loads to its Transmission System. On December 16, 2022, WPLP applied to the OEB in EB-2022-0330 for approval of its Transmission Connection Procedures (TCP), which outline the steps and procedures for WPLP to process requests for new or modified connections to its Transmission System. Notably, WPLP's TCP includes important references to the role and expectations of the Participating First Nations in the development, construction and ongoing operation of the Transmission System, clarifications on the connection applicant's responsibility to engage directly with First Nations in respect of their project, and procedures to ensure that adequate Transmission System capacity is maintained to meet the needs of connected First Nations. The OEB approved WPLP's TCP on April 6, 2023. While WPLP has received applications related to the connection of new industrial loads, no connection applicants have yet proceeded with the Connection Estimates step outlined in WPLP's TCP and WPLP has therefore not yet included any investments related to new industrial connections in its future investment forecasts.

Finally, investments in WPLP's Transmission System may also be driven by the outcomes of regional planning processes. Exhibit B-1-3 provides details of WPLP's participation in various regional planning processes as well as an update on the status of those processes and their implications for WPLP's Transmission System.

4. Investment Strategy

WPLP's historical capital investments to date have primarily been focused on the development, design, construction, commissioning and placing in service of the Transmission Project. Exhibit B-1-4 provides an updated forecast of WPLP's total Transmission Project costs, as well as a summary of its comparatively minimal sustaining capital costs incurred during the historical period and expected to be incurred during the 2026 test year.

WPLP expects that the quantum and the timing of future capital investments will be heavily influenced by the outcome of regional planning processes and connection requests that are currently in progress, as well as the evolution of the organizational and operations strategies discussed above.

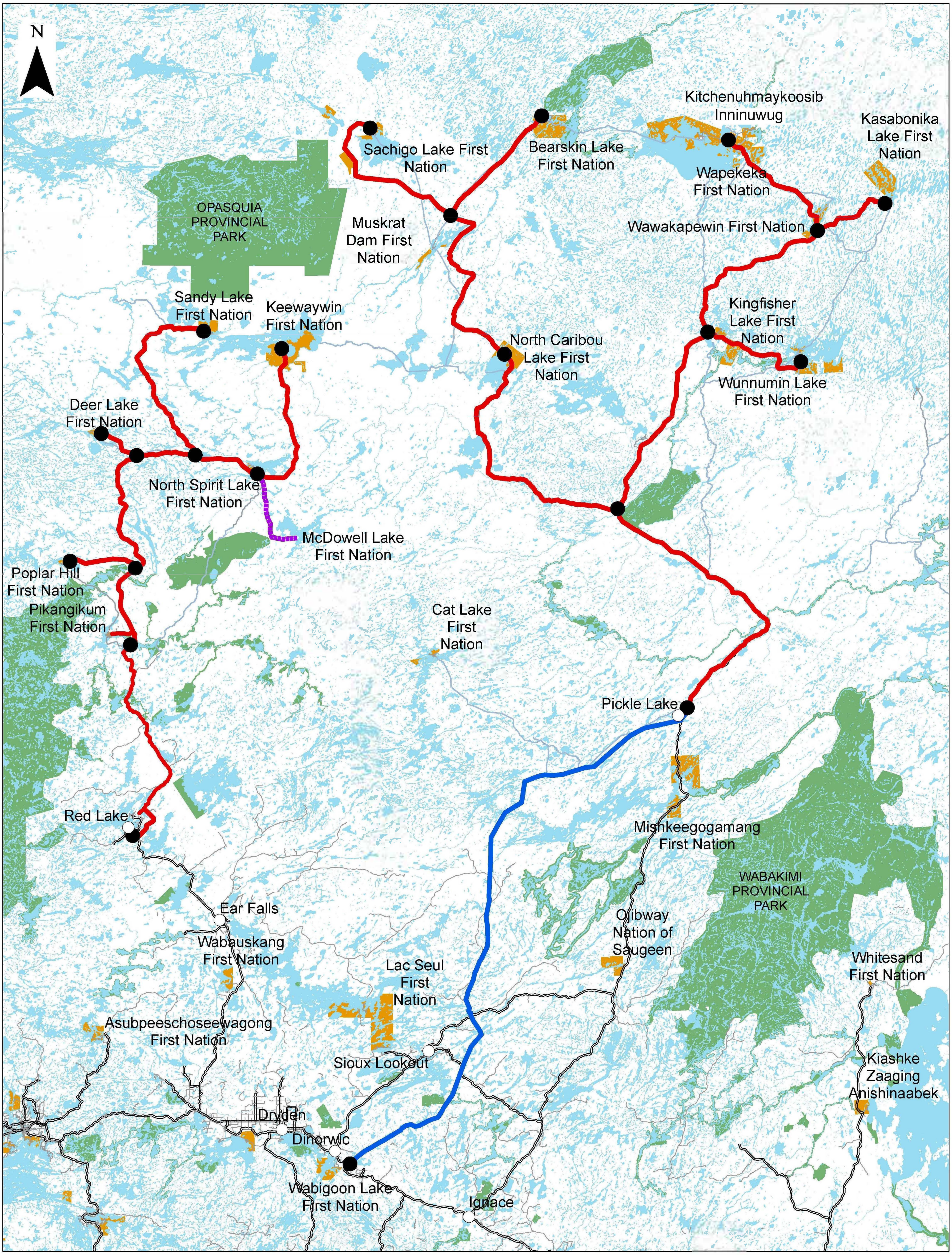
WPLP notes that, as the current application is for a single test year, and in the context of filing an initial TSP as part of the current application on a best-efforts basis, the planned capital expenditures and their associated costs set out in this TSP are focused on the 2026 test year, with a discussion of projects and programs that will be further costed, prioritized and scheduled as part of the next TSP that will be filed with WPLP's first multi-year rate plan. WPLP anticipates that its planning process as documented in this TSP will form the basis of its multi-year investment plan that will be filed with its multi-year rate application in 2026 for a rate period starting with a 2027 test year, which will be based on the best information available at the time. In this initial TSP, WPLP has identified the categories and types of investments that may be required in its future multi-year plan, which are discussed in Exhibit B-1-4. Given that the IESO's North of Dryden Addendum Study is currently in the preliminary engagement stage, and that the outcome of that study in combination with the status of connection applications received by WPLP will have a material impact on WPLP's short to medium term capital investments, it is impractical at this time to cost and schedule any capital projects beyond 2026 as part of this TSP.

Exhibit B, Tab 1, Schedule 1

Transmission System Plan

APPENDIX ‘A’

Transmission System Map



Legend

- Line to Pickle Lake
- Remote Connection Lines
- Future Line to McDowell Lake First Nation
- ● Substation
- 🟧 First Nation Reserve
- 🟩 Provincial Park
- 🟦 Waterbody
- Arterial Road or Highway
- Local Road
- Winter Road

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SYSTEM OVERVIEW

REFERENCE

Base Data - MNR LIO, obtained 2020, NTDB
Transmission Routes - Provided by Wataynikaneyap Power PM
First Nation Communities from Indigenous and Northern Affairs Canada (www.ainc-inac.gc.ca)
Produced by Wataynikaneyap Power PM
Projection: Transverse Mercator Datum: NAD 83
Coordinate System: UTM Zone 15

0 12.5 25 50
km

1:750,000

Exhibit B, Tab 1, Schedule 2

Asset Management Plan

ASSET MANAGEMENT PLAN

The purpose of this schedule is to describe WPLP's Asset Management Plan (AMP) for its transmission assets, and to provide information about the major transmission station and line components that comprise WPLP's Transmission System.

Section A below provides an overview of WPLP's Transmission System Assets, describes WPLP's overall strategy for asset management, and explains its approaches to asset condition monitoring, performance monitoring and asset lifecycle management.

WPLP's Transmission System assets are categorized into various asset classes for asset management purposes. Sections B and C below provide descriptions of asset classes for WPLP's substation and transmission line assets, respectively, as well as a summary of its asset demographics (i.e. asset types, quantities, and, where available, information on expected service life (ESL)). As WPLP's gathers sufficient asset condition and performance data to develop reporting and trending of asset-specific condition and performance, as well as enhanced asset lifecycle management strategies, WPLP will endeavor to include these details in future versions of this AMP.

Section D below provides an inventory of the Transmission System assets, categorized into the various transmission rate pools and identifying which assets are part of the bulk electricity system, as defined by the North American Electric Reliability Corporation (NERC). This categorization supports the cost allocation in Exhibit I and is responsive to certain requirements described in Section 2.4.1 of the Filing Requirements. For ease of reference, tables summarizing the operational designation, geographical reference, voltage level, categorization, and bulk electricity system status are provided in **Appendix 'A'** (Stations) and **Appendix 'B'** (Transmission Line Segments).

A. Asset Information and Asset Lifecycle Management Strategies

1. Overview

WPLP's Transmission System is comprised of 22 substations and approximately 1742 km of lines in northwestern Ontario. These substations and transmission lines are in turn comprised of tens of thousands of managed assets as detailed in Sections B and C below.

To effectively manage the extensive data associated with in-service and commissioning records, inspection programs and diagnostic testing, and to help retrieve, sort and analyze this data to identify and prioritize maintenance needs, WPLP is in the process of implementing a software-based Asset Management Condition Monitoring Solution ("ENGIN", by Engineered Intelligence Inc.).

2. Asset Demographics

All of WPLP's assets were procured, constructed, commissioned and placed in service in the last seven years, with the vast majority of the assets having been placed in service only in the past three years. Asset demographic information presented in Sections B and C below provides the calendar age for various asset classes, compared to the preliminary expected service life (ESL) information where available for certain asset classes.[1]

3. Asset Management Strategy

In the absence of detailed asset-specific condition and performance trending, the comparisons between the calendar age and ESL of WPLP's Transmission System assets in Sections B and C indicate that the majority of WPLP's asset classes have decades of ESL remaining. This supports WPLP's current focus on implementing its initial preventive maintenance strategy, which is primarily schedule-based, in parallel with implementing ENGIN to support the evolution to predictive and/or reliability-centered maintenance strategies, as further detailed in Section 6 below.

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[1] ESL determinations are in progress for many asset classes in ENGIN. WPLP will endeavour to expand on ESL information and analysis in future revisions to this AMP.

4. Asset Condition Monitoring

As assets age, they begin to deteriorate due to many factors such as weather exposure, number/hours of operation, light vs heavy loading etc., resulting in declining trends in overall asset condition when compared to a new asset of the same class. WPLP's process to monitor the degradation of its assets over time and to report on the overall condition of its assets includes the following steps:

a) identification of the degradation factors applicable to each asset class;

b) identification of rating criteria to assess each applicable degradation factor during regular inspection programs;[2]

c) incorporating the evaluation of each degradation factor into regular inspection programs, where experienced substation technicians and powerline technicians assign a rating to each degradation factor for each asset inspected and each rating is entered in ENGIN; and

d) calculating and trending health indices for each asset in ENGIN.

Each of the above steps is explained in further detail in the sections below.

(a) Identification of Degradation Factors

WPLP worked with Engineered Intelligence Inc. to determine the degradation factors applicable to each asset class during the implementation of ENGIN. This effort included a review of research on utility best practices, review of manufacturer documentation and input from members of the implementation team with significant electric utility experience. See Table 2 in section (d) below for an example of the degradation factors applicable to power transformers and variable reactors.

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[2] See Table 3 in Section 6 below for a summary of WPLP's inspection programs.

(b) Identification of Rating Criteria

Generally, all substation and transmission line inspection programs assign a rating between A (Excellent) and E (Poor) to each of the degradation factors identified for each asset class being inspected. Table 1, below, lists the general rating criteria developed to ensure consistency between ratings across multiple degradation factors for multiple assets, as well as an example of the specific rating criteria for a single degradation factor (bushing condition) on a single asset class (power transformers) during a specific type of inspection (visual inspection). The specific rating criteria are provided on digital inspection forms to guide inspectors in the rating of each item.

Table 1 – Asset Inspection Rating Criteria

Asset Inspection Ratings	General Rating Criteria	Sample of Specific Rating Criteria for Transformer Bushing Condition during Visual Inspections
A **Excellent**	Like new; no noticeable wear or degradation; normal expected operating parameters; Only normal cyclic maintenance required; may still be under warranty, if applicable.	Bushings are not broken and are free of chips, radial cracks, flashover burns, copper splash, and copper wash, cementing and fasteners are secure.
B **Good**	Normal service wear and operating parameters, no longer new, but still good condition; may have slightly deteriorated components; only minor and cyclic maintenance required; functional overall; some minor problems or evidence of aging.	Bushings are not broken, but minor chips and cracks are visible, cementing and fasteners are secure.
C **Adequate**	Moderate deterioration: wear or adjustments or part replacements required; Operable but significant maintenance required to return to acceptable level of service; several minor problems or a major problem requires intervention before next scheduled inspection or maintenance interval; has not exceeded useful life	Bushings are not broken, major chips and some flashover burns and copper splash are visible, cementing and fasteners are secure.
D **Marginal**	Intervention required as soon as possible; many serious problems, and without intervention, in-service asset failure condition expected; Component replacement required; Significant renewal/upgrade required; end of useful life.	Bushings are broken; cementing and fasteners are not secure.

E **Poor**	Asset unserviceable; critically damaged components of in need of immediate repair; deteriorated to a stage where the asset failure is imminent; asset requires replacement; well past useful life.	Bushings, cementing, or fasteners are broken/damaged beyond repair; black oil in sight glass.

(c) Ratings During Inspections and Entry into ENGIN

The rating of each asset degradation factor is captured during WPLP's regular inspection and testing programs. Mobile inspection forms currently deployed on tablets for substation inspections guide field inspectors through the process of inspecting and rating each applicable degradation factor for each asset. Upon completion of each inspection, the results entered for each substation are synchronized with the ENGIN platform to capture each applicable rating for the date on which the inspection was completed. The synchronization process includes a review and acceptance step to ensure that any changes in ratings are reviewed for accuracy and to ensure that any material findings are prioritized for reactive maintenance if required.

ENGIN also allows for manual data entry, allowing WPLP to work with the vendor to populate any relevant data from other sources (e.g. inspections completed prior to the deployment of tablet-based inspection forms, results from electrical/mechanical testing, results from online equipment monitors, etc.). Efforts related to population of historical data and development of processes to capture rating data for transmission line assets are currently in progress, following an initial focus on substation inspection data capture due to the frequency of substation inspections as compared to transmission line inspections.

(d) Calculating and Trending Health Indices in ENGIN

After each degradation factor is evaluated and rated, weighted ratings are combined in an algorithm within the ENGIN platform to determine a health index score for each individual asset. Table 2 below provides an example of the degradation factors assigned to power transformers and variable reactors, along with the rating scale applied to each degradation factor[3] and the weighting factor

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[3] Most degradation factors are rated on the 5-point scale described above, however some factors have fewer than 5 rating options.

applied during the calculation of health indices. Higher weighting factors assigned to a degradation factor are an indication of that factor having a greater impact on the overall health of the asset. For example, when referring to Table 2, below, minor bushing damage would have a comparatively small impact on the overall health of a power transformer (not likely to lead to asset failure and the component can be replaced if required), whereas poor dissolved gas analysis (DGA) results are often indicative of faults and degradation in transformer windings and insulation material and therefore attract a higher weighting.

Table 2 - Power Transformer & Variable Reactor Health Index Framework

Degradation Factor	**Rating Scale**	**Factor Weight**
Bushing Condition	A,B,C,D,E	1
Oil Leaks	A,B,C,D,E	1
Main Tank, Cabinets and Controls	A,B,C,D,E	1
Conservator/Oil Preservation System (Airbag Integrity)	A,B,C,D,E	1
Radiators/Cooling System	A,B,C,D,E	1
Foundation/Support Steel/Grounding	A,B,C,D,E	1
Overall Condition	A,B,C,D,E	2
DGA Oil Analysis*	A,B,C,D,E	4
Furan Analysis Proxy via Service Age*	A,B,C,D,E	4
Winding Power Factor	A,B,C,D,E	4
Oil Quality Test	A,B,C,D,E	3
Thermograph (IR)	A,B,C,D,E	2

Bushing DGA Oil Analysis	A,E	4
ULTC Tap Changer	A,B,C,D,E	3

WPLP is in the preliminary stages of calculating, trending and verifying health index calculations using ENGIN for a population of assets that have all been placed in service in the past 1-7 years. As a result, meaningful asset health index calculations and trending are not yet available and WPLP will endeavour to provide this information in a future revision of this AMP.

5. Asset Performance

Recognizing that the reliability of individual assets directly affects the reliability of WPLP's entire transmission system, WPLP's approach to asset condition monitoring described above is meant to minimize power outages caused by asset failure and minimize the occurrence of operating states that could lead to an increased risk of power outages. To date, WPLP has not experienced outages or reliability concerns attributed to deteriorating asset condition or asset failure[4] and has therefore not included asset class-specific performance information in Sections B and C below.

WPLP's outages to date have primarily been attributable to planned outages (both HONI and WPLP), or to external factors such as lightning, abnormal weather or animal contact, as further detailed in Exhibit D-2-1. Trending the frequency and causes of both planned and unplanned power outages will also be factored into the evolution of WPLP's preventative and corrective maintenance strategies, as well as future capital investment planning.

6. Asset Lifecycle Management

WPLP's initial maintenance strategy is primarily focused on preventive maintenance, employing a schedule-based approach to asset inspections and additional testing of major substation assets

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[4] Apart from any failures during or shortly after initial asset energizations, which are being addressed through warranty replacements.

(i.e. transformers, reactors and circuit breakers). To date, WPLP has implemented the following inspection and maintenance programs for its Transmission System assets:

Table 3 - Summary of Inspection and Maintenance Programs

	Annual Programs	Multi-Year Programs
Substations	- 3 inspections per station focused on asset condition - 1 trip per station focused on correction of minor deficiencies and pre-winter heater checks - 1 trip per station for Joint Health & Safety Committee inspections	- Transformer and reactor electrical/mechanical testing (2-year cycle) - Circuit breaker electrical/mechanical testing (5-year cycle)
Transmission Lines	- Aerial inspection of entire transmission system	- Ground inspection of specific transmission lines (6-year cycle) - Climbing inspections of lattice steel towers (~1 tower per 10 km sampled during ground inspections)

The inspection and maintenance programs summarized in Table 3 above are intended to achieve the following objectives:

- Gather sufficient asset condition data to establish initial asset health indices.
- Complete multiple inspections of all substation assets to obtain sufficient asset health index trending to inform future decisions on maintenance strategies.
- Inspect all assets prior to the expiration of the warranty provisions included in WPLP’s EPC contract, with a particular focus on completing multiple inspections and additional testing/trending on high-value substation assets.

The preventive maintenance strategy outlined above is supplemented by corrective maintenance actions as required. As deficiencies, failures or malfunctions are observed through planned inspections, SCADA alarms, or fault records, requirements for troubleshooting, repair and/or replacement are identified and scheduled considering severity, reliability risk, access, and the timing of any other planned work in the vicinity.

Developing and trending asset health indices and tracking the actual reliability performance of its Transmission System over several years will support analysis of the probability and consequence of failure for WPLP's managed assets. Over time, this analysis will factor into WPLP's considerations on transitioning from its initial preventive maintenance program to predictive and/or reliability-centered maintenance strategies for various asset classes.

B. Substation Assets

1. Transformers and Oil-Filled Variable Reactors

(a) Asset Description

Transformers are used to convert power (electric energy) from one voltage level to another by either stepping up (increasing) or stepping down (decreasing) the voltage level between two or more windings. Oil-filled variable reactors are constructed similarly to oil-filled transformers, but with a single winding connected between the rated voltage level and ground potential to absorb reactive power to offset the voltage increases that would otherwise occur on WPLP's long and lightly loaded transmission lines. WPLP's transmission system utilizes several different types of transformers and variable reactors, which are described in Table 4 below.

Table 4 - Power Transformer and Variable Reactor Descriptions

Transformer Type	Description
2-Winding Step-Down	WPLP's 2-winding step-down transformers convert voltage levels from 115 kV or 44 kV to the 25 kV standard distribution voltage level used by HORCI.
3-Winding Step-Down	WPLP's 3-winding step-down transformers convert voltage levels from 115 kV to supply 44 kV and 25 kV buses at the same substation. This approach allows the community closest to the substation containing the 3-winding transformer to be supplied from the 25 kV bus, with an adjacent community

	supplied via the 44 kV winding, an intermediate 44 kV line and a 44/25 kV substation closer to the second community.
Autotransformer	WPLP's single autotransformer is a special type of power transformer, used to cost effectively transform voltages and currents between the 230 kV and 115 kV transmission circuits that are connected at WPLP's Pickle Lake TS.
Variable Shunt Reactor	Variable shunt reactors are used in WPLP's transmission systems to stabilize the voltage following energization of long transmission lines. Integrated tap changers allow adjustments to the amount of reactive power absorbed to further control voltage levels for variations in both load levels and voltage levels at WPLP-HONI connection points.

(b) Asset Demographics

WPLP has 31 transformers and 9 variable reactors in service, summarized in Table 5 and Figure 1 below. WPLP's transformer and variable reactor assets are all relatively new, ranging from one (1) to seven (7) years old, based on energization dates.

Table 5 - Transformer & Variable Reactor Asset Demographics

Type of Transformer	Transformer Ratings	Quantity	Age (Years)	ESL (Years)	ESL Remaining
2-Winding Step-down	115/25KV, 3.75/5 MVA	12	1-3	50	47-49
	44/25KV, 3.75/5 MVA	4	2	50	48
	115/25KV, 7.5/10 MVA	6	1-2	50	48-49
	115x44/25KV, 7.5/10 MVA	2	7	50	43
3-Winding Step-down	115/44/25kV, 7.5/10 MVA	6	1-3	50	47-49
Autotransformer	230/115/13.8kV, 250/333 MVA (25/33.3 MVA Tertiary)	1	3	50	47
Variable Shunt Reactor	115 kV, 1.8 – 6 MVAR	9	1-3	40	37-39
Totals:		**40**	**1-7**	**40-50**	**37-49**

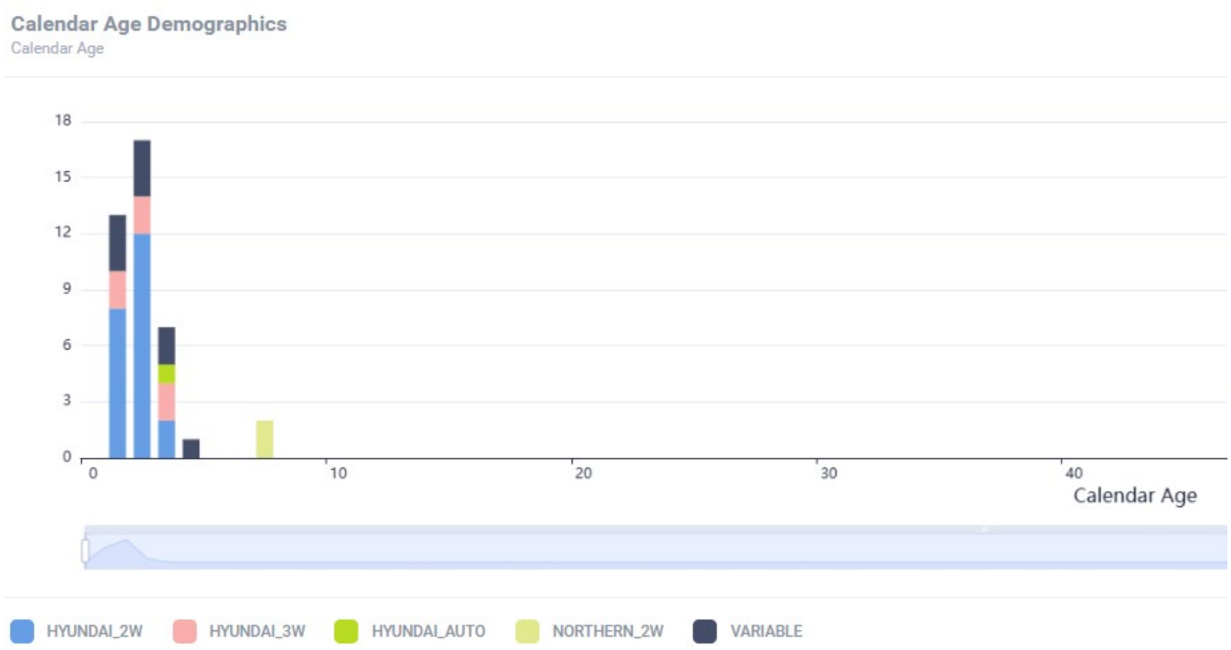

Figure 1: Transformers & Variable Reactors Calendar Age

2. Air Core Reactors

(a) Asset Description

Air core reactors connect directly to high voltage transmission lines and absorb a relatively fixed[5] amount reactive power on the transmission system at the connection point. All of WPLP's air core reactor installations consist of three or six reactor coils that are connected in a three-phase bank. Fixed reactors are strategically located such that they are either normally in-service or normally disconnected but available for contingencies, while the variable reactors discussed in Section B.1 above frequently adjust the amount of inductive reactance connected to the system in response to changes in system load and overall system voltages. This approach minimizes the need for switching larger blocks of fixed reactive compensation, improving power quality and minimizing wear of reactor switchers and circuit breakers.

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[5] While the inductive reactance of each reactor bank (measured in Ohms) is static, the reactive power absorbed by each reactor bank (measured in VAR) is a function of system voltage at the point of connection.

(b) Asset Demographics

WPLP has 10 air core reactor banks in service, summarized in Table 6 and Figure 2 below. WPLP's transformer and variable reactor assets are all relatively new ranging from one (1) to three (3) years old, based on energization dates.

Table 6 - Air Core Reactor Asset Demographics

Voltage Level	Reactor Bank Details	Quantity	Age (Years)	ESL (Years)	ESL Remaining
230 kV	30 MVAR (3 x 10 MVAR)	3	3	40	37
115 kV	20 MVAR (3 x 6.67 MVAR)	2	3	40	37
115 kV	3 MVAR (3 x 1MVAR)	5	1-2	40	38-39
Totals:		**10**	**1-3**	**40**	**37-39**

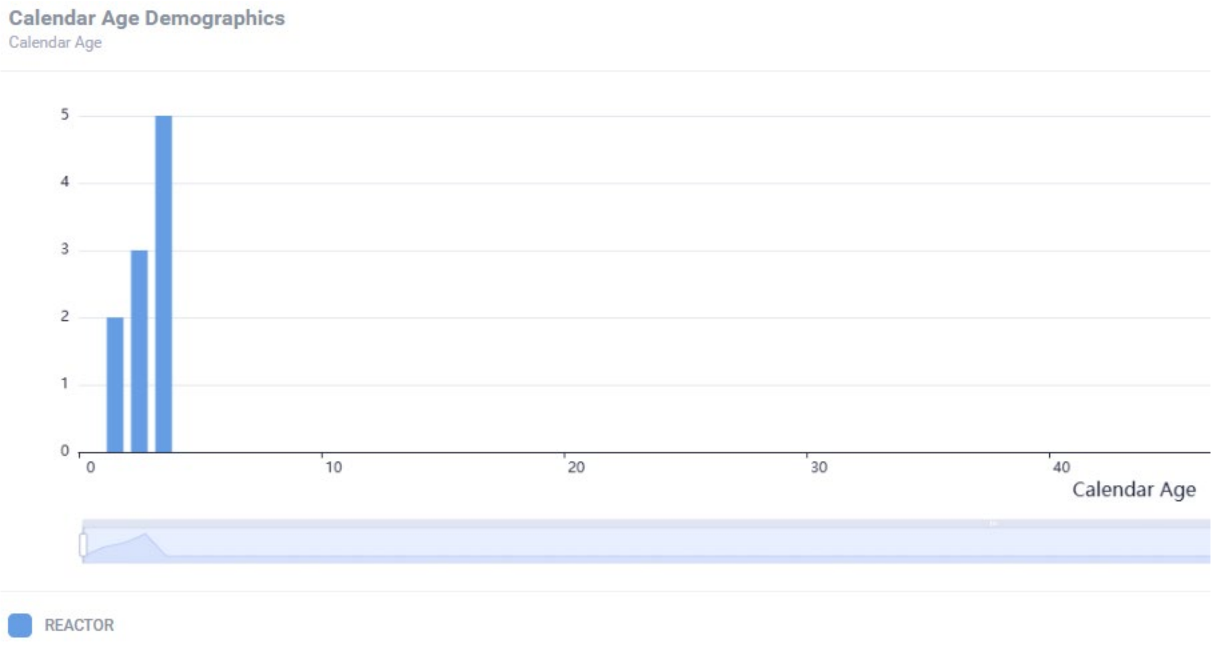

Figure 2: Air Core Reactor Calendar Age

3. Circuit Breakers

(a) Asset Description

Circuit breakers are designed to effectively and safely provide protection and control of critical power transmission infrastructure and equipment under normal system conditions and during fault conditions. The primary function of a circuit breaker is to interrupt the flow of current (load or short circuit) by opening its contacts and thereby isolating the switched parts of the system. Circuit breakers use several different interrupting mediums, with all WPLP's circuit breakers using either SF6 gas or vacuum technology, which are described in Table 7 below.

Table 7 – Circuit Breaker Types

Breaker Type	Interrupting Medium	Manufacturer & Ratings	Production Status
Sulfur Hexafluoride (SF6) Circuit Breaker	SF6	SIEMENS - 25 kV; 40 kA	Commercially Available
	SF6	SIEMENS - 44 kV; 40 kA	Commercially Available
	SF6	SIEMENS - 115 kV; 40 kA	Commercially Available
	SF6-N2	Southern States - 115 kV; 40 kA SF6 Reactor Switcher	Commercially Available
	SF6	ABB - 115 kV; 40 kA	Commercially Available
	SF6	SIEMENS - 115 kV; 63 kA	Commercially Available
	SF6	ABB - 230 kV; 63 kA	Commercially Available
Vacuum Circuit Breaker	Vacuum	G&W - 25kV; 12.5 kA Solid Dielectric Recloser	Commercially Available

(b) Asset Demographics

WPLP has 95 circuit breakers in service (inclusive of reactor switchers and reclosers which perform the same functions), summarized in Table 8 and Figure 3 below. WPLP's circuit breaker assets are all relatively new, ranging from one (1) to seven (7) years old, based on energization dates.

Table 8 - Circuit Breaker Asset Demographics

Breaker Type & Description	HV Qty 115-230 kV	MV Qty 25-44kV	Age (Years)	ESL (Years)	ESL Remaining
SIEMENS - 25 kV; 40 kA; SF6		28	1-3	40	37-39
SIEMENS - 44 kV; 40 kA; SF6		8	1-3	40	37-39

SIEMENS - 115 kV; 40 kA; SF6	28		1-3	40	37-39
ABB - 115 kV; 40 kA; SF6	4		7	40	33
Southern States - 115 kV; 40 kA SF6 Reactor Switcher	16		1-3	40	37-39
SIEMENS - 115 kV; 63 kA; SF6	4		3	40	37
ABB - 230 kV; 63 kA; SF6	5		3	40	37
G&W – 25 kV; 12.5 kA Solid Dielectric Recloser	2		7	50	43
Totals:	**59**	**36**	**1-7**	**40-50**	**33-43**

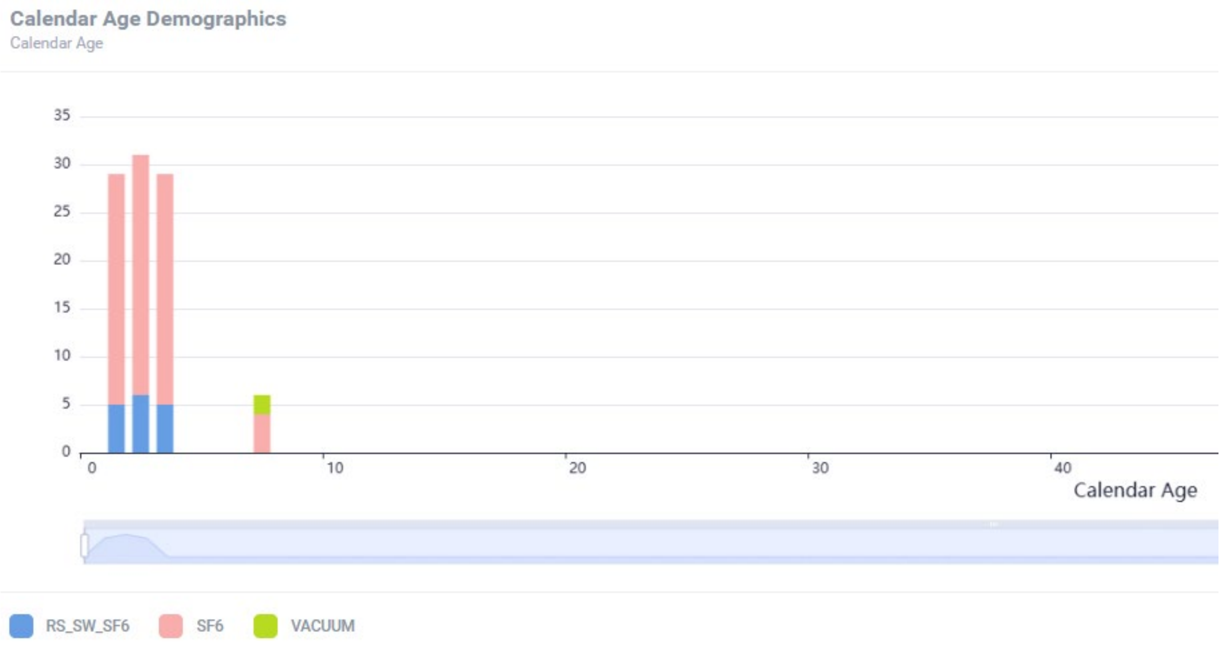

Figure 3: Circuit Breaker Calendar Age

4. *Other Substation Assets*

(a) Asset Description

WPLP's substations also contain several other asset classes that are essential to the operation of the Transmission System including other power equipment, civil infrastructure and ancillary equipment as summarized below.

(i) *Other Power Equipment*

Other power equipment is made up of both high-voltage (HV) & medium voltage (MV) assets that provide protection and control functions and provide the HV and MV electrical connections between various assets within substations, as described in Table 9 below.

Table 9 – Other Power Equipment Assets

Asset	Description
Disconnect Switch	Disconnect switches are used to provide isolation for substation equipment and transmission lines. Grounding switches are a subset of disconnect switches used to de-energize transmission lines following isolation. WPLP's motor-operated disconnect switches can be operated either remotely or locally. Manual disconnect switches can only be operated locally.
Fused Disconnect Switch	Fused disconnect switches are a combination of a switch to disconnect the circuit and a fuse to interrupt faults.
Wave Trap	Wave traps are a key component in power line communications facilitating the transmission of remote-control signals for control exchange between substations within a transmission power line system, ensuring that high-frequency carrier signals remain within the intended zone of protection.
Instrument Transformer (Dry Type & Oil Filled)	Instrument transformers are designed to transform high current and high voltage levels down to low current and low voltage outputs in a known and accurate proportion so that they can be used for measurement by protection, control and metering devices. There are three types of instrument transformers: voltage (potential) transformers (PT), capacitive voltage transformers (CVT) and current transformers (CT).
Surge Arrestor	Surge arresters are used to protect HV and MV equipment in substations, such as transformers, circuit breakers and reactors, against the effects of lightning and switching surges.
Insulator	Insulators electrically and mechanically separate and support live electrical conductors & components to provide adequate electrical clearances while not passing electrical currents through themselves.
Rigid & Strain Bus	A substation rigid bus scheme is the arrangement of overhead pipe and associated switching equipment (circuit breakers and isolators) in a substation, the flexible strain busbar is a hanging, aerial conductor, strung between metal structures used for connections. Rigid-bus structure is composed of rigid pipe (conductors) supported by rigid insulators, while strain-bus structure is composed of flexible conductors supported by strain insulators.

(ii) Civil Infrastructure

WPLP substation civil infrastructure includes all non-electrical assets contained within the substation yard and the surrounding perimeter of the substation. These assets support the function and safety of electrical assets within each substation and limit access to live equipment in the interest of public safety and system security. A description of select civil infrastructure asset classes is provided in Table 10 below.

Table 10 – Civil Infrastructure Assets

Asset Class	Description
Station Buildings	Station buildings consist of control buildings which contain HVAC system, protection, control and SCADA system equipment, AC station service distribution panels, DC batteries, chargers and distribution panels, telecom equipment, etc.
Station Structures & Foundations	Station structures and concrete foundations used to support or attach electrical equipment such as transformers, reactors, circuit breakers, disconnect switches, station service transformers, current transformers, surge arrestors, bus work, etc.
Station Site & Yard	Drainage, ditching, erosion control, insulating stone (crushed aggregate) etc.
Fences & Gates	Fences and gates are used to limit entry and access into the station yards to ensure public safety. Locked gates are used as an entry and exit point for qualified personnel and approved contractors.
Spill Containment Systems	Concrete foundations for oil-filled power transformers and variable reactors are designed to collect and contain oil in the event of a leak/spill to avoid environmental contamination.

(i) Ancillary Systems and Equipment

Ancillary systems include: (1) physical security and monitoring and alarm systems, including fire protection; (2) low-voltage components of the AC station service and AC/DC distribution systems; and, (3) substation grounding systems. Table 11 below describes the functions of each of these systems.

Table 11 – Ancillary Systems and Equipment Assets

Ancillary System	Description
Security System	Substation security systems consist of two major components: (1) a camera system that monitors substation entry and can be accessed remotely to inspect assets; and, (2) electronic access control for substation control buildings, to ensure that access is only available to authorized personnel.

Fire Protection System	Substation fire protection system consists of hydrogen detectors, photoelectric smoke detectors, LED strobe/horn alarms, emergency exit signs etc. that all tie into a fire alarm panel which is designed to detect and alert for fire, smoke and explosive gases.
AC/DC Station Service Equipment & Distribution Systems	AC/DC station service equipment consists of station service transformers, AC/DC distribution panels & circuit breakers, fused disconnect switches, low-voltage wiring, auto-transfer switches, etc. Station Service Equipment is used to supply power to transformer cooling, oil pumps, and load tap changers, circuit breaker charging motors, disconnect switch motors, outdoor equipment heaters, outdoor lighting and receptacles, protection, as well as all control and other equipment contained in substation control buildings, including HVAC and security systems.
DC Battery Banks & Chargers	All substations have at least one DC system, comprised of a battery bank and battery chargers. Substations containing equipment rated 115 kV or higher have redundant DC systems. The battery charger(s) ensures that battery bank is kept charged to ensure all the critical electrical systems in a substation continue to operate in the event of a power outage
Grounding	Grounding is placed throughout a substation to dissipate fault currents into the earth to protect transmission system assets and to ensure that people are not exposed to hazardous voltage levels in or near substations during a system fault.

(b) Asset Demographics

WPLP's other substation assets are summarized in Table 12 and Figures 4-9 below. All assets are between one (1) and seven (7) years old, based on energization dates.

Table 12 - Other Station Component Demographics

Asset Type	Quantity	Age (Years)
Motorized Disconnect Switch	149	1-7
Manual Disconnect Switch	99	1-7
Motorized Ground Disconnect Switch	39	1-3
Wave Traps	2	3
Free Standing Current Transformers (CT) - Oil Filled	21	1-3
Free Standing Current Transformers (CT) – Dry Type	54	1-3
Neutral Current Transformers (CT) – Dry Type	19	1-3
RMU Current Transformers (CT)	48	1-3
Capacitive Voltage Transformers (CVT)	135	1-7
Voltage Transformers (VT)	123	1-7
Surge Arrestors – 1 Per Phase	507	1-7
AC/DC Station Service Equipment[6]	187	1-7
DC Battery Banks	42	1-7

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[6] This category includes station service transformers, fused disconnect switches, distribution panels, transfer switches, etc. that have been assigned unique asset ID's in WPLP's asset management software.

DC Battery Chargers	42	1-7
Station Buildings	44	1-7
Fire Protection Systems	22	1-7
Security Systems	22	1-7
Station Sites/Yards	22	1-7
Spill Containment Systems	40	1-7
Fences & Gates	22	1-7

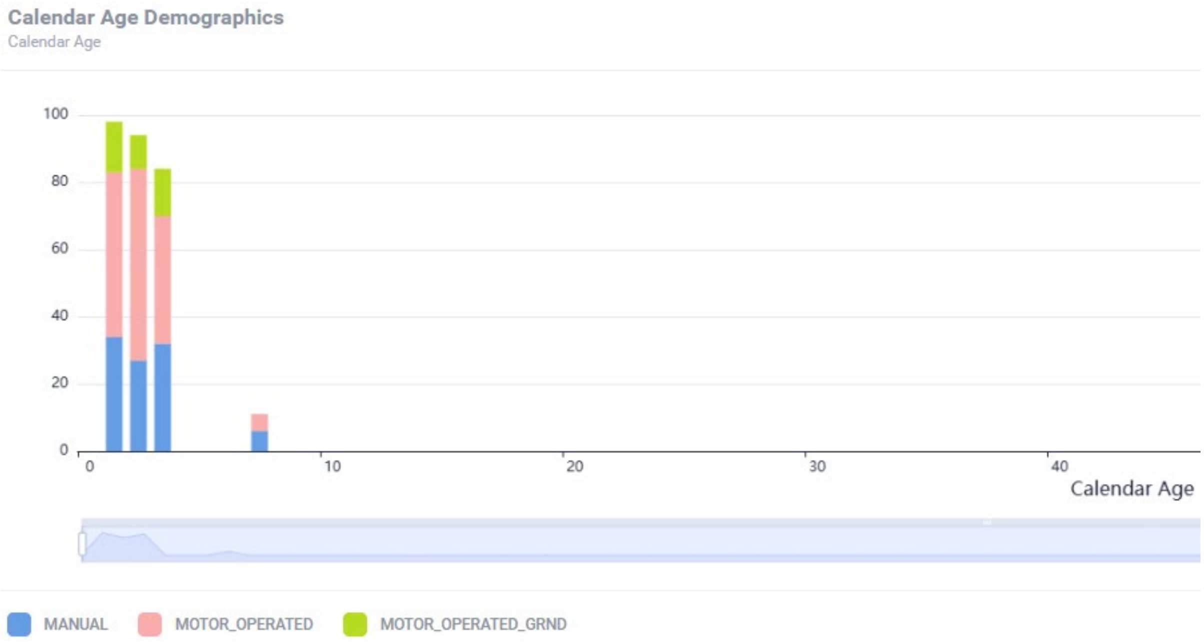

Figure 4: Disconnect Switch Calendar Age

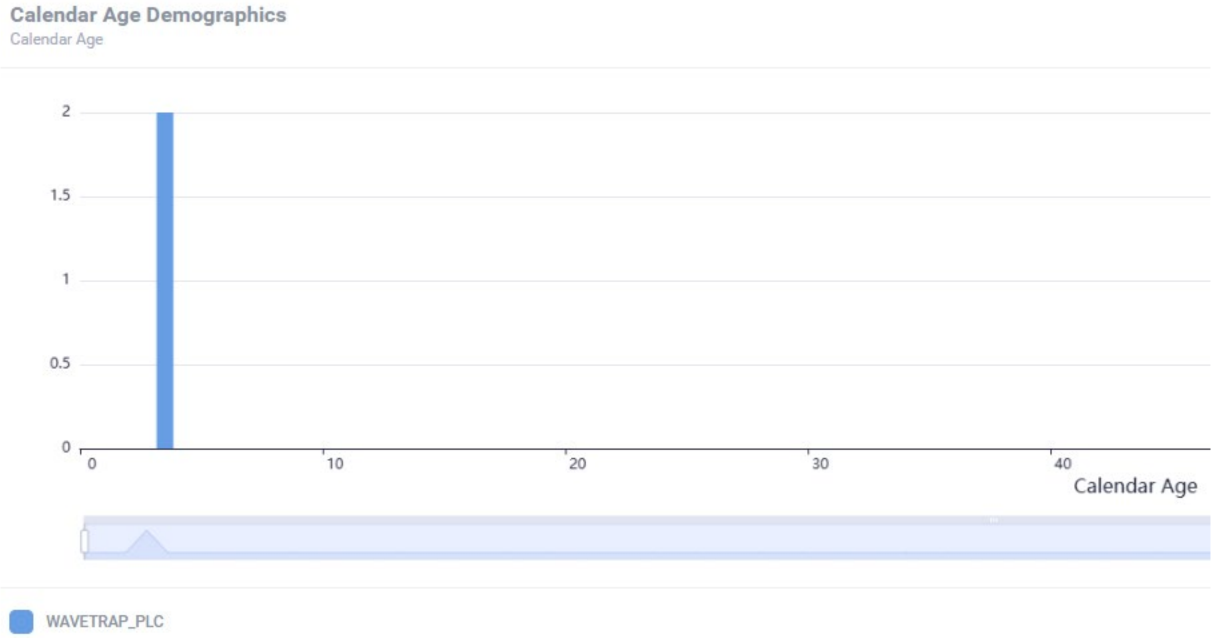

Figure 5: Wave Trap Calendar Age

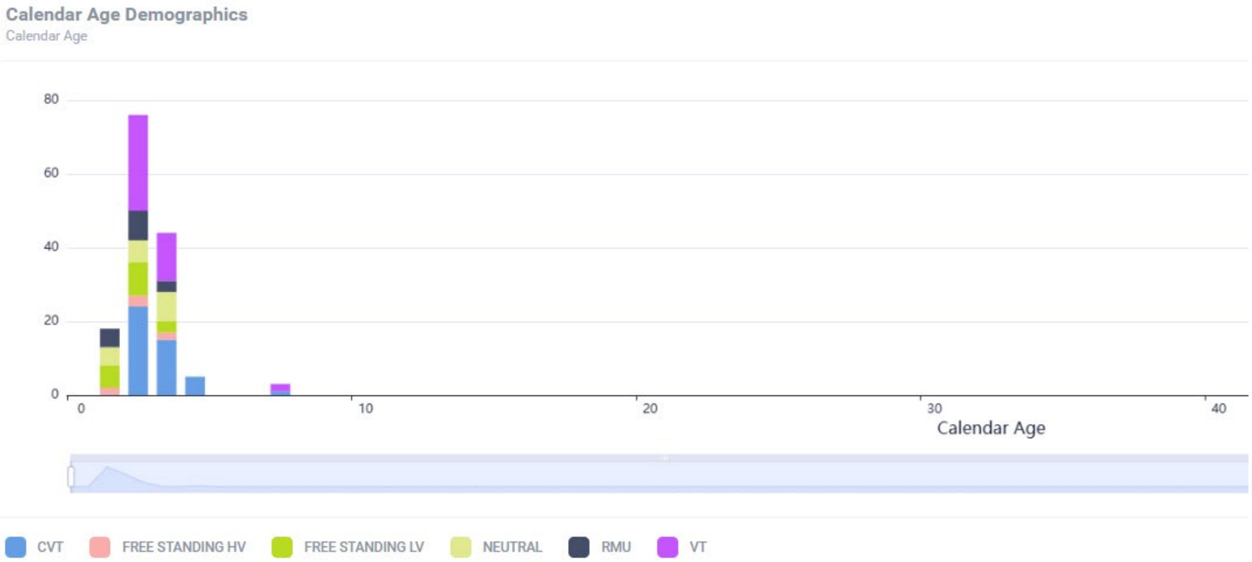

Figure 6: Instrument Transformer (CT, CVT, VT) Calendar Age

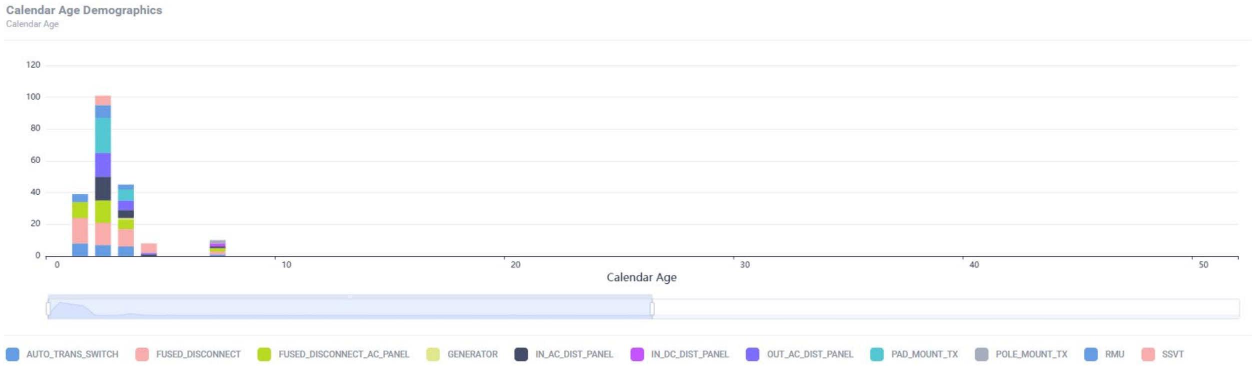

Figure 7: Ancillary Equipment -AC/DC Station Service Equipment Calendar Age

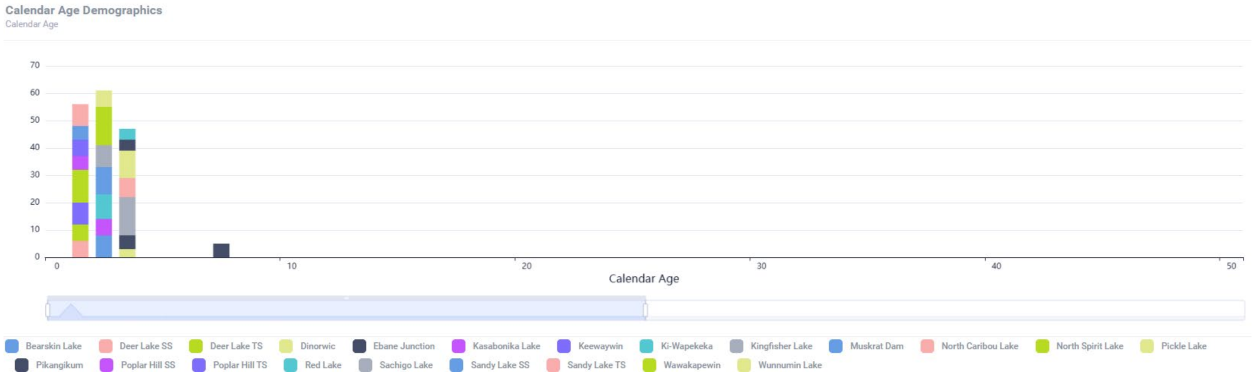

Figure 8: Ancillary Equipment – Surge Arrestors Calendar Age

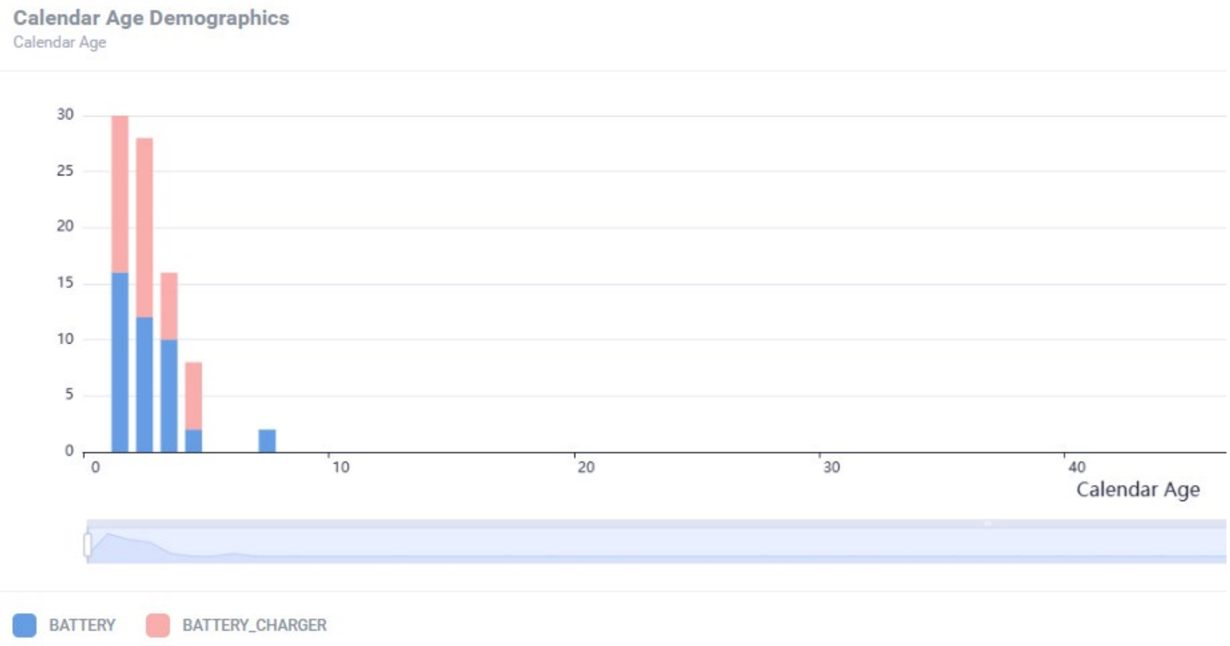

Figure 9: Ancillary Equipment – Battery Banks & Battery Chargers Calendar Age

5. Protection and Control Systems and Power System Communications

(a) Asset Description

A protection and control system detects abnormal or predetermined conditions and takes corrective action. Such actions may include isolating faults to minimize disruptions and restoring or redistributing loads. This provides operational flexibility, helps optimize asset life and improves the reliability of the transmission system by preventing further damage to equipment and either stopping an outage from occurring or facilitating the restoration of power. If faulted equipment is not isolated in a timely manner, it has the potential to cause cascading damage to other equipment, other substations and transmission lines thereby causing a more widespread power outage.

WPLP's protection and control systems and power system communication assets are comprised of Real-Time Automation Controllers (RTAC), microprocessor relays, a Supervisory Control and Data Acquisition (SCADA) system combined with Human-Machine Interface (HMI) computers and displays, sensors, substation LAN infrastructure and inter-station communication networks and equipment. Table 13 below summarizes the categories of equipment that comprise WPLP's protection and control systems and power system communication assets.

Table 13 - Protection and Control System and Power System Communication Assets

Asset Category	**Description**
Protection and Control Digital Assets	This category includes protection relays and other Intelligent Electronic Devices (IED's), which are microprocessor-based devices that receive data from sensors and inputs to monitor transmission system assets and system conditions. These devices also issue commands to control transmission assets in response to changing system conditions (e.g. tap changes to maintain voltage levels) as well as commands to isolate assets in response to fault conditions (e.g. issue a series of switching commands to isolate a faulted transmission line).
Power System Communications	Communication between all of WPLP's substations is achieved through the use of fibre optic strands, contained in optical ground wires (OPGW), or all-dielectric self-supported (ADSS) cables.[7] Communication between WPLP and HONI substations uses a combination of telecom leased circuits and a Power Line Carrier (PLC) system, which uses HONI's 230 kV transmission lines as a communication channel for transmitting protection signals.
Power Supply Assets	This category includes DC power supplies and inverters that provide low voltage power to the assets listed above.

(b) Asset Demographics

WPLP has 589 managed assets relating to its protection and control systems and power system communications, summarized in Table 14 below. All assets are between one (1) and seven (7) years old, based on energization dates.

Table 14 - Protection and Control and Power System Telecom Asset Demographics

Asset Description	**Quantity**
Protection & Control Digital Assets	471
Power Supply Assets	30

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[7] Refer to Section C.1 – Overhead Conductors below for additional detail on OPGW and ADSS cables.

Power System Telecom Assets	88
Totals:	**589**

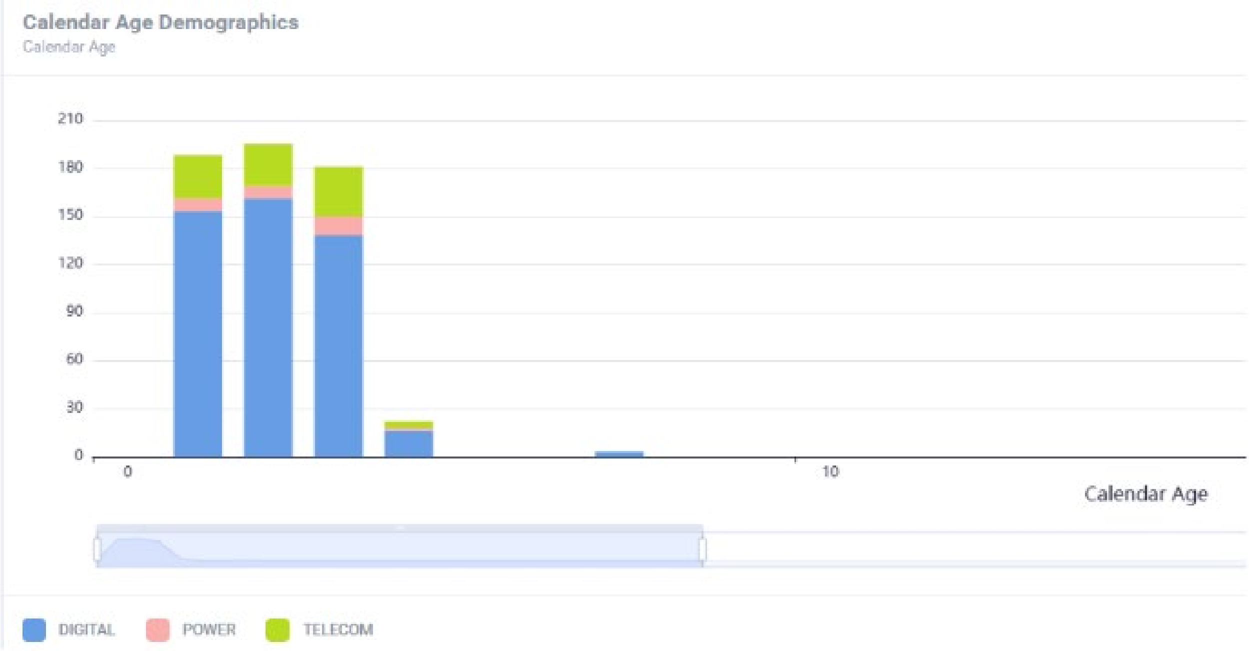

Figure 10: Protection and Control and Power System Communication Assets Calendar Age

C. Transmission Line Assets

1. Overhead Conductors

(a) Asset Description

Overhead conductors provide the electrical path to transmit electricity between WPLP's transmission stations, as well as between WPLP's transmission stations and each 25 kV HORCI delivery point. This asset category also includes the overhead wires and cables that provide shielding for lightning protection and grounding as well as optical fibres for telecommunication functions. The various types of conductors and cables used on WPLP's overhead circuits are summarized in Table 15 below.[8]

Table 15 - Conductor and Cable Applications on WPLP's Transmission System

Conductor/Cable	Application
Aluminum Conductor Steel Reinforced (ACSR)	Phase conductors on 230 kV, 115 kV and 44 kV circuits; neutral conductor on most 25 kV circuits
All Aluminum Conductor (AAC)	Phase conductors on 25 kV circuits; neutral conductor on Q1 25 kV circuit
Optical Ground Wire (OPGW)	Combines shield wire for lightning protection and grounding functions with optical fibers for telecommunication functions on 230 kV and 115 kV circuits
All-Dielectric Self-Supporting (ADSS)	Optical fiber cable for telecommunication functions, strung below phase conductors on 44 kV and 25 kV circuits

(b) Asset Demographics

WPLP's conductor assets consist of approximately 1,742 circuit km employing a mix of the conductor types described above, as summarized in Table 16 below. WPLP's conductor assets are all relatively new, ranging from two (2) to seven (7) years old, based on installation dates.

Table 16 – Conductor Demographics

Conductor Type	Total Circuit Length (km)	Age (Years)	ESL (Years)	ESL Remaining
ACSR – 795 Drake	303	4	45	41
ACSR – 477 Hawk	1,384	2-7	45	38-43
ACSR – 3/0 Pigeon	36	2-3	45	42-43
AAC – 477 Cosmos	18	7	45	38
AAC – 336.4 Tulip	36	2-3	45	42-43
OPGW	1,687	2-7	45	38-43
ADSS	54	2-7	45	38-43

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[8] Two of WPLP's 25 kV circuits also contain short sections of underground cable. For the purpose of this AMP, these assets are included with overhead conductors.

2. Structures and Foundations

(a) Asset Description

Transmission line structures are used to support overhead conductors in a manner that provides the required clearances over the right-of-way, between conductors, as well as from grounded objects and vegetation under various combinations of circuit loading and whether conditions identified during design.

Foundations stabilize transmission line structures by securing them in the ground. This enables the structures to support their own weight and withstand external forces and loads including framing components, the weight of overhead conductors, and the additional loads that can result from weather conditions (e.g. wind, ice & snow loading).

Table 17 - Structure and Foundation Applications on WPLP's Transmission System

Structure / Foundation Category	Application
Steel lattice structures	Used to support overhead conductors on most of WPLP's 230 kV and 115 kV circuits, except for the majority of the WPQ 115 kV circuit (Red Lake to Pikangikum) which was constructed in 2018
Wood poles	Used to support overhead conductors on all of WPLP's 44 kV and 25 kV circuits, as well as the majority of the WPQ 115 kV circuit
Steel poles	Used only in specific applications on the WPQ circuit (e.g. transition from lattice steel to wood pole and for heavily loaded poles with limited space for anchoring)
Fiber reinforced polymer (FRP)	Increasingly used for in-situ replacement of wood poles for resistance to damage from woodpeckers, insects and wildfires.

(b) Asset Demographics

WPLP's transmission lines are made up of 4,223 steel lattice structures, 2,641 wood/steel/FRP poles and over 6800 foundations, as summarized in Table 18 below. These assets are all relatively new, ranging from 1-7 years old, based on installation dates.

Table 18 - Structure Demographics

Structure Type	Structure Qty	Pole Qty	Age (Years)	ESL (Years)	ESL Remaining
Steel Lattice – Guyed	3757	-	2-5	60	55-58
Steel Lattice – Self-Supporting	466	-	2-5	60	55-58
Steel – Multi-pole structures	7	15	3-7	60	53-57
Steel Monopole	45	45	3-7	60	53-57
Wood – Multi-pole structures	33	67	2-7	45	38-43
Wood Pole	2502	2502	2-7	45	38-43
FRP Pole	11	11	1-4	60	56-59

3. Insulators

(a) Asset Description

Insulators are critical components of a transmission line; they prevent the electrical current from flowing to the supporting structures. When failures occur, they compromise the entire transmission system and can cause sustained power outages, equipment damage, safety hazards, and even forest fires thereby causing system instability.

(b) Asset Demographics

WPLP's system includes hundreds of thousands of insulator strings, as summarized in Table 19 below. In the case of toughened glass insulators used on the vast majority of WPLP's structures rated 44 kV and above, the quantities in Table 19 represent the individual glass discs that connect in series to provide the required insulation values to meet design criteria for each insulator assembly.

Table 19 – Insulator Demographics

Insulator Type	Voltage Range (kV)	Approx Qty
Toughened Glass	44-230	212,764
Polymer Braced Post	115	35
Polymer Braced Post	115	36
Transmission Polymer Post	44-115	84
Distribution Polymer Post	25	2,150
Distribution Polymer Dead-End	25	469

4. Rights of Way

(a) Asset Description

WPLP's transmission rights-of-way (ROWs) define the areas that were agreed to, between WPLP, First Nations, Ontario and a small number of private landowners, for the locations of WPLP's transmission lines. WPLP's extensive process of engagement with First Nations and consultation with various other parties on the routing of its transmission lines and the establishment of ROW widths is described in detail in the LTC Application and updated in each of WPLP's rate applications during the Transmission Project construction period.[9]

A key component of WPLP's current First Nation engagement efforts includes the introduction of utility concepts and strategies related to vegetation management and gathering First Nation feedback and perspectives on this topic. This effort is critical to the development of a sustainable vegetation management plan to ensure that WPLP's stewardship of its ROWs supports the long-term reliability of its Transmission System, without the use of herbicides as mandated in WPLP's Guiding Principles.

(b) Asset Demographics

Over 6900 Ha of ROWs were initially cleared between 2018 and 2023 to support the construction of WPLP's Transmission System. WPLP's transmission ROW widths vary by voltage level, as summarized in Table 20.

Table 20 - ROW Width and Area by Voltage Level

Voltage Level (kV)	ROW Width (m)	Total Length (km)	Approx ROW Area (Ha)
230	40	303.4	1,214
115	40	1,289.4	5,158
44	30	95	380
25	30	53.7	161

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[9] See LTC Application (EB-2018-0190), Exhibit I-3-1, as well as Exhibit A-6-1 in each of EB-2021-0134, EB-2022-0149, EB-2023-0168 and EB-2024-0176.

D. Asset Categorization

This section categorizes WPLP's Transmission System assets into the various transmission rate pools and identifies which assets are part of the bulk electricity system. This categorization supports the cost allocation presented in Exhibit I, and is responsive to certain requirements described in Section 2.4.1 of the Filing.

1. Asset Designations and In-Service Dates

Table 21, below, identifies when WPLP's assets were brought into service, by line segment and station.

Table 21: In-Service Schedule by Line Segment and Station

Asset Designation	Description	Actual In-Service Date
Line to Pickle Lake		
Line W54W	230 kV - Dinorwic to Pickle Lake	12-Aug-22
Station A	Dinorwic SS	12-Aug-22
Station B	Pickle Lake TS	12-Aug-22
Pickle Lake Remote Connection Lines		
Line WBC	115 kV - Pickle Lake to Ebane/Pipestone SS	5-Oct-22
Line WCJ	115 kV - Ebane/Pipestone SS to Kingfisher Lake TS	8-Nov-22
Line WJI	44 kV - Kingfisher Lake TS to Wunnumin Lake TS	25-May-23
Line WJK	115 kV - Kingfisher Lake TS to Wawakapewin TS	15-Aug-23
Line WKL	44 kV – Wawakapewin TS to Kasabonika Lake TS	16-Aug-23
Line WKM	115 kV – Wawakapewin TS to KI-Wapekeka TS	13-Dec-23
Line WCD	115 kV - Ebane/Pipestone SS to North Caribou Lake TS	5-Oct-22
Line WDE	115 kV - North Caribou Lake TS to Muskrat Dam TS	6-Jul-23
Line WEF	115 kV - Muskrat Dam TS to Bearskin Lake TS	6-Jul-23
Line WEG	115 kV – Muskrat Dam TS to Sachigo Lake TS	1-Nov-23
Line D1	25 kV – North Caribou Lake TS to HORCI 25 kV	5-Oct-22
Line E1	25 kV – Muskrat Dam TS to HORCI 25 kV	17-Aug-23
Line F1	25 kV – Bearskin Lake TS to HORCI 25 kV	7-Jul-23
Line G1	25 kV – Sachigo Lake TS to HORCI 25 kV	1-Nov-23
Line I1	25 kV – Wunnumin Lake TS to HORCI 25 kV	25-May-23
Line J1	25 kV – Kingfisher Lake TS to HORCI 25 kV	8-Nov-22
Line K1	25 kV – Wawakapewin TS to HORCI 25 kV	16-Aug-23
Line L1	25 kV – Kasabonika Lake TS to HORCI 25 kV	16-Aug-23

Line M+/M-	25 kV – KI-Wapekeka TS to HORCI 25 kV	13-Dec-23
Substation C	Ebane/Pipestone SS	5-Oct-22
Substation D	North Caribou Lake TS	5-Oct-22
Substation E	Muskrat Dam TS	6-Jul-23
Substation F	Bearskin Lake TS	6-Jul-23
Substation G	Sachigo Lake TS	1-Nov-23
Substation I	Wunnumin Lake TS	25-May-23
Substation J	Kingfisher Lake TS	8-Nov-22
Substation K	Wawakapewin TS	15-Aug-23
Substation L	Kasabonika Lake TS	16-Aug-23
Substation M	KI-Wapekeka TS	13-Dec-23
Red Lake Remote Connection Lines		
Line WPQ	115 kV - Red Lake SS to Pikangikum TS	Varies[10]
Line WQR	115 kV - Pikangikum TS to Poplar Hill SS	12-Mar-24
Line WRS	115 kV - Poplar Hill SS to Poplar Hill TS	12-Mar-24
Line WRT	115 kV - Poplar Hill SS to Deer Lake SS	9-Apr-24
Line WTU	115 kV - Deer Lake SS to Deer Lake TS	10-Apr-24
Line WTZ	115 kV - Deer Lake SS to Sandy Lake SS	16-Apr-24
Line WZW	115 kV - Sandy Lake SS to Sandy Lake TS	16-Apr-24
Line WZV	115 kV - Sandy Lake SS to North Spirit Lake TS	27-May-24
Line WVY	115 kV – North Spirit Lake TS to Keewaywin TS	27-May-24
Line Q1	25 kV – Pikangikum TS to HORCI 25 kV	12-May-23
Line S1	25 kV – Poplar Hill TS to HORCI 25 kV	12-Mar-24
Line U1	25 kV – Deer Lake TS to HORCI 25 kV	10-Apr-24
Line W1	25 kV – Sandy Lake TS to HORCI 25 kV	16-Apr-24
Line V1	25 kV – North Spirit Lake TS to HORCI 25 kV	27-May-24
Line Y1	25 kV – Keewaywin TS to HORCI 25 kV	27-May-24
Substation P	Red Lake SS	2-Sep-22
Substation Q	Pikangikum TS	12-May-23
Substation R	Poplar Hill SS	12-Mar-24
Substation S	Poplar Hill TS, S1 25kV to HORCI	12-Mar-24
Substation T	Deer Lake SS	10-Apr-24
Substation U	Deer Lake TS, U1 25kV to HORCI	10-Apr-24
Substation V	North Spirit Lake TS, V1 25kV to HORCI	27-May-24
Substation W	Sandy Lake TS, W1 25kV to HORCI	16-Apr-24
Substation Y	Keewaywin TS, Y1 25kV to HORCI	27-May-24
Substation Z	Sandy Lake SS	16-Apr-24

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[10] 95.5 km of the WPQ line segment was constructed in 2018 as part of the 98.9 km 44 kV line that was constructed between Hydro One's 44 kV system near Red Lake and the Pikangikum TS. The remaining 20.3 km of 115 kV line was constructed between the Red Lake TS and the existing 44 kV Pikangikum Line, which became the new transmission supply and resulted in the entire WPQ line segment operating at 115 kV following a voltage conversion outage on May 12, 2023. The remaining 3.4 km (98.9 km constructed less 95.5 km converted to 115 kV) of the 44 kV distribution line constructed in 2018 has been decommissioned as part of the EPC contract scope of work.

The relevant asset categories for WPLP, each of which is described below, are Network, Line Connection, Transformation Connection, and Common.

2. Network Assets

In its Decision and Order in EB-2018-0190, the OEB confirmed that the Line to Pickle Lake is classified as a network facility and that the revenue requirement associated with the Line to Pickle Lake will be recovered through the UTR network charge.[11]

The Line to Pickle Lake is an approximately 303 km transmission line from a point between Dryden and Ignace to Pickle Lake, including associated stations and ancillary facilities. The Line to Pickle Lake reinforces the transmission supply to Pickle Lake and includes the following elements:

- a 230 kV switching station located adjacent to the existing Hydro One circuit D26A ap-proximately 8 km southeast of Dinorwic ("Dinorwic SS");
- an approximately 303 km single circuit, overhead, 230 kV transmission line running from the Dinorwic SS generally in a northeasterly direction to the Pickle Lake TS (described below); and
- a 230/115 kV transformer station located near the intersection of Hwy 599 and Cohen Avenue in Central Patricia, which is approximately 3 km northeast from the Town of Pickle Lake ("Pickle Lake TS").

The revenue requirement associated with the Line to Pickle Lake has formed part of the UTR network charge since April 1, 2022 per EB-2022-0084.

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[11] EB-2018-0190, Decision and Order, p.23

In the final SIA Report for CAA ID 2016-567, the IESO identified that all of WPLP's Line to Pickle Lake assets fall within the NERC definition of the Bulk Electric System (BES). None of WPLP's other assets meet the BES definition.

3. Line Connection and Transformation Connection Assets

All assets comprising the Remote Connection Lines are categorized as either line connection or transformation connection assets.

WPLP's Transmission System connects remote Indigenous communities by means of approximately 903 km of 115 kV, 44 kV and 25 kV transmission lines north of Pickle Lake to connect 10 communities (the "Pickle Lake Remote Connection Lines")[12], and approximately 535 km of new 115 kV and 25 kV transmission lines north of Red Lake to connect 6 communities (the "Red Lake Remote Connection Lines")[13], including associated stations and ancillary facilities (together, the "Remote Connection Lines").[14] A total of 16 remote Indigenous communities, all of which are Participating First Nations, have connected, or are in the process of connecting[15] to

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[12] (1) Wunnumin Lake First Nation, (2) Kingfisher Lake First Nation, (3) Wawakapewin First Nation, (4) Kasabonika Lake First Nation, (5) Wapekeka First Nation, (6) Kitchenuhmaykoosib Inninuwug, (7) North Caribou Lake First Nation, (8) Muskrat Dam First Nation, (9) Bearskin Lake First Nation, and (10) Sachigo Lake First Nation.

[13] (1) Pikangikum First Nation, (2) Poplar Hill First Nation, (3) Deer Lake First Nation, (4) Sandy Lake First Nation, (5) North Spirit Lake First Nation, and (6) Keewaywin First Nation.

[14] The Red Lake Remote Connection Lines include approximately 113 km of what was an approximately 117 km line that the Applicant originally constructed, and until May 12, 2023 operated on an interim basis, as a distribution line running from a connection point on Hydro One's distribution system in Red Lake to a switching station serving the Pikangikum First Nation. Approximately 95 km of the 113 km portion of the line was constructed to a 115 kV standard but, during the interim period, was supplied by Hydro One's 44 kV system and was therefore only capable of operating at 44 kV. Approximately 18 km of the 113 km portion of the line was constructed to a 25 kV standard. As contemplated by the OEB's Decision and Order in EB-2018-0190, the 18 km segment is now deemed to be part of the Transmission System, and the 95 km portion of the line was converted to a transmission voltage as of May 12, 2023 by changing its connection point from Hydro One's 44 kV distribution system to WPLP's Red Lake Switching Station. Approximately 5 km of the distribution line does not form part of the WPLP Transmission System.

[15] The distribution system in Muskrat Dam First Nation remains in the process of being transferred from the Independent Power Authority to HORCI, along with related system and customer information, and necessary upgrades to the system in coordination with Indigenous Services Canada are in the process of being completed. It is expected that these processes will be completed in 2025. See April 15, 2025 Semi-Annual Report, filed in connection with EB-2018-0190, for more information.

the Transmission System via the local distribution systems owned and operated, or to be owned and operated, by Hydro One Remote Communities Inc. ("HORCI") in each such community.[16]

The Remote Connection Lines help address the significant limitations previously associated with electricity supply in the remote Indigenous communities, which historically had severe impacts on community infrastructure, economic development and quality of life, and contributed to significant environmental and health risks.

Several aspects arising from the EB-2018-0190 proceeding are worth noting in relation to the categorization of these assets:

a) The OEB deemed the 44 kV and 25 kV portions of the Remote Connection Lines to be transmission facilities under subsection 84(b) of the OEB Act;[17]

b) The OEB approved a cost recovery and rate framework that results in the revenue requirement associated with the Remote Connection Lines being recovered via a fixed monthly charge applicable to HORCI, instead of being recovered through UTRs;[18] and

c) Notwithstanding that the fixed monthly charge described in (b) above does not distinguish between line connection and transformation connection assets, WPLP maintains the distinction between these categories to align with the UTR rate pools.[19]

WPLP's line connection assets include approximately 1438 km of single circuit overhead 115 kV, 44 kV and 25 kV transmission lines running from the Pickle Lake and Red Lake areas generally in a northerly direction, to a number of switching and transformer stations, as well as five switching

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[16] The Transmission System is designed to permit the potential future connection of a 17th community, McDowell Lake First Nation.

[17] EB-2018-0190, Decision and Order, pp.23, 30.

[18] EB-2018-0190, Decision and Order, pp. 24-28

[19] In response to various IR's in EB-2018-0190 (e.g. C-Staff-70(c), HORCI Supplemental IR 7), WPLP confirmed that it proposes to charge UTR's in the normal course to any connecting customers other than HORCI, and that it proposes to evaluate CIAC requirements with respect to new connections in accordance with TSC requirements. This implicitly requires that WPLP maintain distinct categorization between line connection and transformation connection assets.

stations that do not contain transformers. Specifically, WPLP's transformation connection assets include 15 transformer stations from which transmission service is being provided to distribution systems owned and operated by HORCI, which in turn serve customers in 16 remote Indigenous communities.[20]

4. Common Assets

WPLP's common assets include general plant such as fleet, facilities, tools and equipment, IT hardware and software, and business systems. Investment in this asset category is relatively immaterial in the context of WPLP's investment in its Transmission System.[21] WPLP's asset demographics for its general plant are managed outside of ENGIN and require compilation and verification from multiple discrete systems. As such, WPLP has not been able to present this information as part of this initial TSP. These assets will be described further, with supporting demographic data where possible and WPLP's approaches to general plant asset management, as part of WPLP's TSP in support of its first multi-year rate application. Generally, these assets support the day-to-day needs of WPLP's small complement of internal staff, with external contractors generally providing their own fleet, tools and accommodation as required. The majority of these assets (aside from buildings and fixtures) have an ESL in the range of 5-10 years and are generally replaced in line with ESL/depreciation cycles.

For rate setting purposes, the rate base amounts related to these assets is allocated between the Line to Pickle Lake and the Remote Connection Lines (i.e. Network Assets vs. Line and Transformation Connection Assets) when WPLP calculates its revenue requirement. Exhibit I-2-1 illustrates the allocation of general plant rate base for the 2026 Test Year.

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[20] One of the 15 transformer stations (North Spirit Lake TS) is designed to accommodate the future connection of a 17th community, McDowell Lake First Nation.

[21] Per Table 5 in Exhibit C-3-1, WPLP's 2026 average net fixed asset value for General Plant of $2.1M is less than 0.2% of WPLP's total 2026 average net fixed asset value of $1.235B.

APPENDIX ‘A’

Summary of WPLP Substations

Designation	Name	Location[1]	Voltage	Functionality[2]	Asset Categorization
Line to Pickle Lake (Bulk Electricity System):					
A	Dinorwic SS	SE of Dinorwic	230 kV	Switching; Reactive Power Compensation	Network
B	Pickle Lake TS	NE of Pickle Lake	230/115 kV	Transformation; Switching; Reactive Power Compensation	Network
North of Pickle Lake Remote Connection Lines (non-Bulk Electricity System):					
C	Ebane/Pipestone Jct	NW of Nord Road / Pipestone River crossing	115 kV	Switching; Reactive Power Compensation	Line Connection
J	Kingfisher Lake TS	NW of Kingfisher Lake Airport	115/44/25 kV	Switching; Transformation; Reactive Power Support	Transformation Connection
I	Wunnumin Lake TS	South of Wunnumin Lake Airport	44/25 kV	Transformation	Transformation Connection
K	Wawakapewin TS	South of Wawakapewin First Nation Reserve boundary	115/44/25 kV	Switching; Transformation; Reactive Power Support	Transformation Connection
L	Kasabonika Lake TS	SW of Kasabonika Lake Airport	44/25 kV	Transformation	Transformation Connection
M	Kitchenuhmaykoosib Inninuwug (KI) - Wapekeka TS	Approximate mid-point between the 2 communities	115/25 kV	Transformation	Transformation Connection
D	North Caribou Lake TS	North of Weagamow Lake Airport	115/25 kV	Switching; Transformation	Transformation Connection
E	Muskrat Dam TS	~12 km NE of Muskrat Dam Airport	115/25 kV	Switching; Transformation; Reactive Power Compensation	Transformation Connection
F	Bearskin Lake TS	SE of Bearskin Lake Airport	115/25 kV	Transformation; Reactive Power Compensation	Transformation Connection
G	Sachigo Lake TS	North of Sachigo Lake Airport	115/25 kV	Transformation; Reactive Power Compensation	Transformation Connection

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[1] Locations are within 5 km of reference point unless otherwise noted.

[2] In the context of this table, "Switching" is meant to indicate which substations have switching/protection functionality between an incoming transmission line and one or more outgoing transmission lines. All stations that contain transformation and/or reactive power functionality have switching and protection features related to that functionality.

Designation	**Name**	**Location**[1]	**Voltage**	**Functionality**[2]	**Asset Categorization**
North of Red Lake Remote Connection Lines (non-Bulk Electricity System):					
P	Red Lake SS	SE of Hydro One Red Lake TS (West of Hwy 105)	115 kV	Switching; Reactive Power Compensation	Line Connection
Q	Pikangikum TS	~11 km SE of Pikangikum Airport (South of Berens River)	115/25 kV[3]	Switching; Transformation	Transformation Connection
R	Poplar Hill SS	~30 km East of Poplar Hill First Nation	115 kV	Switching; Reactive Power Compensation	Line Connection
S	Poplar Hill TS	East of Poplar Hill Airport	115/25 kV	Transformation	Transformation Connection
T	Deer Lake SS	~20 km SE of Deer Lake Airport	115 kV	Switching; Reactive Power Compensation	Line Connection
U	Deer Lake TS	SE of Deer Lake Airport	115/25 kV	Transformation	Transformation Connection
Z	Sandy Lake SS	~55 km South of Sandy Lake Airport	115 kV	Switching; Reactive Power Compensation	Line Connection
W	Sandy Lake TS	West of Sandy Lake Airport	115/25 kV	Transformation; Reactive Power Compensation	Transformation Connection
V	North Spirit Lake TS	SW of North Spirit Lake Airport	115/44/25 kV[4]	Switching; Transformation	Transformation Connection
Y	Keewaywin TS	NE of Keewaywin Airport	115/25 kV	Transformation; Reactive Power Compensation	Transformation Connection

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[3] Interim operation at 44 kV was converted to 115 kV operation on May 12, 2023.

[4] 44 kV winding is available on the transformer to permit a future supply to McDowell Lake First Nation at 44 kV.

APPENDIX 'B'

Summary of WPLP Line Segments

Designation	Origin	Endpoint	Voltage (kV)	Length (km)	Asset Categorization
Line to Pickle Lake (Bulk Electricity System):					
W54W	Dinorwic SS	Pickle Lake TS	230	303.4	Network
North of Pickle Lake Remote Connection Lines (non-Bulk Electricity System):					
WBC	Pickle Lake TS	Ebane/Pipestone SS	115	147.9	Line Connection
WCD	Ebane/Pipestone SS	North Caribou Lake TS	115	132.9	Line Connection
D1	North Caribou Lake TS	HORCI 25 kV Demarcation	25	1.5	Line Connection
WDE	North Caribou Lake TS	Muskrat Dam TS	115	99.5	Line Connection
E1	Muskrat Dam TS	HORCI 25 kV Demarcation	25	15.0	Line Connection
WEF	Muskrat Dam TS	Bearskin Lake TS	115	63.1	Line Connection
F1	Bearskin Lake TS	HORCI 25 kV Demarcation	25	0.02	Line Connection
WEG	Muskrat Dam TS	Sachigo Lake TS	115	83.9	Line Connection
G1	Sachigo Lake TS	HORCI 25 kV Demarcation	25	3.2	Line Connection
WCJ	Ebane/Pipestone SS	Kingfisher Lake TS	115	98.2	Line Connection
J1	Kingfisher Lake TS	HORCI 25 kV Demarcation	25	4.0	Line Connection
WJI	Kingfisher Lake TS	Wunnumin Lake TS	44	55.5	Line Connection
I1	Wunnumin Lake TS	HORCI 25 kV Demarcation	25	1.0	Line Connection
WJK	Kingfisher Lake TS	Wawakapewin TS	115	84.7	Line Connection
K1	Wawakapewin TS	HORCI 25 kV Demarcation	25	4.8	Line Connection
WKL	Wawakapewin TS	Kasabonika Lake TS	44	39.5	Line Connection
L1	Kasabonika Lake TS	HORCI 25 kV Demarcation	25	2.6	Line Connection
WKM	Wawakapewin TS	Kitchenuhmaykoosib Inninuwug (KI) - Wapekeka TS	115	65.5	Line Connection
M1	Kitchenuhmaykoosib Inninuwug (KI) - Wapekeka TS	HORCI 25 kV Demarcation	25	0.3	Line Connection

Designation	Origin	Endpoint	Voltage (kV)	Length (km)	Asset Categorization
North of Red Lake Remote Connection Lines (non-Bulk Electricity System):					
WPQ[1]	Red Lake SS	Pikangikum TS	115	115.8	Line Connection
Q1	Pikangikum TS	HORCI 25 kV Demarcation	25	17.6	Line Connection
WQR	Pikangikum TS	Poplar Hill SS	115	42.6	Line Connection
WRS	Poplar Hill SS	Poplar Hill TS	115	32.7	Line Connection
S1	Poplar Hill TS	HORCI 25 kV Demarcation	25	1.4	Line Connection
WRT	Poplar Hill SS	Deer Lake SS	115	67.9	Line Connection
WTU	Deer Lake SS	Deer Lake TS	115	20.6	Line Connection
U1	Deer Lake TS	HORCI 25 kV Demarcation	25	0.01	Line Connection
WTZ	Deer Lake SS	Sandy Lake SS	115	27.6	Line Connection
WZW	Sandy Lake SS	Sandy Lake TS	115	96.1	Line Connection
W1	Sandy Lake TS	HORCI 25 kV Demarcation	25	0.3	Line Connection
WZV	Sandy Lake SS	North Spirit Lake TS	115	31.7	Line Connection
V1	North Spirit Lake TS	HORCI 25 kV Demarcation	25	1.6	Line Connection
WVY	North Spirit Lake TS	Keewaywin TS	115	78.7	Line Connection
Y1	Keewaywin TS	HORCI 25 kV Demarcation	25	0.3	Line Connection

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[1] 95.5 km of the WPQ line segment was constructed in 2018 as part of the 98.9 km 44 kV line that was constructed between Hydro One's 44 kV system near Red Lake and the Pikangikum TS. The remaining 20.3 km of 115 kV line was constructed between the Red Lake TS and the existing 44 kV Pikangikum Line, which became the new transmission supply and resulted in the entire WPQ line segment operating at 115 kV following a voltage conversion outage on May 12, 2023. The remaining 3.4 km (98.9 km constructed less 95.5 km converted to 115 kV) of the 44 kV distribution line constructed in 2018 has been decommissioned as part of the EPC contract scope of work.

Exhibit B, Tab 1, Schedule 3

Regional Considerations

REGIONAL CONSIDERATIONS

This schedule provides information on the regional planning processes in which WPLP has been and continues to be a participant, to demonstrate that regional considerations have been appropriately considered and addressed in the development of WPLP's plans. There is significant alignment between the development of WPLP's Transmission System, provincial policy objectives as outlined in Long-term Energy Plans ("LTEP"), and the OEB's regional planning process. This historical context, along with a summary of WPLP's current participation in regional planning processes, is discussed below. A key focus for WPLP in these processes, and in considering these processes relative to its planning efforts, is to emphasize the importance of connecting remote First Nations communities and maintaining sufficient transmission capacity and transmission system reliability to meet the needs of those communities once connected.

A. Alignment with Long-Term Energy Plans

In 2010, the Province issued its first LTEP. In the 2010 LTEP, in response to efforts from Participating First Nations, the Province declared that it considered the Line to Pickle Lake to be a priority project and indicated its intention to ask the Ontario Power Authority ("OPA") to develop a plan for remote connections beyond Pickle Lake.[1] Following up on that intention, in a February 17, 2011 Directive the Minister of Energy asked the OPA to develop a plan for remote community connections beyond Pickle Lake. In 2013, the Province issued its second LTEP. In the 2013 LTEP the Province declared not only that it continued to consider the Line to Pickle Lake to be a priority project, but also that it considered connecting remote communities in northwest Ontario to be a priority for the province.[2]

Subsequent to the 2013 LTEP, on August 21, 2014 the OPA issued its Draft Technical Report and Business Case for the Connection of Remote First Nation Communities in Northwest Ontario for

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[1] Ministry of Energy, Building Our Clean Energy Future – Ontario's Long-Term Energy Plan, November 23, 2010, p. 46 (http://www.nexteraenergycanada.com/pdf/ontario_ltep.pdf)

[2] Ministry of Energy, Achieving Balance - Ontario's Long-Term Energy Plan, December 2013, pp. 52 and 72 (http://www.energy.gov.on.ca/en/files/2014/10/LTEP_2013_English_WEB.pdf)

the Northwest Ontario First Nation Transmission Planning Committee ("Draft Remote Community Connection Plan" or "Draft RCCP").[3] This report established a business case for connecting up to 21 remote communities in northwestern Ontario to the provincial transmission system, including the 16 communities that are connected to WPLP's transmission system.[4]

B. Alignment with OEB Regional Planning Process

In the Northwest Ontario Planning Region (Northwest), the first cycle of the regional planning process divided the region into four sub-regions, each with their own Integrated Regional Resource Plan (IRRP) published between January 2015 and December 2016. WPLP's transmission system is located in the North of Dryden sub-region, for which an IRRP was published by the IESO in January 2015.[5] This report recommended, among other things, a new single circuit 230 kV transmission line from the Dryden/Ignace area to Pickle Lake in order to reinforce supply to Pickle Lake and provide capacity for the connection of remote communities north of Pickle Lake and north of Red Lake as recommended by the RCCP.

The first cycle of regional planning for the Northwest concluded in June 2017 with the publication of the Regional Infrastructure Plan (RIP).[6] The RIP confirms the recommendations of the 2015 North of Dryden IRRP with respect to the Line to Pickle Lake and the connection of 16 remote communities and acknowledges WPLP's development of the related transmission project.

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[3] See http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/remote-community-connection/OPA-technical-report-2014-08-21.pdf?la=en. WPLP notes that the Central Corridor Energy Group (CCEG), a predecessor to the formation of WPLP, appointed technical representatives to support the work of this Committee and to report back to the CCEG Steering Committee, which in turn reported to the Chiefs Working Group, which mandated this participation, and the rest of the leadership.

[4] One of the 16 communities, Muskrat Dam First Nation, is in the process of transferring its distribution system to HORCI in order to connect to WPLP's transmission system later in 2025. WPLP's transmission system also allows for the potential future grid connection of a 17th community (McDowell Lake First Nation), which does not currently have a community distribution network. Additionally, the five other communities in the Ring of Fire area which the RCCP determined were economic to connect could be connected to the provincial transmission system via WPLP's transmission system at a future date.

[5] See http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/North-of-Dryden/North-Dryden-Report-2015-01-27.pdf?la=en

[6] See https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/northwestontario/Documents/Northwest%20RIP%20Report%20-%202017June9.pdf

The second cycle of regional planning for the Northwest started in March 2020 and was completed with the release of the Northwest Region Integrated Regional Resource Plan on January 13, 2023 (2023 IRRP). The 2023 IRRP acknowledges the role of WPLP's transmission system in meeting capacity and operational needs in Northwestern Ontario. The 2023 IRRP identifies that moving the open point on HONI's E1C transmission line to supply load in the Pickle Lake subsystem from WPLP's transmission system will cause post-contingency high voltage concerns during certain operating scenarios. An additional reactor on the HONI system at/near Pickle Lake SS was identified as a solution to manage these high voltages and the 2023 IRRP recommends that HONI and IESO collaborate during the 2023 Northwest Regional Infrastructure Plan (2023 RIP) to refine the location of the open point and reactor sizing. WPLP participated in the 2023 RIP led by HONI, which resulted in the publication of the Northwest Ontario RIP Report in August 2023. During this process, WPLP had additional discussions with HONI and IESO to consider the feasibility of alternative interim open point locations to address system capacity and reliability considerations until the additional reactor can be installed on the HONI system. In July 2023, HONI changed the normal open point on the E1C line to an interim location to accelerate the supply of a significant portion of the load connected to the E1C transmission line from HONI's new connection to WPLP's transmission system at Pickle Lake. The additional reactor is expected to be in service at HONI's Pickle Lake SS in 2026[7], which will support improved reliability and operability of the 115 kV system in the area.

Following the 2023 RIP process, WPLP, HONI and IESO have continued to discuss implementation of the recommendations in the Northwest Ontario RIP Report and to coordinate system planning considerations in response to connection requests received subsequent to the completion of the aforementioned regional planning activities. In August 2024, WPLP was informed that the IESO has initiated a study which will be an addendum to the 2023 IRRP, due to emerging growth in the North of Dryden area. This study, which is expected to be completed in

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[7] Hydro One, Regional Planning Process Annual Status Report 2024, November 1, 2024, p.35 (https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/Documents/HONI_2024_Regional_Planning_Status_Report_20241101.pdf)

Summer 2025, will identify options for system upgrades to accommodate forecast and potential load growth scenarios.

C. Coordinated Planning with Third Parties

Each of the regional planning initiatives described above (the RCCP, IRRP and RIP, as well as 2023 IRRP and RIP) have included significant engagement between a variety of parties:

- In preparing the Draft RCCP, the OPA/IESO engaged with 17 of the First Nation communities included in the plan, and discussed its intent to finalize the report only following engagement with all 25 communities.[8]

- In preparing the 2023 IRRP, the IESO identified 65 First Nation communities and eight Métis communities that were invited to six webinars. Further, the IESO engaged with a number of First Nations organizations, municipalities, industry associations, LDCs and transmitters (including WPLP).

- In preparing the 2023 RIP, Hydro One Transmission included input from a working group that includes the IESO, Hydro One Distribution, four LDC's and two neighbouring transmitters (WPLP and East-West Tie LP). The 2023 RIP also considered the results from the other regional planning reports mentioned above, specifically the 2023 IRRP.

- First Nations have consistently emphasized the need for WPLP to ensure that sufficient transmission system capacity is maintained to meet the future needs of First Nations in the Northwest region. WPLP has therefore ensured that forecasts of First Nations loads for regional planning purposes continue to reflect the annual growth rates determined during OPA/IESO engagement with First Nations during the development of the Draft RCCP. WPLP also ensured that priority for First Nations load growth was incorporated into the

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[8] RCCP; pp. 91-92

development of its OEB-approved Customer Connection Procedures, which were approved in EB-2022-0330 and are further discussed in Exhibit B-1-1.

Exhibit B, Tab 1, Schedule 4

Capital Expenditures

CAPITAL EXPENDITURES

A. Overview

This schedule provides a summary of WPLP's capital expenditures over the past five historical years from 2021, and including the 2025 bridge year, as well as its planned capital expenditures over the next five years to 2030, starting with the 2026 test year.

WPLP's efforts during the historical period were largely focused on the construction and in-servicing of the Transmission Project, with Transmission Project cost updates and variance analysis presented in each of WPLP's historical applications for approval of its revenue requirements for a single test year. For consistency with the presentation of capital cost information in WPLP's most recent application (EB-2024-0176), historical/bridge year capital expenditures are discussed in two separate categories:

a) Transmission Project Capital, which includes the costs that WPLP has incurred or expects to incur under its EPC contract, and those capital costs it has incurred outside of that contract in relation to the Transmission Project up to year-end 2024.

b) Sustaining Capital, which includes the cost of discrete wood pole replacements on the Pikangikum system and a small amount of General Plant costs that WPLP expects to incur in 2025.

The updated capital costs of the Transmission Project as set out in the current Application include audited actual costs to December 31, 2024, as well as WPLP's updated forecasts for 2025 Transmission Project capital costs, as at May 31, 2025.[1]

WPLP notes that, as the current application is for a single test year, and in the context of filing this initial TSP on a best-efforts basis, the costs set out in this Schedule for planned capital expenditures

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[1] WPLP recognizes that inflation rates have been elevated since early 2022. However, given that the EPC Contract was for a fixed price, the majority of its capital costs are not subject to the changes in inflation. To the extent inflation impacts the non-EPC costs, it has been reflected in the forecasted amounts.

are focused on the 2026 test year, with a discussion of projects and programs that will be further costed, prioritized and scheduled as part of the next TSP, which will be filed in 2026 with WPLP's first multi-year rate plan for a rate period starting in 2027.

WPLP further notes that, except where otherwise indicated, the impacts of COVID-19 that continue to be the subject of commercial discussions between WPLP and the EPC contractor have not been included in these capital cost forecasts. See Exhibit H-2-2.

B. Historical Capital Expenditures

1. Historical Transmission Project Capital Expenditures

This section presents WPLP's historical Transmission Project capital expenditures by year, as well as by expenditure category, including analysis of variances from capital costs approved by the OEB in WPLP's 2025 revenue requirement application to WPLP's updated capital cost forecast for 2025 as at May 31, 2025.

(a) Cost Categories Underlying Updated Transmission Project Historical Capital Expenditures

WPLP's updated Transmission Project capital expenditures, forecast to the end of 2025, are based on the following sources or cost categories:

a) EPC Contract Costs: engineering, procurement and construction costs based on the EPC contract;

b) Non-EPC Capital Costs: capital costs of items accounted for outside of the EPC contract, but which have nevertheless been planned and are required by WPLP;

c) Overhead Costs: labour, consulting and administrative costs to December 31, 2024, which were previously determined by WPLP through a bottom-up forecast, which was reviewed by Hatch in its capacity as Owner's Engineer (OE) and which identified costs that were either capitalized or allocated to OM&A using the methodology described in WPLP's previous applications[2]; and

d) Contingency Costs: a quantitative risk-based contingency analysis performed by the OE.

(b) Capital Expenditures by Year

WPLP's previous applications provided annual updates on Transmission Project capital expenditures by year for the purpose of explaining changes to the timing of WPLP's in-service additions that were driven primarily by changes to the project schedule. While the Transmission Project was entirely in service at the time of WPLP's most recent application, variances have resulted from underspend on non-EPC Transmission Project capital costs as well as the timing of certain EPC contract closeout activities as described below. WPLP's updated historical and forecast Transmission Project capital expenditures by year, excluding AFUDC, are summarized in Table 1, below.

Table 1 – Transmission Project Capital Expenditures by Year

Year	Capital Expenditures ($000's)		
	Actual/Forecast	2025 Rate Application[3]	Variance
Pre-2021	450,915	450,915	0
2021	443,354	443,354	0
2022	392,413	392,413	0
2023	380,176	380,176	0
2024	69,280	73,508	-4,228
2025	500	0	500

The timing of the capital expenditures set out in Table 1 above have largely been based on the timing of construction activity by WPLP's EPC contractor. These expenditures were recorded as CWIP until the related assets became used or useful. Transfers from CWIP to rate base have been

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[2] Appendix A of Exhibit B-1-5 in EB-2024-0176 provides a detailed explanation of WPLP's overhead cost allocation methodology, including calculations of capitalization factors during the construction period.

[3] Refer to Table 1 of Exhibit B-1-5 in EB-2024-0176.

approved on a forecast basis for all Transmission Project assets, up to and including the 2024 additions that were approved on a forecast basis in EB-2023-0168. Variances arising from differences between forecast and actual in-service dates have been tracked in the In-Service Date Variance Account. The $500k cost forecast for 2025 relates to construction close out costs from final ROW inspections, which were delayed into 2025.

(c) Capital Expenditures by Category

WPLP's updated Transmission Project capital costs (excluding COVID costs) to the end of 2025 are approximately $1.76 billion inclusive of interest, or approximately $1.83 billion inclusive of other development, infrastructure costs (not forming part of the Transmission Project) and COVID costs, which is consistent with WPLP's equivalent forecast as presented in the 2025 rate application. These amounts, both for the current forecast and the forecast presented in the 2025 application, are set out in Table 2, below, using cost categories consistent with those presented in EB-2021-0134. The table is followed by a brief explanation of the forecasted cost savings as compared to WPLP's 2025 rate application.

Table 2 – Capital Cost Forecast and Variance Summary

(Costs in $000's)	Updated Forecast[4]	2025 Rate Application	Variance	
			$	%
EPC Costs				
Transmission Line Facilities - Line to Pickle Lake	215,166	215,166	0	0%
Transmission Line Facilities - Remote Connection Lines	911,938	911,938	0	0%
Station Facilities - Line to Pickle Lake	38,472	38,472	0	0%
Station Facilities - Remote Connection Lines	304,364	304,364	0	0%
Non-EPC Capital Costs				
EPC Excluded (e.g. Insurance, LIDAR, Stumpage)	8,913	10,271	-1,359	-13%

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[4] As at May 2024, with incremental COVID costs reported as separate cost category.

Engineering, Design, Project/Construction Management & Procurement	104,517	106,751	-2,234	-2%
Environmental Assessments, Routing, Permitting, Regulatory & Legal	27,236	27,275	-38	0%
Land Rights	10,844	10,918	-73	-1%
Engagement, Stakeholder Consultation, Participation and Training	42,773	43,433	-661	-2%
Contingency	0	0	0	0%
Costs Included in EB-2018-0190, Pre-AFUDC	***1,664,223***	***1,668,588***	***-4,365***	***0%***
Capitalized Interest	92,794	92,819	-25	0%
Total Costs Included in EB-2018-0190	***1,757,017***	***1,761,407***	***-4,390***	***0%***
Other Infrastructure	1,315	680	636	94%
COVID-19 Costs	71,100	71,100	0	0%
Total Capital Costs[5]	**1,828,932**	**1,833,186**	**-3,755**	**0%**

The table above provides variances between the updated forecast and the forecast presented in the 2025 rate application for the capital costs of the Transmission Project, which was completed in 2024. The main driver of the reduction in capital costs is a reduction in non-EPC capital costs across all categories during the final year of construction. These non-EPC savings included $1.8 million in savings on Owner Engineer costs, reduced community engagement and training costs of $0.6 million given minimal construction activity in 2024, EPC excluded cost savings of $1.3 million and remaining savings ($1.1 million) as a result of other contracted services including legal, independent engineer and other consultants. This reduction is partially offset by additional capital costs related to other infrastructure in 2024, including the purchase of an inventory storage building in the Pickle Lake storage yard for $0.6 million and 3 equipment lifts for $0.2 million to support maintenance activities at remote substations.

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[5] These costs do not include any amounts that may be recorded in the proposed EPC COVID-Related Costs Deferral Account.

2. Historical Sustaining Capital Expenditures

This section presents WPLP's historical sustaining capital expenditures by year, as well as by expenditure category.

(a) Cost Categories Underlying Historical Sustaining Capital Expenditures

WPLP's historical sustaining capital expenditures, forecast to the end of 2025, are based on the OEB's RRFE investment categories:

a) System Access – WPLP has not yet incurred any capital expenditures related to System Access requests.

b) System Renewal – WPLP has incurred investments related to pole replacement on its WPQ line, due to woodpecker damage.

c) System Service – WPLP has not yet incurred any capital expenditures related to the safety, reliability, performance, or efficiency of its transmission system.

d) General Plant – beginning in 2025, WPLP started classifying any capital investments in fleet, facilities and business systems as general plant, distinct from the Transmission Project costs presented in Section B.1 above.

(b) Capital Expenditures by Year

WPLP's historical sustaining capital expenditures by year are summarized in Table 3 below.

Table 3 – Sustaining Capital Expenditures by Year

RRFE Category	Capital Expenditures ($000's)				
	2021	2022	2023	2024	2025[6]
System Access	0	0	0	0	0

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[6] As noted in Exhibit D-2-1, at the time of filing there are ongoing wildfires within the region through which WPLP's Transmission System traverses. At the time of filing, the extent of damage to WPLP's facilities, if any, is unknown. Once this information becomes available, and if the circumstances warrant, WPLP will provide an update to its evidence.

System Renewal	0	0	359	326	800
System Service	0	0	0	0	0
General Plant	0	0	0	0	380
Total Sustaining Capital	**0**	**0**	**359**	**326**	**1,180**

The minimal sustaining investments above relate to wood pole replacement costs on the WPQ line due to woodpecker damage, as well as minor General Plant expenditures related to IT infrastructure and office equipment, consistent with the in-service additions forecasted in Exhibit C-2-1 of WPLP's 2025 rate application.

C. Planned Capital Expenditures

This section describes WPLP's planned capital expenditures, first by discussing how WPLP plans to classify its capital expenditures, followed by a description of its 2026 Test Year capital expenditures, and then by explaining the types of projects by investment category that are being considered by WPLP for inclusion in the multi-year investment plan that will for part of WPLP's future TSPs.

1. Cost Categories Underlying Transmission System Capital Expenditures

WPLP will classify its planned capital expenditures based on the OEB's RRFE investment categories, with the following considerations for how the OEB's distribution system investment categories and example investment drivers relate to WPLP's circumstances as a transmitter serving remote First Nations in a remote portion of Northwestern Ontario.

a) System Access – investments related to requests for new or upgraded connections to WPLP's transmission system and investments related to asset relocation requirements for infrastructure development.

b) System Renewal – investments to replace and/or refurbish assets to extend the service life of the assets or to address asset failure.

c) System Service – investments that improve the safety, reliability, power quality, efficiency and/or performance of the Transmission System.

d) General Plant – investments in assets that are not part of the Transmission System including land and buildings, tools and equipment, rolling stock and electronic devices and software used to support day-to-day business and operations activities.

2. 2026 Test Year Capital Expenditures

WPLP's planned capital expenditures by category for the 2026 test year are summarized in Table 4 below.

Table 4 – 2026 Capital Expenditures ($000's)

RRFE Category	Project / Program	Expenditure by Project/Program[7]
System Access	N/A	0
System Renewal	Wood Pole Replacement	800
System Service	N/A	0
General Plant	IT Hardware and Software	135
	IT Infrastructure and Business Systems	337
	Spare Equipment and Material Storage and Physical Security	400
	Outage / Emergency Response Preparedness	500
	Office Furniture and System Monitoring / Dispatch Workstations	500
Total Sustaining Capital		**2,672**

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[7] As noted in Exhibit D-2-1, at the time of filing there are ongoing wildfires within the region through which WPLP's Transmission System traverses. At the time of filing, the extent of damage to WPLP's facilities, if any, is unknown. Once this information becomes available, and if the circumstances warrant, WPLP will provide an update to its evidence.

As noted in Exhibit A-3-1, WPLP's materiality threshold is calculated as 0.5% of transmission revenue, per Section 2.1.1 of the filing requirements:

$133,031,093* 0.5% = $665,155

WPLP's 2026 test year capital projects and programs below this materiality threshold are briefly described in section (a) below. Section (b) below provides additional information on WPLP's single material capital program (wood pole replacement), per Section 2.4.3 of the Filing Requirements.

(a) 2026 Test Year Expenditures Below Materiality

WPLP's 2026 test year capital projects and programs below the materiality threshold consist of the following General Plant projects:

(i) IT Hardware and Software: $135k

This capital program includes workstations, laptops, software upgrades and licensing and related accessories that support WPLP's day to day business and operations activities.

(ii) IT Infrastructure and Business Systems: $337k

This capital program includes enhancements to and replacements of servers and network equipment to ensure that WPLP's corporate and OT networks continue to meet its day to day business and operational needs as well as to ensure that the electronic and physical security perimeters of WPLP's IT/OT networks and work centres are appropriately secured.

(iii) Spare Equipment and Material Storage and Physical Security: $400k

WPLP has procured reasonable quantities of spare equipment and materials for all transmission line, substation and control room assets to prepare for various scenarios involving asset failure or damage to assets. Projects in 2026 will add additional racking, lighting and physical security (e.g. fencing and security cameras) to ensure that spare equipment and materials remain secure, undamaged and accessible when required.

(iv) Outage / Emergency Response Preparedness: $500k

This project includes the purchase of portable construction trailers and accessories to provide a small amount of office space and emergency shelter/lodging space to support WPLP's outage and emergency response activities. Due to the remoteness of WPLP's transmission system and considering the risk that limited lodging accommodations in the area are often fully booked, lack of suitable accommodation has been identified as a potential risk that could delay WPLP's response to outages and other emergencies.

(v) Office Furniture and System Monitoring / Dispatch Workstations: $500k

This program includes regular investment in office furniture in WPLP's Fort William First Nation office building. Increased investments in 2026 are driven by the need for reconfiguration of existing workspaces to better accommodate the increasing number of employees, as well as the creation of dedicated workstations for positions that will perform system monitoring and dispatch functions during business hours.

(b) 2026 Test Year Material Program

WPLP intends to replace 4 wood pole structures during the 2026 Test Year due to woodpecker damage, at a cost of $800k. Since this expenditure exceeds WPLP's materiality threshold, additional information is provided, per Section 2.4.3 of the filing requirements:

- **Need, Scope and Purpose:** The program involves replacing 4 poles, which will be prioritized based on WPLP's assessment of degradation due to woodpecker damage. As detailed in Exhibit B-1-2, WPLP's transmission system includes approximately 2500 wood poles that were installed in the past 2-7 years. While the majority of these poles have decades of expected service life remaining, a subset of poles are damaged each year by the feeding and nesting activity of woodpeckers. Proactive replacement of the most damaged poles each year ensures that WPLP continues to provide safe and reliable power to remote First Nations.

- **Alternatives Considered and Program Priority:** A do-nothing approach was rejected as running transmission structures to failure would be against good utility practice. Further, the remoteness of WPLP's transmission system would result in prolonged outages and extremely high unit cost for reactive replacement of individual poles. Alternatives for the replacement of existing wood poles include like-for-like replacement with wood, or replacement with alternate materials such as steel or fiber-reinforced polymer (FRP) poles. WPLP is currently using FRP poles for replacements due to minimal difference in total replacement cost, advantages for transportation and assembly in remote areas and resistance to repeated woodpecker damage as well as other forms of decay. WPLP considers that annual replacement of the wood poles in the worst condition is required to mitigate the risk of structure failure, and therefore considers this program as non-discretionary from the perspective of capital investment prioritization.

- **Life Expectancy:** The poles being replaced are in a deteriorated condition, with reduced life expectancy compared to all other in-service wood poles. Prioritization for replacement considers the size, location and orientation of the woodpecker hole(s) on each pole. Once woodpeckers begin nesting and/or feeding in a given wood pole, the resulting holes will continue to expand, resulting in a non-linear decline in life expectancy over time.

- **Program Timing:** Poles are typically replaced during the summer or early fall, in consideration of planned transmission system outages that are required for other reasons. Specific pole replacement timing for 2026 is yet to be determined, pending outage coordination with HONI.

- **Changes in capital expenditures in the test year:** WPLP's 2026 capital expenditure for this program is the same as 2025.

- **Basis for estimated budget:** WPLP's estimated costs for this program are informed by historical costs for similar pole replacements.

3. Future Projects and Programs by Category

This section discusses the types of projects by investment category that are being considered by WPLP for inclusion in the multi-year investment plans that will form part of WPLP's future TSPs.

(a) System Access

System Access projects are difficult to forecast as they are triggered by third-party projects and infrastructure development. WPLP has identified the following projects and approximate timelines for projects that may be included in future TSP's:

- Mining Project Connections: WPLP is currently in the SIA/CIA Study phase of its Customer Connection Procedures for two applications it has received to connect mining projects to its Transmission System. If either or both applicants are able to sufficiently advance their engagement and permitting processes to proceed with their projects, it is likely that WPLP will need to include related System Access investments in the multi-year investment plan to be filed with its 2026 TSP.

- Road Relocations: WPLP has worked proactively with a number of First Nations and First Nation organizations on projects to expand or realign winter roads and all-season roads near its transmission ROWs to ensure that any proposed road realignments or construction of new roads are undertaken with requirements to maintain clearances to transmission assets. To date, no required material investments have been identified to accommodate road relocation projects, however WPLP will continue to monitor these initiatives and engage with First Nations.

(b) System Renewal

As discussed in the context of historical and test year investments above, WPLP's System Renewal investments to date have been limited to a small number of pole replacements annually to address concerns of failure due to woodpecker damage. While the majority of WPLP's Transmission System is constructed using lattice steel towers, the portion of the WPQ line between Red Lake SS and Pikangikum TS that was formerly operated at 44 kV, as well as the Q1 line from

Pikangikum TS to the HORCI 25 kV Demarcation which operates at 25 kV, were constructed using approximately 1,300 poles.[8] These segments were constructed in 2018 and temporarily operated at a distribution voltage to enable WPLP to address the urgent need for grid connection of the Pikangikum First Nation. WPLP expects to continue to replace a small number of poles annually on a reactive basis due to woodpecker damage. Other factors triggering sudden degradation such as wildfire damage and lightning strikes may also trigger reactive replacements of wood poles.

Further, while most of WPLP's Transmission System assets have an expected service life of several decades, a small subset of asset classes have shorter service lives due to factors such as degradation or obsolescence. Examples include battery banks in substation control rooms with declining capacity over multiple charge/discharge cycles and OT networking equipment reaching the end of its support life (i.e. where the manufacturer stops supplying security patches, bug fixes or other updates). Testing and assessments currently in progress will inform the extent of replacements required in the future multi-year investment plans.

(c) System Service

Future system service projects could potentially span a wide range of scope and timing, depending on system performance, system reliability and the overall rate of load growth.

WPLP's Transmission System is comprised of long radial transmission lines that are currently lightly loaded. This characteristic results in a high degree of line charging capacitance that was compensated for with the installation of fixed and variable reactors at many substations to control system voltage profiles. Long-term system planning studies completed during project development identified that with 4% annual load growth on the distribution systems in the connected First Nations, the Transmission System is expected to reach a point in approximately the mid-2030's where the long radial transmission lines will cause voltage drops that will require

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[8] In addition, all 44 kV and 25 kV line segments on the Transmission System use wood poles.

additional capacitive compensation. WPLP intends to monitor actual system peak demand levels to better estimate when these investments will be required.

The rate of load growth in connected First Nations also has an impact on the longevity of the centralized backup power systems that are expected to be operational on 13 of the 16 distribution systems. In the event that generator capacity is exceeded for a small number of hours per day during system peaks, WPLP may be able to make strategic investments in combined energy storage and reactive power infrastructure that would both solve the reactive power compensation needs described above and extend the longevity of the existing backup power solutions, deferring the need for generator upgrades.

It is also possible that the outcome of regional planning processes may drive additional investment needs for WPLP's Transmission System to increase load meeting capability and/or improve the reliability of the system in the North of Dryden area. Some of these potential investments (e.g. adding a second auto-transformer at Pickle Lake) would also significantly reduce WPLP's exposure to low-probability / high-consequence equipment failure contingencies where failure of specific assets could reduce the load meeting capability of the Transmission System for an extended period of time.

(d) General Plant

WPLP expects to include regular investments in IT and OT systems, office furniture, fleet and facilities in the General Plant category. The outcome of the various strategic planning and investment planning processes discussed in Exhibit B-1-1 will also inform the timing and the quantum of any larger one-time investments in facilities and business systems that may be required to complete WPLP's transition into a fully operating utility. These investments may include office facilities that are adequate for WPLP's long-term staffing complement, strategic storage and work centre facilities to support field staff and contractors during planned inspection and maintenance activities as well as emergency response activities, and any additional fleet required to support operational activities.

D. Benchmarking Studies Regarding Capital Expenditures

WPLP has not undertaken any benchmarking studies in respect of its capital expenditures due to the modest amount of sustaining capital expenditures that WPLP is contemplating as part of this Application.

Exhibit C, Tab 1, Schedule 1

Rate Base Overview

RATE BASE OVERVIEW

This Exhibit provides WPLP's forecasted rate base for the 2026 test year, and a description of each component of the forecasted rate base. As no transmission assets were in service prior to 2022, WPLP does not have historical actual data other than for 2022, 2023 and 2024, during which the Line to Pickle Lake and segments of the Remote Connection Lines were brought into service in stages.

A. Rate Base Forecast

WPLP has calculated the proposed rate base by applying the "half-year rule" consistent with the 2025 rate application. Prior to 2025, while the Transmission Project was under construction, WPLP calculated its rate base using a 12-Month Average methodology.

WPLP's historical actual and preceding historical actual comparing 2023 actuals to 2024 actuals is provided in Table 1. WPLP's approved and budgeted rate base for the 2024 historical year and the 2025 bridge year are summarized in Tables 2 and 3, below. Forecasted rate base for the 2026 test year is provided in Table 4.

Table 1 – 2023 and 2024 Rate Base

Item	**2023 Actual ($000's)**			**2024 Actual ($000's)**			**Variance 12-Month Avg**
	Opening	**Closing**	**12-Month Avg**	**Opening**	**Closing**[1]	**12-Month Avg**	
Gross Fixed Assets	679,343	1,177,289	853,157	1,177,289	1,320,381	1,396,795	543,638
Less Accumulated Depreciation	(3,104)	(19,870)	(10,579)	(19,870)	(47,857)	(33,746)	(23,167)
Net Fixed Assets	**676,238**	**1,157,419**	**842,577**	**1,157,419**	**1,272,523**	**1,363,049**	**520,471**
Working Capital Allowance	-	-	-	-	-	-	-
Total Rate Base	**676,238**	**1,157,419**	**842,577**	**1,157,419**	**1,272,523**	**1,363,049**	**520,471**

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[1] The CIAC under the Federal Funding Framework was received on July 11, 2024. The resulting reduction in rate base has been reflected when determining the ending rate base and when calculating the 12-month average.

Table 2 – 2024 Rate Base

Item	**2024 Approved ($000's)**			**2024 Actual ($000's)**			**Variance 12-Month Avg**
	Opening	**Closing[2]**	**12-Month Avg**	**Opening**	**Closing[3]**	**12-Month Avg**	
Gross Fixed Assets	1,114,064	1,749,413	1,501,003	1,177,289	1,320,381	1,396,795	(104,208)
Less Accumulated Depreciation	(20,024)	(50,345)	(33,756)	(19,870)	(47,857)	(33,746)	10
Net Fixed Assets	**1,094,040**	**1,699,068**	**1,467,247**	**1,157,419**	**1,272,523**	**1,363,049**	**(104,198)**
Working Capital Allowance	-	-	-	-	-	-	-
Total Rate Base	**1,094,040**	**1,699,068**	**1,467,247**	**1,157,419**	**1,272,523**	**1,363,049**	**(104,198)**

Table 3 – 2025 Rate Base

Item	**2025 Approved ($000's)**			**2025 Forecast ($000's)[4]**			**Variance Average**
	Opening	**Closing**	**Average**	**Opening**	**Closing**	**Average**	
Gross Fixed Assets	1,324,699	1,325,879	1,325,289	1,320,381	1,322,061	1,321,221	(4,068)
Less Accumulated Depreciation	(47,951)	(74,609)	(61,280)	(47,857)	(74,482)	(61,170)	110
Net Fixed Assets	**1,276,745**	**1,251,270**	**1,264,009**	**1,272,523**	**1,247,579**	**1,260,051**	**(3,958)**
Working Capital Allowance	-	-	-	-	-	-	-
Total Rate Base	**1,276,745**	**1,251,270**	**1,264,009**	**1,272,523**	**1,247,579**	**1,260,051**	**(3,958)**

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[2] In EB-2023-0168 WPLP assumed the Contribution in Aid of Construction (“CIAC”) out of the independent Trust occurred on December 31, 2024 and had no impact on rate base as rate base was calculated on a 12-month average.

[3] The CIAC under the Federal Funding Framework was received on July 11, 2024. The resulting reduction in rate base has been reflected when determining the ending rate base and when calculating the 12-month average.

[4] As noted in Exhibit D-2-1, at the time of filing there are ongoing wildfires within the region through which WPLP’s Transmission System traverses. At the time of filing, the extent of damage to WPLP’s facilities, if any, is unknown. Once this information becomes available, and if the circumstances warrant, WPLP will provide an update to its evidence.

Table 4 – 2026 Rate Base

Item	**2026 Plan ($000's)**[5]		
	Opening	**Closing**	**Average**[6]
Gross Fixed Assets	1,322,061	1,324,733	1,323,397
Less Accumulated Depreciation	(74,482)	(101,346)	(87,914)
Net Fixed Assets	**1,247,579**	**1,223,387**	**1,235,483**
Working Capital Allowance	-	-	-
Total Rate Base	**1,247,579**	**1,223,387**	**1,235,483**

Details of WPLP's 2026 in-service additions by asset category and type are provided in Exhibit C-2-1.

B. Variance Analysis

The change in rate base from 2023 actual to 2024 actual is representative of the remaining community segments being energized, which included 8 substations and 13 line segments. In addition, this change reflects the addition of COVID-19 costs in rate base for 2024.[7]

WPLP's actual 12-month average rate base for 2024 was $104.2 million lower than the 2024 OEB approved value from the 2024 rate application. The primary driver of this variance is the receipt of the CIAC under the Federal Funding Framework on July 11, 2024 vs the date expected in the previous rate application of December 31, 2024. The revenue requirement impact of the earlier receipt of the CIAC was captured within the Federal CIAC Variance Account and, as a result, ratepayers will be held whole for this variance.

The change in rate base from 2024 actuals to 2025 forecast is primarily driven by the contribution in aid of construction being received from the independent Trust in July of 2024, impacting the

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[5] As noted in Exhibit D-2-1, at the time of filing there are ongoing wildfires within the region through which WPLP's Transmission System traverses. At the time of filing, the extent of damage to WPLP's facilities, if any, is unknown. Once this information becomes available, and if the circumstances warrant, WPLP will provide an update to its evidence.

[6] Consistent with the 2025 rate application, WPLP has used the half-year rule for additions in the year.

[7] The COVID 2024 rate base additions are comprised of the $68.2 million approved to rate base in EB-2023-0168, and the $3.1 million audited 2023 balance from the 2021-2023 CCCDA (including carrying costs at AFUDC) which was approved to rate base in EB-2024-0176.

12-month average method used in 2024 and is impacting 2025 for the full year. WPLP's mid-year average forecast rate base budget for 2025 is $4.0 million lower than the 2025 OEB approved value from the 2025 rate application. The primary driver of this variance is savings in Non-EPC construction costs incurred upon the final community segments being energized.[8]

The change in rate base from 2025 forecast to 2026 plan is primarily driven by depreciation expense for 2025, which is partially offset by proposed capital additions for 2026 relating to System Renewal and General Plant.

Additional details on rate base variances and additions are provided in Exhibit C-2-1.

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[8] Further details on Non-EPC cost savings provided in Exhibit B-1-4.

Exhibit C, Tab 2, Schedule 1

In-Service Additions

IN-SERVICE ADDITIONS

WPLP's planned in-service additions for 2026 are comprised of Transmission System renewal in-service additions of $0.8 million for ongoing wood pole replacements on the WPQ line (between Red Lake SS and Pikangikum TS) due to woodpecker damage, and General Plant in-service additions of $1.872 million for (i) facilities investments, primarily related to securing storage for spare equipment and interim staging areas to facilitate emergency response ($900K), (ii) IT/OT infrastructure, hardware and software investments to improve functionality, security and redundancy of various IT and OT systems ($472K), and (iii) office furniture, and workspace reconfiguration to accommodate WPLP's increasing number of employees based at its head office including dedicated workstations for staff to perform system monitoring/dispatch functions during business hours ($500K). Table 1 summarizes WPLP's total in-service additions for 2026.

Table 1 – Total 2026 In-Service Additions

Asset Category	**In-Service Additions ($000's)**[1]
Remote Connection Lines – Lines	800
General Plant	1,872
Total 2026 In-Service Additions	**2,672**

A. Variance Analysis

Variance analysis between approved and forecasted in-service additions up to the end of 2025 for the Line to Pickle Lake and Remote Connection Lines are summarized in Table 2 and Table 3 respectively.

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[1] As noted in Exhibit D-2-1, at the time of filing there are ongoing wildfires within the region through which WPLP's Transmission System traverses. At the time of filing, the extent of damage to WPLP's facilities, if any, is unknown. Once this information becomes available, and if the circumstances warrant, WPLP will provide an update to its evidence.

Table 2 – 2025 Line to Pickle Lake In-Service Addition Variance ($000)

OEB Account and Description	**Line to Pickle Lake (UTR Network Rate)**		**Variance**
	2025 Approved	**2025 Forecast**	
1715 - Station Equipment (Station and Transformers)	45,707	45,707	-
1715A - Station Equipment (Switches and Breakers)	6,211	6,211	-
1715B - Station Equipment (Protection and Control)	1,491	1,491	-
1720 - Towers and Fixtures	114,422	114,422	-
1725 - Poles and Fixtures	-	-	-
1730 - OH Conductor and Devices	153,461	153,461	-
Total	**321,291**	**321,291**	**-**

There is no expected variance between the 2025 OEB approved value and the 2025 forecasted in-service value for the Line to Pickle Lake.

Table 3 – Cumulative 2022-2025 Remote Connection Lines In-Service Addition Variance ($000)

OEB Account and Description	**Remote Connection Lines (H1RCI Rate)**		**Variance**
	2022-2025 Approved[2]	**2025 Forecast**[3]	
1706 – Land Rights	55	55	-
1715 - Station Equipment (Station and Transformers)	328,092	327,030	(1,062)
1715A - Station Equipment (Switches and Breakers)	27,719	27,667	(52)
1715B - Station Equipment (Protection and Control)	13,525	13,472	(53)
1720 - Towers and Fixtures	504,780	502,794	(1,986)
1725 - Poles and Fixtures	58,004	57,710	(294)
1730 - OH Conductor and Devices	558,520	557,480	(1,040)
Total	**1,490,695**	**1,486,207**	**(4,488)**

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[2] Balances from 2025 year-end for Remote Connection lines provided in 2025 rate application in Exhibit C-3-1, Table 3 (EB-2024-0176).

[3] As noted in Exhibit D-2-1, at the time of filing there are ongoing wildfires within the region through which WPLP's Transmission System traverses. At the time of filing, the extent of damage to WPLP's facilities, if any, is unknown. Once this information becomes available, and if the circumstances warrant, WPLP will provide an update to its evidence.

In relation to the Remote Connection Lines, there are three drivers for the variance between OEB approved and forecasted in-service additions in 2025: (1) non-EPC cost savings as further shown in Exhibit B-1-4, (2) line WPQ (Pikangikum Segment) pole replacement cost savings, and (3) write-off of two poles on line WPQ that were retired due to woodpecker damage. Details on the amounts of the cost variances attributable to each of these drivers are provided in Table 4, below.

Table 4 – Remote Connection Lines Changes

	($000)
Transmission Line Costs	
Non-EPC Savings	(3,221)
Sustaining capital costs on line WPQ	(65)
Retirement of 2 poles on line WPQ	(34)
Substation Costs	
Non-EPC Savings	(1,168)
	(4,488)

Fixed asset continuity and depreciation schedules are provided in Exhibit C-3-1.

Exhibit C, Tab 3, Schedule 1

Gross Assets - Property, Plant & Equipment and Accumulated Depreciation

GROSS ASSETS – PROPERTY, PLANT & EQUIPMENT AND ACCUMULATED DEPRECIATION

Table 1 provides the approved, forecasted and resulting variance for the 2025 in-service asset additions.[1] Table 2 provides the approved, forecasted and resulting variance for the 2025 depreciation.[2] The forecasted balances from Tables 1 and 2 are used to determine WPLP's resulting opening balances for 2026 gross assets and accumulated depreciation, which are set out in Tables 6 and 7, below.

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[1] Forecasted balances reflect forecasted capital spend and in-services dates, variance analysis is provided in Exhibit C-2-1.

[2] Forecasted balances reflect forecasted capital spend and in-services dates, depreciation has been adjusted based on the updated forecasted capital spend and in-services dates utilizing the same depreciation methodology as discussed in Exhibit F-4-1.

Table 1 - 2025 Year-End Gross Assets by OEB Account ($000's)

	2025 Rate Approved			**Forecast**			
OEB Account and Description	**Line to Pickle Lake (UTR Network Rate)**	**Remote Connection Lines (HORCI Rate)**	**Total**	**Line to Pickle Lake (UTR Network Rate)**	**Remote Connection Lines (HORCI Rate)**	**Total**	**Variance**
1706 – Land Rights	-	55	55	-	55	55	-
1715 - Station Equipment (Station and Transformers)	45,707	328,092	373,799	45,707	327,030	372,737	(1,062)
1715A - Station Equipment (Switches and Breakers)	6,211	27,719	33,930	6,211	27,667	33,879	(51)
1715B - Station Equipment (Protection and Control)	1,491	13,525	15,016	1,491	13,472	14,963	(53)
1720 - Towers and Fixtures	114,422	504,780	619,202	114,422	502,794	617,215	(1,987)
1725 - Poles and Fixtures	-	58,004	58,004	0	57,710	57,710	(294)
1730 - OH Conductor and Devices	153,461	558,520	711,981	153,461	557,480	710,941	(1,040)
Sub-Total Transmission System Plant	**321,292**	**1,490,694**	**1,811,987**	**321,292**	**1,486,207**	**1,807,500**	**(4,488)**
1908 - Buildings and Fixtures[3]	4	16	20	71	326	397	377
1910 – Leasehold Improvement	44	206	250	41	188	229	(21)
1915 - Office Furniture and Equipment	18	82	100	18	82	100	0
1920 – Computer Hardware	65	301	366	113	524	637	271
1930 - Transportation Equipment	28	128	155	28	128	155	-
1940 – Tools, Shop & Garage Equipment	30	139	169	30	139	169	(1)
1945 – Measurement & Testing Equipment	-	-	-	2	7	9	9
1611 - Computer Software	-	-	-	-	-	-	-
1995 – Contributions & Grants	-	(487,168)	(487,168)	-	(487,134)	(487,134)	34
Total	**321,480**	**1,004,399**	**1,325,879**	**321,592**	**1,000,460**	**1,322,061**	**(3,818)**

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[3] See Exhibit I-2-1 for details on allocation between LTPL and RCL for all general plant assets.

Table 2 – 2025 Year-End Accumulated Depreciation by OEB Account ($000’s)

	2025 Approved			**Forecast**			
OEB Account and Description	**Line to Pickle Lake (UTR Network Rate)**	**Remote Connection Lines (HORCI Rate)**	**Total**	**Line to Pickle Lake (UTR Network Rate)**	**Remote Connection Lines (HORCI Rate)**	**Total**	**Variance**
1706 – Land Rights	-	10	10	-	10	10	-
1715 – Station Equipment (Station and Transformers)	2,775	15,876	18,651	2,775	15,841	18,616	(35)
1715A – Station Equipment (Switches and Breakers)	517	1,594	2,111	517	1,592	2,109	(2)
1715B – Station Equipment (Protection and Control)	248	1,507	1,755	248	1,502	1,751	(4)
1720 – Towers and Fixtures	6,314	19,050	25,363	6,314	18,996	25,310	(53)
1725 – Poles and Fixtures	0	5,244	5,244	0	5,229	5,229	(15)
1730 – OH Conductor and Devices	10,761	31,312	42,074	10,761	31,261	42,023	(51)
Sub-Total Transmission System Plant	**20,616**	**74,592**	**95,208**	**20,616**	**74,431**	**95,047**	**(161)**
1908 – Buildings and Fixtures[4]	-	-	1	1	7	8	7
1910 – Leasehold Improvement	13	62	75	8	38	46	(29)
1915 – Office Furniture and Equipment	1	4	5	1	4	5	-
1920 – Computer Hardware	10	44	54	20	92	112	58
1930 – Transportation Equipment	19	89	109	19	89	109	-
1940 – Tools, Shop & Garage Equipment	5	22	27	3	14	17	(10)
1945 – Measurement & Testing Equipment	-	-	-	-	2	2	2
1611 – Computer Software	-	-	-	-	-	-	-
1995 – Contributions & Grants	-	(20,869)	(20,869)	-	(20,864)	(20,864)	5
Total	**20,664**	**53,945**	**74,609**	**20,670**	**53,813**	**74,482**	**(127)**

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[4] See Exhibit I-2-1 for details on allocation between LTPL and RCL for all general plant assets.

Table 3, below, summarizes WPLP's forecasted year-end gross assets for the 2026 test year, by OEB account and by rate pool, which are consistent with the in-service additions described in detail in Exhibit C-2-1.

Table 3 – 2026 Year-End Gross Assets by OEB Account ($000's)

OEB Account and Description	**Line to Pickle Lake (UTR Network Rate)**	**Remote Connection Lines (HORCI Rate)**	**Total**
1706 – Land Rights	-	55	55
1715 – Station Equipment (Station and Transformers)	45,707	327,030	372,737
1715A – Station Equipment (Switches and Breakers)	6,211	27,667	33,879
1715B – Station Equipment (Protection and Control)	1,491	13,472	14,963
1720 – Towers and Fixtures	114,422	502,794	617,215
1725 – Poles and Fixtures	-	58,510	58,510
1730 – OH Conductor and Devices	153,461	557,480	710,941
Sub-Total Transmission System Plant	**321,292**	**1,487,007**	**1,808,300**
1908 – Buildings and Fixtures[5]	71	326	397
1910 - Leasehold Improvement	201	928	1,129
1915 – Office Furniture and Equipment	36	165	201
1920 - Computer Hardware	253	1,169	1,422
1930 – Transportation Equipment	28	128	155
1940 - Tools, Shop & Garage Equipment	30	139	169
1945 – Measurement & Testing Equipment	2	7	9
1611 – Computer Software	15	71	87
1995 – Contributions & Grants	-	(487,134)	(487,134)
Total	**321,480**	**1,002,728**	**1,324,733**

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[5] See Exhibit I-2-1 for details on allocation between LTPL and RCL for all general plant assets.

Table 4 summarizes WPLP's accumulated depreciation by OEB Account and by rate pool for the 2026 test year. Exhibit F-4-1 provides further detail on the calculation of depreciation expense.

Table 4 – 2026 Year-End Accumulated Depreciation by OEB Account ($000's)

OEB Account and Description	**Line to Pickle Lake (UTR Network Rate)**	**Remote Connection Lines (HORCI Rate)**	**Total**
1706 – Land Rights	-	11	11
1715 – Station Equipment (Station and Transformers)	3,689	22,382	26,071
1715A – Station Equipment (Switches and Breakers)	672	2,283	2,956
1715B – Station Equipment (Protection and Control)	323	2,176	2,499
1720 – Towers and Fixtures	8,221	27,375	35,597
1725 – Poles and Fixtures	-	6,516	6,516
1730 – OH Conductor and Devices	14,172	43,650	57,822
Sub-Total Transmission System Plant	**27,078**	**104,398**	**131,475**
1908 – Buildings and Fixtures[6]	3	13	16
1910 - Leasehold Improvement	32	149	182
1915 – Office Furniture and Equipment	4	16	20
1920 - Computer Hardware	57	261	318
1930 – Transportation Equipment	25	115	140
1940 - Tools, Shop & Garage Equipment	6	28	34
1995 – Contributions & Grants	-	(30,852)	(30,852)
Total	**20,664**	**74,140**	**101,346**

A. Average Values for Rate Base Determination

As of the 2025 test year application (EB-2024-0176), WPLP has calculated its net fixed assets to be included in rates using the half-year approach consistent with the standard approach as set out in the OEB's Filing Requirements. WPLP proposes to continue the approach of calculating its net fixed assets to be included in rate base for the 2026 test year using the half-year approach consistent

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[6] See Exhibit I-2-1 for details on allocation between LTPL and RCL for all general plant depreciation.

with the standard approach as set out in the OEB's Filing Requirements. Table 5 summarizes WPLP's 2026 half year amount using this approach.

Table 5 – Summary of 2026 Average Net Fixed Assets

Item	**2026 Average ($000's)**			
	LTPL	**RCL**	**GP**	**Total**
Gross Fixed Assets	321,292	1,486,607	2,632	1,810,531
Less Accumulated Depreciation	(23,847)	(89,414)	(510)	(113,772)
Less Contribution in Aid of Construction	-	(487,134)	-	(487,134)
Plus Accumulated Amortization of CIAC	-	25,858	-	25,858
Net Fixed Assets	**297,445**	**935,917**	**2,121**	**1,235,483**

Monthly totals of WPLP's gross asset and accumulated depreciation balances supporting the half-year calculation are provided in Tables 6 and 7. Fixed asset continuity schedules reflecting all in-service additions for the 2026 test year are included as Appendix 'A' to this schedule.

Table 6 – 2026 Gross Asset Balances by Month ($000's)

		Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Oct	Nov	Dec	Avg
LTPL	Opening	321,292	321,292	321,292	321,292	321,292	321,292	321,292	321,292	321,292	321,292	321,292	321,292	321,292
	Additions	0	0	0	0	0	0	0	0	0	0	0	0	
	Closing	321,292	321,292	321,292	321,292	321,292	321,292	321,292	321,292	321,292	321,292	321,292	321,292	
RCL	Opening	1,486,207	1,486,207	1,486,207	1,486,207	1,486,207	1,486,207	1,487,007	1,487,007	1,487,007	1,487,007	1,487,007	1,487,007	1,486,607
	Additions	0	0	0	0	0	800	0	0	0	0	0	0	
	Closing	1,486,207	1,486,207	1,486,207	1,486,207	1,486,207	1,487,007	1,487,007	1,487,007	1,487,007	1,487,007	1,487,007	1,487,007	
GP	Opening	1,696	1,696	1,696	1,696	1,696	1,696	3,568	3,568	3,568	3,568	3,568	3,568	2,632
	Additions	0	0	0	0	0	1,872	0	0	0	0	0	0	
	Closing	1,696	1,696	1,696	1,696	1,696	3,568	3,568	3,568	3,568	3,568	3,568	3,568	
CIAC	Opening	-487,134	-487,134	-487,134	-487,134	-487,134	-487,134	-487,134	-487,134	-487,134	-487,134	-487,134	-487,134	-487,134
	Additions	0	0	0	0	0	0	0	0	0	0	0	0	
	Closing	-487,134	-487,134	-487,134	-487,134	-487,134	-487,134	-487,134	-487,134	-487,134	-487,134	-487,134	-487,134	

Table 7 – 2026 Accumulated Depreciation by Month ($000's)

		Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Oct	Nov	Dec	Avg
LTPL	Opening	20,616	21,155	21,693	22,232	22,770	23,309	23,847	24,385	24,924	25,462	26,001	26,539	23,847
	Additions	538	538	538	538	538	538	538	538	538	538	538	538	
	Closing	21,155	21,693	22,232	22,770	23,309	23,847	24,385	24,924	25,462	26,001	26,539	27,078	
RCL	Opening	74,431	76,927	79,424	81,920	84,417	86,913	89,410	91,908	94,406	96,904	99,402	101,900	89,414
	Additions	2,497	2,497	2,497	2,497	2,497	2,497	2,498	2,498	2,498	2,498	2,498	2,498	
	Closing	76,927	79,424	81,920	84,417	86,913	89,410	91,908	94,406	96,904	99,402	101,900	104,398	
GP	Opening	299	319	339	359	379	399	419	470	520	571	621	671	510
	Additions	20	20	20	20	20	20	50	50	50	50	50	50	
	Closing	319	339	359	379	399	419	470	520	571	621	671	722	
CIAC	Opening	-20,864	-21,696	-22,529	-23,361	-24,193	-25,025	-25,858	-26,690	-27,522	-28,355	-29,187	-30,019	-25,858
	Additions	-832	-832	-832	-832	-832	-832	-832	-832	-832	-832	-832	-832	
	Closing	-21,696	-22,529	-23,361	-24,193	-25,025	-25,858	-26,690	-27,522	-28,355	-29,187	-30,019	-30,852	

Exhibit C, Tab 3, Schedule 1

Gross Assets - Property, Plant & Equipment and Accumulated Depreciation

ATTACHMENT ‘A’

WPLP_2025-2026 Fixed Assets Cont Schedule

Fixed Asset Continuity Schedule - All Assets

Accounting Standard ASPE
Year 2025

			Cost					Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Useful Life**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
		Intangible										
	1606	Organization	-	-	-	-	-	-	-		-	-
	1610	Miscellaneous Intangible Plant	-	-	-	-	-	-	-		-	-
	1611	Computer Software	-	-	-	-	5	-	-		-	-
	1612	Land Rights (Intangible)	-	-	-	-	-	-	-		-	-
		Transmission Plant										
	1705	Land (Transmission Plant)	-	-	-	-	-	-	-		-	-
	1706	Land Rights (Transmission Plant)	54,796	-	-	54,796	40	8,219	1,370		9,589	45,206
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-	-	-	-		-	-
	1710	Leasehold Improvements	-	-	-	-	-	-	-		-	-
47	1715	Station Equipment (Station and Transformers)	372,736,933	-	-	372,736,933	50	11,161,351	7,454,739		18,616,090	354,120,843
47	1715A	Station Equipment (Switches and Breakers)	33,878,706	-	-	33,878,706	40	1,261,729	846,968		2,108,696	31,770,010
47	1715B	Station Equipment (Protection and Control)	14,963,021	-	-	14,963,021	20	1,002,770	748,151		1,750,921	13,212,100
47	1720	Towers and Fixtures	617,215,377	-	-	617,215,377	60	15,022,788	10,286,923		25,309,711	591,905,666
47	1725	Poles and Fixtures	56,910,262	800,000	-	57,710,262	45	3,955,892	1,273,561		5,229,453	52,480,809
47	1730	OH Cond and Devices	710,440,555	500,000	-	710,940,555	45	26,229,742	15,793,123		42,022,865	668,917,690
	1735	UG Conduit	-	-	-	-	-	-	-		-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-		-	-
	1745	Roads and Trails	-	-	-	-	-	-	-		-	-
		General Plant										
	1905	Land (General Plant)	-	-	-	-	-	-	-		-	-
10.1	1908	Buildings and Fixtures	396,999	-	-	396,999	50	-	7,940		7,940	389,059
	1910	Leasehold Improvements	228,961			228,961	5	-	45,792		45,792	183,169
8	1915	Office Furn & Equipment	-	100,250	-	100,250	10	-	5,013		5,013	95,238
	1920	Comp Hardware	356,556	280,203	-	636,760	5	12,765	99,332		112,096	524,663
10.1	1930	Transportation Equipment	155,392	-	-	155,392	5	77,696	31,078		108,774	46,618
	1935	Stores Equip	-	-	-	-	-	-	-		-	-
	1940	Tools, Shop & Garage Equip	168,500	-	-	168,500	10	-	16,850		16,850	151,650
	1945	Measurement & Testing Equipment	8,793	-	-	8,793	5	733	1,759		2,491	6,301
	1950	Power Operated Equipment	-	-	-	-	-	-	-		-	-
	1955	Communication Equipment	-	-	-	-	-	-	-		-	-
	1960	Misc. Equipment	-	-	-	-	-	-	-		-	-
	1980	System Supervisory Equipment	-	-	-	-	-	-	-		-	-
	1995	Contributions & Grants	(487,134,094)	-	-	(487,134,094)	Note 1	(10,876,171)	(9,987,579)		(20,863,750)	(466,270,344)
	2440	Deferred Revenue	-	-	-	-	-	-	-		-	-
			-	-	-	-	-		-		-	-
		Sub-Total	**1,320,380,757**	**1,680,453**	**-**	**1,322,061,210**		**47,857,513**	**26,625,019**	**-**	**74,482,533**	**1,247,578,677**
	2055	**Add: Construction Work in Progress**	-	-	-	-					-	

Fixed Asset Continuity Schedule - Line to Pickle Lake

Accounting Standard	ASPE
Year	2025

			Cost					**Accumulated Depreciation**				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Useful Life**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
		Transmission Plant										
	1705	Land (Transmission Plant)	-	-	-	-		-	-		-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-		-	-		-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-		-	-		-	-
	1710	Leasehold Improvements	-	-	-	-		-	-		-	-
47	1715	Station Equipment (Station and Transformers)	45,706,802	-	-	45,706,802	50	1,860,972	914,136		2,775,108	42,931,694
47	1715A	Station Equipment (Switches and Breakers)	6,211,421	-	-	6,211,421	40	361,902	155,286		517,187	5,694,234
47	1715B	Station Equipment (Protection and Control)	1,491,470	-	-	1,491,470	20	173,919	74,573		248,492	1,242,977
47	1720	Towers and Fixtures	114,421,783	-	-	114,421,783	60	4,407,147	1,907,030		6,314,177	108,107,605
47	1725	Poles and Fixtures	-	-	-	-		-	-		-	-
47	1730	OH Cond and Devices	153,460,833	-	-	153,460,833	45	7,351,219	3,410,241		10,761,459	142,699,374
	1735	UG Conduit	-	-	-	-		-	-		-	-
	1740	UG Cond and Devices	-	-	-	-		-	-		-	-
	1745	Roads and Trails	-	-	-	-		-	-		-	-
		Sub-Total	**321,292,308**	**-**	**-**	**321,292,308**		**14,155,158**	**6,461,265**	**-**	**20,616,424**	**300,675,884**
	2055	**Add: Construction Work in Progress**	-	-	-	-					-	
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-	-	-	-					-	
		Total PP&E	321,292,308	-	-	321,292,308		14,155,158	6,461,265	-	20,616,424	300,675,884
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										
		Total Additions to Accumulated Depreciation							6,461,265			

Fixed Asset Continuity Schedule - Remote Connection Lines

Accounting Standard ASPE
Year 2025

			Cost					Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Useful Life**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
		Transmission Plant										
	1705	Land (Transmission Plant)	-	-	-	-		-	-		-	-
	1706	Land Rights (Transmission Plant)	54,796	-	-	54,796	40	8,219	1,370		9,589	45,206
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-		-	-		-	-
	1710	Leasehold Improvements	-	-	-	-		-	-		-	-
47	1715	Station Equipment (Station and Transformers)	327,030,131	-	-	327,030,131	50	9,300,380	6,540,603		15,840,982	311,189,149
47	1715A	Station Equipment (Switches and Breakers)	27,667,285	-	-	27,667,285	40	899,827	691,682		1,591,509	26,075,776
47	1715B	Station Equipment (Protection and Control)	13,471,551	-	-	13,471,551	20	828,851	673,578		1,502,429	11,969,122
47	1720	Towers and Fixtures	502,793,594	-	-	502,793,594	60	10,615,640	8,379,893		18,995,534	483,798,061
47	1725	Poles and Fixtures	56,910,262	800,000	-	57,710,262	45	3,955,892	1,273,561		5,229,453	52,480,809
47	1730	OH Cond and Devices	556,979,722	500,000	-	557,479,722	45	18,878,523	12,382,883		31,261,406	526,218,316
	1735	UG Conduit	-	-	-	-		-	-		-	-
	1740	UG Cond and Devices	-	-	-	-		-	-		-	-
	1745	Roads and Trails	-	-	-	-		-	-		-	-
		Sub-Total	**1,484,907,342**	**1,300,000**	**-**	**1,486,207,342**		**44,487,333**	**29,943,570**	**-**	**74,430,903**	**1,411,776,439**
	2055	**Add: Construction Work in Progress**	-	-	-	-					-	
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-	-	-	-					-	
		Total PP&E	1,484,907,342	1,300,000	-	1,486,207,342		44,487,333	29,943,570	-	74,430,903	1,411,776,439
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										
		Total Additions to Accumulated Depreciation							29,943,570			

Fixed Asset Continuity Schedule - All Assets

Accounting Standard ASPE
Year 2026

			Cost					Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Useful Life**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
		Intangible										
	1606	Organization	-	-	-	-	-	-	-		-	-
	1610	Miscellaneous Intangible Plant	-	-	-	-	-	-	-		-	-
	1611	Computer Software	-	86,600	-	86,600	5	-	8,660		8,660	77,940
	1612	Land Rights (Intangible)	-	-	-	-	-	-	-		-	-
		Transmission Plant										
	1705	Land (Transmission Plant)	-	-	-	-	-	-	-		-	-
	1706	Land Rights (Transmission Plant)	54,796	-	-	54,796	40	9,589	1,370		10,959	43,836
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-	-	-	-		-	-
	1710	Leasehold Improvements	-	-	-	-	-	-	-		-	-
47	1715	Station Equipment (Station and Transformers)	372,736,933	-	-	372,736,933	50	18,616,090	7,454,739		26,070,829	346,666,104
47	1715A	Station Equipment (Switches and Breakers)	33,878,706	-	-	33,878,706	40	2,108,696	846,968		2,955,664	30,923,042
47	1715B	Station Equipment (Protection and Control)	14,963,021	-	-	14,963,021	20	1,750,921	748,151		2,499,072	12,463,949
47	1720	Towers and Fixtures	617,215,377	-	-	617,215,377	60	25,309,711	10,286,923		35,596,634	581,618,743
47	1725	Poles and Fixtures	57,710,262	800,000	-	58,510,262	45	5,229,453	1,291,339		6,520,793	51,989,470
47	1730	OH Cond and Devices	710,940,555	-	-	710,940,555	45	42,022,865	15,798,679		57,821,544	653,119,011
	1735	UG Conduit	-	-	-	-	-	-	-		-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-		-	-
	1745	Roads and Trails	-	-	-	-	-	-	-		-	-
		General Plant										
	1905	Land (General Plant)	-	-	-	-	-	-	-		-	-
10.1	1908	Buildings and Fixtures	396,999	-	-	396,999	50	7,940	7,940		15,880	381,119
	1910	Leasehold Improvements	228,961	900,000		1,128,961	5	45,792	135,792		181,585	947,377
8	1915	Office Furn & Equipment	100,250	100,250	-	200,500	10	5,013	15,038		20,050	180,450
	1920	Comp Hardware	636,760	785,000	-	1,421,760	5	112,096	205,852		317,948	1,103,811
10.1	1930	Transportation Equipment	155,392	-	-	155,392	5	108,774	31,078		139,852	15,539
	1935	Stores Equip	-	-	-	-	-	-	-		-	-
	1940	Tools, Shop & Garage Equip	168,500	-	-	168,500	10	16,850	16,850		33,700	134,800
	1945	Measurement & Testing Equipment	8,793	-	-	8,793	5	2,491	1,759		4,250	4,543
	1950	Power Operated Equipment	-	-	-	-	-	-	-		-	-
	1955	Communication Equipment	-	-	-	-	-	-	-		-	-
	1960	Misc. Equipment	-	-	-	-	-	-	-		-	-
	1980	System Supervisory Equipment	-	-	-	-	-	-	-		-	-
	1995	Contributions & Grants	(487,134,094)	-	-	(487,134,094)	Note 1	(20,863,750)	(9,987,579)		(30,851,329)	(456,282,765)
	2440	Deferred Revenue	-	-	-	-	-	-	-		-	-
			-	-	-	-	-	-	-		-	-
		Sub-Total	**1,322,061,210**	**2,671,850**	**-**	**1,324,733,060**		**74,482,533**	**26,863,558**	**-**	**101,346,090**	**1,223,386,970**
	2055	**Add: Construction Work in Progress**	-	-	-	-					-	

Fixed Asset Continuity Schedule - Line to Pickle Lake

Accounting Standard	ASPE
Year	2026

			Cost					**Accumulated Depreciation**				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Useful Life**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
		Transmission Plant										
	1705	Land (Transmission Plant)	-	-	-	-		-	-		-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-		-	-		-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-		-	-		-	-
	1710	Leasehold Improvements	-	-	-	-		-	-		-	-
47	1715	Station Equipment (Station and Transformers)	45,706,802	-	-	45,706,802	50	2,775,108	914,136		3,689,244	42,017,558
47	1715A	Station Equipment (Switches and Breakers)	6,211,421	-	-	6,211,421	40	517,187	155,286		672,473	5,538,948
47	1715B	Station Equipment (Protection and Control)	1,491,470	-	-	1,491,470	20	248,492	74,573		323,066	1,168,404
47	1720	Towers and Fixtures	114,421,783	-	-	114,421,783	60	6,314,177	1,907,030		8,221,207	106,200,576
47	1725	Poles and Fixtures	-	-	-	-		-	-		-	-
47	1730	OH Cond and Devices	153,460,833	-	-	153,460,833	45	10,761,459	3,410,241		14,171,700	139,289,133
	1735	UG Conduit	-	-	-	-		-	-		-	-
	1740	UG Cond and Devices	-	-	-	-		-	-		-	-
	1745	Roads and Trails	-	-	-	-		-	-		-	-
		Sub-Total	**321,292,308**	**-**	**-**	**321,292,308**		**20,616,424**	**6,461,265**	**-**	**27,077,689**	**294,214,619**
	2055	**Add: Construction Work in Progress**	-	-	-	-					-	
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-	-	-	-					-	
		Total PP&E	321,292,308	-	-	321,292,308		20,616,424	6,461,265	-	27,077,689	294,214,619
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										
		Total Additions to Accumulated Depreciation							6,461,265			

10		Transportation
8		Stores Equipment

Less: ***Fully Allocated Depreciation*** **(input as negative)**	
Transportation	
Stores Equipment	
Net Depreciation	**6,461,265**

Fixed Asset Continuity Schedule - Remote Connection Lines

Accounting Standard	ASPE
Year	2026

			Cost					**Accumulated Depreciation**				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Useful Life**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
		Transmission Plant										
	1705	Land (Transmission Plant)	-	-	-	-		-	-		-	-
	1706	Land Rights (Transmission Plant)	54,796	-	-	54,796	40	9,589	1,370		10,959	43,836
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-		-	-		-	-
	1710	Leasehold Improvements	-	-	-	-		-	-		-	-
47	1715	Station Equipment (Station and Transformers)	327,030,131	-	-	327,030,131	50	15,840,982	6,540,603		22,381,585	304,648,546
47	1715A	Station Equipment (Switches and Breakers)	27,667,285	-	-	27,667,285	40	1,591,509	691,682		2,283,191	25,384,094
47	1715B	Station Equipment (Protection and Control)	13,471,551	-	-	13,471,551	20	1,502,429	673,578		2,176,007	11,295,545
47	1720	Towers and Fixtures	502,793,594	-	-	502,793,594	60	18,995,534	8,379,893		27,375,427	475,418,167
47	1725	Poles and Fixtures	57,710,262	800,000	-	58,510,262	45	5,229,453	1,291,339		6,520,793	51,989,470
47	1730	OH Cond and Devices	557,479,722	-	-	557,479,722	45	31,261,406	12,388,438		43,649,844	513,829,878
	1735	UG Conduit	-	-	-	-		-	-		-	-
	1740	UG Cond and Devices	-	-	-	-		-	-		-	-
	1745	Roads and Trails	-	-	-	-		-	-		-	-
		Sub-Total	**1,486,207,342**	**800,000**	**-**	**1,487,007,342**		**74,430,903**	**29,966,903**	**-**	**104,397,806**	**1,382,609,536**
	2055	**Add: Construction Work in Progress**	-	-	-	-					-	
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-	-	-	-					-	
		Total PP&E	1,486,207,342	800,000	-	1,487,007,342		74,430,903	29,966,903	-	104,397,806	1,382,609,536
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										
		Total Additions to Accumulated Depreciation							29,966,903			

10		Transportation
8		Stores Equipment

Less: ***Fully Allocated Depreciation*** **(input as negative)**	
Transportation	
Stores Equipment	
Net Depreciation	**29,966,903**

Exhibit C, Tab 4, Schedule 1

Allowance for Working Capital

ALLOWANCE FOR WORKING CAPITAL

WPLP does not have sufficient historical revenues on which to base an analysis of revenue lag, nor does it have significant experience under negotiated settlement agreements with IESO or HORCI. WPLP has therefore not prepared a lead/lag study for 2026 and has not requested an allowance for working capital in its 2026 test year rate base. WPLP will consider filing a lead/lag study as part of its first multi-year revenue requirement application, for the 2027 test year, when its forecasted revenue lags are expected to become more certain.

Exhibit C, Tab 5, Schedule 1

Customer Connections and Cost Recovery Agreements

CUSTOMER CONNECTIONS AND COST RECOVERY AGREEMENTS

Section 2.5.4 of the Filing Requirements specifies that certain information must be provided when proposed capital expenditures require contributions from a customer and/or where Connection and Cost Recovery Agreements ("CCRA") are due for review.

Pursuant to the OEB's Decision and Order in EB-2022-0330, WPLP's Transmission Connection Procedures ("TCP") became effective September 1, 2024. WPLP's OEB-approved TCP have been published on WPLP's website. While WPLP has initiated SIA and CIA studies with potential customers, as further discussed in Exhibit B-1-4 at Section C.3, WPLP has not yet entered into any CCRAs with customers. As such, Section 2.5.4 of the Filing Requirements is not applicable for the 2026 Test Year.

Exhibit C, Tab 6, Schedule 1

Capitalization Policy

CAPITALIZATION POLICY

A. Capitalization Policy

As noted in Exhibit A-7-1, WPLP accounts for capital assets in accordance with the Accounting Standards for Private Enterprises (ASPE). Costs included in the carrying amount of property, plant and equipment (i.e. CWIP) include expenditures that are directly attributable to the acquisition or construction of the asset. The cost of self-constructed assets includes: materials, services, direct labour and directly attributable overheads. Borrowing costs associated with major projects are capitalized during the construction period if the capital assets associated with such projects meet the definition of a qualifying asset. Major projects (qualifying assets) are those projects that are under construction for a substantial period of time (i.e. greater than one year). Assets under construction are recorded in the CWIP account until they are available for use.

WPLP's adherence to the capitalization requirements under ASPE can be described as follows:

- Assets that are intended to be used on a continuing basis and are expected to provide future economic benefit (generally considered greater than one year) will be capitalized.

- General Plant items with an estimated useful life of greater than one year and valued at greater than $500 will be capitalized.

- Expenditures that create physical betterment or improvement of the asset (i.e. there is a significant increase in physical output or service capacity, or the useful life of the capital asset is extended) will be capitalized.

- Materials and supplies are charged to capital on the basis of actual costs for non-stock materials and the weighted average price for materials in inventory.

- Where internal resources are used in the construction of an asset, labour is charged to capital at a fully loaded (or "burden") labour rate, which is comprised of direct labour, payroll burden, vehicle charges and other directly attributable costs.

B. Capitalization of Overhead and Burden Rates

If internal resources are used in the construction of an asset, labour is charged at a fully loaded (or "burden") labour rate. On a departmental basis, WPLP uses direct wages, employee benefits and directly attributable overhead costs, in order to calculate the fully loaded labour rates. The 2026 capital additions are not expected to require use of internal resources.

Exhibit D, Tab 1, Schedule 1

Proposed Scorecard

PROPOSED SCORECARD

Section 2.6 (Exhibit 4) of the Filing Requirements outlines the OEB's expectations in relation to reporting on service quality and reliability performance, specifically in relation to scorecard measures aligned with the OEB's four categories of RRF outcomes and reporting related to system reliability. This schedule provides context on WPLP's historical monitoring and reporting during the transition from construction to operations, and considers the OEB's scorecard expectations arising from the four categories of Renewed Regulatory Framework (RRF) outcomes. WPLP's initial proposed scorecard is attached as Appendix 'A'. Reliability performance is addressed in Tab 2 of this Exhibit.

A. Background

In the Settlement Agreement in EB-2024-0176, WPLP agreed to address performance measurement and reporting in the present application by filing, on a best-efforts basis, an initial proposed scorecard. Because 2025 is the first full year that WPLP's entire transmission system is in service, it is the first full calendar year for which WPLP is able to track information for scorecard measures for its entire system.

In previous years, WPLP tracked information for typical scorecard measures related to safety, reliability and costs during the construction period so that this information could be used in setting future performance expectations, with consideration for any adjustments required to reflect the transition from construction to operation. WPLP tracked project status and performance reporting during the project development and construction phase in different ways, as summarized in Section B below. Given that the Transmission Project is no longer in development or construction and WPLP has filed an initial proposed scorecard with the present application, such interim performance measurement and reporting arrangements are no longer relevant for 2026 but are summarized below for context.

B. Performance Standards

This section provides, as context for WPLP's proposed 2026 performance monitoring and reporting, a summary of WPLP's historical performance monitoring and reporting requirements that were applicable during the project construction period.

First, as a condition of approval in EB-2018-0190, WPLP was required to provide the OEB with semi-annual reports on the CWIP account, as well as on the progress of backup supply arrangements for the connecting communities. In addition, in accordance with the approved Settlement Agreement from EB-2021-0134, WPLP expanded the scope of the semi-annual reports commencing with the October 15, 2021 report to include information on the expected connection dates of the remote communities, updates to operations and material changes to long-term operating plans, updated information on the transfer of distribution system assets from Independent Power Authorities to HORCI and updates on community readiness for those communities already served by HORCI. These updates have provided the OEB with information relevant to WPLP's physical progress and cost performance in the construction of its transmission system. As of 2025, with construction of the project complete, these measures are no longer relevant, except in respect of reporting on IPA transfers and implementation of backup power as discussed below.

Second, in accordance with the approved Settlement Agreement from EB-2021-0134, the parties agreed that WPLP would track certain information to facilitate the setting of future performance expectations. Specifically, the parties agreed that, in respect of the Line to Pickle Lake and the portions of the Remote Connection Lines that were placed into service in 2022, WPLP would monitor performance on the basis of the following reliability metrics without establishing performance targets and report to the OEB on such performance, based on data as at Year End 2022, in approximately April 2023 consistent with the timing of (but not pursuant to) the OEB's RRR reporting requirements:

- Total Recordable Injuries Frequency Rate ("TRIFR") - # of recordable injuries per 200,000 hours worked, using Canadian Electricity Association definition of "recordable injuries";

- Recordable Injuries - (# of recordable injuries per year, using Canadian Electricity Association definition of "recordable injuries");
- Violations of NERC FAC-003-4 Vegetation Compliance Standard (in respect of the Line to Pickle Lake portion of the transmission system only);
- OM&A cost per kilometer of line and OM&A cost per station;
- Average system availability;
- Transmission System Average Interruption Duration Index (T-SAIDI); and
- Transmission System Average Interruption Frequency Index (T-SAIFI).

In connection with the two metrics listed above for Recordable Incidents, the parties also agreed that WPLP would advise the OEB if and when the Canadian Electricity Association amends its definition of "recordable injuries".

In EB-2023-0168, WPLP proposed, and the parties to the OEB-approved Settlement Agreement agreed, that WPLP would continue to monitor performance on the basis of the above reliability metrics without establishing performance targets and to report to the OEB on such performance, based on data as at Year End 2023 and as at Year End 2024, in approximately April 2024 and April 2025, respectively, consistent with the timing of (but not pursuant to) the OEB's RRR reporting requirements.

In EB-2024-0176, the parties to the OEB-approved Settlement Agreement agreed that WPLP would, as part of the current application for the 2026 test year, address performance measurement and reporting including through an initial performance scorecard to be prepared on a best-efforts basis. Furthermore, the parties agreed that as part of WPLP's first multi-year revenue requirement application to be filed in 2026 for a rate period commencing with a 2027 test year, WPLP would include a performance scorecard and an econometric benchmarking based on 2025 data. WPLP filed its most recent semi-annual performance report with the OEB on April 15, 2025.

Third, pursuant to the Settlement Agreement in EB-2022-0149, WPLP agreed to the following in respect of monitoring and reporting:

Semi-Annual Reports: Provide additional information in the semi-annual reports that WPLP is required to file with the OEB pursuant to EB-2016-0262, including (i) how the scopes of work under the Control Room Services Agreement and the Inspection, Maintenance and Emergency Response Agreement ("IMER Agreement") would be performed, (ii) the nature and status of permitting and engagement required for operational access, and (iii) WPLP's fleet and facilities plans.

Project/construction monitoring and reporting: If the community connection schedule changes (including in respect of Pikangikum First Nation), post the updated schedule on WPLP's website and file a copy of the updated schedule with the OEB in EB-2022-0149. Provide to HORCI on a monthly basis information and concerns received in relation to issues relevant to HORCI, as well as a summary of the issues and concerns raised by First Nations that are likely to delay connection or to continue to be relevant to HORCI post-connection.

Community Communications: Participate in meetings if a First Nation community requests a meeting with or presentation by HORCI in advance of a community connection date and the community invites WPLP, focusing on WPLP's respective scope of work and in alignment with the First Nation community's expectations.

Furthermore, in the Settlement Agreement in EB-2022-0149, the Parties agreed that WPLP's communications and engagement protocols with First Nations would be at all times preserved and respected, and that the terms in the Settlement Agreement in EB-2022-0149 would not and were not intended to override, dictate or otherwise constrain the manner or substance of WPLP's communications or engagement with First Nations.

With respect to the semi-annual reports, WPLP notes that the April 2025 report and all future reporting is focused solely on backup power and IPA transfers until fully implemented.

C. Alignment with RRF Outcomes

This section describes how WPLP's proposed measures for its initial scorecard and its activities to date align with the OEB's four categories of RRF outcomes.

1. RRF Outcome #1 – Customer Focus

WPLP's sole customer at this time is HORCI, and the quality of service that WPLP provides to HORCI has a direct impact on the quality of distribution service that HORCI is able to provide to customers in the Connected Communities. Based on feedback from First Nations, feedback from WPLP and HORCI staff, and further operating experience with the transmission assets, WPLP and HORCI have established, and are continuing to refine, operational and communications processes in relation to the distribution systems that serve the First Nations that are connected to WPLP's transmission system. Under these processes, WPLP provides HORCI with monthly outage reports and reliability summaries, and will continue to engage with HORCI to consider how customer delivery point performance standards will be integrated with plans for backup power. Progress on backup power plans for each community is a core reporting requirement for WPLP's semi-annual reports, which will continue until such time as a solution is implemented for each community connected to WPLP's Transmission System.

WPLP's initial proposed scorecard includes a measure that will track WPLP's success in coordinating the use of backup power resources, where available, to mitigate the customer impact of transmission system outages when they occur:

Performance Outcomes	**Performance Categories**	**Measures**
Customer Focus	Service Quality	Customer outage impact mitigated by backup power (% SAIDI)

Once WPLP obtains sufficient reliability data to establish specific delivery point performance standards, additional scorecard measures can be added related to performance compared to these standards.[1]

2. RRF Outcome #2 – Operational Effectiveness

WPLP is well positioned to continue tracking certain safety, reliability and cost control measures that were previously included in annual reports and has proposed to include the following measures in its initial scorecard:

Performance Outcomes	**Performance Categories**	**Measures**
Operational Effectiveness	Safety	Total Recordable Incident Frequency Rate (TRIFR)
	System Reliability	T-SAIFI (Average # of interruptions per Delivery Point)
		T-SAIDI (Average total hour interrupted per Delivery Point)
		Average System Availability (%)
	Cost Control	OM&A per kilometre of line
		OM&A per substation

Additionally, WPLP has included placeholder measures in its proposed scorecard related to asset health indices but requires additional time to consider the appropriate level of detail and reporting methodology as it fully implements and tests the reporting functionality of its recently implemented asset management system. WPLP therefore proposes to refine these performance

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[1] See Exhibit D-2-1 for discussion of WPLP's approach to setting delivery point performance standards pursuant to Section 4.5.1 of the TSC.

measures in the proposed scorecard that will be filed in its application for a multi-year period starting with the 2027 test year.

3. RRF Outcome #3 – Public Policy Responsiveness

The initial construction of WPLP's Transmission System and the connection of 16 remote First Nation communities[2] is a result of the 24 Participating First Nations forming a partnership on the basis of their shared interest in developing, owning and operating transmission facilities to connect remote First Nation communities (which are currently powered by diesel generation) to the provincial electricity grid, so as to provide reliable and accessible power to residents and businesses in the region.[3] Through the Guiding Principles the development and construction of WPLP's Transmission System is aligned with policy objectives of the provincial and federal governments to connect remote communities, such as through the designation of the project in 2016 as a priority transmission project under section 96.1 of the OEB Act.

From a "Public Policy Responsiveness" perspective, typical transmission and distribution scorecards focus on the connection of renewable generation and the completion of regional planning objectives. In the context of WPLP's transmission system, the mandate from First Nations leadership, which focuses on connecting First Nations to the Ontario grid in order to meet the energy needs of those First Nations, is the primary policy that WPLP's project has been responsive to. WPLP has therefore renamed this performance outcome on its proposed scorecard as "Policy Responsiveness" and included a placeholder performance measure related to reporting on the capacity available to meet the load growth requirements in the connected First Nations. WPLP plans to develop a methodology for calculating and reporting on this measure, which will be included in the proposed scorecard that will be filed in its application for a multi-year period starting with a 2027 test year.

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[2] Including the design to allow the future connection of a 17th community, McDowell Lake First Nation.

[3] WPLP's development, construction and operation of the Transmission System will also abide by the Guiding Principles, as approved by the leadership of the Participating First Nations.

4. RRF Outcome #4 – Financial Performance

WPLP’s proposed scorecard metrics also include the following financial ratios, which are similar to those reported by LDC’s and other transmitters:

Performance Outcomes	**Performance Categories**	**Measures**	
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	
		Leverage: Total Debt to Equity Ratio	
		Profitability: Regulatory Return on Equity	Deemed (included in rates)
			Achieved

Exhibit D, Tab 1, Schedule 1

Proposed Scorecard

ATTACHMENT ‘A’

Initial Proposed Scorecard

Performance Outcomes	Performance Categories	Measures		2025	2026	2027	2028	2029	Trend	Target
Customer Focus	Service Quality	Customer outage impact mitigated by backup power (% SAIDI)								
Operational Effectiveness	Safety	Total Recordable Incident Frequency Rate (TRIFR)								
	System Reliability	T-SAIFI (Average # of interruptions per Delivery Point)								
		T-SAIDI (Average total hour interrupted per Delivery Point)								
		Average System Availability (%)								
	Asset Management	Asset Health Index - Stations **Level of detail and methodology to be developed for 2027 Test Year application**								
		Asset Health Index - Lines **Level of detail and methodology to be developed for 2027 Test Year application**								
	Cost Control	OM&A per kilometre of line								
		OM&A per substation								
Policy Responsiveness*	Capacity for First Nations	Capacity available for load growth in connected First Nations **Level of detail and methodology to be developed for 2027 Test Year application**								
Financial Performance	Financial Ratios	Liquidity: Current Ration (Current Assets/Current Liabilities)								
		Leverage: Total Debt to Equity Ratio								
		Profitability: Regulatory Return on Equity	Deemed (included in rates)							
			Achieved							

Exhibit D, Tab 2, Schedule 1

Reliability Performance

RELIABILITY PERFORMANCE

Section 2.6.2 of the OEB's Filing Requirements specifies that applicants must document their achieved reliability performance using measures developed by the Canadian Electricity Association (Electricity Canada), including transmission frequency of delivery point interruptions and transmission duration of delivery point interruptions, unsupplied energy in minutes and transmission system unavailability. In addition, applicants must document how they have addressed the performance standards for transmitters as set out in Chapter 4 of the Transmission System Code.

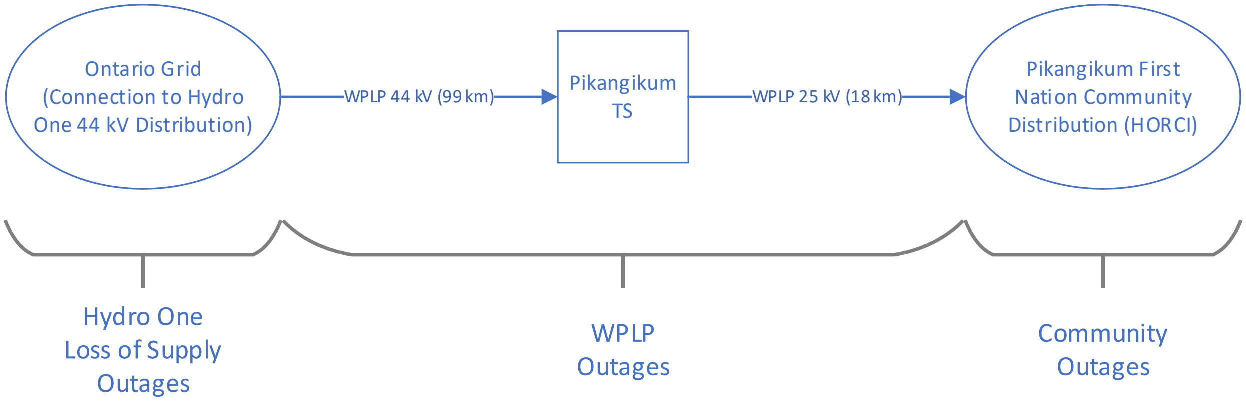
A. Achieved Reliability Performance

1. Pikangikum Distribution Line (December 2018-May 2023)

WPLP tracked historical reliability performance information in respect of its distribution line that previously served Pikangikum, as summarized below. However, as that line operated temporarily as a distribution line before being converted to form part of the Transmission System in May 2023, the corresponding reliability performance data is of limited value for future comparison, particularly with respect to loss of supply outages and planned outages for conversion from 44 kV to 115 kV.

In order to provide context for the reliability performance information that follows, Figure 1 provides a simplified illustration of the connection of the Pikangikum First Nation to the Ontario grid via WPLP's Pikangikum Distribution System, which was in place on an interim basis from December 2018 until May 2023. Figure 1 also illustrates the differences between outages originating on WPLP's distribution system ("WPLP Outages"), as compared to outages originating upstream of that distribution system ("Loss of Supply Outages") or outages originating in the community ("Community Outages").

Figure 1 – Simplified Connection of 2018-2023 Pikangikum Distribution System



In 2019, Pikangikum First Nation experienced eight outages that affected the entire community:

- Two Hydro One Loss of Supply Outages originated on Hydro One’s upstream transmission/distribution network.

- One WPLP Outage originated as a Community Outage, however most of the outage duration was related to issues with settings and coordination on a WPLP recloser that were resolved.

- One WPLP Outage occurred when WPLP de-energized its distribution system at the request of MNRF to allow for safe aerial water-bombing of an out-of-control forest fire in the vicinity of WPLP’s assets.

- Four Community Outages tripped the recloser at the WPLP/HORCI demarcation point, resulting in community-wide outages.

In 2020, Pikangikum First Nation experienced two community-wide outages, both of which were Hydro One Loss of Supply Outages.

In 2021, Pikangikum First Nation experienced seven community-wide outages, two of which related to WPLP Outages and five of which related to Hydro One Loss of Supply Outages. The two WPLP Outages related to maintenance within the substation.

In 2022, Pikangikum First Nation experienced four community-wide outages, three of which related to WPLP Outages and one of which related to a Hydro One Loss of Supply Outage. Two of the three WPLP Outages were planned in advance and related to work required to convert from HONI's 44 kV distribution system to WPLP's 115 kV transmission system. The third WPLP Outage related to unintended WPLP protection operations following capacitor bank switching at a nearby Hydro One substation.

In 2023, up to the date the Pikangikum Distribution System was converted to transmission on May 12, 2023, Pikangikum First Nation experienced two community-wide outages, one of which related to a planned outage by HONI for emergency pole replacement and one of which related to a planned outage by WPLP for the last stage of the conversion from 44 kV distribution to 115 kV transmission on May 12, 2023.

2. Partial Transmission System (2022-2024)

As noted in Exhibit D-1-1, the parties to the Settlement Agreement in EB-2021-0134 agreed that in respect of the Line to Pickle Lake and the portions of the Remote Connection Lines that were placed into service in 2022, WPLP would monitor performance based on certain agreed-upon reliability metrics without establishing performance targets and that WPLP would report to the OEB on such performance in approximately April 2023, based on data as at year end 2022. Such report was filed with the OEB on May 12, 2023. Further to the Settlement Agreement in EB-2023-0168, WPLP agreed to continue to monitor performance targets on the same agreed upon reliability metrics, inclusive of the portions of the transmission assets placed in service in 2023 and 2024. As such, the numbers of outages identified below reflect the year over year increases in the number of transmission delivery points served by WPLP's Transmission System as additional segments were brought into service. WPLP filed its subsequent performance reports on April 23, 2024 and April 24, 2025, and the updated reliability performance for the transmission assets is summarized below. Furthermore, WPLP has proposed a preliminary transmission scorecard in Exhibit D-1-1 that would result in annual reporting of, among other things, the same transmission reliability measures reported to date (i.e. T-SAIFI, T-SAIDI and Average System Availability).

In 2022, WPLP's Pickle Lake Remote Connection Line experienced two outages to transmission delivery points:

- A vehicle contact with a 25 kV pole on the HORCI distribution system in North Caribou Lake First Nation caused WPLP's substation breakers to trip and reclose. This event was recorded as a momentary outage by WPLP (WPLP's circuit breakers tripped and reclosed approximately 2 seconds later) and a sustained outage by HORCI (the downstream HORCI recloser remained open until crews could be mobilized to site).

- Protection systems registered a line-to-ground fault approximately 6-7 seconds after a 230 kV reactor at Pickle Lake TS was energized, causing WPLP's Line to Pickle Lake to trip, which resulted in a 30-minute outage to North Caribou Lake First Nation and Kingfisher Lake First Nation while switching was completed to restore the WPLP system.

In 2023, WPLP experienced 26 outages to transmission delivery points (inclusive of the Pikangikum outages summarized in Section 1 above):

- 6 outages were required for completion of construction activities in proximity to previously energized assets, including final connection work with HONI and final voltage conversion work on the Pikangikum system.

- 8 loss of supply outages from HONI, one of which was a planned outage and seven of which were unplanned.

- 10 outages that were caused by lightning strikes and quickly restored from the control room.

- Two outages from other causes, being bird contact and a protection operation for a fault on HORCI’s 25 kV system.

In 2024, WPLP experienced 46 outages to transmission delivery points:

- 7 outages were caused by loss of supply from Hydro One Networks;
- 9 planned outages were required, primarily for Valard to install additional wildlife guards at previously energized substations after a bird contact outage at a substation in 2023;
- 20 outages were caused by lightning, which were quickly restored from the control room;
- 1 outage was caused by a single tree; and
- 9 outages from other causes, which included ice build-up, equipment issues and unknown causes.

3. Full Transmission System (2025 Onward)

The bridge year, 2025, is the first full year of WPLP’s Transmission System being fully in-service. As at May 31, 2025, WPLP has experienced 8 outages to transmission delivery points:

- 1 outage was caused by lighting, which was quickly restored from the control room;
- 1 outage was classified as having an unknown cause;
- 2 planned outages were to remove bird’s nests from hazardous locations in substations; and
- 1 momentary outage resulted from a WPLP mis-coordination between HORCI and WPLP protection relays immediately prior to a sustained outage caused by a fault on the HORCI distribution system.

- An extended outage event related to a significant out-of-control wildfire (Red Lake 12) in the vicinity of Deer Lake First Nation, recorded as 3 separate outages due to a successful short-duration restoration, followed by a long-duration outage due to restricted air space limiting access, followed by a period of further isolation to support the safety of fire response personnel. The overall customer impact of this outage was significantly reduced through early and ongoing coordination between WPLP, HORCI and MNR to consider safety and reliability risks between the use of grid power and diesel backup generation at various points during the wildfire event. Between May 28-31, 2025, WPLP's Deer Lake First Nation delivery point was out of service for approximately 58.5 hours, with backup power used to power the entire community for approximately 57.5 hours during this time.

The Red Lake 12 wildfire referenced above has since expanded to an area of over 194,000 hectares (over 1940 km^2) and caused additional outages to the WPLP circuit supplying Sandy Lake First Nation in June 2025, which were similarly mitigated through the use of diesel backup generation. As of the filing date, the Red Lake 12 wildfire remains not under control and has resulted in the ongoing evacuation of nearby First Nations as well as evacuation alerts for other First Nations.

B. Reliability Performance Trending

WPLP's reliability performance for 2022 to 2024 is summarized in Table 1, below:[1]

Table 1 - 2022-2024 Reliability Performance

	2022	2023	2024
All Causes:			
T-SAIFI	4.67	7.89	9.44
T-SAIDI (minutes)	1,662.2	1,469.7	1,786.3
Average System Availability	99.6837%	99.7204%	99.6610%
Excluding Loss-of-Supply:			
T-SAIFI	3.67	6.07	7.42
T-SAIDI (minutes)	1,626.8	1,091.3	1,167.5

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[1] These transmission reliability metrics include outages on the Pikangikum Distribution System that occurred prior to its conversion to 115 kV.

Average System Availability	99.691%	99.792%	99.779%
	Excluding Loss-of-Supply and Planned Outages:		
T-SAIFI	1.67	3.94	6.58
T-SAIDI (minutes)	121.3	84.1	964.8
Average System Availability	99.977%	99.984%	99.817%

The single largest driver of both outage duration and outage frequency in 2022 was planned outages related to construction. Two planned outages, with an average duration of 12.5 hours, were required for voltage conversion activity to prepare for the conversion of WPLP's Pikangikum Distribution System from 44 kV to 115 kV.

The largest driver of outage duration in 2023 was planned outages related to construction, including completion of Pikangikum voltage conversion and correction of punch list items. Six planned outages, with an average duration of 6.5 hours, contributed to 69% of WPLP's total SAIDI result for 2023. The largest driver of outage frequency in 2023 was lightning, where 10 outages contributed to 46% of WPLP's total SAIFI result for 2023. These lightning-caused outages were restored relatively quickly from the control room, minimizing SAIDI impacts.

The largest drivers of outage duration in 2024 were tree contact (36% of SAIDI attributable to a single tree contact outage) and Hydro One loss of supply (35% of SAIDI, primarily from planned outages). While the results above are presented from the perspective of WPLP delivery point availability, WPLP was able to work with HORCI in 2024 to maximize the use of community-wide backup generation in many First Nations to significantly reduce outage impacts to end-use customers during prolonged outages, both planned and unplanned, as summarized in Section C below. The largest driver of outage frequency in 2024 was lightning, where 20 outages contributed to 40% of WPLP's total SAIFI result for 2024. These lightning-caused outages were restored relatively quickly from the control room, minimizing SAIDI impacts.

Due to the significant evolution of the Transmission System during between 2022 and 2024, which came into service in stages between August of 2022 and May of 2024, reliability performance and trends for this period should not be viewed as indicative of future performance.

C. Reliability Performance Standards

Section 2.6.2 of the OEB's Filing Requirements specifies that applicants should compare the results of their system performance to the performance of other systems, nationally and internationally, where available.

WPLP operates 1742 km of radial transmission lines[2] in an extremely remote area of Northwestern Ontario, through challenging terrain, with limited road access and with backup generation at most of its delivery points. As such, WPLP does not believe that transmission system reliability comparison with other utilities would be appropriate. Instead, WPLP plans to establish future transmission system reliability performance standards that are based on trending of its own system performance over multiple years, supplemented by consideration of unitized outage statistics from other sources where such data is both available and aligned with WPLP's unique circumstances. This approach will require tracking and analyzing multiple years of baseline performance data for WPLP's transmission system, with 2025 being the first year in which 100% of the transmission system is in service for the entire calendar year.

With respect to requirements in Section 4.5.1 of the Transmission System Code (TSC) to establish performance standards that apply at the customer delivery point level, WPLP notes that on September 28, 2023, the OEB established a new RPQR Transmission Subgroup to review the policy framework related to the current customer-specific reliability standards. The subgroup has recommended a shift from HONI's current approach of setting transmission delivery point performance standards based on load size, to an approach where performance standards are set based on supply circuit length, with an emphasis on the length of radial line(s) serving each delivery point. Assuming that the OEB accepts this recommended change in approach for HONI, WPLP plans to analyze its reliability performance over multiple years to determine whether a similar distance-based approach would be appropriate.

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[2] While WPLP's 230 kV Line to Pickle Lake is not technically a radial line, it is operated radially, with extremely limited transfer capability from HONI's E1C path during outages.

Section 4.5.1 of the TSC requires transmitters to develop performance standards that reflect the historical performance of their transmission systems at the customer delivery point level. For WPLP as a new entrant transmitter, this requires the collection and analysis of historical data to set future performance targets, regardless of whether the OEB accepts the possible change in approach for HONI described above. While WPLP continues to gather and analyze reliability data for the purpose of establishing its future transmission delivery point performance standards, WPLP also continues to monitor progress on the implementation of backup power in the connected First Nations[3], which has provided immediate improvements - beyond the level of reliability as measured at the transmission delivery point - for many of the connected First Nations. In 2024, WPLP began tracking the impact of using community-wide backup power where available to reduce outage duration. Table 2, below, shows the significant reduction in outage duration from an end-use customer perspective resulting from the use of backup power where available.

Table 2 – 2024 Adjusted Reliability Performance

	2024 Results[4]	2024 Adj for Backup[5]	SAIDI Reduction %
All Causes:			
T-SAIDI (minutes)	1,786.3	764.8	57%
Excluding Loss-of-Supply:			
T-SAIDI (minutes)	1,167.5	522.2	55%
Excluding Loss-of-Supply and Planned Outages:			
T-SAIDI (minutes)	964.8	494.2	49%

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[3] 13 of 16 connected communities are expected to have full community back-up power by leveraging the generation assets and associated infrastructure that previously served as the primary electricity supply within the communities, before connecting to WPLP's Transmission System. Given the remoteness, access challenges and radial transmission line distance, it is important to establish and maintain full back up in each of the connected First Nation communities.

[4] Results in this column are based on transmission system availability to supply power to each delivery point.

[5] Results in this column calculate adjusted SAIDI values to exclude the portion of time during an outage when the entire load at an affected delivery point is supplied by generation on the local distribution system.

WPLP continues to report to the OEB semi-annually on the status backup power implementation, with the most recent report filed on April 15, 2025.

Exhibit E, Tab 1, Schedule 1

Load and Revenue Forecasts

LOAD AND REVENUE FORECASTS

A. Operating Revenue

WPLP's forecasted 2026 operating revenue consists of revenue earned through the Network Uniform Transmission Rate (for the revenue requirement associated with the Line to Pickle Lake), and revenue earned through fixed monthly charges applicable to HORCI (for the revenue requirement associated with the Remote Connection Lines). Table 1 summarizes WPLP's 2026 revenue requirement, as calculated and allocated in Exhibit I.

Table 1 – 2026 Revenue Requirement Forecast

	LTPL	RCL	Total
Revenue Requirement for Rates	29,685,502	103,345,591	133,031,093

WPLP's 2025 approved revenue requirement is provided in Table 2.

Table 2 – 2025 Approved Revenue Requirement

	LTPL	RCL	Total
Revenue Requirement for Rates	43,489,861	132,731,158	176,221,020

B. Load Forecast

As detailed in Exhibit I, WPLP's revenue requirement is allocated between the Line to Pickle Lake (for recovery through the UTR Network rate) and the Remote Connection Lines (for recovery through monthly fixed charges applicable to HORCI). For the purpose of UTR calculations, WPLP's load forecast therefore needs to consider the incremental network charge determinants related to its transmission system, but does not need to consider line connection or transformation connection charge determinants. The load supplied by WPLP's transmission system in 2026 will fall into three categories:

1. Some or all of the load currently supplied by HONI's transmission system in the Pickle Lake area, which is supplied by WPLP's Line to Pickle Lake via a 115 kV interconnection between WPLP's Pickle Lake TS and HONI's new Pickle Lake SS;
2. Load on the distribution systems in the ten First Nation communities[1] that are connected to the North of Pickle Lake Remote Connection Lines, which are supplied directly by WPLP's Transmission System; and,
3. Load on the distribution systems in the six First Nation communities that are connected to the North of Red Lake Remote Connection Lines, which are supplied directly by WPLP's Transmission System via HONI's transmission system, but which is not included in HONI's UTR charge determinant forecast.

Since the delivery points included in the first category are connected to HONI's transmission system, the associated charge determinants are not included in WPLP's load forecast as this would double-count the related charge determinants. To the extent that any of these loads increase over time as a result of the additional capacity enabled by WPLP's Line to Pickle Lake, WPLP expects that this will be considered in HONI's future charge determinant forecasts in the normal course of their transmission rate applications.

For the purpose of UTR calculations, WPLP's 2026 UTR Network charge determinants should therefore be limited to the second and third categories above, specifically the load associated with the sixteen First Nations that will continue to be connected to WPLP's Remote Connection Lines in 2026.

In lieu of developing a load forecast based on weather-normalized historical data (which WPLP does not have at this point in time), WPLP has taken the following approaches to forecast charge determinants:

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[1] In the case of Muskrat Dam First Nation, community connection is pending IPA upgrades and information transfers, and is therefore not expected to occur until late 2025. WPLP has included their load forecast in this 2026 rate application.

1. For the twelve First Nations[2] that are supplied by WPLP's transmission system, and which have been served by HORCI for the entirety of 2024 and 2025, WPLP requested and received recent historical peak demand data from HORCI. This data was used, normalized to remove anomalies such as cold starts,[3] and escalated for each month in 2026 by 4%.[4]

2. For the four First Nations[5] that are supplied by WPLP's transmission system and which have historically been served by IPAs, WPLP used a combination of the forecasts that were included within WPLP's SIA Application and the monthly demand data from HORCI[6] to forecast monthly demand. Using annual peak demand forecast details from WPLP's SIA Application, which were informed by prior OPA and IESO data[7], WPLP first identified annual peak demand forecasts for these four communities. This data included a 4% annual growth rate, consistent with the expected level of growth identified in HORCI's 2018 backup power report and load growth included in Backup Power Plan prepared by Backup Power Working Group.[8]

   Secondly, WPLP used the historical demand data provided by HORCI for the other 12 First Nations, WPLP determined the average ratio of monthly demand to annual peak demand for the twelve First Nations where historical monthly peak demand data was available and multiplied the annual demand forecast (from the SIA Application) for the other four First

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[2] North Caribou Lake, Bearskin Lake, Sachigo Lake, Kingfisher Lake, Kasabonika Lake, Kitchenuhmaykoosib Inninuwug, Wapekeka, Pikangikum, Deer Lake, Wunnumin Lake, Wawakapewin and Sandy Lake.

[3] Approximately 2% of the entries for the monthly peak demand by community obtained from HORCI also required estimation to resolve incomplete data. In these cases, WPLP estimated the missing peak demand values for 2023 by escalating the corresponding monthly peak demand from 2022, by the average of 2023 vs. 2022 peak demand increase for all other months for that community.

[4] Consistent growth % with WPLP's SIA Application.

[5] Muskrat Dam, Poplar Hill, North Spirit Lake and Keewaywin.

[6] Partial year information was available for the 3 communities (Poplar Hill, North Spirit Lake and Keewaywin) were energized in late 2024 and early 2025.

[7] Consistent with prior rate applications.

[8] Report was provided in letter dated July 15, 2021 as part of CWIP filings on EB-2018-0190.

Nations by these ratios as a proxy for estimating the monthly demand for each month in 2026 that the load is expected to be in-service.

The resulting demand forecast is provided in Table 3, and the total 2026 forecasted charge determinants of 210.0 MW for all 16 of the connected communities is included in the UTR calculation in Exhibit I-3-1.

WPLP expects to develop a more robust load forecasting method as it acquires a suitable amount of historical consumption data, over at least two years, for the grid-connected communities. For the 2026 test year, WPLP notes that its portion of the overall 2026 Network UTR charge determinants[9] resulting from the above method is approximately 0.089%.

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[9] Consistent with Exhibit I-3-1, WPLP has assumed values for all other transmitters remain the same as in EB-2024-0244 to determine 2026 UTR impacts.

Table 3 – WPLP Peak Demand (MW) for UTR Charge Determinants

Delivery Point	**2026 Annual Peak Forecast (MW)**	**Forecast Demand by Month (MW)**												
		Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
D - North Caribou Lake	1.9	1.9	1.8	1.7	1.3	1.2	1.1	1.0	0.9	0.9	1.3	1.5	1.7	16.2
E - Muskrat Dam[10]	1.0	1.0	1.0	0.8	0.7	0.6	0.5	0.5	0.5	0.5	0.6	0.8	0.9	8.3
F - Bearskin Lake	1.0	1.0	0.9	0.8	0.7	0.7	0.6	0.6	0.5	0.5	0.7	0.7	0.9	8.7
G - Sachigo Lake	1.1	1.1	1.1	0.9	0.9	0.7	0.7	0.7	0.6	0.6	0.8	0.9	1.1	10.1
I - Wunnumin Lake	1.2	1.2	1.1	1.0	0.9	0.9	0.8	0.7	0.8	0.7	0.9	1.2	1.2	11.5
J - Kingfisher Lake	1.2	1.2	1.1	0.9	0.8	0.8	0.6	0.5	0.6	0.5	0.8	0.9	1.1	9.9
K - Wawakapewin	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.7
L - Kasabonika Lake	1.7	1.7	1.5	1.4	1.3	1.2	1.0	0.9	0.9	0.9	1.2	1.3	1.6	14.7
M - KI	*2.1*	*2.1*	*2.0*	*1.7*	*1.5*	*1.4*	*1.1*	*1.1*	*1.0*	*1.0*	*1.4*	*1.9*	*2.0*	*18.4*
M - Wapekeka	*2.1*	*2.1*	*2.0*	*1.7*	*0.6*	*0.6*	*0.4*	*0.4*	*0.4*	*0.4*	*0.5*	*0.6*	*0.8*	*10.6*
M - KI-Wapekeka Total	4.2	4.2	4.0	3.5	2.1	2.0	1.6	1.5	1.5	1.4	2.0	2.5	2.7	29.0
Pickle Lake Total	***13.3***	***13.3***	***12.7***	***11.3***	***8.8***	***8.1***	***6.8***	***6.4***	***6.2***	***6.0***	***8.3***	***9.9***	***11.4***	***109.1***
Q - Pikangikum	3.6	3.6	3.6	3.0	2.2	1.9	1.4	1.6	1.6	1.6	2.2	3.0	3.4	29.2
S - Poplar Hill	1.1	1.1	1.1	0.9	0.8	0.7	0.5	0.5	0.5	0.5	0.7	0.8	1.0	9.1
U - Deer Lake	1.7	1.7	1.6	1.4	1.2	0.8	0.7	0.7	0.7	0.7	1.0	1.3	1.6	13.4
V - North Spirit Lake	0.8	0.8	0.8	0.7	0.6	0.5	0.4	0.4	0.4	0.4	0.5	0.7	0.8	7.1
W - Sandy Lake	4.0	4.0	3.8	3.3	2.9	2.4	1.9	2.0	2.0	2.0	2.8	3.3	3.8	34.3
Y – Keewaywin	1.0	1.0	0.9	0.6	0.7	0.6	0.5	0.5	0.5	0.4	0.6	0.7	0.9	7.7
Red Lake Total	***12.2***	***12.2***	***11.8***	***9.9***	***8.3***	***6.9***	***5.4***	***5.7***	***5.6***	***5.6***	***7.9***	***9.9***	***11.5***	***100.9***
WPLP System Total	***25.5***	***25.5***	***24.5***	***21.2***	***17.2***	***15.1***	***12.2***	***12.1***	***11.9***	***11.6***	***16.2***	***19.8***	***22.8***	***210.0***

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[10] IPA community that still requires upgrades outside of WPLP work scope before connecting to WPLP Transmission System assets.

Exhibit E, Tab 2, Schedule 1

Accuracy of Load Forecast and Variance Analysis

ACCURACY OF LOAD FORECAST AND VARIANCE ANALYSIS

The following peak demand forecast for UTR charge determinants for 2024 was included in the Settlement Agreement approved in EB-2023-0168:

Table 1 – WPLP Peak Demand (MW) for UTR Charge Determinants

Community	**Forecast Demand by Month (MW)**												
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
North Caribou First Nation	1	1.2	1.5	1.1	1	0.8	0.9	0.8	0.9	1.1	1.2	1.2	12.9
Muskrat Dam First Nation	0.9	0.9	0.9	0.7	0.7	0.6	0.5	0.5	0.5	0.7	0.8	0.9	8.5
Bearskin Lake First Nation	0.9	0.9	0.7	0.7	0.7	0.6	0.5	0.5	0.5	0.6	0.8	0.9	8.2
Sachigo Lake First Nation	0.9	0.9	0.9	0.8	0.7	0.6	0.6	0.6	0.6	0.8	0.8	0.9	9.2
Wunnumin Lake First Nation	1.2	1.2	1.2	1	0.9	0.8	0.7	0.7	0.7	0.9	1	1.2	11.4
Kingfisher Lake First Nation	0.9	1.1	1.2	0.7	0.6	0.5	0.5	0.6	0.6	0.7	0.7	0.9	9.1
Wawakapewin First Nation	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	1.8
Kasabonika Lake First Nation	1.3	1.4	1.2	1.1	1	0.9	0.9	0.9	1	1.1	1.2	1.3	13.3
Kitchenuhmaykoosib Inninuwug	*0*	*0*	*0*	*1*	*0.9*	*0.8*	*0.8*	*0.8*	*0.8*	*0.9*	*1.1*	*1.2*	*8.4*
Wapekeka First Nation	*0*	*0*	*0*	*1*	*0.9*	*0.7*	*0.7*	*0.7*	*0.7*	*1*	*1.2*	*1.3*	*8.3*
Pikangikum First Nation	2.9	3	3	2.5	2.3	2	1.6	1.5	1.5	1.5	2.2	2.7	26.8
Poplar Hill First Nation	0	0	0	0.8	0.7	0.6	0.6	0.6	0.6	0.7	0.9	1	6.5
Deer Lake First Nation	0	0	0	0	1	0.9	0.8	0.7	0.8	1.1	1.3	1.5	8.2
North Spirit Lake First Nation	0	0	0	0	0	0	0.5	0.4	0.5	0.6	0.7	0.7	3.3
Sandy Lake First Nation	0	0	0	0	0	2.2	2	1.9	2	2.7	3	3.4	17.2
Keewaywin First Nation	0	0	0	0	0	0	0	0.5	0.5	0.6	0.7	0.8	3.2
Total	**10.2**	**10.8**	**10.8**	**11.6**	**11.5**	**12.1**	**11.7**	**11.8**	**12.3**	**15.1**	**17.8**	**20.1**	**156.2**

The actual peak demand values for 2024 and resulting variances between forecast and actual peak demand were as follows:

Community	**Actual Demand by Month (MW)**												
	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
North Caribou First Nation	1.3	1.5	1.5	1.2	1.1	1.0	0.9	0.8	0.8	1.2	1.4	1.6	14.4

Muskrat Dam First Nation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bearskin Lake First Nation	0.8	0.9	0.8	0.7	0.6	0.5	0.5	0.5	0.5	0.6	0.7	0.9	7.9
Sachigo Lake First Nation	0.9	0.9	0.9	0.8	0.7	0.6	0.6	0.6	0.6	0.8	0.9	1.0	9.2
Wunnumin Lake First Nation	0.8	0.8	0.9	0.8	0.8	0.7	0.7	0.7	0.6	0.8	1.2	1.1	10.0
Kingfisher Lake First Nation	0.8	1.0	0.9	0.7	0.7	0.6	0.5	0.5	0.5	0.7	0.8	1.0	8.8
Wawakapewin First Nation	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.7
Kasabonika Lake First Nation	1.3	1.4	1.4	1.2	1.1	0.9	0.8	0.8	0.8	1.1	1.2	1.4	13.5
Kitchenuhmaykoosib Inninuwug	1.5	1.7	1.6	1.4	1.3	1.1	1.0	1.0	0.9	1.3	1.8	1.8	16.3
Wapekeka First Nation	0.6	0.8	0.7	0.6	0.5	0.4	0.4	0.4	0.4	0.5	0.6	0.7	6.5
Pikangikum First Nation	2.5	3.0	2.9	2.1	1.7	1.3	1.5	1.5	1.5	2.0	2.8	3.2	25.9
Poplar Hill First Nation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Deer Lake First Nation	0.0	0.0	0.0	1.1	0.8	0.6	0.6	0.6	0.6	1.0	1.2	1.5	8.1
North Spirit Lake First Nation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sandy Lake First Nation	0.0	0.0	0.0	2.7	2.3	1.7	1.8	1.8	1.8	2.6	3.1	3.5	21.4
Keewaywin First Nation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**10.5**	**12.1**	**11.7**	**13.4**	**11.7**	**9.5**	**9.4**	**9.2**	**9.1**	**12.7**	**15.5**	**17.9**	**142.5**
Variance	**0.3**	**1.3**	**0.9**	**1.8**	**0.2**	**-2.6**	**-2.3**	**-2.6**	**-3.2**	**-2.4**	**-2.3**	**-2.2**	**-13.7**

For context, WPLP's 2024 OEB-approved Network UTR charge determinants represented 0.06% of the Ontario total.[1] The variance is primarily driven by timing differences between the forecasted and actual connections of Muskrat Dam, Poplar Hill, Keewaywin and North Spirit Lake to WPLP's transmission system. As outlined in Exhibit E-1-1, WPLP expects to develop a more robust load forecasting method as it acquires a suitable amount of historical consumption data for the grid-connected communities. As illustrated above, variances resulting from WPLP's interim approach to load forecasting result in immaterial variances in the context of UTR calculations.

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[1] In its January 18, 2024 Decision and Order in EB-2023-0222, the OEB approved Network UTR determinants of 156.151 MW for WPLP and 237,801.119 MW for all transmitters combined.

Exhibit E, Tab 3, Schedule 1

Other Revenue

OTHER REVENUE

WPLP is not forecasting any Other Revenues for the 2026 test year and expects that its 2026 revenues will consist solely of the transmission service revenues outlined in Exhibit E-1-1.

Exhibit F, Tab 1, Schedule 1

Operating Costs Overview

OPERATING COSTS OVERVIEW

WPLP's operating costs for the 2026 test year include operations, maintenance and administration (OM&A); depreciation and amortization; and income taxes. A summary of WPLP's operating costs for the 2026 test year is presented in Table 1 below.

Table 1 – Summary of Operating Costs

Operating Cost Category	2026 Test Year ($000's)
OM&A Expenses	38,354
Depreciation and Amortization	26,864
Income Taxes	596
Total Operating Costs	**65,814**

WPLP confirms that no charitable or political donations are included in its 2026 test year revenue requirement. Moreover, WPLP's forecasted property tax expense is immaterial (less than $1,000) and is therefore included in the OM&A Expenses category instead of in a distinct property tax category.

This Exhibit provides forecasted costs for the 2025 bridge year and the 2026 test year, and a variance analysis for the changes in OM&A expense over the historical, bridge and test years. As WPLP's rates were first approved for the 2022 rate year, its historical period in the current application is comprised of the three years from 2022-2024.

The Settlement Agreement in EB-2021-0134 required WPLP to file in its 2023 revenue requirement application two benchmarking studies to compare (i) WPLP's OM&A spending levels on a per line kilometer basis and on a per station basis relative to comparable Ontario and Canadian transmitters (the "Unit Cost Benchmarking Study"), and (ii) WPLP's compensation costs relative to Hydro One compensation costs.[1] Further, the Settlement Agreement in EB-2024-0176 required WPLP to file an updated Econometric Benchmarking Study in 2026, based on 2025 data, in

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[1] WPLP filed benchmarking reports prepared by Clearspring Energy Advisors LLP in respect of the OM&A costs and by Korn Ferry in respect of compensation costs.

conjunction with WPLP's first multi-year revenue requirement application for a period beginning with the 2027 rate year. It is expected that the updated Econometric Benchmarking study will address the limitations identified in the Unit Cost Benchmarking Study by allowing for appropriate adjustments for WPLP's unique business circumstances and transmission system characteristics. Given the terms of the Settlement Agreement in EB-2024-0176, WPLP has not filed comparable studies in the current rate application.

Pursuant to the Settlement Agreement in EB-2022-0149, WPLP agreed to establish a new Construction Period OM&A Variance Account, effective January 1, 2023, to record the difference, if any, between forecast and actual OM&A expenses, with any shortfall in actual spending relative to the amounts approved in EB-2022-0149 to be returned to ratepayers in a future rate proceeding, over a 1-year disposition period. Pursuant to the Settlement Agreement in EB-2023-0168, WPLP agreed to continue the Construction Period OM&A Variance Account for 2024. In the Settlement Agreement in EB-2024-0176, the parties agreed that the Construction Period OM&A Variance Account should continue as an asymmetrical account in 2025 to record any variances between approved and actual OM&A expense along with applicable carrying charges, and that it should therefore be renamed the "OM&A Variance Account". WPLP is not seeking to add to the principal balance of this account in 2026, as further discussed in Exhibit H. .

Additional information for each item listed in Table 1 can be found as follows:

- OM&A – Exhibit F, Tab 2, Schedule 1 and Exhibit F, Tab 3, Schedule 1
- Depreciation and Amortization – Exhibit F, Tab 4, Schedule 1
- Income Taxes – Exhibit F, Tab 5, Schedule 1

Exhibit F, Tab 2, Schedule 1

OM&A Summary and Cost Driver Tables

OM&A SUMMARY AND COST DRIVER TABLES

A. Overview

This schedule provides a breakdown of WPLP's OM&A expenses for the 2026 test year along with a variance analysis for the change in OM&A expense for the 2026 test year relative to each of the 2025 bridge year and the 2022-2024 historical years.

B. OM&A Summary

WPLP's OM&A expenses include costs associated with the following activities:

- **Operation:** System control functions, inspection and operation of transmission station equipment, line patrols and inspections, environmental commitments and costs associated with land rights.
- **Maintenance:** Preventative maintenance programs designed to maintain asset health, corrective maintenance required to address deficiencies or deteriorating condition, including repairs of a non-capital nature during outages or other emergency conditions.
- **Administration & General:** Indigenous engagement, communications and participation, accounting, health, safety and environment, information technology, insurance, and general administration. This includes labour-related costs that are not specifically allocated to operation or maintenance activities.

WPLP's OM&A expenses are summarized in Table 1 below.

Table 1 – OM&A Expenses ($000's)

Category	**2022 Actuals**	**2023 Actuals**	**2024 Actuals**	**2025 Forecast**	**2026 Plan**	**Variance 2025 to 2026**
Operations	1,318	5,533	9,573	16,038	18,096	2,058
Maintenance	-	2,890	1,271	7,997	10,875	2,878
Administration & General	2,638	8,578	14,061	9,537	9,382	(155)
Total OM&A	**3,956**	**14,534**	**25,084**	**33,572**	**38,354**	**4,782**

The increase in total OM&A from the 2025 bridge year to the 2026 test year is driven by: (1) ramp up of WPLP's vegetation management planning and field activities given the timing for when the right of way was cleared, with assumption of 50% of a typical annual brushing cycle, resulting in an additional $3.5 million cost from prior year[1], and (2) additional line inspection (including LiDAR scope not carried out in 2025) and substation activities resulting in an additional $1.8 million from the prior year[2]. These increases are partially offset by lower affiliate and related party costs ($0.3M), as explained in Exhibit F-3-1 and other administrative cost reductions ($0.2M). Due to the timing of assets coming into service in 2022, 2023 and 2024 and the allocation method applied during construction period, the 2022, 2023 and 2024 OM&A cost actuals are of limited value in comparing to WPLP's OM&A forecast for 2025 and its planned OM&A costs for 2026.

C. OM&A Cost Drivers

1. Summary of Cost Drivers

Table 2 below presents the cost drivers for each component of WPLP's planned 2026 OM&A expenses along with the associated variances.

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[1] Additional details on vegetation management planning are provided in section C, below.

[2] Additional details on line inspection and substation activities are provided in section C, below.

Table 2 – 2026 OM&A Cost Drivers

	Category of Expense	**2022 OM&A Actuals**	**2023 OM&A Actuals**	**2024 OM&A Actuals**	**2025 OM&A Budget[3]**	**2026 OM&A Cost Driver ($000's)**				**2025 v 2026 Variance ($)**	**2025 v 2026 Variance (%)**
						Operations	**Maintenance**	**Administration**	**Total**		
Direct Operating	Direct O&M Labour and Department Costs	-	1,639	2,566	3,416	1,777	1,777	-	**3,555**	**139**	4.1%
	Controlling Authority (3rd Party)	294	1,543	2,201	2,783	2,839	-	-	**2,839**	**56**	2.0%
	Substation and Line Routine Maintenance	279	2,244	4,399	5,499	7,328	-	-	**7,328**	**1,829**	33.3%
	Emergency Response and Reactive Maintenance	-	367	1,224	2,886	-	2,936	-	**2,936**	**49**	1.7%
	Forestry	-	21	186	1,094	-	4,551	-	**4,551**	**3,458**	316.2%
	Environmental	-	-	490	2,540	2,343	-	-	**2,343**	**(198)**	-7.8%
	Other (Material, Fleet, Insurance)	337	142	602	1,032	728	201	403	**1,331**	**300**	29.0%
	Sub-Total	*909*	*5,956*	*11,668*	*19,250*	15,015	9,465	403	***24,883***	***5,633***	29.3%
Overhead Costs Allocated to OM&A	Labour and Departmental Costs	1,893	3,884	6,093	6,459	1,671	-	5,239	6,911	**452**	7.0%
	Environmental Services	48	137	98	581	-	-	-	-	**(581)**	-100.0%
	Other Consultants	116	116	576	1,412	-	-	1,088	1,088	**(324)**	-23.0%
	Indigenous Engagement & Communications	639	1,958	2,908	3,403	1,410	1,410	-	2,820	**(583)**	-17.1%
	Stakeholder Engagement	3	-	-	-	-	-	-	-	**-**	-
	Indigenous Participation and Training	187	1,512	2,226	816	-	-	977	977	**161**	19.7%
	Administrative Costs	160	973	1,514	1,652	-	-	1,676	1,676	**24**	1.5%
	Sub-Total	*3,046*	*8,578*	*13,416*	*14,322*	3,081	1,410	8,980	*13,471*	***(851)***	-5.9%
Total		**3,956**	**14,534**	**25,084**	**33,572**	**18,096**	**10,875**	**9,382**	**38,354**	**4,782**	**14.2%**

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[3] 2025 budget was reduced per EB-2024-0176 settlement, where WPLP agreed to a 6% reduction in OM&A costs, in addition to agreed upon amounts for expenses relating to income taxes which increased.

Table of OM&A expenses by OEB account is provided in Attachment A.

2. Description of Cost Drivers

This section describes the types of expenses included in Table 2 and provides variance analysis for the changes in OM&A expenses from the 2025 bridge year to the 2026 test year. A comparison to 2022-2024 actuals is not considered valuable given the smaller number of assets in service in 2022 and 2023, as well as that not all assets were in service for the entirety of each of these years and efficiencies as a result of the EPC contractor being in the field, which is no longer available in 2026.

(a) Direct Operating Costs

WPLP's O&M strategy for 2026 will continue to be focused entirely on operations, similar to 2025. Overall, Direct Operating Costs are forecast to increase based on (i) ramp up of vegetation management planning and field activities, and (ii) additional line and substation inspections, as described above. Based on WPLP's O&M strategy, its executed IMER Services Agreement and using a bottom-up forecasting approach, WPLP has forecast direct operating costs for the 2026 Test Year as follows:

- Approximately $3.56 million for operations staff managing in-service assets and managing third-party agreements including the Operating Services Agreement with HONI and the IMER Services Agreement with Eptcon[4].

- Approximately $2.84 million related to third-party control room operation, which is based on a unit cost estimate for HONI to provide control room services for WPLP substation assets and related control points. WPLP has an agreement with HONI to provide control room services for an interim period until such time that WPLP develops its own control room.

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[4] Eptcon assumed PowerTel's obligations under the IMERs Agreement as at January 1, 2025.

- Approximately $2.9 million for outage and emergency response, plus $7.3 million related to routine line and substation inspection and maintenance activities. These costs are based on pricing within the IMER Services Agreement and anticipated emergency provision based on T&M rates with the addition of LiDAR work planned for 2026. The IMER services include planned inspections of transmission line and substation assets, substation equipment testing and maintenance, and response to power outages and other emergencies. These are critical activities given the remoteness and radial nature of the system (which, for the most part, requires access by helicopter).

- Approximately $4.55 million related to continued ramp up of WPLP's vegetation management program. The scope of activities planned for 2026 includes 50% of scope for typical brushing cycle as WPLP continues to accumulate additional information on growth patterns on Right of Way. This work is expected to be carried out by third parties as outlined in section 2 of Exhibit B-1-1.

- Approximately $2.3 million for environmental post construction commitments required under the Environmental Assessment. As noted in Exhibit B-1-1, WPLP executed a contract with Giiwedin to execute this program in accordance with requirements under WPLP's Endangered Species Act exemption permit.

- Approximately $1.3 million for other costs that include GIS services, fleet and insurance costs for operations staff (gas, insurance premiums, communication services, software subscriptions, general maintenance and repairs), as well as a provision for materials issued from inventory during the performance of outage and emergency response.

(b) Overhead Cost Allocated to OM&A

As set out in Table 2, above, overhead cost allocations deal directly with operations, maintenance and general administrative costs. WPLP's overhead costs include costs such as internal labour and departmental costs,[5] and other third-party consultants and professionals, costs related to continued Indigenous engagement and communications, Indigenous participation and training, stakeholder engagement and general administrative costs.

Consistent with WPLP's 2025 rate application, all overhead costs are attributable to OM&A costs. WPLP's 2026 planned overhead costs result in the following 2026 plan for OM&A costs:

- Approximately \$5.2 million for labour costs[6], including related overheads, for WPLP's internal staff, whose focus is on ongoing operations and maintenance of the transmission system, plus land rents of \$1.7 million as shown in the operating column of Table 2, above.

- Approximately \$1.09 million for other consultants that provide services and expertise in a wide variety of areas (e.g. legal/regulatory, finance/audit, engineering, etc.).

- Approximately \$2.8 million for Indigenous engagement, communications and stakeholder engagement, and \$0.98 million for Indigenous participation and training. These activities relate to WPLP's Indigenous engagement and communications on operational activities, facilitating meaningful economic participation by Indigenous businesses in all aspects of the Transmission operations, and consultations with stakeholders (such as municipalities and potentially affected landowners). These activities will ensure that WPLP's transmission system is operated in a manner that respects the Guiding Principles, Aboriginal and Treaty, and Inherent rights of the Anishinabe and Anishinninuwug, and considers input from other stakeholders.

- Approximately \$1.68 million for general administrative costs including non-capital costs related to office space, fleet and insurance premiums for management staff, as well as executive and board of director oversight.

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[5] For clarity, any labour for WPLP operations staff that is included in the forecast of direct O&M costs under part (a) is excluded from the internal labour costs under overhead costs in part (b).

[6] Further detail on labour costs provided in Exhibit F-3-1.

Attachment A – OM&A Expenses by OEB Account

The table below provides the 2025 bridge-year forecast and 2026 planned OM&A expenses by OEB account.

($000s)	**2025 Year**	**2026 Year**
Transmission Expense Operation		
4805 Operation Supervision and Engineering	1,708	1,777
4810 Load Dispatching	2,783	2,839
4820 Transformer Station Equipment - Operating Labour	4,315	4,892
4830 Overhead Line Expenses	2,611	3,846
4845 Miscellaneous Transmission Expense	3,560	3,071
4850 Rents	1,748	1,671
Subtotal	*16,725*	*18,096*
Transmission Expense Maintenance		
4905 Maintenance Supervision and Engineering	1,708	1,777
4930 Maintenance of Towers, Poles and Fixtures	577	587
4935 Maintenance of Overhead Conductors and Devices	3,735	3,758
4940 Maintenance of Overhead Lines - Right of Way	1,094	4,551
4965 Maintenance of Miscellaneous Transmission Plant	197	201
Subtotal	*7,311*	*10,875*
Administrative and General Expense		
5610 Management Salaries and Expenses	1,295	1,558
5615 General Administrative Salaries and Expenses	1,234	1,360
5620 Office Supplies and Expenses	2,862	3,135
5630 Outside Services Employed	3,567	2,734
5635 Property Insurance	396	403
5655 Regulatory Expenses	15	25
5670 Rent	160	160
5672 Lease Payment Expense	7	7
Subtotal	*9,537*	*9,382*
Total	**33,572**	**38,354**

Exhibit F, Tab 3, Schedule 1

Program Delivery Costs with Variance Analysis

PROGRAM DELIVERY COSTS WITH VARIANCE ANALYSIS

This Schedule provides a breakdown of WPLP's OM&A expenses for the 2026 test year, which reflects the categorization in Section 2.8.3 of the Filing Requirements. WPLP's OM&A expenses, aggregated according to those categories, are summarized in Table 1 below and described in detail in Sections A through F of this Schedule.

Table 1 – OM&A Expenses by Program

OM&A Expense Category	2026 Test Year ($000's)
Employee compensation	4,981
Shared services and corporate cost allocation	4,944
Purchase of non-affiliate services	28,429
One-time costs	0
OEB costs	0
Charitable and political donations	0
Total	**38,354**

The total OM&A expense in Table 1 above is equal to and reflects the same amounts as are included in the total 2026 test year OM&A expenses presented in Exhibit F-2-1. However, Table 1 above categorizes those amounts differently by considering OM&A expenses according to the nature or sources of such costs, as opposed to the activity/cost driver-based categorization in Exhibit F-2-1.

As described in Exhibit A-4-1, Wataynikaneyap Power PM Inc. ("WPPM") has the responsibility to develop, construct and operate the Transmission Project through a Management Agreement with WPLP. WPPM provides these services in part through the use of dedicated staff that are employed directly by WPPM. Since these compensation costs are billed to WPLP at cost, the discussion of employee compensation in Section A below includes details of employee compensation related to WPPM employees.

Services are also provided under service agreements by parties related to WPLP, including Opiikapawiin Services LP ("OSLP") and FortisOntario Inc. These services are billed according to pre-determined schedules of hourly rates, which reflect market pricing, and are detailed in Section B (Shared Services and Corporate Cost Allocation).

WPLP's rationale for distinguishing employee compensation costs in Section A as compared to shared services in Section B relates to the manner in which the costs are incurred, in an effort to align the categorization with Sections 2.8.4 and 2.8.5 of the Filing Requirements. Both categories of costs are equally important to the ongoing operation of WPLP's Transmission System.

Any costs originating from third parties (i.e. parties that are not affiliates of or related to WPLP or one of its partners) are detailed in Section C (Purchase of Non-Affiliate Services), including any such third-party costs that are incurred by affiliated or related parties and passed through to WPLP (without markup).

The rationale for not segregating one-time costs is provided in section D below, the rationale for segregating regulatory costs for amortization over a multi-year period is provided in Section E below, and WPLP confirms in Section F that its revenue requirement includes no amounts for charitable or political donations.

A. Employee Compensation

This section provides an overview of WPPM's compensation framework, including an outline of WPPM's approach to employee benefits and incentive pay, as well as WPLP's approach to benchmarking its compensation costs to other utilities. WPLP has a single direct employee, being the Chief Executive Officer, as described below. The discussion of WPPM's compensation framework in this section therefore does not apply to WPLP's CEO.[1] The breakdown of total

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[1] Because there is a single direct employee for WPLP, a description of the compensation for that position is not provided. In accordance with Section 2.8.4 of the Filing Requirements "where there are three or fewer employees in any category, the applicant must aggregate this category with the category to which it is most closely related". As such, the total compensation costs for WPLP's CEO are included in the "Management (including executive)" rows of Table 2 at the end of this section, notwithstanding that the details of the compensation framework described below are not applicable to this position.

forecasted employee compensation costs to December 31, 2026 in Table 2 is provided in a format consistent with Appendix 2-K (Employee Costs) of the OEB's Chapter 2 Appendices.

Employee compensation costs for WPLP and WPPM relate to the following functions and departments:

- Executive oversight for WPLP, provided by the Chief Executive Officer of WPLP;
- Health and safety, environmental compliance, engineering and operations, under the direction of the Chief Operating Officer of WPPM;
- Finance, audit, risk management, regulatory and procurement, under the direction of the VP Finance and CFO of WPPM; and
- Corporate services, including HR, IT, legal, administrative support and WPPM's participation in the various recruitment, training, engagement and communication activities that are coordinated by OSLP, under the direction of the VP Corporate Services and Indigenous Relations of WPPM.

1. Base Pay Compensation

Overall compensation for WPPM employees is designed to remain competitive with market compensation to attract and retain qualified personnel. Overall compensation includes base pay and a portion of the pay which is at risk. WPLP follows the process outlined below in establishing and making changes to employee compensation.

WPPM uses Korn Ferry's Job Evaluation method for position evaluation. This method of job evaluation is the most widely used job measurement system in the world. Position evaluations for the WPPM Executive positions were established by Korn Ferry. Management and Non-Union employee positions are either evaluated by Korn Ferry, by internal staff trained on job evaluation, or assigned to job classes within the Korn Ferry evaluation system based on similar evaluations completed previously. WPPM does not have any unionized employees.

WPPM uses a reference group of participants in the Korn Ferry Compensation Comparison. This reference group is used to establish the market rates for similar positions in Ontario. To attract and retain qualified staff, WPPM sets midpoint salaries using a policy line recommended by MEARIE[2] management consultants. Actual salaries are set by reference to these recommendations and based on corporate and individual performance.

For members of the WPPM Executive, the WPPM Board of Directors considers Korn Ferry compensation data and other policies to validate that the compensation practices are market competitive. All Executive salaries are set and all increases must be approved by the WPPM Board of Directors.[3]

Salary increases for all WPPM employees are based on market information provided by MEARIE[2]. The resulting salaries are reflective of base compensation for similar positions in Ontario. All salaries are approved by senior management and/or the WPPM Board of Directors, as applicable.

2. Incentive Compensation

(a) Description

Another element of the overall WPPM employee compensation package is incentive compensation. Implicit in the analysis contained in Korn Ferry's recommendations is the fact that incentive compensation is a normal component of compensation for management positions in Canadian corporations.

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[2] In prior years WPPM has used Korn Ferry to set annual policy lines, however Korn Ferry did not have sufficient data in 2024 to run the survey. Therefore, WPPM used MEARIE for this update but continued to use Korn Ferry for all other compensation reviews and benchmarking.

[3] As noted above, this discussion applies to WPPM and this discussion of WPPM Executive compensation excludes the CEO of WPLP.

Incentive compensation for all WPPM employees reflects an element of compensation put at risk to elicit and sustain continued good performance. The more senior the employee, the greater the percentage of overall compensation that is put at risk.

(b) Format

A short-term incentive ("STI") plan includes both an individual and a corporate component for all WPPM employees. Key aspects of this plan together with the targets are outlined below.

(i) Minimum Corporate Performance Criterion

Prior to any incentive payments being made, a minimum corporate performance criterion, or trigger, must be reached. WPPM must achieve a pre-determined corporate threshold/target as approved by the WPPM Board of Directors; otherwise, no incentive payments will be made.

(ii) Corporate Targets

WPPM's corporate targets may relate to the following: cost control, customer service, OM&A management, reliability, safety and environment and regulatory compliance. Accordingly, all corporate incentive payments included in WPLP's compensation costs presented in Table 2 benefit ratepayers as described below. Corporate measures have three performance levels and are reflective of key corporate targets or goals.

Each of the corporate targets benefits ratepayers. In particular, the cost control measure sets targets for reducing operating costs. These measures are primarily customer related as they represent a cost control target. Customer service corporate measures ensure efficient and effective levels of service that meet OEB standards and service quality indices. Safety and environmental measures benefit ratepayers by minimizing high risk incidents and promoting a proactive approach to managing safety and the environment. Regulatory compliance benefits ratepayers as it helps ensure a reliable supply of electricity and a high quality of customer service at reasonable rates.

(iii) Individual Targets

Individual targets, like the corporate targets, support the broader design objective of aligning the interests of all stakeholder groups with an overall focus on efficient delivery of service to customers.

Individual measures are developed in consultation with individuals and their immediate superiors. Each measure has three performance levels, is reflective of key projects or goals and focuses on departmental or divisional priorities. Individual measures may relate to the following: human resources, safety and environment, reliability, regulatory compliance, customer service, efficiencies, cost reduction and training targets. These measures primarily benefit ratepayers for the reasons discussed herein. Human Resources primarily benefit ratepayers by ensuring that skilled personnel are recruited and retained to provide safe and reliable service and to maintain service levels. Cost reduction and efficiency measures relate to maintaining or reducing operating costs, which directly impact ratepayers through rates. Safety and environment, training, reliability, regulatory compliance and customer service measures directly benefit ratepayers by incenting employees to contribute to the delivery of a safe and reliable supply of electricity in compliance with regulations and established customer service levels.

(iv) Payout Structure

WPPM’s STI payouts are based on a percentage of annual salary and range between 7.5% and 35%, depending on position. WPPM’s STI objectives and targets are set annually and establish criteria upon which the corporation’s performance and individual performance are measured, as discussed above. The objectives are then scored, which results in an STI rating between 0% and 200%.

The individual performance component is designed to reflect the degree of opportunity which employees in each management group have to influence corporate performance. The weighting for the individual component varies by position level and ranges between 30% and 75%. The balance of the weighting is based on a corporate STI scorecard approved annually by the WPPM Board of Directors.

The incentive regime is structured in a manner that emphasizes the greater ability of more senior individuals to impact corporate performance by making a greater portion of their compensation dependent on corporate, as opposed to individual, performance.

(c) Assessment and Payment

The WPPM Board of Directors approves the corporate targets for all participants and the individual targets for Executives. The corporate component is reflective of key corporate targets or goals and WPPM's actual performance against those targets is assessed and approved annually by the WPPM Board of Directors. Actual performance against individual targets is evaluated by each individual's immediate superior. Payments are generally made in February, once all corporate and individual performance measures for the relevant financial year have been finalized. WPPM budgets for incentive payments at target payment levels.

3. Pension and Post-Retirement Benefits Expense

WPPM employees are eligible to participate in a Defined Contribution Pension Plan, where the Company generally matches employee contributions up to 6.5% of base pay. Employer contributions to the Defined Contribution Pension Plan are included in the Total Benefits amounts provided in Section 5 below.

4. Other Benefits

Other benefits include the employer portion of Canadian Pension Plan contributions, the employer portion of Employment Insurance expense, Employee Health Tax expense, WSIB expense, insurance benefit, extended health and dental care plan expense, share purchase plan expenses, wellness reimbursements and employee assistance plan services.

5. Staffing Levels and Total Compensation

WPPM initially began recruitment with a significant number of leadership positions to create the framework for the company. Given the completion of Transmission Project construction, a number of construction-related contract positions ended in 2024, and WPPM's headcount has decreased to 24 employees including a number of non-management positions which has balanced the management to non-management ratio to 8:16. As FTE positions have evolved from construction- to operations-related positions, the company plans to have 27 (9:18) employees in 2025 and increase to 30 (9:21) by the end of 2026. The driver of these FTE changes includes identified needs for IT administrator position, environmental coordinator position and a system monitoring and compliance position. Based on review of workloads of existing staff, these additional positions were identified to provide timely in-office IT support, support for post-construction environmental commitment monitoring/reporting and support for Transmission system monitoring. This updated structure in 2026 will ensure effective implementation and oversight of WPLP's O&M Strategy as discussed in Exhibit B-1-1.

WPPM's FTEs now include an increased number of operational positions, which utilize the Korn Ferry methodology to determine appropriate rates for compensation. Due to the difficulty in recruiting experienced project candidates with a utility background, WPPM has had to modify some position expectations.

WPPM had to become more flexible with the structure of positions to build a strong team to lead the organization through construction and beyond. Standard 'utility positions' didn't always fit the requirement for the position or the candidate. These positions are often unique in nature and do not always have comparable positions within the industry. These positions have been evaluated based on Korn Ferry's Hay methodology to ensure compensation is appropriate for the job expectations.

A breakdown of total forecasted employee compensation costs to December 31, 2026 is provided in Table 2, below.

Table 2: Employee Compensation Breakdown

	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Forecast	2026 Plan
Number of Employees (FTEs including Part-Time)						
Management (including executive)	12	12	12	11	9	9
Non-Management (all non-union)	14	15	19	19	18	21

Total	**26**	**27**	**31**	**30**	**27**	**30**
Total Salary and Wages including overtime and incentive pay						
Management (including executive)	$2,335,708	$2,735,577	$2,973,922	$2,619,391	$1,790,691	$1,948,877
Non-Management (all non-union)	$912,428	$1,327,607	$1,659,043	$1,572,230	$2,090,934	2,382,269
Total	**$3,248,136**	**$4,063,184**	**$4,632,965**	**$4,191,620**	**$3,881,624**	**$4,331,146**
Total Benefits (Current + Accrued)						
Management (including executive)	$317,038	$357,246	$416,349	$420,671	$268,604	$292,332
Non-Management (all non-union)	$127,338	$205,631	$232,266	$252,498	$313,640	$357,340
Total	**$444,376**	**$562,876**	**$648,615**	**$673,170**	**$582,244**	**$649,672**
Total Compensation (Salary, Wages, & Benefits)						
Management (including executive)	$2,652,746	$3,092,823	$3,390,271	$3,040,062	$2,059,294	$2,241,209
Non-Management (all non-union)	$1,039,766	$1,533,238	$1,891,309	$1,824,728	$2,404,574	$2,739,609
Total	**$3,692,512**	**$4,626,060**	**$5,281,580**	**$4,864,790**	**$4,463,868**	**$4,980,818**
Total Allocated to Capital	$3,549,118	$3,755,747	$2,368,370	$887,006	-	-
Total Allocated to Distribution Deferral Account (Pikangikum)	$143,394	$118,942	$70,178	-	-	-
Total Allocated to OM&A	-	$751,371	$2,843,033	$3,977,784	$4,463,868	4,980,818

6. Variance Analysis

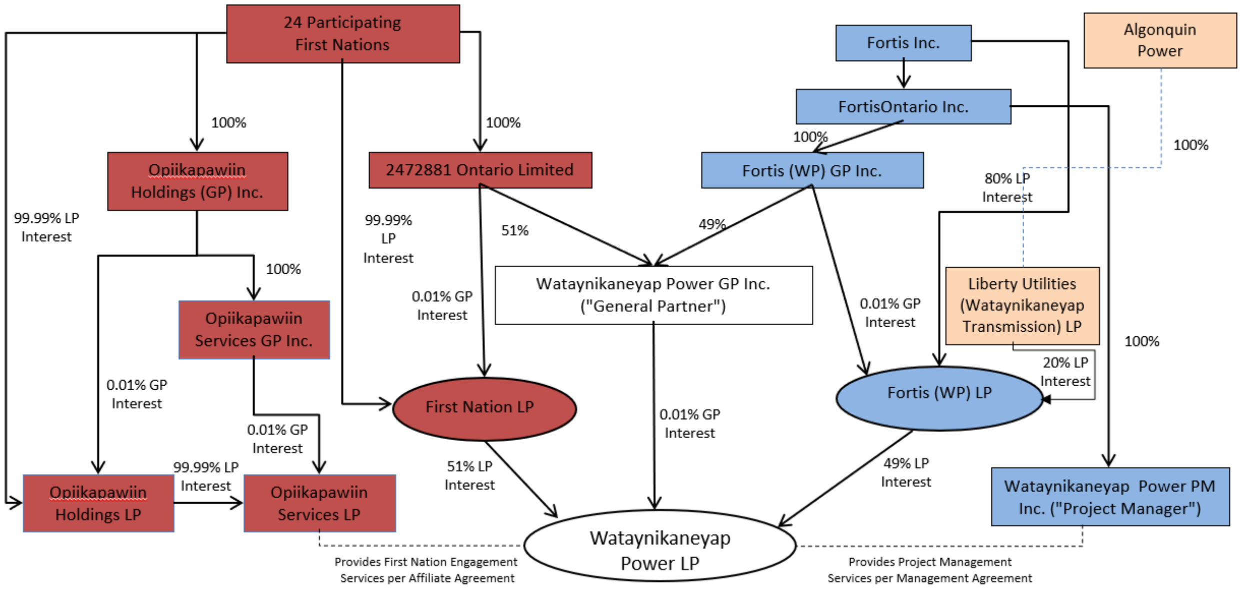
Total compensation costs increased year-over-year during the 2022 to 2024 period, coinciding with WPLP's growing needs over the construction period. From 2024 to 2025 total compensation costs decreased significantly due to reductions in construction-related management and non-management positions as WPLP transitioned from the construction phase of the Transmission Project to full operations. From 2025 to 2026, total compensation costs are increasing as WPLP fills three positions identified as necessary for its long-term operational requirements and to meet certain post-construction environmental commitments. A description of WPLP's approach to the organization and the transition to ongoing operation and maintenance, is provided in Exhibit B-1-1. Some salaries, particularly during the construction period, appear higher than industry norm as they reflect short-term construction contracts that require specific skills set for the duration of the construction period ending in 2024. In order to attract and retain these employees, WPPM has had to rely on the market for salary references to remain competitive and secure employees for the duration of the project.

Table 2, above, also illustrates a shift from labour costs being primarily capitalized during the construction period, to increasing allocations to OM&A as more assets went into service in 2023 and 2024, and with all assets being fully in service in 2025 and 2026.

B. Shared Services and Corporate Cost Allocation

This section provides details of the services that WPLP receives from affiliates and other related parties. WPLP's corporate structure is described in detail in Exhibit A-4-1, and is reproduced in Figure 1 below, with the addition of affiliated and related entities that provides services to WPLP.

Figure 1 – WPLP Corporate Structure with Affiliated/Related Service Providers



WPLP previously managed the construction of the Transmission Project and is now managing the operation of the Transmission System, primarily through services received from affiliated and related parties, through the service agreements described below. While the costs resulting from these agreements are not strictly related to "shared services" or "corporate cost allocation", as those terms are defined in Section 2.8.5 of the OEB's Filing Requirements, WPLP has used this section to summarize annual costs from affiliated and related parties that are not otherwise captured in Section A (Employee Compensation) above or Section C (Purchase of Non-Affiliate Services) below.

1. Service Agreements

WPLP receives services from affiliated and related parties through the following agreements:

- **Management Agreement (WPPM):** Wataynikaneyap Power PM Inc. ("WPPM"), a wholly-owned subsidiary of FortisOntario Inc., is responsible for providing project management, construction oversight, engineering, operations, finance, regulatory and various corporate service functions (including health and safety, environmental compliance, HR, IT and procurement), pursuant to a Management Agreement between WPLP and WPPM. WPPM is a related party but is not an affiliate of WPLP.

- **Affiliate Contract (OSLP):** Opiikapawiin Services LP ("OSLP"), a service company indirectly owned by the 24 Participating First Nations, is responsible for scopes of work identified by WPPM, which include administering projects and programs for WPLP relating to community engagement, community readiness, education and training, business readiness, stakeholder engagement, communications, and capacity building, pursuant to an Affiliate Contract between WPLP and OSLP. OSLP is an affiliate of WPLP because they are both under the common control of the Participating First Nations. Additional information about OSLP is provided in Exhibit A-4-1.

- **Services Contract (FortisOntario):** FortisOntario Inc. provides similar but distinct complementary services as provided by WPPM under the Management Agreement (i.e. IT, HR oversight, overall company oversight), pursuant to a Services Contract between WPLP and FortisOntario Inc. FortisOntario is a related party but is not an affiliate of WPLP.

The pricing structure for the agreements includes a base annual fee, as well as reimbursement for direct costs and amounts paid to third parties (without markup). Where services are provided by

WPPM employees to WPLP under the Management Agreement, these services are provided at cost, consistent with the compensation-related discussion in Section A above. Where services are provided by employees of OSLP or FortisOntario, these amounts are billed according to a pre-determined schedule of hourly rates for various positions and levels of seniority, which reflects market pricing.

2. Summary of Costs from Affiliated and Related Parties

Table 3 summarizes the costs charged to WPLP from affiliates and related parties, excluding third-party costs incurred by those parties which are addressed in Section C:

- OSLP, which costs are primarily related to labour charges and related costs for the services provided under the Affiliate Agreement described above; and
- FortisOntario, which costs are primarily related to labour charges and related costs for the services provided under the Services Contract described above, including costs for employees of various Fortis Inc. subsidiaries other than WPPM that are indirectly charged to WPLP through time allocations.

OSLP and WPPM also procure services from third parties on behalf of WPLP, and are reimbursed by WPLP, without markup. These third-party costs are excluded from the costs presented in Table 3 since they are addressed in Section C below. Compensation costs for employees directly employed by WPPM are also excluded since they are addressed in Section A above.

Table 3 – Affiliate and Related Party Costs by Year[4]

Name of Company		**Service Offered**	**Cost for the Service ($)**					
From	**To**		**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
			Actual	**Actual**	**Actual**	**Actual**	**Forecast**	**Plan**
Fortis Subsidiaries	WPLP	Multiple per Services Contract	1,705,252	1,745,527	1,640,879	2,125,422	2,333,927	2,405,767
OSLP and FNLP	WPLP	Multiple per Affiliate Contract	2,822,838	2,885,790	3,044,327	3,056,847	2,900,550	2,537,877

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[4] Costs related to COVID-19 are minimal and are not tracked separately.

Total:	**4,528,090**	**4,631,318**	**4,685,206**	**5,182,269**	**5,234,477**	**4,943,644**

Affiliate costs are trending down since 2024, and WPLP has continued to focus on cost savings as it has transitioned from capital project construction to full operations.

Table 4, below, summarizes the annual allocation of the costs presented in Table 3 between: (a) capital costs (development and CWIP); (b) costs related to the interim operation of WPLP's Pikangikum distribution system (recorded in WPLP's Distribution System Deferral Account); and (c) OM&A costs associated with transmission system assets in service.

Table 4 – Allocation of Affiliate and Related Party Costs[5]

Cost Category	**Annual Cost Allocation ($)**					
	2021	**2022**	**2023**	**2024**	**2025**	**2026**
	Actual	**Actual**	**Actual**	**Actual**	**Forecast**	**Plan**
Capital	4,434,098	3,930,740	2,159,345	523,374	-	-
Distribution Deferral Acct (Pikangikum)	93,992	109,163	26,226	-	-	-
OM&A	-	591,416	2,499,636	4,658,895	5,234,477	4,943,644
Total	**4,528,090**	**4,631,318**	**4,685,206**	**5,182,269**	**5,234,477**	**4,943,644**

WPLP's methodology for allocating overhead costs, including the affiliate and related party costs presented above for 2025 and 2026, no longer follows the approach used during the construction period given all transmission assets were in service as of mid-2024. Support for the resulting capital and OM&A costs is provided in the following Exhibits:

- Capital cost forecasts and variance analysis is provided in Exhibit B-1-4.
- OM&A costs, by cost driver, are described in Exhibit F-2-1.

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[5] Costs related to COVID-19 are minimal and are not tracked separately.

C. Purchase of Non-Affiliate Services

This section describes the purchase of services from third parties, including third-party services procured directly by WPLP (administered by WPPM) and third-party services procured by OSLP, WPPM or FortisOntario Inc. on behalf of WPLP with the associated costs being passed through to WPLP without markup.

WPLP's procurement policy is based on the concept of securing "best value" in the procurement of goods and/or services from non-affiliated parties. In consideration of the remote location of WPLP's transmission system, local knowledge is critical to the successful delivery of any services. Providing services and supporting local opportunities and capacity will provide long-term benefits to WPLP, and the customers in the Indigenous communities that it serves. From a procurement perspective, best value must therefore include considerations such as local knowledge, use of local content, First Nation ownership, health and safety, reliability, price, quality, service and support levels, environmental performance, and timely delivery. In all cases, suppliers of goods and providers of services must be appropriately qualified in consideration of qualifications and standards regularly employed by transmission facility owners. A copy of WPLP's Procurement Policy is provided as Appendix 'A' to this schedule.

As described in Section B above, WPPM provides services to WPLP under a Management Agreement, which include project management, construction oversight, operational services and various corporate services. These services include the use of third-party services, which are procured in accordance with WPPM's Procurement Policy and in adherence to WPLP's Procurement Policy. A copy of WPPM's Procurement Policy, with supporting documents and policies, is provided as Appendix 'B' to this schedule.

In order to ensure best value in procurement, the procurement policies referenced above set out requirements for Indigenous participation, Participating First Nation involvement, local content, safety, quality, price and reliability, among other considerations. Further, the procurement policies prescribe requirements for competitive sourcing of goods and services, with limited exceptions, and describe approval levels and processes.

Table 5, below, provides a summary of WPLP's annual costs related to the purchase of goods and services from third parties, which WPLP confirms to be in compliance with WPLP's and WPPM's procurement policies.

Table 5 – Third-Party Costs by Year[6]

Cost Category	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Forecast	2026 Plan
Indigenous Engagement, Indigenous Participation, Communication	2,393,026	2,961,282	3,769,022	3,049,496	1,968,700	1,928,700
Admin, Office, Fleet and Support	378,735	1,107,051	820,634	344,466	364,000	349,000
O&M Service Providers	805,437	1,658,216	4,086,694	8,611,792	15,834,634	21,328,131
Overheads and Easement/Access Fees	920,430	2,858,659	3,612,086	4,305,570	3,649,312	3,811,006
Consulting, Professional and Advisory	13,347,675	11,786,940	11,104,332	8,339,039	2,057,450	1,012,511
Total	**17,845,302**	**20,372,148**	**23,392,768**	**24,650,363**	**23,874,096**	**28,429,347**

Table 6, below, summarizes the annual allocation of the costs presented in Table 5 between: (a) capital costs (development and CWIP); (b) costs related the interim operation of WPLP's Pikangikum distribution system (recorded in WPLP's Distribution System Deferral Account); and (c) OM&A costs for transmission system assets in service.

Table 6 – Allocation of Third-Party Costs[7]

Cost Category	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Forecast	2026 Plan
Capital	16,899,726	16,308,061	13,651,709	8,202,901	-	-
Distribution Deferral Acct (Pikangikum)	945,576	1,450,370	537,599	-	-	-
OM&A	-	2,613,717	9,203,460	16,447,462	23,874,096	28,429,347
Total	**17,845,302**	**20,372,148**	**23,392,768**	**24,650,363**	**23,874,096**	**28,429,347**

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[6] Costs related to COVID-19 are minimal and are not tracked separately, and are recorded as capital or in the EPC COVID-Related Cost Deferral account. See Exhibit H-2-2 for additional details on COVID costs.

[7] Costs related to COVID-19 are minimal and are not tracked separately, and are recorded as capital or in the EPC COVID-Related Cost Deferral account. See Exhibit H-2-2 for additional details on COVID costs.

WPLP's 2025 and 2026 costs no longer follow the methodology for allocating overhead costs during construction period. Support for the resulting capital and OM&A costs is provided in the following Exhibits:

- Capital cost forecasts and variance analysis is provided in Exhibit B-1-4.
- OM&A costs, by cost driver, are described in Exhibit F-2-1.

D. One-Time Costs

WPLP has filed a single test-year application for 2026. Accordingly, there is no need in the current application to amortize any one-time costs over any incentive rate setting period.

E. Regulatory Costs

WPLP's anticipated regulatory costs associated with the current application, are part of its total forecasted OM&A costs to December 31, 2025. WPLP has included its costs for OEB assessment in the current application, in the amount of $40,000[8]. WPLP has not included in its proposed 2026 OM&A costs the forecasted regulatory costs for the first multi-year revenue requirement application which, pursuant to the Settlement Agreement in EB-2024-0176, WPLP will file in 2026 for a period commencing with a 2027 test year. As the regulatory costs of the application to be filed in 2026 will be in respect of a multi-year rate application for a rate period commencing with a 2027 test year, WPLP will apply for these costs as part of the multi-year rate application and seek recovery of those costs over the future incentive rate setting period from 2027 to 2031.

F. Charitable and Political Donations

WPLP confirms that no charitable or political donations have been included in the calculation of its revenue requirement.

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[8] These one-time costs are included in the services from non-affiliates envelope consistent with prior rate application filings.

Exhibit F, Tab 3, Schedule 1

Program Delivery Costs with Variance Analysis

ATTACHMENT ‘A’

WPLP Procurement Policy

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WATAYNIKANEYAP PROCUREMENT POLICY

GENERAL STATEMENT

In the provision of services to First Nation communities and the public as an electricity transmitter, Wataynikaneyap shall engage in the procurement of goods and services.

As of June 2018, twenty-two First Nations are acting together to develop the Project through First Nations LP, and have set out Guiding Principles for development, which principles include the right of Participating First Nations to pursue sustainable economic and business opportunities in their homelands, for the benefit of their future generations and as part of a long term vision to secure opportunities from the lands and resources, pursue economic development and energy while protecting the environment, and maintain their peoples' responsibilities to the land as given by the Creator.

Given the significant challenges faced by Participating First Nations due to their remote locations, lack of access to reliable power, and the ongoing legacy of the residential schools system and the *Indian Act*, specific measures are required in order to ensure Participating First Nations have opportunities to compete for business opportunities.

This Procurement Policy sets out specific measures that will ensure business opportunities are readily available for Participating First Nations, and measures to ensure uniformity, best value, efficiency and effectiveness in the acquisition of goods and services.

1. DEFINITIONS AND PURPOSES

1.1. For the purposes of this Procurement Policy:

a) **"Best Value"** means a demonstration of the merits of any particular bid, proposal or offer of goods and/or services to Wataynikaneyap, as against the merits any reasonably-available alternatives. A determination of Best Value shall be arrived at by weighing considerations such as: local knowledge (including demonstrated history of the ability to provide reliable service or supply of goods with an indigenous workforce, and ability to speak Ojibwaymowin and Anishiniinimowin), use of local content (including labour, equipment, material and training), Participating First Nation ownership and control, health and safety, reliability, price, quality, service and support levels, environmental performance, and timely delivery;

b) **“Competitive Procurement Process”** means a tender, request for proposals or any other similar procurement process;

c) “**First Nations Business**” means a business, joint venture or consortium that is at least 51 per cent owned and controlled, directly or indirectly, by one or more Participating First Nation(s);

d) **“First Nations LP”** means the limited partnership which has a 51% majority and controlling ownership interest in Wataynikaneyap;

e) **“Fortis”** means Fortis Ontario Inc., a, electricity and gas utility company which holds a 49% ownership interest in Wataynikaneyap;

f) **“Guiding Principles”** means the document approved by the Participating First Nations which sets out guiding principles for the Project;

g) **“Indigenous Participation KPIs”** means the following key performance indicators:

  i. number of Individual Members that are employees, and percentage of the workforce that this represents;

  ii. number of employees that speak Ojibwaymowin and Anishiniinimowin, and percentage of workforce that this represents;

  iii. number of Individual Members in management, supervisory or leadership roles;

  iv. dollar value of spend with First Nations Businesses and Individual Member Businesses, and percentage of total spend that this represents; and

  v. number of Individual Members participating in education, training or entrepreneurship program(s) or other capacity development initiatives;

h) **“Indigenous Participation Target”** means the 5-year development plan prepared by Wataynikaneyap and Participating First Nations in accordance with section 4.2 of this Procurement Policy, with annual revenue targets for working with and providing opportunities to First Nation Businesses either directly or through contractors and subcontractors;

i) “**Individual Member**” means an individual band member of a Participating First Nation;

j) **“Individual Member Business”** means a business, joint venture or consortium that is at least 51 per cent owned and controlled, directly or indirectly, by one or more Individual Member(s);

k) **“Indigenous Participation Plan”** means the plan that all participants in Competitive Procurement Processes shall prepare in accordance with section 4.9 and Appendix A of this Procurement Policy;

l) **“Participating First Nations”** means the First Nations that are limited partners in First Nations LP;

m) **“Price Preference”** has the meaning set out in section 4.7(g);

n) **“Priority”** is used in Competitive Procurement Processes, and means that where two or more participants are reasonably comparable, the participant with Priority shall be awarded the contract;

o) **“Procedures Manual”** is the manual setting out the procedures by which Wataynikaneyap will implement this Procurement Policy;

p) **“Project”** means a new regional electricity transmission system in northwestern Ontario to connect 17 remote First Nations currently powered by diesel generation to the provincial electrical grid;

q) **“Registry”** means a database under the care and control of Wataynikaneyap which identifies First Nations Businesses that are interested in working on or in relation to the Project, and their capabilities;

r) **“Shareholders Agreement”** means the unanimous shareholders agreement dated August 27, 2015 between the general partners of Wataynikaneyap, Fortis and First Nations LP regarding the governance and control of Wataynikaneyap; and

s) **“Wataynikaneyap”** means Wataynikaneyap Power LP, an Ontario limited partnership established for the purposes of developing, constructing, owning and operating the Project.

1.2. The purposes of this policy are:

a) to ensure procurement activities provide opportunities for First Nations Businesses and Individual Member Businesses, and facilitate education, training, meaningful employment and capacity-building for Individual Members;

b) to ensure prices paid are reasonable in the circumstances; and

c) to standardize procurement processes.

2. GENERAL PRINCIPLES

2.1. Procurement processes shall provide sustainable economic and business opportunities for First Nations Businesses and Individual Member Businesses.

2.2. Procurement processes shall be conducted with diligence and care, and ensure that all relevant information is obtained and considered.

2.3. All procurement decisions shall be reasonable under the circumstances known to Wataynikaneyap at the time the decision is made.

2.4. All procurements shall be in accordance with the current annual budget.

2.5. All procurements shall be in accordance with the policies of Wataynikaneyap.

2.6. In the course of procuring goods and services for Wataynikaneyap, no person shall use their authority or office for personal gain.

2.7. When considering the advantages to Wataynikaneyap of maintaining a continuing relationship with a supplier, any arrangement which might in the long term prevent the effective operation of fair competition shall be avoided.

3. PROCUREMENT METHODS

3.1. Procurements shall be awarded to the supplier offering the Best Value.

3.2. Procurements shall only be awarded to businesses that are qualified to perform the services or supply the goods sought, in accordance with industry standards and qualifications regularly employed by transmission facility owners, including but not limited to health and safety qualifications and standards.

3.3. Subject to section 4.7 of this Procurement Policy, the manager of the procurement process shall give consideration to using a Competitive Procurement Process for any purchase in excess of $500,000.

3.4. Wataynikaneyap shall make commercially reasonable efforts to comply with applicable local procurement rules.

4. COMMITMENTS REGARDING FIRST NATIONS BUSINESSES

4.1. Wataynikaneyap may pre-qualify First Nation Businesses for particular contracts.

4.2. Wataynikaneyap shall:

a) work with the Participating First Nations to set the Indigenous Participation Target;

b) make commercially reasonable efforts to meet or exceed the Indigenous Participation Target;

c) annually review performance and update the Indigenous Participation Target; and

d) provide reports to Participating First Nations on Indigenous Participation KPIs, on a regular basis as set out in the Procedures Manual, and instruct its contractors and subcontractors to do the same.

4.3. Wataynikaneyap shall maintain and regularly update the Registry, and shall proactively communicate procurement opportunities to First Nations Businesses using the information contained in the Registry. In doing so, Wataynikaneyap shall clearly identify the work that is going to be contracted out and any requirements for the contract.

4.4. In order to facilitate First Nation Business development and foster a marketplace that includes competitive First Nation Businesses, Wataynikaneyap shall continue to support work on business readiness.

4.5. Where reasonable from a cost and timing perspective, Wataynikaneyap shall break work into smaller portions, so that a greater number of First Nations Businesses can access procurement opportunities.

4.6. Where reasonable from a cost and timing perspective, for contracts with reasonably anticipated and significant local impacts on a particular Participating First Nation, Wataynikaneyap shall provide a directed procurement opportunity to a qualified First Nations Business owned by that Participating First Nation. In so doing, Wataynikaneyap shall use open book negotiations or other appropriate mechanisms to demonstrate Best Value.

4.7. In Competitive Procurement Processes, Wataynikaneyap shall:

a) inform participants that Wataynikaneyap puts a priority on:

   i. local knowledge including demonstrated history of the ability to provide reliable service or supply of goods with an indigenous workforce, working with Participating First Nations, and ability to speak Ojibwaymowin and Anishiniinimowin;

   ii. full utilization of all available local content, including Participating First Nation labour, equipment, and materials;

   iii. sub-contracting opportunities for First Nations Businesses and Individual Member Businesses; and

   iv. education, training, entrepreneurship and capacity-building opportunities for Individual Members;

   and therefore requires each participant to prepare an Indigenous Participation Plan according to the instructions set out in Appendix A to this Procurement Policy;

b) inform participants that the quality of their Indigenous Participation Plan shall form 25% of their evaluation score, with 15% allocated to overall quality of the plan and 10% allocated to the percentage of contract price to be provided by First Nations Businesses and Individual Member Businesses;

c) inform participants that the contract shall contain obligations and defaults in relation to their performance on the Indigenous Participation Plan;

d) include in the documents: (i) a list of labour, material, equipment, services and other resources available from First Nations Businesses, (ii) a copy of the most recent version of Wataynikaneyap's *Indigenous Participation Guide* (this item to be provided for background purposes only), and (iii) a list of current gaps in community readiness and recommendations for addressing those gaps;

e) invite the Participating First Nations to participate in drafting the documents and evaluating the tenders/proposals;

f) during evaluation, provide a Price Preference to First Nation Businesses and Individual Member Businesses scaled to the size of the contract, as follows:

Contract value in CAN$	***Price preference as % of contact value***
From 0 to 50,000	15%
From 50,001 to 250,000	10%
From 250,001 to 1,000,000	8%
From 1,000,001 to 3,000,000	5%
From 3,000,001 to 5,000,000	4%
From 5,000,001 to 10,000,000	3%
From 10,000,001 to 15,000,000	2.5%
More than 15,000,000	No price preference

g) and, in order to ensure procurement opportunities are widely available:

    i. for spend of up to $250,000 assign Priority to Individual Member Businesses;

    ii. for spend of $250,001 to $1,000,000 assign Priority to First Nations Businesses owned by a single Participating First Nation; and

    iii. for spend of $1,000,000 or more, assign Priority to First Nations Businesses owned by two or more Participating First Nations, or in instances of competition between more than one such entity, assign Priority to the entity with the greater number of Participating First Nations owners.

4.8. Wataynikaneyap may designate certain long-term or high-value contracts for a Competitive Procurement Process open only to qualified First Nations Businesses.

4.9. If a First Nation Business or Individual Member Business participated in a Competitive Procurement Process but did not secure a contract, Wataynikaneyap may offer to meet with said business after the process in order to provide honest feedback, on condition that the meeting shall be held on a confidential and without prejudice basis, and on the express understanding that no commercially sensitive information shall be shared.

4.10. Wataynikaneyap shall perform an annual review of this Procurement Policy and the performance of Wataynikaneyap and all contractors and subcontractors on Indigenous Participation KPIs.

4.11. For major work that is being contracted or sub-contracted out, Wataynikaneyap shall ensure that the contractor and/or sub-contractor provides sustainable economic and business opportunities for First Nations Businesses and Individual Member Businesses. Wataynikaneyap will accomplish this by either:

a) requiring, or causing the contractor to require, that the terms of this Procurement Policy be followed for all procurements relating to the Project; or

b) agreeing to a different approach, but only if Wataynikaneyap is confident that the different approach will lead to better results.

5. PURCHASE AUTHORIZATION LIMITS

5.1. Purchase authorization limits are to be in accordance with the Material Contract as defined in the Shareholders Agreement.

6. HEALTH, SAFETY & ENVIRONMENTAL CONSIDERATIONS

6.1. Wataynikaneyap supports the use of environmentally sustainable and safe products and practices and expects staff to pursue this objective in the acquisition of goods and services.

This shall be accomplished by ensuring specifications to include environmentally sustainable choices and promote a safe and healthy workplace subject to both suitability and cost.

6.2. General principles in relation to environmental protection in the review of potential service providers and as part of any assessment of the performance of any supplier, contractor or subcontractor pursuant to any agreement with Wataynikaneyap include:

a) to comply with the Guiding Principles and other directives that have been received;

b) to preferentially select products that do not harm the environment in their manufacture, use or disposal;

c) to consider the environmental factors; and

d) to secure comprehensive, accurate and meaningful information about the environmental performance of products or services sufficient to determine environmental impacts.

APPENDIX A

Instructions for the Indigenous Participation Plan

1. The participant shall provide an Indigenous Participation Plan setting out how the participant shall:
   a) engage, communicate, collaborate and maintain good relationships with Participating First Nations;
   b) support and enhance commercial relationships with Participating First Nations and Individual Members;
   c) provide training, employment, entrepreneurship and capacity-building opportunities for Individual Members;
   d) address any identified community readiness gaps and recommendations; and
   e) track and report actual performance of the above, including through Key Performance Indicators ("KPIs").
2. Without limiting what may be included, each Indigenous Participation Plan shall:
   a) set out the participant's plan for communications with Participating First Nations;
   b) itemize anticipated subcontracts with First Nations Businesses and Individual Member Businesses;
   c) itemize plans for growing the scope of work subcontracted to First Nations Businesses over the course of the contract, including through transitioning subcontracts to First Nations Businesses as they become available to do the work;
   d) itemize intended purchases of supplies from Participating First Nations, First Nations Businesses or Individual Member Businesses, if available when required for the work and with the caveat that the participant may substitute such material with other material of the participant's choice subject to prior written notice and such substitute material meeting the requirements of the contract;
   e) itemize intended use of pieces of construction equipment leased or rented from Participating First Nations, First Nations Businesses or Individual Member Businesses, with the caveat that the participant may substitute such equipment with other equipment of the participant's choice subject to prior written notice;
   f) set out the number of Individual Members that shall be employed, in what position and for what period, and commit that if employment of any person identified is terminated prior to completion of the term indicated above, the participant shall hire another Individual Member in his/her place unless no such person is available and qualified;
   g) itemize any plans for education, training or entrepreneurship programs or other capacity-building initiatives for Individual Members, including duration, number of participants and projected outcomes;
   h) set out KPIs (see below) and tracking/reporting approaches; and
   i) include a summary table.
3. The KPIs included in the Indigenous Participation Plan shall include the following:
   a) number of Individual Members that are employees, and percentage of the workforce that this represents;

b) number of employees that speak Ojibwaymowin and Anishiniinimowin, and percentage of workforce that this represents;

c) number of Individual Members in management, supervisory or leadership roles;

d) dollar value of spend with First Nations Businesses and Individual Member Businesses, and percentage of total spend that this represents;

e) number of Individual Members participating in a participant-supported education, training or entrepreneurship program(s) or other capacity development initiatives; and

f) any other KPIs that the participant considers appropriate in relation to the participant's Project-related work and workforce

(collectively, the "Indigenous Participation KPIs").

4. Document X *[insert reference to document package]* includes a list of First Nations Businesses and Individual Member Businesses, and labour, material, equipment, services, and other resources available from Participating First Nations. Document X is provided for information only, and is intended to facilitate the participant's preparation of the Indigenous Participation Plan. It is the responsibility of the participant to review the qualifications, availability, and appropriateness of the listed resources and to make the necessary arrangement for their employment, purchase, rental, or use. To obtain contact details, participants may contact *[insert name]*.

5. Participants shall acknowledge that their Indigenous Participation Plan shall be attached to the contract and the contract shall contain obligations and defaults in relation to participant's performance of the Indigenous Participation Plan. A possible contract clause, which is provided for information only and may be changed at any time, is as follows: *"Contractor shall, at its own expense, comply with the plan for engagement with and participation of First Nations (the "Indigenous Participation Plan"), which is attached hereto as Schedule [X], and shall provide regular reporting on Contractor's implementation of the Indigenous Participation Plan as further described in [insert reference]. Should Contractor fail, in Owner's opinion, acting reasonably, to comply with the Indigenous Participation Plan, then Owner may direct Contractor to take remedial action in order to comply. Such remedial action may include but shall not be limited to directing Contractor to use Participating First Nations resources (either via Individual Member labour or by procuring goods or services from First Nations Businesses) nominated by Owner, unless Contractor can demonstrate to Owner's satisfaction that it would be commercially unreasonable to allow such participation. Notwithstanding the foregoing, price considerations shall not be the basis for concluding that it would be commercially unreasonable to allow such participation."*

Exhibit F, Tab 3, Schedule 1

Program Delivery Costs with Variance Analysis

ATTACHMENT B

WPPM Procurement Policy

Wataynikaneyap Power PM Inc.

Procurement Policy

Document:	PRO-001
Owner:	CFO
Revision:	0
Issued:	2020.04.15
Page:	Page 1 of 4

1. Purpose

a) The purpose of this Policy is to ensure that the purchase of materials, equipment and services (goods and services), by employees of the Wataynikaneyap Power PM Inc. (“WPPM”) is performed in accordance with best business practices.
b) To obtain the best overall value (focusing on First Nation involvement, benefit of participating communities, quality, price, reliability, service, safety, environment, support and delivery) for Wataynikaneyap Power, the ratepayers and the limited partners.
c) To ensure accountability and transparency with a clear auditable trail for every acquisition.

2. Scope

a) WPPM must adhere to WPLP procurement policy dated June 12, 2018 or as otherwise updated by WPLP when fulfilling procurement activities.
b) Unless otherwise specified, any purchase of goods or services shall be made on a competitive basis, keeping with best practices, and in accordance with any applicable Federal, Provincial or Municipal legislation.
c) All departments therein of WPPM, shall have their purchasing requirements for goods and or services filled in accordance with this Policy.
d) No purchase of goods or services shall be authorized unless it is following this Policy.
e) No employee shall be exempt from this Policy.
f) All purchases under this Policy are to be entered and approved through the SAP Purchasing Module, or DocuSign and be in accordance with Section 3 of the Authorization Policy.
g) Appropriate segregation should exist between initiating a purchase, approving, receiving and then issuing payment for that same purchase.
h) Employees shall endeavour to contribute to environmental, economic and social sustainability as it pertains to the purchasing of goods and services.
i) Changes to this Policy require the approval of the CFO.
j) Supporting procedures and/or policies may be periodically updated provided there is no conflict with this Policy.

3. Exemptions to this Policy

a) The following list (but not limited to) are expenses that are not subject to this Policy:

- i. Procurement Card Purchases (A-103 Corporate Card policy)
- ii. Emergencies Purchases as defined in Section 5 Emergency Purchasing.
- iii. Utilities - Telephone & cell phone, Water/Gas/Electricity bills
- iv. Normal and recurring payroll related disbursements
- v. Recurring payments as described in Authorization Policy Section 5 “Statutory Payments”
- vi. Mobile equipment permits such as license plates, inspection renewals (does not include approval of any environmental permits)
- vii. Miscellaneous freight bills (as per contract)
- viii. Recurring monthly lease payments
- ix. Miscellaneous, recurring invoices providing they are on contracts (i.e. site security, contract labor, Mercer, WSIB - "Workers Safety Insurance Board" installments)
- x. Approved environmental & land permits
- xi. Logistics/Transportation distribution costs (Rail, Truck, warehousing, etc.)
- xii. Purchases of items set up in Company stores catalogs, (“Stores Inventory”, raw materials, and MRO supplies with a defined description, price, and physical inventory quantity previously approved by management as an inventory requirement and added to the Company catalog).

4. Requirement for Approved Funds

a) Any employee with the authorization to approve a purchase is accountable and responsible to ensure that either adequate budget exists or that any budget overage has been adequately justified, and that the purchase is not in violation of this Policy.

b) Where a requirement exists to initiate a purchase that is not part of the departments approved annual budget envelope, the responsible employee must get approval from the CFO and or the Board of Directors prior to any expenses being incurred.

c) All expenses must be approved by an authorized person in accordance with the FIN-001 Authorization Policy.

5. Emergency Purchasing

a) In the event of an emergency that requires the immediate purchase of any goods or services, reasonable effort shall be made to acquire the necessary authorization required under WPPM Authorization Policy Section 3 “Purchase Requisition or Signature Approval – Operating and Capital Expenditures” in advance of the purchase or as soon as possible after the emergency. An emergency is defined as a situation where there is an adverse effect on the health and safety of any person, the environment or a disruption of the services provided by the business units.

6. Business Ethics

a) All employees are subject to the policies and procedures of WPPM. The following policies in conjunction with PRO-001 shall provide the necessary guidance for ethical behavior during the purchasing process:
   i. B101 Code of Conduct;
   ii. B102 Reporting Allegations of Wrong Doing;
   iii. B103 Anti Corruption Policy; and
   iv. FIN-001 Authorization Policy

b) For clarity:
   i. All employees are expected to act in an ethical manner (B101);
   ii. No action or communication by any employee is to lead to one vendor or service provider having an advantage over another (B101);
   iii. No one purchase shall be divided to avoid compliance with this Policy and the Authorization Policy (FIN-001); and
   iv. The use of Company funds and resources to purchase personal goods or services is prohibited. Leveraging Company rates and discounts from vendors for personal gain is also prohibited, except in circumstances where a corporate agreement with a vendor explicitly considers extension of rates/discounts for personal use.

7. Pre-Payment or Progress payments

a) The following are expenses where milestone or pre-payments are allowed:
   i. Major equipment where there is more than one stage of production;
   ii. Services where mobilization is required; or
   iii. Non-tangible items such as software and licenses where the vendor requires prepayment in order to activate.

b) All milestone and pre-payment terms must be clearly defined in the Purchase Requisition and must be approved by the CFO.

8. Supporting Procedures

a) The following list of Procedures are supplemental to this Policy:
   i. PRO-001-01 Sourcing Procedure;
   ii. PRO-001-02 Purchasing Documents; and
   iii. A-103 Corporate Card.

[end of document]

Wataynikaneyap Power PM Inc.

Purchasing Procedures Sourcing Methods		
	Document:	PRO-001-01
	Owner:	CFO
	Revision:	0
	Issued:	2020.04.15
	Page:	Page 1 of 4

1. Purpose

To establish guidance for obtaining and summarizing competitive price quotations and providing a formal system of evaluating commitments of corporate funds prior to placement of purchase orders. The Company is committed to using supplier competition to effectively gain the most value for its business expenditures. Only Procurement personnel are to issue requests for bids for materials and services.

2. Scope

This procedure is applicable to all Employees at Wataynikaneyap Power PM Inc. (“WPPM) and is subject to the corporate purchasing policy PRO-001.

3. Prerequisites

3.1 Identification of required goods or services

Before any Purchasing is to take place the Employee is to have an understanding of what is required. The following (but not limited to) are considerations that must be taken into account prior to any of the other steps:

a) Are budget funds available?
b) Is there a Scope of Work or Material Specification?
c) What is the quantity required?
d) What is the delivery and requirement dates?
e) Is there a list of qualified Vendors or Service Providers?
f) Is this a standalone Purchase or part of a larger Project?

For all intents and purposes, once Section 3.1 has been satisfied a request is to be sent to Procurement for further processing and sourcing using the purchase requisition form.

3.2 Request for Information (RFI)

There may not be enough suitable information available to determine if a Vendor is qualified or has the resources to carry out the work required. An RFI may be issued to assist with determining if a Vendor is suitable to source from.

An RFI does not:

a) Reference a specific Scope of Work or Project.
b) Ask for prices or any type of rate.

c) Ask if a delivery date can be met.
d) Ask for signatures, bind or commit the Vendor.
e) Use the words “quote”, “proposal” or “tender”

An RFI may request (but is not limited to) the following information:

a) Work the Vendor is capable of doing.
b) Human resources (labour) available.
c) Equipment resources.
d) Training programs.
e) Health, safety or environmental practices.
f) If the Vendor is capable of working with different types of software.

The RFI process will prequalify Vendors for RFQ/RFP process and ensure they are compliant with our Health, Safety and Environmental obligations.

4. Sourcing

4.1 Once all of the prerequisite information is confirmed then Procurement may proceed with soliciting Vendors for information and prices. The following shall be used as the minimum standard when soliciting Bids:

a) All efforts shall be made to find more than one source of supply.
b) Three Bidders is the ideal number for a competitive bid.
c) Generally bidding is by invite only and not open to the Public.
d) All Bidders shall have access to the same information in the process.
e) All proprietary information and bids submitted are to be considered confidential.
f) All compliant Bids submitted are to be considered for award.
g) Any practice used to skew the outcome of the Bid or give one Bidder an advantage over another is considered unethical and prohibited.
h) Information about the award is not to be shared with the other Proponents.

If less than three bids are received, an explanation is to be provided and attached to the Purchase Requisition.

For the Purpose of this Document, the following are the accepted means of Sourcing:

4.2 Request for Quote (RFQ)

a) The Goods or Services are clearly defined and usually less technical, i.e., inventory items, cost center expenses and low level services.
b) The bidding documents are simple, often being an email with price and delivery being the evaluation criteria.
c) Review committee of one person from requesting department and a representative from purchasing.
d) Output documents are Purchase Orders with terms and conditions as required for Services.

4.3 Request for Proposal (RFP)

a) The Goods or Services are clearly defined by the Business Unit in a Scope of Work.
b) The Bidding documents are more complex with the Contract A and Contract B scenario.
c) Evaluation criteria for the Bid must be established.
d) Review committee is to be more than one person from requesting department, a representative from Purchasing, and one person finance department.
e) Output documents are a Purchase Order and a Contract (for Services).

Examples requiring an RFP: Large capital projects, intent to establish a multi-year contract or when there is a high-level scope with multiple deliverables.

4.4 Single or Sole Source Procurement.

Sole sourcing is where only one vendor is chosen to supply a quotation for goods or services. Sole sourcing should only be used where obtaining three quotations is not viable or reasonable. Therefore, sole sourcing shall be looked upon as a “method of exception” rather than the “normal method” of procurement. Sole sourcing approval must be done by the Wataynikaneyap Power COO or designate. The approval will be captured through the purchase requisition with approval documents for sole sourcing justification.

Purchases under $20,000

a) Sole Source Purchasing may be used for purchases where the anticipated price will be under $20,000. The quote from the sole source vendor may be written or verbal.
b) Output documents are a Purchase Order and a Contract (for Services).

Exceptions over $20,000

The following is the criteria to be used when justifying a single source for procurement purposes:

a) Only one source of supply has been identified for the requesting materials, equipment or services, and attempts to either identify additional sources or to modify the request to allow for alternate sources has not been successful.

b) The requested materials or equipment must be purchased from the original equipment manufacturer, in order to match or replace existing equipment.
c) The requested material, equipment, or services provide unique qualifications or technology.
d) The requested material and equipment has been approved as sole source by the Engineering Standards Group.
e) There is an urgent delivery requirement for the requested materials or service, and there is not sufficient time to solicit competitive bids.
f) Price quotations for the requested goods or services which definitely indicate a low cost provider are on file. Such quotations must be less than one year old, market rate information (i.e. labour rates, etc) and in the professional judgment of the Procurement Department, reflect the current market for the requested materials.
g) Output documents are a Purchase Order and a Contract (for Services).

5. Record of Change

A Record of Change shall be completed and maintained by the Procurement Manager. Changes made to this document are to be recorded and submitted to the CFO for review and approval prior to coming into effect.

Wataynikaneyap Power PM Inc.

Purchasing Documents		
	Document:	PRO-001-02
	Owner:	CFO
	Revision:	0
	Issued:	2020.04.15
	Page:	Page 1 of 5

1. Purpose

The purpose of this document is to provide information on the internal documents required for the purchasing of good and services. The foundation for these Documents is an approved Purchase Order from SAP which forms the basis for our internal audit trail as well as output documents for our Suppliers.

Purchasing Documents refers to any type of Purchase Order, Contract or Lease.

2. Scope

This procedure is applicable to all employees at the Wataynikaneyap Power and is subject to the corporate purchasing policy PRO-001

3. Prerequisites

3.1 Sourcing Requirements

Sourcing is to be completed as outlined in document PRO-001-01

3.2 Purchase Requisition

The Purchase Requisition (PR) precedes the issue of any Purchasing Document. Purchase requisitions are documents generated to notify the Company procurement group of material and/or service requirements. Requisitions provide a means of circulating a purchase request to designated approvers for their review and approval prior to initiating the purchase of material and/or services. The approval process for requisitions and purchase justification may be electronic through the SAP Procurement systems, DocuSign or by manual form, for internal departments using paper requisitions. See section 3 of PRO-001 Procurement Policy for expenditure exemptions not requiring a PR. The general steps and requirements for the processing of a Purchase Requisition include:

a) Submission of hand-written or electronic purchase requisition.; or
b) When automated systems (SAP Procurement systems or DocuSign) are available at a site, automated system requisitions are to be utilized for all purchases;

c) All purchases have clearly defined scope and item descriptions complete enough that the buyer and vendor can accurately identify the purchase requirement. (e.g., Part Number, Model, Size, Material, etc.);

d) Completed RFQ/RFP process or sole sourcing justification provided per PRO-001-01 Sourcing Methods;

e) Purchase requisition will need to be approved as per Section 3 “Purchase Requisition or Signature Approval – Operating and Capital Expenditures” per FIN-001 Authorization Policy;

f) Purchase requisitions approved manually or through DocuSign will be entered into the SAP and electronic copy attached to the SAP Requisition for audit purposes;

g) Historical approval documentation be maintained in hand-written or DocuSign as long as retrieval for subsequent audit purposes can be performed.

4. Purchasing Documents

4.1 Prerequisites

An approved PR is required in order to create a PO. A purchase order is the document that is used to order materials and services from a supplier and is the acceptance of a supplier's offer. Depending on the nature of the purchase, the contractual agreement can take the form of a purchase order or a contract as per Section 17 “Contracts” of the WPPM Authorization Policy. A PO must be issued prior to ordering required material and/or service.

4.2 Purchase Orders

The Purchase Order is an agreement between the Company and third party which includes at a minimum but is not limited to:

i. Agreed upon Price or estimated value: as per quote submitted

ii. Description of Goods, Services and Deliverables: as per quote submitted

iii. Purchase Order Number: A unique number assigned through SAP to a specific purchase order, to facilitate accountability throughout the ordering, receiving, and payment process.

iv. Date: All purchase orders must be dated to determine the contractual start date.

v. Supplier Name and Address: The Supplier's complete legal name and address must be displayed on the purchase order.

vi. Ship to Address: The full address of the location where the material being purchased is to be delivered.

vii. Payment Terms: The predetermined terms by which the Company will pay the supplier for the goods and/or services being purchased. In all cases, payment terms must be determined prior to an order being issued. Standard Company payment terms are outlined below in Section 9 “Payment Terms” of the PRO-001 Policy

viii. Transportation Terms: Transportation terms identify two key pieces of information:

  a. F.O.B. (free-on-board) point: Specifies where title to the goods transfers from the seller to the buyer. "FOB Destination" should be designated if at all feasible.

  b. Freight Payment: Specifies which party is responsible for payment of freight charges to the carrier. "Freight Prepaid and Allowed" or "Freight Prepaid and Charge" are examples of typical freight payment terms.

ix. Sales Tax Requirements: All goods and services purchased are either subject to or exempt from provincial and local sales, use, or value added tax. The tax status of each purchase is based upon information entered into in a properly completed requisition, purchase order or vendor record.

x. Approval: at least one signature on purchase requisition through DocuSign as per Section 4 “Purchase Order – Operating and Capital Expenditures” as per WPPM Authorization Policy.

Types of Purchase Orders

a) Standard Purchase Orders
  i. Must be created from an approved purchase requisition in SAP;
  ii. No changes to internal standard Terms and Conditions;
  iii. Used for the purchase of goods based on quantity and price;
  iv. Are applicable to all non-exempt purchases;
  v. Are not required for Procurement Card purchases;
  vi. Are not to be created after the goods have been received; and
  vii. All inventoried material must be purchased in this manner.

b) Blanket Purchase Orders
  i. Must be created from an approved purchase requisition in SAP;
  ii. No changes to internal standard Terms and Conditions;

   iii. A monetary drawdown from an approved amount;
   iv. Defined validity period;
   v. Primarily used for the purchase of Services;
   vi. Must be used with Service Contracts for processing payments;
   vii. Used to issue work against a Master Services Agreement;
   viii. Shall not be used to purchase assets or capital equipment;
   ix. Acceptable for the purchase of Stationary supplies; and
   x. Changes to an existing the Blanket Order either to add additional funds or extend the validity period must be entered in a new Purchase Requisition.

c) Internal Purchase Order
   i. Must be created from an approved annual department budget;
   ii. A monetary drawdown from an approved amount;
   iii. Defined validity period;
   iv. Primarily used for the purchase of Services; and
   v. Must be attached to a specific vendor.

Invoices recorded against Blanket and Internal purchase orders require approval authorization in accordance with section 4 of FIN-001 Authorization policy prior to be processed for payment.

4.3 Reconciliation of PO to Invoice

In the instance of reconciling difference due to minor changes in invoices expenses and approved PO value, purchasing manager has authorization of 2% of PO value up to a maximum of $20,000 to adjust PO to actual invoice value. Changes greater than authorization limit will require a new PR with approvals as described in section 3 of FIN-001 Authorization Policy.

4.4 Contracts

The majority of "routine" materials and services are purchased using the Company's standard contract templates with terms and conditions and issued on Company's standard purchase order. This section is to establish guidelines for the management of "non-routine" purchases such as project work where it is common to have vendor proposed changes to Company's standard contract documents with detailed scope of work.

Given the increased risk of non-routine purchases, the review process and approvals must follow the requirements laid out in section 17 of the FIN-001 Authorization Policy. Internal legal or external counsel opinion will be obtained on the contract to ensure the company's risk is mitigated when standard terms and conditions are changed or when a vendor's contract template is used and spend is over $20,000.

5. Document Management

All copies of Purchasing Documents issued by WPPM are to reside on the Watay Partner and Finance drive in their respective folders. All Purchase order documents are to be retained for a period of 10 years.

The Contract file will have the following format:

E:\WatayPikang\Corporate\WataynikaneyapPower\Contracts – Vendor Name

The Purchase Order will have the following formats:

J:\Purchase Orders_PRs_VP1As\Purchase Orders & Cos-PO – Vendor Name

Quarterly reviews of "Partner" E drive access will be conducted by Procurement Department to verify user access and maintain document control. At this time Procurement will cross reference all new or changed contracts on file per the "Partner" E drive in the quarter with key stakeholders at Watay to ensure completeness of contracts.

6. Record of Change

A Record of Change shall be completed and maintained by the Procurement Manager. Changes made to this document are to be recorded and submitted to the CFO for review and approval prior to coming into effect.

HUMAN RESOURCES POLICIES AND PROCEDURES

FORTIS ONTARIO

Corporate Card	HR Policy:	A-103
	Page:	1 of 1
	Issued:	July 12, 2001
	Revised:	February 28, 2007
	Issue No.:	2.0

1.0 SCOPE

This policy applies to all employees of FortisOntario and its operating subsidiaries who are authorized to have a corporate credit card.

2.0 POLICY

Corporate charge cards are to be used for business purposes only. Employees are to use their cards whenever possible for business expenses including all meals, airfare, lodging, and car rentals. Senior management will determine the monthly limits based on specific job requirements.

FortisOntario will process the payment of all cards through one (1) monthly payment. Electronic monthly statements are distributed to all employees. Employees are responsible for reconciling & allocating these expenses to the appropriate accounts prior to the next billing cycle. All statements must be appropriately coded with **all** receipts attached prior to being signed by their Manager and returned to Finance.

Employees shall notify their Manager or department head immediately, in cases where the card becomes lost or stolen. Corporate credit cards shall be returned upon completion of an employee’s active employment.

Wataynikaneyap Power PM Inc.

Authorization Policy

Document:	FIN-001
Owner:	CFO
Revision:	0
Issued:	2020.04.15
Page:	Page 1 of 9

1 - Objective

a) The objective of this Policy is to outline the authorization levels for goods and service purchases, employee expense purchases using a corporate credit, financial transactions (i.e. cheque signing, approval of wire transfers, account transfers, direct deposits, credit facilities and other derivative instruments), monthly statutory payments, timesheet and payroll approval, disposition of assets, emergency purchases, and contracts.

b) This Policy is applicable to Wataynikaneyap Power PM Inc. (WPPM).

2 - Approval Levels

a) The following table outlines the positions assigned to the various Approval Levels where referenced within this Policy:

Approval Levels	Position Assigned
Level 1	• See Appendix A
Level 2	• See Appendix A
Level 3	• Director
Level 4	• Vice President, CFO & COO
Level 5	• President & CEO
Level 6	• Board of Director

b) Level 3 & 4 employees will be responsible for assigning and approving the allocation of resources to Levels 1 and 2 as outlined in Appendix A of this Policy.

3 - SAP Purchase Requisition or Signature Approval – Operating and Capital Expenditures

The following table outlines Approval Levels for SAP or Manual Purchase Requisition (PR), or signature approvals:

Approval Levels	Up to $14,999	Up to $39,999	Up to $99,999	Up to $199,999	$200,000 to $499,999	Over $500,000
Level 1	✓					
Level 2		✓				
Level 3			✓			
Level 4				✓	✓✓✓	✓✓✓
Level 5						✓

a) Splitting PRs to circumvent the Approval Levels is not permitted. PR Approval Levels are based on total pre-tax dollar value of the PR.
b) All PRs over $200,000 and under $500,000 require approval by 1 Vice President, CFO and COO (3 level 4 approvals).
c) All PRs over $500,000 require approval by Vice President, CFO, COO and the President.
d) The intent of the policy is to have the COO or CFO included in all approvals.

4 - SAP Purchase Order – Operating and Capital Expenditures

Manager of Finance will review SAP Purchase Order (PO) entered from approved PR and ensure accuracy. The list below provides fields verified for Manager of Finance to release PO:

- Levels of approvals are appropriate
- Coding of PO is appropriate to specific department/Capital Project
- PO Value matches PR

The following table outlines Approval Levels for PO approval in DocuSign:

Approval Levels	Dollar Limit Per Approval Level				
	Up to $14,999	Up to $39,999	Up to $99,999	Up to $199,999	$200,000 and Over
Level 1	✓				
Level 2		✓			
Level 3			✓		
Level 4				✓	✓✓

a) Splitting POs to circumvent the Approval Levels is not permitted. PO Approval Levels are based on total pre-tax dollar value of PO.
b) Evidence of Level 5/Level 6 approval not required for POs as approval received as part of PRs outlined in Section 3 above unless a material contract per.
c) No PO can be issued for a material contract as defined in Section 17 “Contracts” without Wataynikaneyap Power GP (“WPGP”) Board of Director approval.
d) When a PO has been issued for a material contract, a change order and an amendment PO can be processed up to and including the amount in the budget approved by WPGP Board of Directors. All change orders require the COO approval and the amended PO requires one Level 4 approval.

5 - Statutory Payments

WPPM makes ongoing statutory payments. Refer to Section 3 for Approval Levels for processing of payments. Supporting documentation is retained for record keeping purposes. Staff responsible for the preparation and review of supporting documentation for statutory payments are as follows:

Statutory Payment Type	Prepared by	Reviewed & Approved by
Corporate Income Taxes	Financial Accountant	Manager of Finance
Workplace Safety & Insurance Board	Financial Accountant	
Other Payroll payments including RRSP, Union Dues, Social Club and etc.		
Harmonized Sales Tax	Financial Accountant	
Statutory Payroll payments including employee tax, CPP, EI and EHT	Prepared and Submitted to CRA by payroll processor (ADP)	
Property Taxes	Municipality	Approval Levels in accordance with Section 3
Financing Interest and Fees	Financial Accountant /Lenders	Manager of Finance

6 - Corporate Credit Card Purchases

a) In accordance with Human Resources Policy A-103 Corporate Card, corporate credit cards are to be used for business purpose only including purchases of meals, travel, car rentals and lodging. Other permitted miscellaneous credit card purchase limits are outlined in Section 7 below. Approval Levels of all corporate credit card purchases are outlined in Section 9 below.

7 - Corporate Credit Card Miscellaneous Purchases

a) The purchase of Inventory items using corporate credit cards is not permitted. See threshold limits below for single purchases of miscellaneous expenses permitted on the corporate credit card:

Type of Other Expenses	Threshold
Capital Expenditures	Up to $2,500
Operating Expenses	Up to $5,000

b) Single one-time purchase limits of $1,500 are typically in place for corporate credit card purchases, so temporary increases to approval limits may need to be obtained from Finance in advance of the purchase transaction being completed. Changes to temporary limits will require same approvals as provided in section 9.

8 - Expense Report

a) An Expense Account Report form is to be prepared monthly for each employee for business expenses, other than those expenses incurred through the use of the corporate credit card. All expense amounts must be properly approved by the person whom the employee directly reports to as outlined in Section 9 and on expense report form. If Expense Report exceeds $10,000 approval by CFO or COO is required. Employees are required to provide receipts as evidence of expenditure. For further details regarding preparation of expense reports, refer to HR Policy A-104 Expense Accounts.

9 - Approval Level for Corporate Credit Card & Employee Expense Claims

a) Expense reports are to be reviewed and approved by the individual that the submitter reports directly to, as outlined in the table below:

Claims For	Approver
Employee	Supervisor, Manager, Director, Vice President, COO or President
Supervisor	Manager, Director, Vice President, CFO or COO
Manager	Director, CFO or COO
Director	Vice President, CFO or COO
CFO	Vice President or President
COO	President
President	Chair of the Board of Directors

11 - Invoices/Cheque Requisition Requiring Signature of Approval

a) In certain circumstances, the PR process may not be appropriate for the purchase of goods or services. Examples may include electricity purchases, legal, audit, or actuarial invoices. Additional exception examples have been provided in the Purchasing Policy. For these cases, invoices are to be approved by the appropriate level of management in accordance with Section 3 above, prior to being processed for payment.

b) For invoices to be charged against blanket POs, approval by the appropriate level of management in accordance with Section 4 above must be obtained prior to being processed for payment.

c) For invoices received from affiliate organizations (FNLP, FON, Newfoundland Power, OSLP and Fortis) two approvals must be obtained from either Level 4 or Level 5 in accordance with section 2.

d) For invoices to be charged against Service PO’s, approval by the requisition originator or manager is first required to verify that services have been received/performed satisfactorily. Then approval by the appropriate level of management in accordance with Section 4 above must be obtained prior to being processed for payment.

12 - Banking Transactions

a) Payment is the final stage of the commitment process. All banking transactions must be approved by two individuals who have been granted authority in accordance with a banking resolution that has been previously approved by the Board of Directors. Signing authority levels are outlined below:

Signing Authority Maximum Approval Levels for Banking Transactions	
Cheque Signing	Any two in Level 4 or 5 in accordance with Section 2.
Wire Transfers / Payments	
Credit Facility	
Electronic Bill Payments	

b) Credit Facilities are approved by the Board of Directors.

13 - Timesheet Approval

a) Timesheets are to be approved in ADP by the appropriate management level considering the most current organization chart. Approval authority is outlined as follows:

  i. Vice President, CFO & COO (VP) Direct Reports:

    i. VPs to approve all direct report timesheets in ADP on a timely basis for payroll processing. If VP is absent, have a delegate approve in ADP for payroll processing, AND VP to evidence review/approval outside of ADP upon return from absence (i.e. signed and dated print-out of direct report timesheets).

  ii. Director/Manager/Supervisor Direct Reports:

    i. Approve all direct report timesheets in ADP on a timely basis for payroll processing. If absent:

      1. Operational group Directors/Managers/Supervisors - a designated Director/Manager/Supervisor approve in ADP for payroll processing, AND the Director/Manager/Supervisor is required to evidence review/approval outside of ADP upon return from absence (i.e. signed and dated print-out of direct report timesheets).

    2. Non-operational group Directors/Managers/Supervisors – VP or another designate of same authorization level will approve in ADP for payroll processing, AND Directors/Managers/Supervisors required to evidence review/approval outside of ADP upon return from absence (i.e. signed and dated print-out of direct report timesheets).

b) Where approvals of timesheets have been completed outside of ADP as outlined above, it is the approver's responsibility to retain sufficient evidence of review and approval as it may be subjected to further review.

14 - Payroll Approval Level

a) After reviewing ADP payroll reports and disbursements including supporting documentation (i.e. payroll detail report, status change form, payroll employee changes report, payroll register), payroll related payments are approved by the Chief Financial Officer.

15 - Disposal of Assets

a) Disposal of assets require appropriate level of approval in accordance with the following net book values upon disposition:

Net Book Value	Approval Level
Up to $74,999	Level 3
$75,000 and Over	Level 4

16 - Emergency Purchases

a) As defined in the Purchasing Policy, if an emergency exists, a reasonable effort shall be made to acquire the necessary authorization required in advance of the purchase. Approval evidence may be obtained outside of SAP. The appropriate level of documentation and approval in accordance with Section 3 above must be obtained as soon as possible after the emergency.

17 - Contracts

17.1 - WPPM Contracts on behalf of Wataynikaneyap Power LP (WPLP)

a. The Procurement Manager must review, prior to signing, and execution:
    i. All contracts with obligations in the aggregate or related financial exposure that exceed the Level 1 threshold as defined in Section 3,
    ii. Contracts entered by WPPM on behalf of WPLP that obligate WPLP to significant non-financial or performance obligations, such as warranties or indemnifications,

iii. Any quotation or proposal from a third party for the purchase of goods or services, and/or

iv. All material contracts as defined in the Wataynikaneyap Power GP Inc. Unanimous Shareholder Agreement (WPGP USA) dated August 27, 2015 quoted below:

> “ *1. Involves expenditures or payments in excess of $3,000,000 in aggregate;*
>
> *2. Involves expenditure or payments in excess of $500,000 in aggregate and has a term in excess of one year;*
> *3. Is outside of the ordinary course of the Partnership Business;*
> *4. Is in relation to land in respect of which a First Nation has an interest;*
> *5. Is in relation to Project Financing;*
> *6. Her Majesty the Queen in Right of Canada or Ontario or an agent of the Crown is a party;*
> *7. A First Nation is a party;*
>
> *And, for the avoidance of doubt includes the Project Management Agreements, all EPC Contracts and all Affiliate Contracts.”*

Contracts that do not exceed the Level 1 threshold as defined in Section 3 or meet the definition of Material Contract above, should also be reviewed by the Procurement Manager if there are concerns about the content of the contract. Whether or not a contract involves an expenditure of financial commitment, a minimum signature of CFO and COO will be required. Higher levels of approval would be required in accordance with the thresholds outlined in Section 3 and unanimous Board of Directors approval is required for all Material Contracts as defined in WPGP USA.

b. Commitments binding WPLP financially or contractually may not be made without first obtaining the necessary approvals. Documents bearing signatures in accordance with Section 3 of this policy must be in hand prior to the commitment. The dollar limits specified for a particular expenditure are for the entire expenditure. Dividing expenditures into smaller amounts to circumvent the intent of this policy is not permitted.

17.2 – WPLP Contracts

a. The Procurement Manager must review, prior to signing, and execution:

  v. All contracts with obligations in the aggregate or related financial exposure that exceed the Level 1 threshold as defined in Section 3,

  vi. Contracts that obligate WPLP to significant non-financial or performance obligations, such as warranties or indemnifications, and/or

vii. Any quotation or proposal from a third party for the purchase of goods or services, and/or

viii. All material contracts as defined in the Wataynikaneyap Power GP Inc. Unanimous Shareholder Agreement (WPGP USA) dated August 27, 2015 quoted below:

> “ *1. Involves expenditures or payments in excess of $3,000,000 in aggregate;*
>
> *8. Involves expenditure or payments in excess of $500,000 in aggregate and has a term in excess of one year;*
> *9. Is outside of the ordinary course of the Partnership Business;*
> *10. Is in relation to land in respect of which a First Nation has an interest;*
> *11. Is in relation to Project Financing;*
> *12. Her Majesty the Queen in Right of Canada or Ontario or an agent of the Crown is a party;*
> *13. A First Nation is a party;*
>
> *And, for the avoidance of doubt includes the Project Management Agreements, all EPC Contracts and all Affiliate Contracts.”*

Contracts that do not exceed the Level 1 threshold as defined in Section 3 should also be reviewed by the Procurement Manager if there are concerns about the content of the contract. Whether or not a contract involves an expenditure of financial commitment, a minimum signature of two officers of Wataynikaneyap Power GP Inc. (WPGP). Contracts that meet the definition of a Material Contract above will require unanimous WPGP Board of Directors approval.

b. Commitments binding WPLP financially or contractually may not be made without first obtaining the necessary approvals. Documents bearing signatures of WPGP officers must be in hand prior to the commitment. The dollar limits specified for a particular expenditure are for the entire expenditure. Dividing expenditures into smaller amounts to circumvent the intent of this policy is not permitted.

18 - Leases

a) WPPM on WPLP’s behalf is required to review and report on an ongoing basis contracts that are lease related. Any lease contract that conveys the right to control the use of an identified property, plant, or equipment (an identified asset) for a period of time in exchange for consideration must be submitted to Finance for review and consideration under US GAAP reporting requirements. Key stakeholders are required to respond to a quarterly questionnaire to ensure lease population completeness and accuracy.

19– Temporary Delegation of Signing Authority

a) In accordance with the Procurement Procedure delegation of approval is permitted during temporary absences of a person having permanent signing authority. The delegate must be of equal or higher status than that of the regular signing authority. A delegate of their signatures and the period of time for which the delegation is valid, is required.

b) In cases where the delegate is not of equivalent or higher status, and is named in an acting capacity for the position held but the permanent signing authority, an approval by the CFO or COO is required. If the CFO or COO is unavailable the CFO of FortisOntario may approve an individual in the CFO's absence.

20– Prepayment/Progress Payment Authorization

a) The Company issues payments to suppliers upon completion of services or material delivery. Requests to pay in advance of delivery must be approved by the CFO.

b) Capital or Repair Projects requiring progress payments require approval from the CFO and COO.

21– Cash Advances

c) VISA cash advances to a maximum of $500 for the $5000 credit limit cardholders and $1000 for cardholders with credit limits greater than $5000 can be used for extreme cases where employees travel to remote First Nations communities, need to pay for services such as transportation, translation, meals, lodging etc and cash payment is the only possibility. The Employee must reconcile the cash advance on the visa statement with supporting documentation.

22 - Complementary Policies

a) The following policies and procedures have been referenced within, and should be considered in conjunction with this Policy:
   - ii. PUR-001 Purchasing Policy
   - iii. A-103 Corporate Card
   - iv. A-104 Expense Accounts

[end of document]

Wataynikaneyap Power PM Inc.

Authorization Policy Level 1 & 2 Allocation Process	Document:	FIN-001 Appendix A
	Owner:	VP of Finance
	Revision:	5
	Issued:	2025-05-01
	Page:	Page 1 of 2

1 – Introduction

This Appendix provides a listing of position assignments to the Level 1 & 2 Approval Levels as noted in FIN-001. The Appendix also provides guidance on the change management requirements for making any updates to this Appendix.

2 – Approval Level Assignments

Level 1

Position	Name
Senior HR Advisor	K. Wright
Manager Accounting	F. Nisioiu
Executive Assistant	

Level 2

Position	Name
Manager Health Safety & Environment	C. Neale
Manager Project Control	J. Fretz-Joseph
Manager Communications	M. Kita
Manager Operations	E. Chopee
Manager Project Relations & Project Engineer	
Manager Construction	M. Applin
Manager IT	G. Visentin

3 - Change Management

a. Level 3 & 4 Employees are responsible for assigning and approving the allocation of resources to the Approval Levels outlined in Section 2 above, and to ensure the steps below are followed:
    i. New Employee onboarding paperwork is to be completed indicating what level, if any, is required; or
    ii. Changes to the existing authorizations in Section 2 are to be documented in an email and sent to Director of Finance.
b. The Director of Finance is to be informed of any changes required to this Document.

[end of document]

Exhibit F, Tab 4, Schedule 1

Depreciation, Amortization and Depletion

DEPRECIATION, AMORTIZATION AND DEPLETION

WPLP will use straight-line depreciation calculations based on the depreciable gross book value of each asset class.[1] The CIAC that was received in July 2024 under the Federal Funding Framework, as discussed in Exhibit I-4-1, has been allocated to the Remote Connection Line assets, and is being depreciated at the same rate as those assets.[2] The useful lives and corresponding depreciation rates determined by WPLP are shown in Table 1.

Table 1 – Useful Lives and Depreciation Rates

OEB Account and Description	Useful Life (Yrs)	Depreciation Rate
1706 – Land Rights	40	2.50%
1715 - Station Equipment (Station and Transformers)	50	2.00%
1715A - Station Equipment (Switches and Breakers)	40	2.50%
1715B - Station Equipment (Protection and Control)	20	5.00%
1720 - Towers and Fixtures	60	1.67%
1725 - Poles and Fixtures	45	2.22%
1730 - Overhead Conductor and Devices	45	2.22%
1908 – Buildings and Fixtures	50	2.00%
1910 - Leasehold Improvements	5	20.00%
1915 – Office Furniture	10	10.00%
1920 – Computer Hardware	5	20.00%
1930 - Transportation Equipment[3]	5-10	10.00-20.00%
1940 – Tools, Shops & Garage Equipment	10	10.00%
1945 – Measurement & Testing Equipment	5	20.00%
1611 – Computer Software	5	20.00%

WPLP's 2026 depreciation expense is summarized in Table 2, with detailed calculations provided in **Appendix 'A'** of this Schedule. WPLP's proposed depreciation expense for the 2026 test year

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[1] As discussed in Exhibit C-3-1, Pikangikum Project assets were added to 2024 opening balances with the CIAC from Indigenous Services Canada. Gross assets and CIAC are being depreciated at the same rate to have a nil impact on rate base and revenue requirement calculations.

[2] This approach is consistent with the treatment in the 2025 rate application.

[3] All in-service fleet is based on 5-year useful life (20% depreciation rate).

is based on a forecast of net fixed assets, calculated based on the standard “half-year” rule. This approach is consistent with WPLP’s approach to calculate rate base, as detailed in Exhibit C-3-1.

Table 2 – 2026 Depreciation Expense (Costs in $000’s)

OEB Account and Description	**Line to Pickle Lake (UTR Network Rate)**	**Remote Connection Lines (HORCI Rate)**	**Total**
1706 – Land Rights	0	1	1
1715 - Station Equipment (Station and Transformers)	914	6,541	7,455
1715A - Station Equipment (Switches and Breakers)	155	692	847
1715B - Station Equipment (Protection and Control)	75	674	748
1720 - Towers and Fixtures	1,907	8,380	10,287
1725 - Poles and Fixtures	0	1,291	1,291
1730 - OH Conductor and Devices	3,410	12,388	15,799
Sub-Total Transmission System Plant	**6,461**	**29,967**	**36,428**
1995 – Land Rights	0	-1	-1
1995 - Station Equipment (Station and Transformers)	0	-1,924	-1,924
1995 - Station Equipment (Switches and Breakers)	0	-184	-184
1995 - Station Equipment (Protection and Control)	0	-179	-179
1995 - Towers and Fixtures	0	-2,233	-2,233
1995 - Poles and Fixtures	0	-1,117	-1,117
1995 - OH Conductor and Devices	0	-4,349	-4,349
Sub-Total Contribution	**0**	**-9,988**	**-9,988**
1908 - Buildings and Fixtures	1	7	8
1910 - Leasehold Improvement	24	112	136
1915 - Office Furniture and Equipment	3	12	15
1920 - Computer Hardware	37	169	206
1930 - Transportation Equipment	6	26	31
1940 - Tools, Shop & Garage Equipment	3	14	17
1945 - Measurement and Testing Equipment	0	1	2
1611 - Computer Software	2	7	9
Total	**6,536**	**20,327**	**26,864**

The useful lives determined by WPLP are comparable to the range of useful lives used by other Ontario transmitters, as well as the ranges in the Asset Depreciation Study prepared by Kinectrics

Inc.[4], as shown in Table 3 below. For this comparison, WPLP used the useful life ranges as stated by CNPI, FNEI and GLPT (prior to being acquired by Hydro One). With the exception of towers and fixtures,[5] WPLP adopted the same useful lives as CNPI Transmission.

WPLP adopted a 60-year useful life for towers and fixtures, since the lattice steel towers employed are expected to last longer than wood-pole structures. This approach is consistent with GLPT's differentiation between 45-year useful lives for wood poles/towers, vs. 60-year useful lives for steel and composite poles/towers.

The only fixed asset account where WPLP's useful life is outside the Kinectrics recommended range is Account 1730 (Overhead Conductors and Devices). WPLP notes that the assessment of overhead conductor included in the Kinectrics Depreciation Study focused solely on the aluminum and copper conductors used for phase and neutral conductors in overhead lines. In contrast, the OEB's definition of Account 1730[6] includes assets such as ground wires (which for WPLP includes integrated fiber optic cable), ground clamps, insulators, lightning arresters and switches. WPLP therefore considered it appropriate to use an overall expected life of 45 years for this asset category, consistent with the useful life adopted by each of CNPI and FNEI.

HONI, B2M and NRLP are excluded from the analysis in Table 3 since these transmitters all rely on a more complex method of calculating depreciation expense.[7]

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[4] EB-2010-0178, Asset Depreciation Study for the Ontario Energy Board, July 8, 2010.

[5] CNPI's transmission towers and fixtures associated with Account 1720 consist primarily of wood poles, and are therefore not comparable to WPLP's towers and fixtures.

[6] OEB Accounting Procedures Handbook; Issued December 2011; p.56

[7] These transmitters rely on a Depreciation Rate Review study completed by a third-party expert on behalf of HONI, which calculates depreciation rates in consideration of differences in estimated remaining life by asset vintage.

Table 3 – Comparison of Useful Lives

WPLP			**CNPI Useful Life Range[8]**	**FNEI Useful Life Range[9]**	**GLPT Useful Life Range[10]**	**Kinectrics**	
OEB Account and Description	**Useful Life (Yrs)**	**Depreciation Rate**				**Category/Component**	**Useful Life Range**
1706 – Land Rights	40	2.50%	N/A	N/A	N/A	N/A	N/A
1715 - Station Equipment (Station and Transformers)	50	2.00%	50	10-50	45-50	Power Transformers (Overall)	30-60
						Rigid Busbars	30-60
						Steel Structure	35-90
1715A - Station Equipment (Switches and Breakers)	40	2.50%	40		30-45	Station Independent Breakers	35-65
						Station Switch	30-60
1715B - Station Equipment (Protection and Control)	20	5.00%	20		5-20	DC System (Overall)	15-20
						Digital & Numeric Relays	15-20
1720 - Towers and Fixtures	60	1.67%	45	N/A	60	N/A[11]	
1725 - Poles and Fixtures	45	2.22%	45	15-40	45	Fully Dressed Wood Pole (Overall)	35-75
1730 - Overhead Conductor and Devices	45	2.22%	45	25-60	60	Overhead Conductors	50-75
1908 - Buildings and Fixtures	40	2.50%	N/A	20-40	25	Administrative Buildings	50-75
1910 – Leasehold Improvements	5	20.00%	N/A	N/A	5-20	Leasehold Improvements	N/A[12]
1915 - Office Furniture and Equipment	10	10.00%	N/A	4-10	10	Office Equipment	5-15
1920 – Computer Hardware	5	20.00%	N/A	3-4	5	Computer Hardware	3-5
1930 - Transportation Equipment	5-10	10.00-20.00%	N/A	5-7	5	Vehicles (Various)	5-20

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[8] EB-2014-0204, Exhibit 4, Tab 10, Schedule 2, p.1.

[9] EB-2016-0231, IRR 6-Staff-30(e).

[10] EB-2014-0238, Exhibit 4, Tab 3, Schedule 1, p.2.

[11] The Kinectrics Depreciation Study did not include lattice steel structures.

[12] Dependent on lease arrangement.

1940 – Tools, Shop & Garage Equipment	10	10.00%	N/A	5-10	10	Tools, Shop & Garage	5-10
1945 – Measurement & Testing Equipment	5	20.00	N/A	N/A	5	Measurement & Testing Equipment	5-10
1611 – Computer Software	5	20.00%	N/A	4	5-15	Computer Software	2-5

Exhibit F, Tab 4, Schedule 1

ATTACHMENT ‘A’

Depreciation Expense Detail

Calculation of Depreciation Expense - All Assets

Accounting Standard	ASPE
Year	2025

CCA Class	OEB	Description	Opening Gross PP&E	Less Fully Depreciated	Net for Depreciation	Current Year Additions	Total for Depreciation	Useful Life	Depreciation Rate	Depreciation Expense
Intangible			*A*	*B*	*C = A - B*	*D*	E = C + D/2	*F*	*G = 1/F*	*H = E * G*
	1606	Organization	-	-	-	-	-	-	-	-
	1610	Miscellaneous Intangible Plant	-	-	-	-	-	-	-	-
	1611	Computer Software	-	-	-	-	-	5	20.00%	-
	1612	Land Rights (Intangible)	-	-	-	-	-	-	-	-
Transmission Plant			*A*	*B*	*C = A - B*	*D*	*(Sum of 'E" for LTPL and RCL)*	*F*	*G = 1/F*	*(Sum of 'H' for LTPL and RCL)*
	1705	Land (Transmission Plant)	-	-	-	-	-	-	-	-
	1706	Land Rights (Transmission Plant)	54,796	-	54,796	-	54,796	40	2.50%	1,370
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-	-	-	-	-
	1710	Leasehold Improvements	-	-	-	-	-	-	-	-
47	1715	Station Equipment (Station and Transformers)	372,736,933	-	372,736,933	-	372,736,933	50	2.00%	7,454,739
47	1715A	Station Equipment (Switches and Breakers)	33,878,706	-	33,878,706	-	33,878,706	40	2.50%	846,968
47	1715B	Station Equipment (Protection and Control)	14,963,021	-	14,963,021	-	14,963,021	20	5.00%	748,151
47	1720	Towers and Fixtures	617,215,377	-	617,215,377	-	617,215,377	60	1.67%	10,286,923
47	1725	Poles and Fixtures	56,910,262	-	56,910,262	800,000	57,310,262	45	2.22%	1,273,561
47	1730	OH Cond and Devices	710,440,555	-	710,440,555	500,000	710,690,555	45	2.22%	15,793,123
	1735	UG Conduit	-	-	-	-	-	-	-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-	-
	1745	Roads and Trails	-	-	-	-	-	-	-	-
General Plant			*A*	*B*	*C = A - B*	*D*	E = C + D/2	*F*	*G = 1/F*	*H = E * G*
	1905	Land (General Plant)	-	-	-	-	-	-	-	-
10.1	1908	Buildings and Fixtures	396,999	-	396,999	-	396,999	50	2.00%	7,940
10.1	1908	Buildings and Fixtures	228,961	-	228,961	-	228,961	5	20.00%	45,792
8	1915	Office Furn & Equipment	-	-	-	100,250	50,125	10	10.00%	5,013
	1920	Comp Hardware	356,556	-	356,556	280,203	496,658	5	20.00%	99,332
10.1	1930	Transportation Equipment	155,392	-	155,392	-	155,392	5	20.00%	31,078
	1935	Stores Equip	-	-	-	-	-	-	0.00%	-
	1940	Tools, Shop & Garage Equip	168,500	-	168,500	-	168,500	10	10.00%	16,850
	1945	Measurement & Testing Equipment	8,793	-	8,793	-	8,793	5	20.00%	1,759
	1950	Power Operated Equipment	-	-	-	-	-	-	0.00%	-
	1955	Communication Equipment	-	-	-	-	-	-	0.00%	-
	1960	Misc. Equipment	-	-	-	-	-	-	0.00%	-
	1980	System Supervisory Equipment	-	-	-	-	-	-	0.00%	-
	1995	Contributions & Grants	(487,134,094)	-	(487,134,094)	-	(487,134,094)	Note 1	Note 1	(9,987,579)
	2440	Deferred Revenue	-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-
		Total	**1,320,380,757**	**-**	**1,320,380,757**	**1,680,453**	**1,321,220,983**			**26,625,019**

Note 1: Contribution useful life and depreciation rate is based on the assets useful life the funds are allocated to.

Calculation of Depreciation Expense - Line to Pickle Lake

Accounting Standard ASPE
Year 2025

CCA Class	OEB	Description	Opening Gross PP&E	Less Fully Depreciated	Net for Depreciation	Current Year Additions	Total for Depreciation	Useful Life	Depreciation Rate	Depreciation Expense
		Transmission Plant	*A*	*B*	*C = A - B*	*D*	*E = C + D/2*	*F*	*G = 1/F*	*H = E*G*
	1705	Land (Transmission Plant)	-	-	-	-	-	-	-	-
	1706	Land Rights (Transmission Plant)	-	-	-	-	-	-	-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-	-	-	-	-
	1710	Leasehold Improvements	-	-	-	-	-	-	-	-
47	1715	Station Equipment (Station and Transformers)	45,706,802	-	45,706,802	-	45,706,802	50	2.00%	914,136
47	1715A	Station Equipment (Switches and Breakers)	6,211,421	-	6,211,421	-	6,211,421	40	2.50%	155,286
47	1715B	Station Equipment (Protection and Control)	1,491,470	-	1,491,470	-	1,491,470	20	5.00%	74,573
47	1720	Towers and Fixtures	114,421,783	-	114,421,783	-	114,421,783	60	1.67%	1,907,030
47	1725	Poles and Fixtures	-	-	-	-	-	-	0.00%	-
47	1730	OH Cond and Devices	153,460,833	-	153,460,833	-	153,460,833	45	2.22%	3,410,241
	1735	UG Conduit	-	-	-	-	-	-	-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-	-
	1745	Roads and Trails	-	-	-	-	-	-	-	-
		Total	**321,292,308**	**-**	**321,292,308**	**-**	**321,292,308**			**6,461,265**

Calculation of Depreciation Expense - Remote Connection Lines

Accounting Standard	ASPE
Year	2025

CCA Class	OEB	Description	Opening Gross PP&E	Less Fully Depreciated	Net for Depreciation	Current Year Additions	Total for Depreciation	Useful Life	Depreciation Rate	Depreciation Expense
		Transmission Plant	A	B	C = A - B	D	E = C + D/2	F	G = 1/F	H = E*G
	1705	Land (Transmission Plant)	-	-	-	-	-	-	-	-
	1706	Land Rights (Transmission Plant)	54,796	-	54,796	-	54,796	40	2.50%	1,370
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-	-	-	0.00%	-
	1710	Leasehold Improvements	-	-	-	-	-	-	0.00%	-
47	1715	Station Equipment (Station and Transformers)	327,030,131	-	327,030,131	-	327,030,131	50	2.00%	6,540,603
47	1715A	Station Equipment (Switches and Breakers)	27,667,285	-	27,667,285	-	27,667,285	40	2.50%	691,682
47	1715B	Station Equipment (Protection and Control)	13,471,551	-	13,471,551	-	13,471,551	20	5.00%	673,578
47	1720	Towers and Fixtures	502,793,594	-	502,793,594	-	502,793,594	60	1.67%	8,379,893
47	1725	Poles and Fixtures	56,910,262	-	56,910,262	800,000	57,310,262	45	2.22%	1,273,561
47	1730	OH Cond and Devices	556,979,722	-	556,979,722	500,000	557,229,722	45	2.22%	12,382,883
	1735	UG Conduit	-	-	-	-	-	-	-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-	-
	1745	Roads and Trails	-	-	-	-	-	-	-	-
		Total	**1,484,907,342**	**-**	**1,484,907,342**	**1,300,000**	**1,485,557,342**			**29,943,570**

Calculation of Depreciation Expense - All Assets

Accounting Standard ASPE
Year 2026

CCA Class	OEB	Description	Opening Gross PP&E	Less Fully Depreciated	Net for Depreciation	Current Year Additions	Total for Depreciation	Useful Life	Depreciation Rate	Depreciation Expense
		Intangible	*A*	*B*	*C = A - B*	*D*	E = C + D/2	*F*	*G = 1/F*	*H = E * G*
	1606	Organization	-	-	-	-	-	-	-	-
	1610	Miscellaneous Intangible Plant	-	-	-	-	-	-	-	-
	1611	Computer Software	-	-	-	86,600	43,300	5	20.00%	8,660
	1612	Land Rights (Intangible)	-	-	-	-	-	-	-	-
		Transmission Plant	*A*	*B*	*C = A - B*	*D*	*(Sum of 'E" for LTPL and RCL)*	*F*	*G = 1/F*	*(Sum of 'H' for LTPL and RCL)*
	1705	Land (Transmission Plant)	-	-	-	-	-	-	-	-
	1706	Land Rights (Transmission Plant)	54,796	-	54,796	-	54,796	40	2.50%	1,370
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-	-	-	-	-
	1710	Leasehold Improvements	-	-	-	-	-	-	-	-
47	1715	Station Equipment (Station and Transformers)	372,736,933	-	372,736,933	-	372,736,933	50	2.00%	7,454,739
47	1715A	Station Equipment (Switches and Breakers)	33,878,706	-	33,878,706	-	33,878,706	40	2.50%	846,968
47	1715B	Station Equipment (Protection and Control)	14,963,021	-	14,963,021	-	14,963,021	20	5.00%	748,151
47	1720	Towers and Fixtures	617,215,377	-	617,215,377	-	617,215,377	60	1.67%	10,286,923
47	1725	Poles and Fixtures	57,710,262	-	57,710,262	800,000	58,110,262	45	2.22%	1,291,339
47	1730	OH Cond and Devices	710,940,555	-	710,940,555	-	710,940,555	45	2.22%	15,798,679
	1735	UG Conduit	-	-	-	-	-	-	-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-	-
	1745	Roads and Trails	-	-	-	-	-	-	-	-
		General Plant	*A*	*B*	*C = A - B*	*D*	E = C + D/2	*F*	*G = 1/F*	*H = E * G*
	1905	Land (General Plant)	-	-	-	-	-	-	-	-
10.1	1908	Buildings and Fixtures	396,999	-	396,999	-	396,999	50	2.00%	7,940
10.1	1908	Buildings and Fixtures	228,961	-	228,961	900,000	678,961	5	20.00%	135,792
8	1915	Office Furn & Equipment	100,250	-	100,250	100,250	150,375	10	10.00%	15,038
	1920	Comp Hardware	636,760	-	636,760	785,000	1,029,260	5	20.00%	205,852
10.1	1930	Transportation Equipment	155,392	-	155,392	-	155,392	5	20.00%	31,078
	1935	Stores Equip	-	-	-	-	-	-	-	-
	1940	Tools, Shop & Garage Equip	168,500	-	168,500	-	168,500	10	10.00%	16,850
	1945	Measurement & Testing Equipment	8,793	-	8,793	-	8,793	5	20.00%	1,759
	1950	Power Operated Equipment	-	-	-	-	-	-	-	-
	1955	Communication Equipment	-	-	-	-	-	-	-	-
	1960	Misc. Equipment	-	-	-	-	-	-	-	-
	1980	System Supervisory Equipment	-	-	-	-	-	-	-	-
	1995	Contributions & Grants	(487,134,094)	-	(487,134,094)	-	(487,134,094)	Note 1	Note 1	(9,987,579)
	2440	Deferred Revenue	-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-
		Total	**1,322,061,210**	**-**	**1,322,061,210**	**2,671,850**	**1,323,397,135**			**26,863,558**

Note 1: Contribution useful life and depreciation rate is based on the assets useful life the funds are allocated to.

Calculation of Depreciation Expense - Line to Pickle Lake

Accounting Standard ASPE
Year 2026

CCA Class	OEB	Description	Opening Gross PP&E	Less Fully Depreciated	Net for Depreciation	Current Year Additions	Total for Depreciation	Useful Life	Depreciation Rate	Depreciation Expense
		Transmission Plant	*A*	*B*	*C = A - B*	*D*	E = C + D/2	*F*	*G = 1/F*	*H = E*G*
	1705	Land (Transmission Plant)	-	-	-	-	-	-	0.00%	-
	1706	Land Rights (Transmission Plant)	-	-	-	-	-	-	0.00%	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-	-	-	0.00%	-
	1710	Leasehold Improvements	-	-	-	-	-	-	0.00%	-
47	1715	Station Equipment (Station and Transformers)	45,706,802	-	45,706,802	-	45,706,802	50	2.00%	914,136
47	1715A	Station Equipment (Switches and Breakers)	6,211,421	-	6,211,421	-	6,211,421	40	2.50%	155,286
47	1715B	Station Equipment (Protection and Control)	1,491,470	-	1,491,470	-	1,491,470	20	5.00%	74,573
47	1720	Towers and Fixtures	114,421,783	-	114,421,783	-	114,421,783	60	1.67%	1,907,030
47	1725	Poles and Fixtures	-	-	-	-	-	-	0.00%	-
47	1730	OH Cond and Devices	153,460,833	-	153,460,833	-	153,460,833	45	2.22%	3,410,241
	1735	UG Conduit	-	-	-	-	-	-	0.00%	-
	1740	UG Cond and Devices	-	-	-	-	-	-	0.00%	-
	1745	Roads and Trails	-	-	-	-	-	-	0.00%	-
		Total	**321,292,308**	**-**	**321,292,308**	**-**	**321,292,308**			**6,461,265**

Calculation of Depreciation Expense - Remote Connection Lines

Accounting Standard ASPE
Year 2026

CCA Class	OEB	Description	Opening Gross PP&E	Less Fully Depreciated	Net for Depreciation	Current Year Additions	Total for Depreciation	Useful Life	Depreciation Rate	Depreciation Expense
		Transmission Plant	A	B	C = A - B	D	E = C + D/2	F	G = 1/F	H = E*G
	1705	Land (Transmission Plant)	-	-	-	-	-	-	0.00%	-
	1706	Land Rights (Transmission Plant)	54,796	-	54,796	-	54,796	40	2.50%	1,370
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-	-	-	0.00%	-
	1710	Leasehold Improvements	-	-	-	-	-	-	0.00%	-
47	1715	Station Equipment (Station and Transformers)	327,030,131	-	327,030,131	-	327,030,131	50	2.00%	6,540,603
47	1715A	Station Equipment (Switches and Breakers)	27,667,285	-	27,667,285	-	27,667,285	40	2.50%	691,682
47	1715B	Station Equipment (Protection and Control)	13,471,551	-	13,471,551	-	13,471,551	20	5.00%	673,578
47	1720	Towers and Fixtures	502,793,594	-	502,793,594	-	502,793,594	60	1.67%	8,379,893
47	1725	Poles and Fixtures	57,710,262	-	57,710,262	800,000	58,110,262	45	2.22%	1,291,339
47	1730	OH Cond and Devices	557,479,722	-	557,479,722	-	557,479,722	45	2.22%	12,388,438
	1735	UG Conduit	-	-	-	-	-	-	0.00%	-
	1740	UG Cond and Devices	-	-	-	-	-	-	0.00%	-
	1745	Roads and Trails	-	-	-	-	-	-	0.00%	-
		Total	**1,486,207,342**	**-**	**1,486,207,342**	**800,000**	**1,486,607,342**			**29,966,903**

Exhibit F, Tab 5, Schedule 1

Income and Property Taxes

INCOME AND PROPERTY TAXES

A. Overview

This Schedule provides the details supporting WPLP's forecasted income tax expense for the purpose of rate recovery for the 2026 test year. It also provides context with respect to the tax implications of WPLP's corporate structure with respect to various legislation.

Appendix 'A' to this Schedule contains detailed calculations of WPLP's income tax expenses for the 2026 test year, which have also been filed in Excel format. A copy of WPLP's most recent tax return is included as an Appendix "A" to Exhibit A-7-1.

WPLP has calculated a total income tax expense of $596,335 for the 2026 test year. As detailed in this Schedule, this expense is limited to the Ontario Corporate Minimum Tax ("OCMT"), as applicable to its partners, because WPLP is a limited partnership and continues to have loss carry forwards in excess of taxable income for 2026.

B. Corporate Structure

WPLP is not a corporation that is exempt from tax under Section 149(1) of the *Income Tax Act* (Canada) and the *Taxation Act*, *2007* (Ontario). As such, WPLP is not subject to the payments in lieu of corporate income taxes ("PILs") regime under the *Electricity Act, 1998*.

WPLP is a limited partnership pursuant to the *Limited Partnerships Act* (Ontario). As a limited partnership, WPLP is not a taxable entity for federal and provincial income tax purposes, but is required to compute its taxable income, which is then allocated to its partners as follows:

- 51% of WPLP's taxable income is allocated to First Nation LP, whose limited partnership interests are held directly by the 24 Participating First Nations in equal shares; and,

- 49% of WPLP's taxable income is allocated to Fortis (WP) LP, whose limited partnership interests are held by Fortis Inc. (80%) and indirectly by Algonquin Power & Utilities Corp. (20%).

The 24 Participating First Nations that are shareholders of First Nation LP are not subject to corporate income tax. As such, the 51% portion of WPLP's taxable income that is allocated to First Nation LP is not subject to income tax, which results in savings to ratepayers.

C. Regulatory Income Tax Expense

A combined income tax rate of 26.5% (15% federal + 11.5% provincial) is used for the calculation of the 2026 income tax expense. However, as detailed in Appendix "A", WPLP's forecasted allowable CCA deduction of approximately $80.3 million and use of loss carry forwards, result in zero taxable income.

D. Ontario Corporate Minimum Tax

The Ontario Corporate Minimum Tax ("OCMT") rate is 2.7%. This rate is applied to accounting income, without most tax adjustments, and the tax payable is equal to the amount by which the OCMT exceeds the Ontario corporate income tax.

Detailed calculations are provided in Appendix "A" with WPLP's 2026 forecasted OCMT payable summarized in Table 1 below.

Table 1 – WPLP's 2026 Ontario Corporate Minimum Tax ($000's)

Item	Description	Allocation / Rate	Amount
A	WPLP Regulatory Net Income (before Tax and adjustments)		45,074
B	% of LP Interests Held by Taxable Entities	49%	
C = A x B	Regulatory Net Income subject to Taxation		22,086
D	Ontario Minimum Corporate Tax Rate	2.7%	
E = C x D	***Ontario Minimum Corporate Tax***		***596***
F	Ontario Corporate Income Tax Payable		0
G = E-F	**Ontario Corporate Minimum Tax Payable**		**596**

As detailed in Appendix "A", WPLP will record credits in the amount of the OCMT paid to be applied to reduce taxes payable in future years.

E. Reconciliation Between Regulatory Net Income Before Tax and Taxable Income

The difference between WPLP's regulated net income before tax and WPLP's taxable income consists of tax adjustments related to depreciation, CCA and financing fees (which are deductible for tax purposes over a five-year period), as detailed in Appendix "A". WPLP confirms that the depreciation amount included in Appendix "A" is equal to the depreciation expense included in its 2026 test year revenue requirement, as calculated in Exhibit F-4-1.

WPLP's CCA calculation for the 2026 test year is provided in Appendix "B" to this Schedule, and includes the effect of Accelerated CCA.

F. Taxable Income and Income Tax Expense

WPLP confirms that its forecasted 2026 regulatory net income before tax is equal to the return on equity component of its revenue requirement, as calculated in Exhibit G-2-1. WPLP's taxable income is determined by adding depreciation expense and deducting CCA and financing fees, following which, the resulting taxable income is allocated to each partner, as detailed in Appendix "A". For each partner (i.e. First Nation LP and Fortis (WP) LP), Appendix "A" then calculates the relevant income tax expense, with consideration of applicable tax rates and loss treatment of losses/credits.

The OCMT portion of each partner's tax expense calculation is applied to an allocation of WPLP's regulatory net income before tax, which is shown as "Allocation of Accounting Income" in Appendix "A".

As discussed above, First Nation LP and its direct shareholders are not taxable entities. The tax rates applicable to First Nation LP are therefore set at 0% and the resulting income tax and OCMT expenses are $Nil.

The Fortis (WP) LP section of Appendix "A" provides the income tax and OCMT calculations applicable to Fortis (WP) LP's 49% allocation of WPLP's income, according to the process described above.

G. Property Tax Expense

WPLP has included an immaterial property tax expense (less than $1,000) in its 2026 test year OM&A cost forecasts in relation to WPLP's land interests for the Pickle Lake TS.

APPENDIX “A”

WPLP 2026 Income Tax Calculation

APPENDIX "B"

WPLP 2026 CCA Calculation

Exhibit F, Tab 5, Schedule 1

Income and Property Taxes

ATTACHMENT 'A'

Income and Property Taxes - Tax Calculations

WPLP
Calculation of Utility Income Taxes
2026 Test Year
($000's)

SUMMARY OF TAX EXPENSE

	2026
First Nation LP	0
Fortis (WP) LP	596
Total	**596**

WPLP

Line No.	Particulars		2026	
	Determination of Taxable Income			
1	Regulatory Net Income (before tax)		45,074	(1)
2	Book to Tax Adjustments:			
3	Depreciation and amortization		26,864	
4	Capital Cost Allowance		-80,301	
5	Other		0	
6	Total Adjustments	$	-53,437	
7	Regulatory Taxable Income/(Loss) before Loss Carry Forward	$	-8,364	
	Allocation of Taxable Income			
8	First Nation LP (51%)		-4,265	
9	Fortis (WP) LP (49%)		-4,098	
10	Total	$	-8,364	
	Tax Rates			
11	Federal Tax		15.00	%
12	Provincial Tax		11.50	%
13	Total Tax Rate		26.5	%

(1) The regulated income of $44,477,388 provided in G-2-1 Table 1 has been grossed up for tax purposes.

WPLP
Calculation of Utility Income Taxes
2026 Test Year
($000's)

First Nation LP

Line No.	Particulars		2026	
	Determination of Taxable Income			
1	Allocation of Taxable Income from WPLP		-4,265	
4	Tax Rate		0.00	%
5	**Income Tax Expense**	**$**	**0**	
	Determination of Corporate Minimum Tax			
	Allocation of Accounting Income from WPLP		22,988	
	Corporate Minimum Tax Rate		0.00	%
	Corporate Minimum Tax Payable (Utilized)	**$**	**0**	
	Total Taxes Expense for First Nation LP	**$**	**0**	

WPLP
Calculation of Utility Income Taxes
2026 Test Year
($000's)

Fortis (WP) LP

Line No.	Particulars		2026	
	Determination of Taxable Income			
1	Allocation of Taxable Income from WPLP		-4,098	
2	Loss Carryforward		4,098	
3	Taxable Income after Loss Carryforward		0	
4	Tax Rate		26.50	%
5	**Income Tax Expense**	**$**	**0**	
	Loss Continuity Schedule			
6	Opening Losses Carryforward		-89,821	
7	Losses (Incurred)/Utilized during the year		-4,098	
8	Closing Losses Carryforward		-93,919	
	Determination of Corporate Minimum Tax			
9	Allocation of Accounting Income from WPLP		22,086	
10	Corporate Minimum Tax Rate		2.70	%
11	Corporate Minimum Tax Potentially Applicable		596	
12	Ontario Income Tax		0	
13	**Corporate Minimum Tax Payable (Utilized)**	**$**	**596**	
14	Opening CMT Credit Carryforward		1,688	
15	CMT Credit Incurred/(Utilized)		596	
16	Closing CMT Credit Carryforward		2,284	
17	**Total Taxes Expense for Fortis (WP) LP**	**$**	**596.325**	

Exhibit F, Tab 5, Schedule 1

Income and Property Taxes

ATTACHMENT ‘B’

Income and Property Taxes - CCA

WPLP
Calculation of Utility Income Taxes
2026 Test Year
($000's)

CCA Class	Opening UCC	Net Additions	Contribution in Aid of Construction	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Accelerated CCA Initiative	Closing UCC
1	373	-	-	373	-	373	0.04	15	-	359
8	218	100	-	318	(50)	268	0.20	54	-	265
10.1	23	-	-	23	-	23	0.30	7	-	16
12	-	-	-	-	-	-	1.00	-	-	-
13	165	900	-	1,065	(450)	615	0.20	123	-	942
50	319	872	-	1,191	(436)	755	0.55	415	-	776
47	995,689	800	-	996,489	(400)	996,089	0.08	79,687	-	916,802
UCC	996,788	2,672	-	999,460	(1,336)	998,124		80,301	-	919,159

TOTAL CCA **80,301**

Exhibit G, Tab 1, Schedule 1

Capital Structure

CAPITAL STRUCTURE

Consistent with its approach in EB-2024-0176, WPLP is using a deemed capital structure for rate-making purposes for the 2026 test year, comprised of 4% short-term debt, 56% long-term debt, and 40% common equity.

WPLP's capital structure is consistent with the OEB's findings in its Decision and Order in the generic proceeding on cost of capital parameters and deemed capital structure used to set rates (EB-2024-0063), dated March 27, 2025. Table 1 illustrates the application of this capital structure to WPLP's 2026 rate base.

Table 1 – Capital Structure

	Capitalization Ratio	
	(%)	**($)**
Long-term Debt	56%	$691,870,486
Short-term Debt	4%	$49,419,320
Total Debt	*60%*	*$741,289,806*
Common Equity	*40%*	*$494,193,204*
Total	**100%**	**$1,235,483,010**

WPLP, Canada and Ontario signed definitive documents to establish the Federal Funding Framework on July 3, 2019. The Federal Funding Framework includes a Contribution Agreement that outlines the terms and conditions upon which Canada was to provide funding into an independent Trust, and a Trust Agreement that outlines how such funding is to be disbursed from the Trust to the Project. See Exhibit I-4-1 for additional information on the Federal Funding Framework, its implications for WPLP's capital structure, and prior applications for historical details on Federal Funding Framework.

WPLP's partners (First Nation LP and Fortis (WP) LP) have made significant equity contributions to the Project in 2022, 2023 and 2025 in consideration of assets coming into service and the overall financing and funding framework for the project:

- In 2022, First Nation LP and Fortis (WP) LP contributed $245,760,000 ($120,998,107 and $124,761,893, respectively);

- In 2023, First Nation LP and Fortis (WP) LP contributed an additional $60,300,000 ($30,753,000 and $ 29,547,000, respectively); and

- In April 2025, First Nation LP and Fortis (WP) LP contributed an additional $70,000,000 ($35,700,000 and $34,300,000, respectively) to ensure WPLP's Owner Equity for 2025 is consistent with the OEB deemed capital structure.

There is no requirement for additional contributions from First Nation LP or Fortis (WP) LP in 2026.

Table 3 below illustrates the required equity build-up to ensure WPLP's Owner Equity for 2026 is sufficient for the Owner Equity included in determining the 2026 revenue requirement.

Table 3 – WPLP's Owner Equity Summary

Audited 2024 Equity Balance	$417,961,806
2025 Forecasted Earnings	$46,768,323
2025 Contribution	$70,000,000
Forecasted Opening 2026 Equity Balance	**$534,730,129**
2026 Mid-Year Earnings	$22,229,934
2026 Forecasted Distributions	($36,355,698)
Mid-Year Partners Equity	**$520,613,125**[1]

The cost of capital parameters are discussed in Exhibit G-2-1.

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[1] In excess of the requirement identified in Exhibit G-1-1 Table 1 of $494,193,204 of equity.

Exhibit G, Tab 2, Schedule 1

Cost of Capital

COST OF CAPITAL

A. Overview

This schedule supports the cost rates applied to each component of WPLP's 2026 cost of capital. WPLP's total cost of capital for the 2026 test year is summarized in Table 1 below.

Table 1 – Capital Structure and Cost of Capital

	Capitalization Ratio		**Cost Rate**[1]	**Return**
	(%)	**($)**	**(%)**	**($)**
Long-term Debt	56%	$691,870,486	4.60%[2]	$31,858,166
Short-term Debt	4%	$49,419,320	3.91%	$1,932,295
Total Debt	*60%*	*$741,289,806*	*4.56%*	*$33,790,462*
Common Equity	*40%*	*$494,193,204*	*9.00%*	*$44,477,388*
Total	**100%**	**$1,235,483,010**	**6.34%**	**$78,267,850**

B. Cost of Equity

WPLP's proposed revenue requirement reflects its use of the OEB's deemed rate of return on equity ("ROE") of 9.00% for 2025 rate applications, as established by the OEB's Decision and Order in the Generic Proceeding, as a placeholder. WPLP will update this rate at a later stage of the proceeding to reflect the OEB's ROE for 2026 rate applications once the OEB publishes its cost of capital parameters for 2026.

C. Cost of Short-Term Debt

WPLP's proposed cost of short-term debt reflects its use of the OEB's deemed short-term debt rate of 3.91% for 2025 rate applications, as established by the OEB's Decision and Order in the Generic Proceeding, as a placeholder. WPLP will update this rate at a later stage of the proceeding

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[1] Consistent with the OEB's final cost of capital parameters for 2025, as determined by the OEB's Decision and Order in EB-2024-0063 (the "Generic Proceeding"), dated March 27, 2025.

[2] The debt structure between Ontario and Senior Banks changes from 66:34 as described below to 49:51 given the CIAC contribution from the Trust is only used to pay down the Ontario Facility, as prescribed within Trust Agreement.

to reflect the OEB's deemed short-term debt rate for 2026 applications once the OEB publishes its cost of capital parameters for 2026.

D. Cost of Long-Term Debt

As this is WPLP's fifth transmission revenue requirement application and, having completed constructing the Transmission System, WPLP has transitioned into its role as an operating transmitter, this section first describes the process and overall approach to financing that WPLP has taken and then explains the basis for the proposed cost of long-term debt.

1. Context and Process Related to Project Financing

WPLP has worked with Price Waterhouse Coopers ("PwC") to secure appropriate third-party financing for the construction of its transmission system. WPLP entered into a 'club deal' with a consortium of five bank lenders (the "Senior Bank Lenders") and Ontario to allow for better financing terms through increased competition among the lenders which supported a better outcome for WPLP and, ultimately, for ratepayers. In 2019, WPLP negotiated a Common Terms and Inter-Creditor Agreement ("CTIA") with Ontario and the Senior Bank Lenders (collectively the "Lenders") to provide total project financing of up to $2.02 billion, consisting of up to $1.34 billion from Ontario (the "Ontario Facility") and up to $680 million from the Senior Bank Lenders (the "Senior Bank Facility"). For clarity, WPLP is not forecasting to require the entire amount of available financing.[3] However, it has secured financing that would cover a combination of pre-COVID-19 pandemic worst-case scenarios in consideration of cost increases, interest rate increases and construction delays.

The CTIA between WPLP and the Lenders contemplates that each draw will be funded by all of the Lenders, in proportion to the total amount of funding available from each lender. This arrangement resulted from the negotiations between the parties and ensures that the Senior Bank

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[3] Discussions between WPLP and its EPC contractor over responsibility for costs related to delays in the construction schedule due to the COVID-19 pandemic and related matters are ongoing. The outcome of these discussions could impact the amount of financing required. At this time, WPLP does not know what portion of such EPC contractor cost overruns may be WPLP's responsibility and therefore, is not able to determine the ultimate impact on financing.

Lenders would be able to lend a reasonable portion of the funds that they have committed, which in turn enables them to offer that funding at competitive rates. As a result of this agreement, approximately 66% (1.34/2.02) of the total project financing will be provided by Ontario, and approximately 34% (0.68/2.02) will be provided by the Senior Bank Lenders[4]. Therefore, as an example if WPLP ultimately needs to borrow $1.9 billion, then it would get approximately $1.254 billion from Ontario and approximately $646 million from the Senior Bank Lenders.

In March 2025, the CTIA was amended to extend the Longstop Date to July 31, 2027, the Final Maturity date to December 31, 2027, and to allow for distributions to WPLP partners prior to full repayment of debt facilities with no change in interest rates and no incremental financing fees to facilities. This amendment provides WPLP additional time to reach settlement or final resolution with its EPC contractor, Valard, and certainty around earnings and cash flow from operations to secure a more preferrable long-term financing rate.

2. Interest Rates Applicable to Long-Term Debt

The Ontario Facility calculates interest based on a per annum rate comprised of: (a) a variable rate equal to the rate applicable to three-month Treasury bills issued by Ontario at the time of each advance, plus (b) a margin of 50 basis points[5], and (c) an administrative fee of 10 basis points applicable to the amount drawn and outstanding.

The Senior Bank Facility calculates interest based on a per annum rate comprised of: (a) a variable rate equal to the Canadian Dealer Offered Rate ("CDOR")[6] at the time of each advance, plus (b) a margin of 150 basis points, and (c) an administrative fee of 45 basis points on the amount of financing available but not yet advanced.

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[4] The debt structure between Ontario and Senior Banks changes from 66:34 as described above to 49:51 given the CIAC contribution from the Trust. Draws from financing will continue to follow the 66:34 split from Ontario and Senior Banks.

[5] The CTIA specifies that the margin may be increased by 5 basis points under certain conditions, none of which are expected to occur during the 2026 Test Year.

[6] The CDOR rate has been updated to the Canadian Overnight Repo Rate Average ("CORRA"), effective June 12, 2024, given the discontinuance of CDOR by its administrator on June 28, 2024.

WPLP has calculated its cost of long-term debt based on the weighted average of the interest rates for the debt facilities described above, consistent with the approach contemplated in the OEB's Decision and Order in the Generic Proceeding. Debt issuance costs are amortized over the term of the Ontario Facility and the Senior Bank Facility. The total of 2026 amortization of debt issuance costs and forecasted administrative fees described above are included in the determination of total 2026 interest and fees. The effective 2026 cost of debt rate for each debt facility is then calculated by dividing the forecasted 2026 total interest and fees by the forecasted 2026 12-month average principal balance. Based on this methodology, WPLP's long-term debt rate is calculated to be 4.60% for 2026, as illustrated in Table 2.

Table 2 – Debt Facilities and Cost of Long-Term Debt

Description	**Lender**	**2026 Principal ($) (12-month Average)[7]**	**2026 Interest & Fees ($)**	**Rate (%)[8]**
Ontario Facility	Province of Ontario	466,123,520	18,738,571	4.02%
Senior Bank Facility	Senior Bank Lenders	494,880,204	25,512,220	5.16%
Total		**961,003,724**	**44,250,791**	**4.60%**

WPLP's actual cost of debt will largely be determined by: (a) the timing and amount of advances on WPLP's debt facilities, which will mostly be determined by payment requirements related to WPLP's EPC contract; and (b) the actual Ontario T-Bill and CORRA rates in 2026, which could vary significantly from the forecasts underpinning the calculations in Table 2. WPLP is therefore proposing to continue the Construction Period Interest Costs Variance Account that was established in EB-2021-0134, and amended in EB-2024-0176, to record the difference between its

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[7] Principal balance reflects repayment of debt expected when assets go in-service in accordance with WPLP's CTIA. The debt structure between Ontario and Senior Banks changes from 66:34 as described above to 49:51 given the CIAC contribution from the Trust is only used to pay down Ontario Facility, as prescribed within Trust Agreement.

[8] Interest rate for Ontario facility is based on a T-bill forecasted rates and Senior bank facility is based on forecasted CDOR rates. Senior bank facility includes additional cost mechanisms on unused balance of facility resulting in minimal change as value of principal changes.

forecasted and actual costs of debt during the construction and contract closeout phase of the project, as well as partial disposition thereof, as further detailed in Exhibit H-1-1.

WPLP plans to seek take out, or long-term financing, in place of the current project financing, at the end of 2026, assuming it has reached a full and final settlement or resolution with Valard by that time. To the extent the project financing is taken out prior to the end of 2026, WPLP would continue to record any variance in interest expense in the Construction Period Interest Costs Variance Account.

Exhibit H, Tab 1, Schedule 1

Overview of Deferral and Variance Accounts

OVERVIEW OF DEFERRAL AND VARIANCE ACCOUNTS

This Exhibit provides an overview of WPLP's existing deferral and variance accounts, and identifies the accounts it proposes to continue and discontinue for the 2026 test year. The disposition of account balances is discussed in Exhibit H-2-1 and H-2-2, with the latter setting out WPLP's proposed approach, for 2026, to the treatment of COVID-related amounts incurred in the construction of the Transmission Project.[1]

A. Existing Accounts and their Continuation or Discontinuation

To understand WPLP's existing regulatory accounts, it is helpful to understand the regulatory context for the accounts, including how the accounts were established and have evolved, as well as how they have related to the in-servicing of portions of WPLP's transmission system during the construction period.

In respect of accounts for which WPLP seeks to dispose of the balance in full and no longer expects to record any additional principal amounts, WPLP intends to close such accounts at the end of 2026 with any variance in carrying charges in 2026 to be written off at the end of 2026.

1. Pikangikum Distribution System Deferral Account

In EB-2018-0267, WPLP received approval to establish a deferral account for the purposes of recording and facilitating the future recovery of costs relating to the temporary operation of its distribution system, which was then being constructed between Red Lake and the Pikangikum First Nation Reserve. WPLP proposed to record costs incurred in respect of the distribution system from the date it went into service until such time as the system is incorporated into and becomes part of WPLP's Transmission System. WPLP explained that all or substantially all of the capital costs of developing and constructing the distribution system were paid for through federal government funding from Indigenous and Northern Affairs Canada (INAC),[2] and that the account

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[1] As discussed in this Exhibit H-1-1 and in Exhibit H-2-2, the treatment of COVID-related known amounts incurred in the construction of the Transmission Project during 2020 has already been determined by the OEB, and the treatment of such amounts incurred during 2021-2023 has also been determined by the OEB.

[2] Currently Indigenous Services Canada (ISC).

would be used only to record the OM&A costs for the system, as well as any capital costs that may be incurred after the in-service date that are not paid for by the INAC funding. The OEB authorized the requested Pikangikum Distribution System Deferral Account to be established, effective from the in-service date for the distribution system until such time as it is converted to form part of WPLP's Transmission System. The account was established in lieu of setting a distribution revenue requirement and charging distribution rates to Hydro One Remote Communities Inc. (HORCI) during the temporary period that the system was being operated at a distribution voltage. Specifically, the OEB required WPLP to establish six sub-accounts (1508.004 through 1508.009) of Account 1508, Other Regulatory Assets, as follows:

- Sub-account 1508.004 is to record OM&A costs.
- Sub-account 1508.005 is to record capital costs incurred after the distribution system is in service.
- Sub-account 1508.006 is to record depreciation expense.
- Sub-account 1508.007 is to record accumulated depreciation.
- Sub-account 1508.008 is to record OM&A carrying charges.
- Sub-account 1508.009 is to record capital carrying charges.

WPLP's Pikangikum Distribution System was placed in service on December 20, 2018, from which time it operated as a distribution system, supplied by HONI's 44 kV distribution system and providing service to the HORCI distribution system that serves end-use customers in Pikangikum. On May 12, 2023, the Pikangikum Distribution System was converted to being supplied by HONI's 115 kV transmission system and, effective from such date, has formed part of WPLP's Transmission System. In EB-2024-0176, WPLP received approval to dispose of the December 31, 2023 audited balance for this account, less approved 2024 dispositions, plus forecasted carrying charges to year-end 2025 and forecasted variance on 2024 carrying charges, and to recover those costs in its 2025 revenue requirement for the Remote Connection Lines. WPLP also received approval to continue the account in 2025 without adding new principal amounts thereto.

In the current application, as described in Exhibit H-2-1, WPLP is seeking full and final disposition of the account, based on the audited balance as at December 31, 2024, less the approved 2025 rate application recovery and forecasted variance on 2025 carrying charges[3], and to close this account at the end of 2026. Any remaining variance due to carrying charges will be written off in 2026.

2. In-Service Date Variance Account (ISDVA)

In EB-2021-0134, WPLP received approval to establish Account 1508 (Other Regulatory Assets), Sub-Account: In-Service Date Variance Account for the purpose of recording the difference between WPLP's approved revenue requirement based on forecasted in-service dates for the various lines/stations comprising its Transmission System and its revenue requirement if calculated based on WPLP's actual in-service dates for those lines/stations. The ISDVA was established as a symmetrical account, such that it tracks higher revenue requirements for earlier in-service dates that may be achieved, as well as lower revenue requirements if later in-service dates occur. In effect, the purpose of the ISDVA is to true-up WPLP's revenue requirement to ensure ratepayers do not end up paying for transmission service they do not ultimately receive, while also providing WPLP with appropriate cost recovery if it is able to provide transmission service on parts of its system earlier than forecast.

In approving the Settlement Agreement in EB-2021-0134, the OEB authorized the establishment of the ISDVA with an effective date of January 1, 2022. Moreover, continuation of this account was approved in EB-2022-0149, EB-2023-0168 and EB-2024-0176. There are separate sub-accounts to record principal and interest amounts related to the Line to Pickle Lake and the Remote Connections Lines.

In requesting the ISDVA, WPLP stated that it expected this account would be maintained until after WPLP's entire Transmission System is in service. Given that construction of the Transmission Project was completed in 2024, and no additional project-related transmission assets (i.e. under the EPC contract) will be coming into service in the 2026 test year, WPLP does not

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[3] As the principal balance of the account will be recovered at the end of 2025, there are no forecasted carrying charges for 2026.

expect to record additional amounts other than carrying charges in this account in 2026. Therefore, in the current application, as described in Exhibit H-2-1, WPLP is seeking full and final disposition of the account, based on the audited balance as at December 31, 2024, plus forecasted carrying charges for 2025 and 2026, less the approved 2025 rate application recovery, and to close this account at the end of 2026. Any remaining variance due to carrying charges will be written off in 2026.

3. Construction Period Interest Costs Variance Account (CPICVA)

In EB-2021-0134, WPLP received approval to establish Account 1508 (Other Regulatory Assets), Sub-Account: Construction Period Interest Costs Variance Account for the purpose of recording the revenue requirement impact attributable to the difference between the effective interest rate for long-term debt approved in that application and WPLP's actual effective interest rate on long-term debt during the construction period (the "Interest Cost Differential"). Due to the variable-rate debt facilities WPLP secured with Ontario and Senior Bank Lenders to finance the Transmission Project, there could be differences in interest rates that could lead to material variances between the interest costs included in rates and WPLP's actual interest costs. The CPICVA was established as a symmetrical account, such that it tracks higher revenue requirements for higher interest costs, as well as lower revenue requirements for lower interest costs.

The Interest Cost Differential in respect of an asset is recorded from the actual in-service date of the asset[4] until the effective date of an approved WPLP revenue requirement that reflects WPLP's cost of long-term debt financing for that asset. As WPLP has relied upon project specific financing for the duration of the construction period and will transition to long-term debt financing after all assets comprising the Line to Pickle Lake and Remote Connection Line are in service,[5] it is expected based on the current project schedule that Interest Cost Differentials will continue to be

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[4] Prior to the in-service date, interest was calculated on WPLP's CWIP account balance, in accordance with the OEB's Decision and Order in EB-2018-0190 and is recorded as a carrying cost within the CWIP account.

[5] The timing and approach for transitioning to long-term financing, taking into consideration the ongoing commercial discussions with the EPC contractor, is discussed in Exhibit G-2-1.

recorded up to and during the 2026 rate year, with WPLP's 2027 revenue requirement reflecting the cost of long-term debt.

In approving the Settlement Agreement in EB-2021-0134, the OEB authorized the establishment of the CPICVA with an effective date of January 1, 2022. Moreover, continuation of this account was approved in EB-2022-0149, EB-2023-0168 and EB-2024-0176. Further, in EB-2024-0176, the term of the CPICVA was modified from expiring as of the end of the construction period, as previously determined in EB-2021-0134, to instead expire as at such time that WPLP's construction financing has been transitioned to long-term debt financing and the audited balance of the CPICVA can thereafter be disposed of in full, including any residual carrying charges. There are separate sub-accounts to record principal and interest amounts related to the Line to Pickle Lake and the Remote Connections Lines.

WPLP proposes to continue using the CPICVA to record differences between the effective interest rate for long-term debt approved in this Application and WPLP's actual effective interest rate on long-term debt in 2026, as WPLP plans to continue to rely on variable rate project financing during this period and interest rate differences may continue to arise. WPLP is therefore seeking partial disposition of the audited balance as at December 31, 2024 (as described in Exhibit H-2-1), less the disposition amount approved in the 2025 rate application, plus forecasted carrying charges for 2025 and 2026, and will seek disposition of the final balance of the CPICVA, along with applicable carrying charges, in a future application.

4. Deferred Contingency Deferral Account (DCDA)

Pursuant to the approved Settlement Agreement in EB-2021-0134, the parties agreed that WPLP would remove and defer recovery of $48,075,777 in forecasted contingency amounts from its 2022 in-service asset additions used to calculate year-end rate base (such amount referred to as the "Deferred Contingency Amount"). The parties also agreed that WPLP would establish a new deferral account, being Account 1508 (Other Regulatory Assets), Sub Account: Deferred Contingency Deferral Account, effective January 1, 2022, to track the revenue requirement impacts associated with the Deferred Contingency Amount, which WPLP would seek to recover, to the extent the forecasted contingency is actually realized, subject to OEB review in a future transmission rate application. The amount eligible to be recorded in the DCDA was limited to the revenue requirement impact attributed to contingency costs to a maximum of $48,075,777 for 2022. There are separate sub-accounts to record principal and interest amounts related to the Line to Pickle Lake and the Remote Connections Lines.

Pursuant to the approved Settlement Agreement in EB-2022-0149, the parties agreed with WPLP's proposal to use the same approach to contingency in 2023 as was approved for 2022 in EB-2021-0134, subject to the modification that the DCDA would also be used to record the revenue requirement impact attributable to contingency costs associated with 2023 in-service additions. WPLP therefore removed and deferred $17,299,725 of contingency from the 2023 rate base and recorded the revenue requirement impact associated with that contingency amount, to the extent it was realized and did not exceed the amount removed from 2023 rate base, in the DCDA. Pursuant to the approved Settlement Agreement in EB-2023-0168, the parties agreed with WPLP's proposal to use the same approach in 2024.

As such, the amount eligible to be recorded in the DCDA is therefore limited to the revenue requirement impact attributable to contingency costs to a maximum of $48,075,777 in respect of 2022, $17,299,725 in respect of 2023, and $64,582,124 in respect of 2024, corresponding to the forecasted contingency amounts which were removed and deferred from the 2022, 2023, and 2024 in-service additions used to calculate WPLP's 2022 2023, and 2024 rate bases. In the prior proceedings, WPLP agreed to establish separate sub-accounts within the DCDA to separately record principal and interests amounts related to the Line to Pickle Lake and the Remote Connection Lines. WPLP received approval to continue this account in 2025 to track residual carrying charges until such time that it is able to dispose of its audited year-end 2024 balance, along with applicable carrying charges.

In the current Application, as described in Exhibit H-2-1, WPLP is seeking full and final disposition of the account, based on the audited balance as at December 31, 2024, plus forecasted carrying charges for 2025 and 2026, less the approved 2025 rate application recovery, and to close this account at the end of 2026. Any remaining variance due to carrying charges will be written off in 2026.

5. COVID Construction Costs Deferral Account (CCCDA)

On April 13, 2021, the OEB issued a letter in EB-2020-0133 indicating its determination that the guidelines being developed for the generic Account 1509 - Impacts Arising from the COVID-19 Emergency will not apply to greenfield utilities, including WPLP. The OEB recognized that the circumstances and impacts of the pandemic on greenfield utilities is distinct, and that any ratemaking implications of the pandemic should therefore be determined through each greenfield utility's rate proceedings.

In EB-2021-0134, WPLP requested approval to establish Account 1508 (Other Regulatory Assets), Sub-Account: COVID Construction Costs Deferral Account to record its incremental development and construction costs resulting from the COVID-19 pandemic. WPLP explained that the CCCDA was required to facilitate the recovery of WPLP's incremental COVID-related Project costs as an expense rather than as a cost of capital in its revenue requirement, as further described in Exhibit H-2-2.

In approving the Settlement Agreement in EB-2021-0134, the OEB authorized the establishment of the CCCDA with an effective date of March 10, 2020. There are separate sub-accounts to record principal and interest amounts related to the Line to Pickle Lake and the Remote Connections Lines. The approved Settlement Agreement also provided that WPLP would record in the account and over a 4-year period dispose of its COVID costs incurred to December 31, 2020 (i.e. 25% in each of 2022, 2023, 2024 and 2025). In the approved Settlement Agreement in EB-2022-0149, the parties agreed that WPLP would continue to recover the 2020 COVID costs as recorded in the CCCDA over the remaining three years of the disposition period approved in EB-2021-0134 (2023, 2024 and 2025). The parties also agreed that WPLP would not record in the CCCDA or dispose of any incremental year-end 2021 COVID costs in 2023, but instead that it would record such costs and any incremental year-end 2022 and 2023 COVID costs in a new "2021-2023 COVID Construction Costs Deferral Account", as described below. In EB-2023-0168, the parties agreed that WPLP would recover the third tranche of the balance during 2024, and in EB-2024-0176 the parties agreed that WPLP would recover the fourth and final tranche of the balance during 2025. In the current application, as described in Exhibit H-2-1, WPLP is seeking full and final disposition of the remaining portion of the account, based on the audited balance as at December 31, 2024, less the approved 2025 rate application recovery and forecasted variance on 2025 carrying charges[6], and to close this account at the end of 2026. Any remaining variance due to carrying charges will be written off in 2026.

6. OM&A Variance Account

In approving the Settlement Agreement in EB-2022-0149, the OEB authorized the establishment of a new variance account, being Account 1508, Other Regulatory Assets – Sub Account "Construction Period OM&A Variance Account", effective January 1, 2023. The account was asymmetrical, to the benefit of ratepayers, and the amounts eligible to be recorded in the Construction Period OM&A Variance Account were the differences, if any, between WPLP's forecast annual OM&A expenses as approved by the OEB and its actual OM&A expenses[7] for the corresponding year (in each case excluding depreciation expense and income tax expense), during the period that WPLP's transmission project was under construction. Any shortfall in actual spending relative to forecast, together with applicable carrying charges on the principal balance recorded, was to be returned to ratepayers in a future rate proceeding.[8] WPLP also agreed to establish separate sub-accounts within the Construction Period OM&A Variance Account to separately record principal and carrying charges related to the Line to Pickle Lake and the Remote Connection Lines. Pursuant to the approved Settlement Proposal in EB-2023-0168, the parties agreed that WPLP should continue this account in 2024. In EB-2024-0176, the parties agreed to continue the account in 2025 under the new name "OM&A Variance Account" as an asymmetrical

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[6] As the principal balance of the account will be recovered at the end of 2025, there are no forecasted carrying charges for 2026.

[7] This excludes any donation expenses incurred by WPLP.

[8] WPLP notes that while it has a budget for donations, those costs are not included in the calculation of the balance in this account, and WPLP does not otherwise seek to recover any amounts relating to donations from ratepayers.

account, and to record any variances between approved and actual OM&A expense along with applicable carrying charges. In the current Application, WPLP is seeking partial disposition based on the audited balance of the OM&A Variance Account as at December 31, 2024 (as described in Exhibit H-2-1), plus forecasted carrying charges for 2025 and 2026. WPLP is not seeking to add principal additions to the account in 2026. WPLP requests that the account be continued until such time that it is able to dispose of its audited year-end 2025 balance, along with applicable carrying charges, in a future application.

7. Federal CIAC Variance Account

In approving the Settlement Agreement in EB-2023-0168, the OEB authorized the establishment of a new variance account, being Account 1508, Other Regulatory Assets – Sub Account "Federal CIAC Variance Account", effective January 1, 2024 until December 31, 2024, for the purpose of recording the revenue requirement impact of the difference, if any, between WPLP's forecasted date of the Contribution in Aid of Construction (CIAC) funds being distributed to WPLP pursuant to the Federal Funding Framework and the actual date such funds are distributed to WPLP, based on a forecast date of December 31, 2024. For the purpose of settlement, the Parties agreed that the account will be asymmetrical to the benefit of ratepayers and that the term of the account will expire December 31, 2024, such that if the CIAC is not distributed to WPLP until after such date then the rate impacts thereof would be a matter for consideration in a future rate application.

In EB-2024-0167, the parties agreed to modify the Federal CIAC Variance Account, by extending its term from December 31, 2024, as previously approved in EB-2023-0168, to a modified expiry date of December 31, 2026, to allow for the principal amounts that were recorded in 2024 to be audited in 2025 for disposition in 2026. As such, in the current Application, as described in Exhibit H-2-1, WPLP is seeking full and final disposition of the account, based on the audited balance as at December 31, 2024, inclusive of forecasted carrying charges for 2025 and 2026, and to close this account at the end of 2026. Any remaining variance due to carrying charges will be written off in 2026.

8. EPC COVID-Related Costs Deferral Account

In approving the Settlement Agreement in EB-2023-0168, the OEB authorized the establishment of a new deferral account, being Account 1508, Other Regulatory Assets – Sub Account "EPC COVID-Related Costs Deferral Account", effective January 1, 2024, to record costs, including applicable carrying charges, incurred and to be incurred by WPLP under its EPC Contract that relate to 2020 or later and which are in respect of anticipated claims from the EPC contractor for cost and schedule relief under the EPC Contract in relation to COVID and related access issues in the Whitefeather Forest area. Moreover, the Parties agreed that WPLP will establish sub-accounts for each year from 2020 to such year that all outstanding amounts are determined and shall record in such sub-accounts any amounts relating to such years. Furthermore, for the purpose of settlement, the Parties agreed that the method of recovery – as capital or as expenses – will be subject to determination in a future application, and that the carrying cost shall on an interim basis be the OEB prescribed rate but shall be recalculated on the basis of the applicable CWIP rate if and when recovery is determined to be as capital.

In EB-2024-0176, the parties agreed to continue the account in 2025. The parties further agreed that if WPLP is not in a position to seek clearance of the balance from the EPC COVID-Related Cost Deferral Account as part of the present application in respect of a 2026 test year or its first multi-year revenue requirement application to be filed in 2026 in respect of a rate period starting with the 2027 test year, on account of WPLP not having reached a final settlement with (or not having received a final arbitration award in respect of) its EPC contractor, it would be appropriate for WPLP to have the ability to seek mid-term clearance of such account during its first multi-year rate term and the parties will not object to such a proposal if included as part of WPLP's initial multi-year revenue requirement application.

As commercial discussions with the EPC Contractor are still in progress, WPLP is proposing to continue to use the EPC COVID-Related Costs Deferral Account in 2026 to record costs, including applicable carrying charges, incurred and to be incurred by WPLP under its EPC Contract that relate to 2020 or later and which are in respect of anticipated claims from the EPC contractor for cost and schedule relief under the EPC Contract in relation to COVID and related access issues in the Whitefeather Forest area. WPLP will seek disposition in a future rate application.

B. Continuity Schedule for Existing Accounts

Table 1, below, provides a summary of WPLP's existing deferral and variance account balances, including each of the sub-accounts that remain in effect as described above, as at December 31, 2024. Continuity schedules for WPLP's existing regulatory accounts from their inception up to and including their audited balances as at December 31, 2024 have been filed in Excel format with the application as "H-1-1_WPLP Deferral and CWIP Continuity 2026.xlsx".

Table 1: Existing Regulatory Account Balances (December 31, 2024)

Account	**Principal (Net)**	**Carrying Charges (Net)**	**Total**
2055 – CWIP: Transmission Development Costs	$ -	$ -	$ -
1508 – Pikangikum Distribution System Deferral Account	$634,004	$59,123	$693,127
1508 – In-Service Date Variance Account	$5,439,257	$92,973	$5,532,231
1508 – Construction Period Interest Costs Variance Account	$21,569,327	$1,495,023	$23,064,350
1508 – COVID Construction Costs Deferral Account	$4,349,913	$603,153	$4,953,066
1508 – Deferred Contingency Deferral Account	$243,262	$13,124	$256,386
1508 –OM&A Variance Account	($9,680,566)	($274,140)	($9,954,705)
1508 - Federal CIAC Variance Account	($14,023,877)	($113,800)	($14,137,677)
1508 - EPC COVID-Related Costs Deferral Account[9]	$82,099,560	$1,761,849	$83,861,409

WPLP confirms that it calculated monthly carrying charges for its deferral accounts by applying the OEB's prescribed interest rates for deferral and variance accounts[10] to the monthly opening principal balances in each account.

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[9] Further information on the EPC COVID-Related Cost Deferral account is provided in Exhibit H-2-2.

[10] See: https://www.oeb.ca/industry/rules-codes-and-requirements/prescribed-interest-rates

In addition to the accounts noted above in Table 1, WPLP in 2025, is using the sub-accounts Return on Equity Variance Account and Deemed Short-term Debt Rate Variance Account to capture the revenue requirement impact as a result of OEB’s Decision and Order in the Generic Proceeding.

C. Proposed New Accounts or Modifications to Existing Accounts

WPLP is not proposing any new deferral or variance accounts, or modifications to existing accounts, in the current Application.

Exhibit H, Tab 2, Schedule 1

Disposition of Deferral and Variance Accounts

DISPOSITION OF DEFERRAL AND VARIANCE ACCOUNTS

This Exhibit describes WPLP's proposals for the disposition of amounts recorded in its existing regulatory accounts, which are described in Exhibit H-1-1 and are as follows:

- Pikangikum Distribution System Deferral Account;
- In-Service Date Variance Account ("ISDVA");
- Construction Period Interest Costs Variance Account ("CPICVA");
- Deferred Contingency Deferral Account ("DCDA");
- COVID Construction Costs Deferral Account ("CCCDA");
- OM&A Variance Account; and
- Federal CIAC Variance Account.

In summary, WPLP is seeking final disposition for 5 of its accounts and partial disposition for 2 of its accounts in the 2026 test year. Table 1, below, sets out the amounts proposed for final disposition from the Pikangikum Distribution System Deferral Account, the ISDVA, the DCDA, the CCCDA and the Federal CIAC Variance Account. Table 1 also includes the amounts proposed for partial disposition from the CPICVA and the OM&A Variance Account. Each of these proposals for disposition is described in greater detail below. WPLP is not seeking disposition, in full or in part, for the EPC COVID-Related Costs Deferral Account.

WPLP is proposing to dispose of the net amount from the above dispositions, as set out in Table 1, below, over a 1-year period consistent with the disposition period approved in EB-2024-0176.

Table 1 – Deferral Account Disposition Continuity

	Audited 2024 Balance[1]	**Forecasted Carrying Charges[2]**	**2025 Application Recovery**	**Adjusted Balance**	**Net Amount Disposition to LTPL[3]**	**Net Amount Disposition to RCL[3]**
Pikangikum Distribution System Deferral Account	$693,127	$11,496	($708,178)	($3,555)	-	($3,555)
In-Service Date Variance Account	$5,532,231	$290,157	$724,235	$6,546,623	(224,793)	6,771,416
Construction Period Interest Costs Variance Account	$23,064,350	$444,993	($21,770,683)	$1,738,661	$334,137	$1,404,524
Deferred Contingency Deferral Account	$256,386	$6,394	($196,794)	$65,986	$13,261	$52,725
COVID Construction Costs Deferral Account	$4,953,066	$78,877	($5,056,324)	($24,381)	($17,001)	($7,380)
OM&A Variance Account	($9,954,705)	($313,439)	$5,730,870	($4,537,273)	($1,954,835)	($2,582,438)
Federal CIAC Variance Account	($14,137,677)	($698,834)	-	($14,836,511)	-	($14,836,511)
	$10,406,778	**($180,354)**	**($21,276,874)**	**($11,050,450)**	**($1,849,231)**	**($9,201,219)**

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[1] Audited balances include carrying charges.

[2] Forecasted carrying charges for 2025 and 2026 as applicable.

[3] Disposition amounts for LTPL and RCL total 100% of adjusted account balances.

A. Pikangikum Distribution System Deferral Account

As noted in Exhibit H-1-1, the Pikangikum Distribution System was converted to being supplied by HONI's 115 kV transmission system on May 12, 2023, and effective from that date has formed part of WPLP's Transmission System. In the current Application, WPLP is seeking full and final disposition of the account, based on the audited balance as at December 31, 2024, less the approved 2025 rate application recovery and forecasted variance on 2025 carrying charges, and to close this account at the end of 2026. Any remaining variance due to carrying charges will be written off in 2026.

Specifically, WPLP proposes to dispose of $3,555, being the audited 2024 year-end balance of $693,127, plus forecasted 2025 carrying charges in the amount of $11,496, less the disposition amount of $708,178, included in the 2025 rate application[4], by adding these amounts to the portion of its 2026 base transmission revenue requirement that is allocated to the Remote Connection Lines.

Adding the amounts being disposed of to the portion of the base revenue requirement that is allocated to the Remote Connection Lines will result in cost recovery through the fixed monthly charge that is applicable to HORCI. This is appropriate since HORCI is the distributor providing service to the Pikangikum First Nation, which is the only load that was served by WPLP's Pikangikum Distribution System. HORCI is therefore the entity that would have otherwise paid these costs if WPLP had established distribution rates instead of this deferral account.

B. In-Service Date Variance Account (ISDVA)

WPLP is seeking full and final disposition of the account in the amount of $6,546,623, based on the audited December 31, 2024 balance of $5,532,231, plus forecasted carrying charges for 2025 and 2026 in the amount of $290,157, less the disposition amount of $724,235, approved in the

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[4] The amount included in the 2025 rate application disposition was the 2023 audited balance plus forecasted carrying charges to the end of 2025. Therefore, the amount being requested for disposal in the 2026 revenue requirement includes the variance between the 2025 forecasted carrying charges and the amount approved in the 2025 rate application.

2025 rate application[5], and to discontinue this account at the end of 2026 with any carrying charge variance to be written off in 2026.

C. Construction Period Interest Costs Variance Account (CPICVA)

WPLP is seeking partial disposition of the account in the amount of $1,738,661, being the audited December 31, 2024 balance of $23,064,350, plus forecasted carrying charges for 2025 and 2026 in the amount $444,993, less the disposition amount of $21,770,683, as approved in the 2025 rate application[6], and to continue using this account in 2026 to record the revenue requirement impact attributable to the difference between the effective interest rate for long-term debt approved in the 2026 rate application and WPLP's actual interest rate on long-term debt during this period.

D. Deferred Contingency Deferral Account (DCDA)

WPLP is seeking full and final disposition of the account in the amount of $65,986[7], being the audited December 31, 2024 balance in this account of $256,386, plus forecasted carrying charges for 2025 and 2026 in the amount $6,394, less the disposition amount of $196,794, approved in the 2025 rate application[8], and to discontinue this account at the end of 2026. Any variance in carrying charges will be written off in 2026.

E. COVID Construction Costs Deferral Account (CCCDA)

Pursuant to the approved Settlement Agreement in EB-2021-0134 and as confirmed in the approved Settlement Agreements in EB-2022-0149, EB-2023-0168 and EB-2024-0176, WPLP is recovering its audited 2020 year-end balance over a four-year period (i.e. 25% in each of 2022, 2023, 2024 and 2025) plus applicable carrying charges. Accordingly, in 2026 WPLP seeks recovery of $24,381 being the audited December 31, 2024 balance in this account of $4,953,066, and forecasted carrying charges for 2025 in the amount of $78,877, less the disposition amount of

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[5] See footnote 3, above.

[6] See footnote 3, above.

[7] Contingency costs are less than the maximum amount approved in the 2024 rate application.

[8] See footnote 3, above.

$5,056,324, approved in the 2025 rate application[9]. WPLP is proposing to discontinue the account at the end of 2026 with any variance in carrying charges to be written off in 2026.

F. OM&A Variance Account

WPLP is seeking partial disposition of the account in the amount of $4,537,273 being the audited year-end 2024 balance in the amount of $9,954,705, plus forecasted carrying charges for 2025 and 2026 in the amount $313,439, less the disposition amount of $5,730,870, approved in the 2025 rate application. WPLP will continue the account to record any variances between approved and actual OM&A expense along with applicable carrying charges for the 2025 and 2026 year as agreed in EB-2024-0176, but is not seeking to add to principal balance in 2026.

G. Federal CIAC Variance Account

WPLP is seeking full and final disposition of the account in the amount of $14,836,511, being the audited year-end 2024 balance in the amount of $14,137,677, along with forecasted carrying charges for 2025 and 2026 in the amount of $698,834. WPLP is proposing to close the account at the end of 2026 with any variance in carrying charges to be written off in 2026.

WPLP has included Appendix ‘A’ which provides the continuities for each account and the forecasted carrying charges for recovery.

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[9] See footnote 3, above.

Exhibit H, Tab 2, Schedule 1

Disposition of Deferral and Variance Accounts

ATTACHMENT ‘A’

Continuity Tables for Deferral and Variance Account Recovery

Wataynikaneyap Power LP
Interest Schedule
2026 Rate Application Support

Distribution System Deferral Account	**Jan-25**	**Feb-25**	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**	**Jan-26**	**Feb-26**	**Mar-26**	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**
Opening Principle Balance	634,004	581,170	528,337	475,503	422,669	369,836	317,002	264,168	211,335	158,501	105,667	52,834	0	0	0	0	0	0	0	0	0	0	0	0
Principle Recovery	-52,834	-52,834	-52,834	-52,834	-52,834	-52,834	-52,834	-52,834	-52,834	-52,834	-52,834	-52,834	-	-	-	-	-	-	-	-	-	-	-	-
Closing Principle Balance	581,170	528,337	475,503	422,669	369,836	317,002	264,168	211,335	158,501	105,667	52,834	0	0	0	0	0	0	0	0	0	0	0	0	0
OEB Interest Rate	3.64%	3.64%	3.64%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%
# of days in month	31	28	31	30	31	30	31	31	30	31	30	31	31	28	31	30	31	30	31	31	30	31	30	31
Opening Interest Balance	59,123	54,902	50,343	45,796	40,849	35,803	30,582	25,252	19,780	14,147	8,392	2,485	-3,554	-3,258	-2,962	-2,666	-2,370	-2,073	-1,777	-1,481	-1,185	-889	-592	-296
Interest Addition	1,960	1,623	1,633	1,235	1,134	961	851	709	549	425	274	142	0	0	0	0	0	0	0	0	0	0	0	0
Interest Recovery	-6,181	-6,181	-6,181	-6,181	-6,181	-6,181	-6,181	-6,181	-6,181	-6,181	-6,181	-6,181	296	296	296	296	296	296	296	296	296	296	296	296
Closing Interest Balance	54,902	50,343	45,796	40,849	35,803	30,582	25,252	19,780	14,147	8,392	2,485	-3,554	-3,258	-2,962	-2,666	-2,370	-2,073	-1,777	-1,481	-1,185	-889	-592	-296	0

2024 Audited Balance	
Principle	634,004
Interest	59,123
	693,127
Per FS	693,127
Variance	-

In-Service Date Variance Account	**Jan-25**	**Feb-25**	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**	**Jan-26**	**Feb-26**	**Mar-26**	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**
Opening Principle Balance	5,439,257	5,489,495	5,539,732	5,589,970	5,640,207	5,690,445	5,740,682	5,790,920	5,841,157	5,891,395	5,941,632	5,991,869	6,042,107	5,538,598	5,035,089	4,531,580	4,028,071	3,524,562	3,021,053	2,517,545	2,014,036	1,510,527	1,007,018	503,509
Principle Recovery	50,237	50,237	50,237	50,237	50,237	50,237	50,237	50,237	50,237	50,237	50,237	50,237	-503,509	-503,509	-503,509	-503,509	-503,509	-503,509	-503,509	-503,509	-503,509	-503,509	-503,509	-503,509
Closing Principle Balance	5,489,495	5,539,732	5,589,970	5,640,207	5,690,445	5,740,682	5,790,920	5,841,157	5,891,395	5,941,632	5,991,869	6,042,107	5,538,598	5,035,089	4,531,580	4,028,071	3,524,562	3,021,053	2,517,545	2,014,036	1,510,527	1,007,018	503,509	-0
OEB Interest Rate	3.64%	3.64%	3.64%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%
# of days in month	31	28	31	30	31	30	31	31	30	31	30	31	31	28	31	30	31	30	31	31	30	31	30	31
Opening Interest Balance	92,973	119,904	145,348	172,590	197,224	222,477	247,372	272,894	298,552	323,838	349,765	375,312	401,509	375,682	347,065	318,536	288,262	257,030	224,141	190,206	154,920	118,108	80,119	40,692
Interest Addition	16,816	15,328	17,126	14,519	15,137	14,780	15,407	15,542	15,171	15,812	15,432	16,081	16,216	13,426	13,513	11,770	10,811	9,154	8,108	6,757	5,231	4,054	2,615	1,351
Interest Recovery	10,115	10,115	10,115	10,115	10,115	10,115	10,115	10,115	10,115	10,115	10,115	10,115	-42,043	-42,043	-42,043	-42,043	-42,043	-42,043	-42,043	-42,043	-42,043	-42,043	-42,043	-42,043
Closing Interest Balance	119,904	145,348	172,590	197,224	222,477	247,372	272,894	298,552	323,838	349,765	375,312	401,509	375,682	347,065	318,536	288,262	257,030	224,141	190,206	154,920	118,108	80,119	40,692	0

2024 Audited Balance	
Principle	5,439,257
Interest	92,973
	5,532,231
Per FS	5,532,231
Variance	-

Construction Periond Interest Cost Variance	**Jan-25**	**Feb-25**	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**	**Jan-26**	**Feb-26**	**Mar-26**	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**
Opening Principle Balance	21,569,327	19,913,518	18,257,708	16,601,899	14,946,090	13,290,281	11,634,471	9,978,662	8,322,853	6,667,043	5,011,234	3,355,425	1,699,616	1,557,981	1,416,346	1,274,712	1,133,077	991,442	849,808	708,173	566,539	424,904	283,269	141,635
Principle Recovery	-1,655,809	-1,655,809	-1,655,809	-1,655,809	-1,655,809	-1,655,809	-1,655,809	-1,655,809	-1,655,809	-1,655,809	-1,655,809	-1,655,809	-141,635	-141,635	-141,635	-141,635	-141,635	-141,635	-141,635	-141,635	-141,635	-141,635	-141,635	-141,635
Closing Principle Balance	19,913,518	18,257,708	16,601,899	14,946,090	13,290,281	11,634,471	9,978,662	8,322,853	6,667,043	5,011,234	3,355,425	1,699,616	1,557,981	1,416,346	1,274,712	1,133,077	991,442	849,808	708,173	566,539	424,904	283,269	141,635	0
OEB Interest Rate	3.64%	3.64%	3.64%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%
# of days in month	31	28	31	30	31	30	31	31	30	31	30	31	31	28	31	30	31	30	31	31	30	31	30	31
Opening Interest Balance	1,495,023	1,403,290	1,300,481	1,198,511	1,083,216	964,915	841,019	713,829	582,196	445,399	304,878	159,479	10,070	11,378	11,901	12,448	12,505	12,293	11,614	10,641	9,288	7,505	5,392	2,874
Interest Addition	66,682	55,605	56,444	43,119	40,113	34,518	31,225	26,781	21,617	17,893	13,015	9,005	4,561	3,777	3,801	3,311	3,041	2,575	2,281	1,901	1,471	1,140	736	380
Interest Recovery	-158,414	-158,414	-158,414	-158,414	-158,414	-158,414	-158,414	-158,414	-158,414	-158,414	-158,414	-158,414	-3,254	-3,254	-3,254	-3,254	-3,254	-3,254	-3,254	-3,254	-3,254	-3,254	-3,254	-3,254
Closing Interest Balance	1,403,290	1,300,481	1,198,511	1,083,216	964,915	841,019	713,829	582,196	445,399	304,878	159,479	10,070	11,378	11,901	12,448	12,505	12,293	11,614	10,641	9,288	7,505	5,392	2,874	0

2024 Audited Balance	
Principle	21,569,327
Interest	1,495,023
	23,064,350
Per FS	23,064,350
Variance	-

Deferred Contingency Deferral Account	**Jan-25**	**Feb-25**	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**	**Jan-26**	**Feb-26**	**Mar-26**	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**
Opening Principle Balance	243,262	228,203	213,144	198,085	183,025	167,966	152,907	137,848	122,789	107,730	92,671	77,612	62,553	57,340	52,127	46,915	41,702	36,489	31,276	26,064	20,851	15,638	10,425	5,213
Principle Recovery	-15,059	-15,059	-15,059	-15,059	-15,059	-15,059	-15,059	-15,059	-15,059	-15,059	-15,059	-15,059	-5,213	-5,213	-5,213	-5,213	-5,213	-5,213	-5,213	-5,213	-5,213	-5,213	-5,213	-5,213
Closing Principle Balance	228,203	213,144	198,085	183,025	167,966	152,907	137,848	122,789	107,730	92,671	77,612	62,553	57,340	52,127	46,915	41,702	36,489	31,276	26,064	20,851	15,638	10,425	5,213	-0
OEB Interest Rate	3.64%	3.64%	3.64%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%
# of days in month	31	28	31	30	31	30	31	31	30	31	30	31	31	28	31	30	31	30	31	31	30	31	30	31
Opening Interest Balance	13,124	12,535	11,832	11,151	10,325	9,476	8,572	7,642	6,671	5,650	4,599	3,499	2,367	2,249	2,102	1,955	1,791	1,617	1,426	1,223	1,007	775	531	272
Interest Addition	752	637	659	514	491	436	410	370	319	289	241	208	168	139	140	122	112	95	84	70	54	42	27	14
Interest Recovery	-1,340	-1,340	-1,340	-1,340	-1,340	-1,340	-1,340	-1,340	-1,340	-1,340	-1,340	-1,340	-286	-286	-286	-286	-286	-286	-286	-286	-286	-286	-286	-286
Closing Interest Balance	12,535	11,832	11,151	10,325	9,476	8,572	7,642	6,671	5,650	4,599	3,499	2,367	2,249	2,102	1,955	1,791	1,617	1,426	1,223	1,007	775	531	272	0

2024 Audited Balance	
Principle	243,262
Interest	13,124
	256,386
Per FS	256,386
Variance	-

COVID Construction Cost Deferral Account - 2020	**Jan-25**	**Feb-25**	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**	**Jan-26**	**Feb-26**	**Mar-26**	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**
Opening Principle Balance	4,349,913	3,987,420	3,624,928	3,262,435	2,899,942	2,537,449	2,174,957	1,812,464	1,449,971	1,087,478	724,985	362,493	-0	-0	-0	-0	-0	-0	-0	-0	-0	-0	-0	-0
Principle Recovery	-362,493	-362,493	-362,493	-362,493	-362,493	-362,493	-362,493	-362,493	-362,493	-362,493	-362,493	-362,493	-	-	-	-	-	-	-	-	-	-	-	-
Closing Principle Balance	3,987,420	3,624,928	3,262,435	2,899,942	2,537,449	2,174,957	1,812,464	1,449,971	1,087,478	724,985	362,493	-0	-0	-0	-0	-0	-0	-0	-0	-0	-0	-0	-0	-0
OEB Interest Rate	3.64%	3.64%	3.64%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%
# of days in month	31	28	31	30	31	30	31	31	30	31	30	31	31	28	31	30	31	30	31	31	30	31	30	31
Opening Interest Balance	603,152	557,733	509,999	462,338	411,944	360,859	308,582	255,552	201,549	146,447	90,498	33,514	-24,381	-22,349	-20,317	-18,286	-16,254	-14,222	-12,190	-10,159	-8,127	-6,095	-4,063	-2,032
Interest Addition	13,448	11,134	11,206	8,473	7,783	6,590	5,837	4,864	3,766	2,919	1,883	973	-0	-0	-0	-0	-0	-0	-0	-0	-0	-0	-0	-0
Interest Recovery	-58,868	-58,868	-58,868	-58,868	-58,868	-58,868	-58,868	-58,868	-58,868	-58,868	-58,868	-58,868	2,032	2,032	2,032	2,032	2,032	2,032	2,032	2,032	2,032	2,032	2,032	2,032
Closing Interest Balance	557,733	509,999	462,338	411,944	360,859	308,582	255,552	201,549	146,447	90,498	33,514	-24,381	-22,349	-20,317	-18,286	-16,254	-14,222	-12,190	-10,159	-8,127	-6,095	-4,063	-2,032	0

2024 Audited Balance	
Principle	4,349,913
Interest	603,152
	4,953,065
Per FS	4,953,066
Variance	-

OMA Variance Account	**Jan-25**	**Feb-25**	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**	**Jan-26**	**Feb-26**	**Mar-26**	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**
Opening Principle Balance	-9,680,566	-9,236,382	-8,792,199	-8,348,015	-7,903,831	-7,459,648	-7,015,464	-6,571,280	-6,127,096	-5,682,913	-5,238,729	-4,794,545	-4,350,362	-3,987,832	-3,625,301	-3,262,771	-2,900,241	-2,537,711	-2,175,181	-1,812,651	-1,450,121	-1,087,590	-725,060	-362,530
Principle Recovery	444,184	444,184	444,184	444,184	444,184	444,184	444,184	444,184	444,184	444,184	444,184	444,184	362,530	362,530	362,530	362,530	362,530	362,530	362,530	362,530	362,530	362,530	362,530	362,530
Closing Principle Balance	-9,236,382	-8,792,199	-8,348,015	-7,903,831	-7,459,648	-7,015,464	-6,571,280	-6,127,096	-5,682,913	-5,238,729	-4,794,545	-4,350,362	-3,987,832	-3,625,301	-3,262,771	-2,900,241	-2,537,711	-2,175,181	-1,812,651	-1,450,121	-1,087,590	-725,060	-362,530	0
OEB Interest Rate	3.64%	3.64%	3.64%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%
# of days in month	31	28	31	30	31	30	31	31	30	31	30	31	31	28	31	30	31	30	31	31	30	31	30	31
Opening Interest Balance	-274,140	-270,678	-263,080	-256,873	-245,166	-232,989	-218,975	-204,415	-188,662	-171,187	-153,050	-133,268	-112,746	-108,846	-102,937	-97,091	-89,989	-82,197	-73,212	-63,474	-52,763	-40,953	-28,296	-14,603

Interest Addition	- 29,928	- 25,791	- 27,181	- 21,682	- 21,213	- 19,375	- 18,828	- 17,636	- 15,914	- 15,252	- 13,606	- 12,868	- 11,676	- 9,667	- 9,730	- 8,474	- 7,784	- 6,591	- 5,838	- 4,865	- 3,766	- 2,919	- 1,883	- 973
Interest Recovery	33,389	33,389	33,389	33,389	33,389	33,389	33,389	33,389	33,389	33,389	33,389	33,389	15,576	15,576	15,576	15,576	15,576	15,576	15,576	15,576	15,576	15,576	15,576	15,576
Closing Interest Balance	- 270,678	- 263,080	- 256,873	- 245,166	- 232,989	- 218,975	- 204,415	- 188,662	- 171,187	- 153,050	- 133,268	- 112,746	- 108,846	- 102,937	- 97,091	- 89,989	- 82,197	- 73,212	- 63,474	- 52,763	- 40,953	- 28,296	- 14,603	-

2024 Audited Balance	
Principle	- 9,680,566
Interest	- 274,140
	- 9,954,705
Per FS	- 9,954,705
Variance	- 0

Federal CIAC Variance Account	**Jan-25**	**Feb-25**	**Mar-25**	**Apr-25**	**May-25**	**Jun-25**	**Jul-25**	**Aug-25**	**Sep-25**	**Oct-25**	**Nov-25**	**Dec-25**	**Jan-26**	**Feb-26**	**Mar-26**	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**Oct-26**	**Nov-26**	**Dec-26**
Opening Principle Balance	- 14,023,877	- 14,023,877	- 14,023,877	- 14,023,877	- 14,023,877	- 14,023,877	- 14,023,877	- 14,023,877	- 14,023,877	- 14,023,877	- 14,023,877	- 14,023,877	- 14,023,877	- 12,855,221	- 11,686,565	- 10,517,908	- 9,349,252	- 8,180,595	- 7,011,939	- 5,843,282	- 4,674,626	- 3,505,969	- 2,337,313	- 1,168,656
Additions																								
Principle Recovery	-	-	-	-	-	-	-	-	-	-	-	-	1,168,656	1,168,656	1,168,656	1,168,656	1,168,656	1,168,656	1,168,656	1,168,656	1,168,656	1,168,656	1,168,656	1,168,656
Closing Principle Balance	- 14,023,877	- 14,023,877	- 14,023,877	- 14,023,877	- 14,023,877	- 14,023,877	- 14,023,877	- 14,023,877	- 14,023,877	- 14,023,877	- 14,023,877	- 14,023,877	- 12,855,221	- 11,686,565	- 10,517,908	- 9,349,252	- 8,180,595	- 7,011,939	- 5,843,282	- 4,674,626	- 3,505,969	- 2,337,313	- 1,168,656	0
OEB Interest Rate	3.64%	3.64%	3.64%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%	3.16%
# of days in month	31	28	31	30	31	30	31	31	30	31	30	31	31	28	31	30	31	30	31	31	30	31	30	31
Opening Interest Balance	- 113,800	- 157,155	- 196,314	- 239,669	- 276,092	- 313,730	- 350,154	- 387,792	- 425,429	- 461,853	- 499,491	- 535,915	- 573,552	- 543,471	- 506,914	- 470,559	- 430,157	- 387,530	- 341,058	- 292,157	- 240,120	- 184,542	- 126,232	- 64,583
Interest Addition	- 43,355	- 39,159	- 43,355	- 36,424	- 37,638	- 36,424	- 37,638	- 37,638	- 36,424	- 37,638	- 36,424	- 37,638	- 37,638	- 31,162	- 31,365	- 27,318	- 25,092	- 21,247	- 18,819	- 15,682	- 12,141	- 9,409	- 6,071	- 3,136
Interest Recovery	-	-	-	-	-	-	-	-	-	-	-	-	67,719	67,719	67,719	67,719	67,719	67,719	67,719	67,719	67,719	67,719	67,719	67,719
Closing Interest Balance	- 157,155	- 196,314	- 239,669	- 276,092	- 313,730	- 350,154	- 387,792	- 425,429	- 461,853	- 499,491	- 535,915	- 573,552	- 543,471	- 506,914	- 470,559	- 430,157	- 387,530	- 341,058	- 292,157	- 240,120	- 184,542	- 126,232	- 64,583	0

2024 Audited Balance	
Principle	- 14,023,877
Interest	- 113,800
	- 14,137,677
Per FS	- 14,137,677
Variance	-

Exhibit H, Tab 2, Schedule 2

COVID-Related Construction Costs

COVID-RELATED CONSTRUCTION COSTS

This schedule provides an overview of the OEB-approved and WPLP-proposed treatments for construction costs resulting from the COVID-19 pandemic and related matters.

A. BACKGROUND

The COVID-19 pandemic has impacted the Transmission Project's cost, including costs related to WPLP's EPC Contract as well as costs unrelated to its EPC Contract. Some of the impacts have been described in WPLP's previous transmission rate applications.[1] Since its last rate application, WPLP has continued to diligently monitor and oversee the close out activities of its EPC Contractor, Valard. WPLP no longer requires Valard to implement the COVID-19 Management Plan that was previously in place.

In EB-2023-0168, WPLP forecasted that, by the end of 2023, it would have incurred known COVID-19 Project costs unrelated to its EPC Contract of approximately $1.4 million, and under its EPC Contract of approximately $92 million. The total COVID amounts incurred under the EPC Contract for 2020-2023 were approximately $87.23 million and the amount incurred by WPLP unrelated to its EPC Contract at the end of 2023 was $1.29 million. Notably, as explained in EB-2023-0168 and EB-2024-0176, there are additional COVID-19 costs not included in these amounts that are the subject of commercial discussions that are progressing, and which continue to progress, between WPLP and its EPC Contractor in relation to EPC costs and schedule. As these additional costs are the subject of ongoing commercial discussions between the parties, they remain uncertain. In 2024, as further discussed below, WPLP executed an interim COVID cost change order for $90M to provide an interim payment to the EPC Contractor as negotiations continue on COVID cost overruns. While these additional costs may relate to the period since the onset of the pandemic in early 2020, due to their remaining uncertainty they have not been recognized by WPLP as having been incurred given the status of the commercial discussions to date.

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[1] See Exhibit H-2-2 in each of EB-2021-0134, EB-2022-0149, EB-2023-0168 and EB-2024-0176.

B. PREVIOUSLY APPROVED RATE TREATMENT

Through WPLP's prior transmission rate proceedings, the OEB has provided for (a) the recovery of known and audited 2020 costs from the COVID-19 pandemic over a 4-year period as an expense, (b) the recording of known 2021-2023 costs from the COVID-19 pandemic in a deferral account, (c) disposal of the audited 2021-2023 amounts, along with applicable carrying charges, as capital, and (d) recording (when known) of unknown COVID-related costs incurred by WPLP under its EPC Contract that relate to 2020 or later and which are in respect of anticipated claims from the EPC Contractor for cost and schedule relief under the EPC Contract in relation to COVID and related access issues in the Whitefeather Forest area, with the method of recovery to be determined in a future application. These treatments are described in greater detail, as follows.

1. 2020 COVID-19 Costs

In EB-2021-0134, the OEB approved a Settlement Proposal pursuant to which the parties agreed that WPLP will (a) establish a new COVID Construction Costs Deferral Account (CCCDA), effective March 11, 2020, to record the amount of construction costs relating to the Transmission System that are directly attributable to the COVID-19 pandemic, and (b) recover the audited year-end 2020 balance thereof, together with applicable carrying charges, as an expense through disposition over a 4-year period (i.e. 25% in each of 2022, 2023, 2024 and 2025). WPLP incurred total known COVID-19 costs of approximately $17.4 million in 2020 and is recovering the final portion of this amount, plus carrying charges, in 2025 in accordance with the OEB's Decision and Order in EB-2021-0134.

The cost of $17.4 million for 2020 reflects the known impacts of implementing COVID-19 health and safety measures, lost productivity in performing construction work and impacts on construction activities during 2020. This cost was incurred by WPLP through the execution of Change Orders under the EPC Contract, arising from the COVID-related Force Majeure event, which provided Valard with specific cost and schedule relief, including for 2020. It is important to note that, to the extent Valard claims any additional costs for COVID-19 impacts and related matters (which continue to be the subject of commercial discussions between the parties) related to 2020, such amounts have not been recognized by WPLP as having been incurred to date. In accordance with the OEB-approved Settlement Proposal in EB-2023-0168, discussed below, any 2020 capital cost amounts that have not been recorded in the CCCDA, if and when they are recognized as having been incurred by WPLP under the EPC Contract in respect of anticipated claims from the EPC Contractor for cost and schedule relief in relation to COVID and related access issues in the Whitefeather Forest area, would instead be recorded in the EPC COVID-Related Costs Deferral Account ("EPC COVID Account") at that time. Recovery, whether as capital or expense, will be subject to determination in a future application. In the interim, the carrying cost shall be the OEB prescribed rate, but this shall be recalculated on the basis of the applicable CWIP rate if and when recovery is determined to be as capital.

2. 2021-2023 COVID-19 Costs

In EB-2022-0149, the OEB approved a Settlement Proposal pursuant to which the parties agreed that WPLP will establish the 2021-2023 COVID Construction Costs Deferral Account (the "2021-2023 CCCDA"), effective January 1, 2021, to record the year-end construction costs from 2021 to 2023 which are directly attributable to the COVID-19 pandemic, with prudence and the approach to disposition (i.e. as capital or as an expense) to be determined at the time of disposition in a future rate proceeding once the COVID-19 costs for these years are known, and with the applicable carrying charges to be consistent with the approach to disposition that is ultimately approved at the time of disposition (i.e. the CWIP rate/AFUDC if disposed of as capital and the OEB prescribed rate if disposed of as an expense).

WPLP's audited year-end known construction costs directly attributable to the COVID-19 pandemic, as recorded in the 2021-2023 CCCDA, were approximately $42.1 million for 2021 and $26.27 million for 2022. In EB-2023-0168, the OEB-approved Settlement Proposal provided for these amounts to be disposed of and recovered as capital, by adding these amounts to WPLP's rate base. The parties also agreed that WPLP should not be permitted to recover its unaudited forecast of 2023 known construction costs directly attributable to the COVID-19 pandemic, which was approximately $6.4 million. Instead, the parties agreed that disposition of 2023 amounts should be on an audited basis in a subsequent application. As such, the 2023 known construction costs directly attributable to COVID remained in the 2021-2023 CCCDA.

In EB-2024-0176, WPLP's reported that its audited 2023 year-end balance in the account was approximately $3 million. The parties to the OEB-approved Settlement Agreement agreed that the account would be disposed of on a final basis, inclusive of applicable carrying charges and adjustments to reflect AFUDC, and the account discontinued. The amount was added to WPLP's rate base effective from the time the corresponding assets were placed into service during 2024.

3. EPC COVID-Related Costs Deferral Account

In EB-2023-0168, as noted above, the OEB authorized the establishment of a new deferral account, being the EPC COVID-Related Costs Deferral Account, or "EPC COVID Account", effective January 1, 2024, to record costs, including applicable carrying charges, incurred and to be incurred by WPLP under its EPC Contract that relate to 2020 or later and which are in respect of anticipated claims from the EPC Contractor for cost and schedule relief under the EPC Contract in relation to COVID and related access issues in the Whitefeather Forest area. The Parties to the approved settlement agreed that the method of recovery – as capital or as expenses – will be subject to determination in a future application, and that the carrying cost shall on an interim basis be the OEB prescribed rate but shall be recalculated on the basis of the applicable CWIP rate if and when recovery is determined to be as capital.

It was therefore important to note, and continues to be important to understand, that pending the resolution of final EPC costs with Valard, additional costs for COVID-19 impacts and related matters (which continue to be the subject of commercial discussions between the parties and therefore remain uncertain) related to the period from 2020 onward, have not been recognized by WPLP as having been incurred to date and have never been recorded in either of the CCCDA or the 2021-2023 CCCDA. Any such amounts, if and when they are recognized as having been incurred by WPLP, would instead be recorded in the EPC COVID Account at that time.

C. PROPOSED RATE TREATMENT

The following sections describe WPLP's proposed rate treatment for its recognized or potential Project costs arising from the COVID-19 pandemic and related matters.

1. 2020 COVID-19 Costs

In this Application, in accordance with the OEB's determination in EB-2021-0134, WPLP is completing its recovery of the audited year-end 2020 balance of the CCCDA, together with applicable carrying charges. Accordingly, as indicated in Exhibit H-2-1, WPLP is seeking recovery of $24,381 in 2026, which represents forecasted carrying charges variance for 2025. WPLP is proposing to close the account at the end of 2026.

Moreover, as noted above, if and to the extent WPLP recognizes any additional amounts relating to 2020 arising from the resolution of final EPC costs with Valard and recognized for accounting purposes as having been incurred, any such amounts would be recorded in the EPC COVID Account at the time they are recognized, with the manner of disposition as an expense or as capital to be determined by the OEB upon WPLP requesting disposition of that account.

2. 2021-2023 COVID-19 Costs

For the known COVID-related costs related to the 2021-2023 period, WPLP has received approval in prior applications to dispose of audited amounts on a final basis and to discontinue the account in EB-2024-0176.

3. COVID-19 Costs for 2024 Onward

WPLP anticipates that it will incur additional COVID-related costs associated with the Project in 2024 and later years, which costs would arise from a settlement or other final resolution of the costs that are the subject of the ongoing commercial discussions with Valard. Any such amounts, if incurred in respect of 2024 or later, would be recorded in the EPC COVID-Related Costs Deferral Account and would be treated as capital. As at December 31, 2024, WPLP has recorded

$82.1 million[2] in the EPC COVID-Related Costs Deferral Account and $1.8 million in carrying charges reflecting an interim payment on Valard cost overruns currently under negotiation. This conservative provisional amount associated with Valard's COVID-related cost overruns will offset future settlement and any interest that may be owed to Valard at a future date upon settlement. In a future application, WPLP would propose to add such costs to its rate base and, upon approval of such rate base addition, the additional CIAC discussed in Exhibit I-4-1 would be triggered under the Federal Funding Framework, as amended.

4. Contractor Cost Overruns

As noted above, the final resolution of EPC-related costs between Valard and WPLP that relate to COVID-19 impacts and related matters not otherwise recorded in the CCCDA or the now discontinued 2021-2023 CCCDA will be recorded in the EPC COVID Account. These amounts are expected to be due primarily to productivity loss, incremental costs and schedule delays that the EPC Contractor takes the position arose from implementation of COVID-19 health and safety measures, as well as access issues in the Whitefeather Forest. These additional costs continue to be the subject of commercial discussions between WPLP and Valard and therefore remain uncertain in terms of quantum and responsibility. They may relate to any year of the construction period since the pandemic commenced in early 2020. When provisional or final settlement amounts are recognized as having been incurred by WPLP upon the conclusion of the commercial discussions or upon otherwise being determined, such amounts, including applicable carrying charges[3], would be recorded in the EPC COVID Account, which is discussed in Exhibit H-1-1.

As discussed in Exhibit I-4-1, based on the 2024 Amendment to the Trust Agreement under the Federal Funding Framework, it is WPLP's expectation that in its next revenue requirement

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[2] The $82.1 million is inclusive of the $90 million interim COVID cost change order less the value of EPC COVID cost accrual reversals on Testing, Quarantine and Vaccinations as result of a final change order ($7.9 million) finalized in 2024.

[3] WPLP will record carrying charges at the OEB prescribed rate for deferral and variance accounts, however carrying charges will be dependent on OEB's future ruling on the disposition of the balance recorded in the EPC COVID Account as capital or expense. Carrying charges will be calculated based on WPLP's actual cost of debt (AFUDC) if disposition of costs is deemed to be capital.

application after recording the final settlement amount in the EPC COVID Account, WPLP would bring forward for disposition the balance thereof, together with carrying charges (AFUDC), to rate base.[4] After the OEB undertakes a prudence review and approves the rate base addition, a second CIAC under the Federal Funding Framework will be triggered and the independent Trust would then provide to WPLP a second CIAC based on and to fully offset the approved amount of the rate base addition.

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[4] In EB-2024-0176, the parties agreed that if WPLP is not in a position to seek clearance of the balance from the EPC COVID-Related Cost Deferral Account as part of the present application in respect of the 2026 test year or its first multi-year revenue requirement application to be filed in 2026 in respect of a rate period starting with the 2027 test year, on account of WPLP not having reached a final settlement with (or not having received a final arbitration award in respect of) its EPC Contractor, it would be appropriate for WPLP to have the ability to seek mid-term clearance of such account during its first multi-year rate term and the parties will not object to such a proposal if included as part of WPLP's initial multi-year revenue requirement application.

Exhibit I, Tab 1, Schedule 1

Overview of Cost Allocation & Rate Design

OVERVIEW OF COST ALLOCATION & RATE DESIGN

In contrast to other Ontario transmitters, where cost recovery is predominantly achieved through the three UTR rate pools, WPLP is subject to a unique cost recovery and rate framework, approved by the OEB in EB-2018-0190, as described further in Exhibit I-2-1. Under this framework, WPLP must allocate its revenue requirement between the Line to Pickle Lake (for recovery through the UTR Network rate) and the Remote Connection Lines (for recovery through monthly fixed charges applicable to HORCI).

This exhibit provides details of WPLP's cost allocation process, impacts to the UTR Network rate, the determination of the fixed monthly rate applicable to HORCI, and the bill impacts resulting from WPLP's 2026 revenue requirement.

The components of WPLP's 2026 revenue requirement, with references to supporting schedules in this Application, are summarized in Table 1, below.

Table 1 – Summary of 2026 Revenue Requirement

	Total	**Reference**
Gross Fixed Assets (avg)	1,323,397,135	C-3-1
Accumulated Depreciation (avg)	-87,914,125	C-3-1
Net Fixed Assets (avg)	1,235,483,010	C-3-1
Working Capital Allowance	0	C-4-1
Rate Base	1,235,483,010	C-1-1
Regulated Rate of Return	6.34%	G-2-1
Regulated Return on Rate Base	78,267,850	G-2-1
OM&A Expenses	38,353,810	F-2-1
Property Taxes	0	F-5-1
Depreciation Expense	26,863,558	F-4-1
Income Taxes	596,325	F-5-1
Service Revenue Requirement	**144,081,543**	
Other Revenue Offset	0	E-3-1

Base Revenue Requirement	**144,081,543**	
Disposition of Pikangikum Distribution System Deferral Account	-3,555	H-2-1
Disposition of COVID Deferral Account (CCCDA)	-24,381	H-2-1
Disposition of In-Service Date Variance Account	6,546,623	H-2-1
Disposition of Construction Period Interest Costs Variance Account	1,738,661	H-2-1
Disposition of Deferred Contingency Deferral Account	65,986	H-2-1
Disposition of OM&A Variance Account	-4,537,273	H-2-1
Disposition of Federal CIAC Variance Account	-14,836,511	H-2-1
Revenue Requirement for Rates	**133,031,093**	

A. Cost Allocation

WPLP's 2026 Revenue Requirement of approximately $133.0 million is allocated between the Line to Pickle Lake and the Remote Connection Lines as shown in Table 2.

Table 2 – Allocation of 2026 Revenue Requirement

	LTPL	**RCL**	**Total**
Revenue Requirement	**29,685,502**	**103,345,591**	**133,031,093**

Exhibit I-2-1 provides the details supporting this allocation, along with references to supporting sections of the Application.

B. Rate Design and Bill Impacts

In Exhibit I-3-1, WPLP has calculated a resulting reduction in the UTR Network rate of $0.05, using status-quo values for all other transmitters in order to isolate the impact of this Application. The bill impact resulting from the Line to Pickle Lake revenue requirement is a reduction of $0.10 per month, or 0.07% for a typical residential customer, as detailed in Exhibit I-4-1. WPLP anticipates that the OEB will determine actual 2026 UTRs in a generic proceeding, based on the approved 2026 revenue requirements of each transmitter in Ontario.

In accordance with WPLP's OEB-approved cost recovery and rate framework, the revenue requirement allocated to the Remote Connection Lines will be recovered through a fixed monthly charge of $8,612,133 applicable to HORCI, effective from January 1, 2026, as described in Exhibit I-3-2. The expense incurred by HORCI in respect of this transmission rate would form part of HORCI's revenue requirement and as such form part of the RRRP funding calculation and RRRP payable to HORCI. The impact of HORCI recovering this amount through the RRRP pool is a reduction of $0.16 per month, or 0.12% for a typical residential customer,[1] as detailed in Exhibit I-4-1. Exhibit I-4-1 also describes how the transmission rate charged to HORCI does not result in bill increases for HORCI's residential customers in remote communities.

The total bill impact for a typical residential customer arising from WPLP's 2026 revenue requirement is a reduction of $0.26 per month, or 0.18%.

Details of bill impacts for typical general service customers and transmission-connected customers arising from WPLP's 2026 revenue requirement are provided in Exhibit I-4-1.

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[1] Throughout this Exhibit I, a typical residential customer is considered to be a Hydro One Networks Medium-Density (R1) customer, using 750 kWh/month on Time-of-Use rates.

Exhibit I, Tab 2, Schedule 1

Cost Allocation

COST ALLOCATION

A. WPLP's Cost Recovery and Rate Framework

In EB-2018-0190, WPLP requested OEB approval for a project-specific cost recovery and rate framework to support the unique funding and financing circumstances surrounding WPLP's project, which is summarized as follows:

> Under the proposed framework, the revenue requirement impacts arising from the Remote Connection Lines (based on direct and indirect capital expenditures and OM&A expenses) would be charged by WPLP through fixed monthly transmission rates applicable to service provided to HORCI from the Remote Connection Lines, which rates would be approved by the Board from time to time in future transmission rate proceedings. The revenue requirement impacts arising from all other in-service capital and OM&A costs would be recovered through the UTR. HORCI would include in its revenue requirement the costs it incurs to pay WPLP's transmission rates. In accordance with section 4(2.1) of the RRRP Regulation, the incremental amount in HORCI's revenue requirement attributable to the rates charged by WPLP would be recovered through the RRRP mechanism, while rates applicable to HORCI's customers would be expected to continue to be set based only on inflationary adjustments in accordance with the RRRP Regulation.[1]

In its decision and order in EB-2018-0190, the OEB approved the cost recovery and rate framework as requested.[2] As a result of that decision, and consistent with its prior rate applications, WPLP is required to allocate its total revenue requirement into two categories:

1. **Line to Pickle Lake** – network assets for which direct costs, and an allocation of indirect costs, will be recovered through the UTR Network rate; and
2. **Remote Connection Lines** – assets that would otherwise be categorized as line connection and transformation connection assets, for which direct costs, and an allocation of indirect costs, will be recovered through a monthly fixed charge applied to service provided to

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[1] EB-2018-0190; WPLP Reply Submission; February 15, 2019; pp. 24-25

[2] EB-2018-0190; Decision and Order; April 1, 2019; pp. 27-28

HORCI, in lieu of requiring a capital contribution and applying UTR Line and Transformation Connection rates.

Further detail on the categorization of WPLP's assets is provided in Exhibit B-1-2-A and B-1-2-B.

B. Rate Base

The rate base information from Exhibit C is summarized in Table 1 below.

Table 1 – Rate Base by Category

Category	**Item**	**2026 Forecast ($000's)**		
		Opening	**Closing**	**Average**
LTPL	Gross Fixed Assets	321,292	321,292	321,292
	Less Accumulated Depreciation	-20,616	-27,078	-23,847
	Net Fixed Assets	**300,676**	**294,215**	**297,445**
	Working Capital Allowance	0	0	0
	Rate Base			**297,445**
	% of Gross Fixed Assets			**17.8%**
RCL	Gross Fixed Assets	1,486,207	1,487,007	1,486,607
	Less Accumulated Depreciation	-74,431	-104,398	-89,414
	Less Contribution in Aid of Construction	-487,134	-487,134	-487,134
	Plus Accumulated Depreciation CIAC	20,864	30,852	25,858
	Net Fixed Assets	**945,506**	**926,327**	**935,917**
	Working Capital Allowance	0	0	0
	Rate Base			**935,917**
	% of Gross Fixed Assets			**82.2%**
Sub-Total Transmission System		**1,246,182**	**1,220,542**	**1,233,362**
GP	Gross Fixed Assets	1,696	3,568	2,632
	Less Accumulated Depreciation	-299	-722	-510
	Net Fixed Assets	**1,397**	**2,846**	**2,121**
	Working Capital Allowance	0	0	0

	Rate Base		**2,121**
Total Rate Base			**1,235,483**

For the purpose of determining WPLP's 2026 revenue requirement and setting rates, rate base attributable to General Plant ("GP") assets (i.e. $2.1 million in 2026) is allocated 17.8% to the LTPL and 82.2% to the RCL based on the respective proportions of the gross fixed asset costs[3] of 2026 transmission system rate base for each category, as shown in Table 2.

Table 2 – Rate Base by Category with General Plant Allocations

Category	**2026 Rate Base**		
	Transmission System Assets	**Allocation of GP Assets**	**Total**
LTPL	297,445	377	297,822
RCL	935,917	1,744	937,661
Total	**1,233,362**	**2,121**	**1,235,483**

C. OM&A Expenses and Income Taxes

WPLP's 2026 OM&A includes direct expenses that are directly related to fixed assets, as well as indirect overheads. WPLP's 2026 income tax expense consists of the Ontario Corporate Minimum Tax payable by one of WPLP's partners, as detailed in Exhibit F-5-1.

Based on the calculations in Table 1, indirect OM&A costs for the 2026 test year are allocated 17.8% to the Line to Pickle Lake and 82.2% to the Remote Connection Lines, as illustrated in Table 3.

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[3] Consistent with the 2025 rate application filing.

Table 3 – Allocation of 2026 OM&A and Income Tax Expense

	LTPL	**RCL**	**Total**
Direct OM&A Expenses	769,835	8,011,755	8,781,591
Indirect OM&A Expenses			29,572,219
Income Tax Expense			596,325
Allocation Factor from Table 1	*17.8%*	*82.2%*	*100%*
Allocation of Indirect OM&A	5,255,450	24,316,769	29,572,219
Allocation of Income Tax Expense	105,976	490,349	596,325
Total 2026 OM&A	**6,025,286**	**32,328,524**	**38,353,810**
Total 2026 Allocated Income Tax	**105,976**	**490,349**	**596,325**

D. Depreciation Expense

In Exhibit F-4-1, 2026 depreciation expenses are calculated separately for each of the Line to Pickle Lake and the Remote Connection Lines, based on the forecasted number of in-service months for assets in each category. Depreciation expenses related to General Plant are allocated between the Line to Pickle Lake and the Remote Connection Lines on the same 17.8%/82.2% basis described above. Table 4 below shows the depreciation expense for each rate category for the 2026 test year.

Table 4 – 2026 Depreciation Expense by Rate Category

	LTPL	**RCL**	**Total**
Depreciation Expense	6,536,434	20,327,124	26,863,558

E. Disposition of Deferral Account Balances

As described in Exhibit H-2-1, WPLP is proposing to recover its proposed deferral and variance account dispositions over one year, consistent with the disposition period approved in EB-2024-0176 (unless previously approved on a different basis) as follows:

1. **Pikangikum Distribution System Deferral Account:** WPLP proposes to add the 2024 year-end balance inclusive of forecasted carrying charges, less disposal amount approved in the 2025 rate application of ($3,555) to the portion of the 2026 base revenue requirement that is allocated to the Remote Connection Lines. Further detail on the proposed disposition and the appropriateness of allocating the entire amount to the Remote Connection Lines rate category is provided in Exhibit H-2-1. Recovery for this account is over 1 year, consistent with each of the prior rate applications.

2. **ISDVA**: As described in Exhibit H-1-1, WPLP has two sub-accounts in the ISDVA that track costs separately for the Line to Pickle Lake and the Remote Connection Lines. Since the costs are based on direct tracking for each asset pool, no further cost allocation is required. Accordingly, WPLP proposes to dispose of the balance of $6,546,623. The disposal would be a balance of ($224,793) in the Line to Pickle Lake sub-account and a balance of $6,771,416 in the Remote Connection Line sub-account, by adding them to the respective revenue requirements, as further shown in Table 6 below.

3. **CPICVA**: As described in Exhibit H-1-1, WPLP has two sub-accounts in the CPICVA that track costs separately for the Line to Pickle Lake and the Remote Connection Lines. Since the costs are based on direct tracking for each asset pool, no further cost allocation is required. Accordingly, WPLP proposes to dispose of the balance of $1,738,661. WPLP proposes to dispose of the balance of $334,137 in the Line to Pickle Lake sub-account and the balance of $ 1,404,524 in the Remote Connection Line sub-account by adding them to the respective revenue requirements, as further shown in Table 6 below.

4. **DCDA**: As described in Exhibit H-1-1, WPLP has two sub-accounts in the DCDA that track costs separately for the Line to Pickle Lake and the Remote Connection Lines. Since the costs are based on direct tracking for each asset pool, no further cost allocation is required. Accordingly, WPLP proposes to dispose of the balance of $65,986. WPLP proposes to dispose of the balance of $13,261 in the Line to Pickle Lake sub-account and the balance of

$52,725 in the Remote Connection Line sub-account by adding them to the respective revenue requirements, as further shown in Table 6 below.

5. **CCCDA:** In accordance with the OEB's decision in EB-2021-0134, WPLP has calculated that the amount of COVID-related construction costs from 2020 to be recovered in 2026, inclusive of applicable carrying costs as described in Exhibit H-2-1, is ($24,381). WPLP records portions of this cost separately for the Line to Pickle Lake and the Remote Connection Lines. The balances for disposal are ($17,001) in the Line to Pickle Lake sub-account and ($7,380) in the Remote Connection Line sub-account. The costs included in Table 6 are based on direct tracking for each asset pool and no further cost allocation is required.

6. **OM&A Variance Account:** As described in Section C above, direct operating costs are tracked separately for the Line to Pickle Lake and the Remote Connection Line, and the indirect costs are allocated based on their respective proportions of 2024 and 2025 transmission system rate base for each category. WPLP has two sub-accounts in the OM&A Variance Account that track costs separately for the Line to Pickle Lake and the Remote Connection Lines. Since the direct costs are based on direct tracking for each asset pool, no further cost allocation is required. However, for indirect costs, any indirect cost savings must be allocated based on their respective proportions of 2024 and 2025 transmission system rate base for each category. WPLP proposes to dispose of the balance of ($4,537,273). WPLP proposes to dispose of the balance of ($1,954,835) in the Line to Pickle Lake sub-account and the balance of ($2,582,438) in the Remote Connection Line sub-account by adding them to the respective revenue requirements, as further shown in Table 6 below.

7. **Federal CIAC Variance Account:** As described in Exhibit H-1-1, WPLP has the Federal CIAC Variance Account to track the revenue requirement impact to the Remote Connection Lines of the difference, if any, between WPLP's forecasted date of the CIAC funds being distributed to WPLP pursuant to the Federal Funding Framework and the actual date such

funds are distributed to WPLP, based on a forecast date of December 31, 2024. Accordingly, WPLP proposes to dispose of the balance of ($14,836,511) by adding it to the Remote Connection Lines' revenue requirement, as further shown in Table 6 below.

Table 5 provides a summary of the balances in the various accounts that are subject to disposition.

Table 5 –Disposition of Deferral Account Balances

	2024 Audited Balances		Forecasted Carrying Charges		2025 Approved Recoveries		Total	
	LTPL	**RCL**	**LTPL**	**RCL**	**LTPL**	**RCL**	**LTPL**	**RCL**
Disposition of Pikangikum Distribution System Deferral Account	-	693,127	-	11,496	-	(708,178)	-	(3,555)
Disposition of COVID Construction Costs Deferral Account (CCCDA)	3,453,755	1,499,310	55,001	23,876	(3,525,757)	(1,530,567)	(17,001)	(7,380)
Disposition of In-Service Date Variance Account (ISDVA)	(303,872)	5,836,103	(11,691)	301,848	90,770	633,465	(224,793)	6,771,416
Disposition of Construction Period Interest Costs Variance Account (CPICVA)	7,497,655	15,566,695	137,420	307,574	(7,300,938)	(14,469,745)	334,137	1,404,524
Disposition of Deferred Contingency Deferral Account (DCDA)	41,421	214,965	1,111	5,283	(29,271)	(167,523)	13,261	52,725
Disposition of OM&A Variance Account	(3,569,910)	(6,384,794)	(122,524)	(190,915)	1,737,599	3,993,271	(1,954,835)	(2,582,438)
Disposition of Federal CIAC Variance Account	-	(14,137,677)	-	(698,834)	-	-	-	(14,836,511)
Total	**7,119,049**	**3,287,729**	**59,317**	**(239,671)**	**(9,027,597)**	**(12,249,277)**	**(1,849,231)**	**(9,201,219)**

F. Allocation of Revenue Requirement

WPLP's 2026 revenue requirement for each of the Line to Pickle Lake and the Remote Connection Lines is summarized in Table 6, along with references to the relevant sections of the Application supporting each component of the revenue requirement.

Table 6 – Allocation of 2026 Revenue Requirement

	LTPL	**RCL**	**Total**	**Reference**
Gross Fixed Assets (avg)	321,759,981	1,001,637,154	1,323,397,135	C-3-1
Accumulated Depreciation (avg)	-23,937,770	-63,976,355	-87,914,125	C-3-1
Net Fixed Assets (avg)	297,822,211	937,660,799	1,235,483,010	C-3-1
Working Capital Allowance	0	0	0	C-4-1
Rate Base	297,822,211	937,660,799	1,235,483,010	C-1-1
Regulated Rate of Return	6.34%	6.34%	6.34%	G-2-1
Regulated Return on Rate Base	18,867,037	59,400,813	78,267,850	G-2-1
OM&A Expenses	6,025,286	32,328,524	38,353,810	F-2-1
Property Taxes	0	0	0	F-5-1
Depreciation Expense	6,536,434	20,327,124	26,863,558	F-4-1
Income Taxes	105,976	490,349	596,325	F-5-1
Service Revenue Requirement	**31,534,733**	**112,546,810**	**144,081,543**	
Other Revenue Offset	0	0	0	E-3-1
Base Revenue Requirement	**31,534,733**	**112,546,810**	**144,081,543**	
Disposition of Pikangikum Distribution System Deferral Account	0	-3,555	-3,555	H-2-1
Disposition of COVID Construction Costs Deferral Account (CCCDA)	-17,001	-7,380	-24,381	H-2-1
Disposition of In-Service Date Variance Account (ISDVA)	-224,793	6,771,416	6,546,623	H-2-1
Disposition of Period Interest Costs Variance Account (CPICVA)	334,137	1,404,524	1,738,661	H-2-1
Disposition of Deferred Contingency Deferral Account (DCDA)	13,261	52,725	65,986	H-2-1
Disposition of OM&A Variance Account	-1,954,835	-2,582,438	-4,537,273	H-2-1
Disposition of Federal CIAC Variance Account	0	-14,836,511	-14,836,511	H-2-1
Revenue Requirement for Rates	**29,685,502**	**103,345,591**	**133,031,093**	

Exhibit I, Tab 3, Schedule 1

Calculation of Uniform Transmission Rates

CALCULATION OF UNIFORM TRANSMISSION RATES

A. Overview

Transmission rates in Ontario were established on a uniform basis for all licensed transmitters in Ontario on April 30, 2002 as per RP-2001-0034/RP-2001-0035/RP-2001-0036/RP-1999-0044, and have generally been updated on an annual basis ever since. Uniform Transmission Rates ("UTRs") are determined by aggregating the most recent OEB-approved revenue requirements for each Ontario licensed transmitter, allocating those revenue requirements between the three UTR rate pools, and dividing the allocated revenue requirements by forecasted charge determinants. On January 22, 2025, the OEB issued its decision and rate order in EB-2024-0244 for the 2025 UTRs, effective January 1, 2025.

As described in Exhibit I-2-1, the portion of WPLP's revenue requirement associated with the Line to Pickle Lake, which is $29,685,502 for the 2026 test year, will be recovered through the UTR Network rate, as detailed in this schedule. As a result of the assets that WPLP expects to have in-service for 2026, WPLP is forecasting Network charge determinants of 210.0MW, as detailed in Exhibit E-1-1.[1]

The addition of the above revenue requirement and charge determinants results in a decrease of $0.05/kW, or 0.9287%, to the Network UTR rate.

B. Current Uniform Transmission Rates

Table 1 below illustrates the calculation of the current UTRs, effective January 1, 2025, which includes WPLP's approved 2025 UTR revenue requirement. These values serve as the starting point for comparison in the tables that follow.

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[1] Additional amounts may be added to WPLP's rate base in respect of the Line to Pickle Lake (and Remote Connection Lines) in a future period upon disposition of any balance that may be recorded in the EPC COVID-Related Costs Deferral Account.

Table 1 – Current UTR Calculations

Transmitter	**Revenue Requirement**			
	Network	**Line Connection**	**Transformation Connection**	**Total**
FNEI	$4,788,179.00	$830,384	$2,369,529.00	$7,988,092
CNPI	$2,785,600	$483,089	$1,378,511	$4,647,200
WPLP	$43,489,861	$0	$0	$43,489,861
UCT 2	$75,681,985	$0	$0	$75,681,985
H1N SSM	$26,007,789	$4,510,371	$12,870,489	$43,388,649
H1N	$1,280,063,491	$221,993,543	$633,465,726	$2,135,522,760
B2MLP	$37,647,615	$0	$0	$37,647,615
NRLP	$8,314,329	$0	$0	$8,314,329
CLLP	$18,535,124	$0	$0	$18,535,124
All Transmitters	**$1,497,313,973**	**$227,817,387**	**$650,084,255**	**$2,375,215,615**
Transmitter	**Total Annual Charge Determinants (MW)***			
	Network	**Line Connection**	**Transformation Connection**	
FNEI	230.410	248.860	73.040	
CNPI	522.894	549.258	549.258	
WPLP	193.876	0.000	0.000	
UCT 2	0.000	0.000	0.000	
H1N SSM	3,498.236	2,734.624	635.252	
H1N	230,449.267	223,707.783	190,298.856	
B2MLP	0.000	0.000	0.000	
NRLP	0.000	0.000	0.000	
CLLP	0.000	0.000	0.000	
All Transmitters	**234,894.683**	**227,240.525**	**191,556.406**	
Transmitter	**Uniform Rates and Revenue Allocators**			
	Network	**Line Connection**	**Transformation Connection**	
Uniform Transmission Rates ($/kW/Month)	**6.37**	**1.00**	**3.39**	
	↓	↓	↓	
FNEI	0.00320	0.00364	0.00364	
CNPI	0.00186	0.00212	0.00212	
WPLP	0.02905	0.00000	0.00000	
UCT 2	0.05055	0.00000	0.00000	
H1N SSM	0.01737	0.01980	0.01980	
H1N	0.85490	0.97444	0.97444	
B2MLP	0.02514	0.00000	0.00000	
NRLP	0.00555	0.00000	0.00000	

CLLP	0.01238	0.00000	0.00000	
Sum of Allocation Factors	**1.00000**	**1.00000**	**1.00000**	

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

C. Calculation of 2026 Test Year UTRs

Table 2 below shows the calculation of 2026 UTRs, with the addition of WPLP's forecasted Network revenue requirement and charge determinants, and assuming that the values for all other transmitters remain the same as in EB-2024-0244[2]. WPLP expects that the OEB will determine the actual 2026 UTRs once 2026 revenue requirements are approved for all other Ontario licensed transmitters.

WPLP has also provided an analysis of the changes in 2026 UTRs resulting from the current Application in Table 3 below.

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[2] WPLP's forecasted Network revenue requirement is reflective of OEB's Decision and Order in the Generic Proceeding, but for all other transmitters remain the interim amounts set in EB-2024-0244 as updated information is not available.

Table 2 – Calculation of 2026 UTRs

Transmitter	**Revenue Requirement ($)**			
	Network	**Line Connection**	**Transformation Connection**	**Total**
FNEI	$4,788,179	$830,384	$2,369,529	$7,988,092
CNPI	$2,785,600	$483,089	$1,378,511	$4,647,200
WPLP	$29,685,502	$0	$0	$29,685,502
UCT 2	$75,681,985	$0	$0	$75,681,985
H1N SSM	$26,007,789	$4,510,371	$12,870,489	$43,388,649
H1N	$1,280,063,491	$221,993,543	$633,465,726	$2,135,522,760
B2MLP	$37,647,615	$0	$0	$37,647,615
NRLP	$8,314,329	$0	$0	$8,314,329
CLLP	$18,535,124	$0	$0	$18,535,124
All Transmitters	$1,483,509,614	$227,817,387	$650,084,255	$2,361,411,256
Transmitter	**Total Annual Charge Determinants (MW)**			
	Network	**Line Connection**	**Transformation Connection**	
FNEI	230.410	248.860	73.040	
CNPI	522.894	549.258	549.258	
WPLP	209.974	0.000	0.000	
UCT 2	0.000	0.000	0.000	
H1N SSM	3,498.236	2,734.624	635.252	
H1N	230,449.267	223,707.783	190,298.856	
B2MLP	0.000	0.000	0.000	
NRLP	0.000	0.000	0.000	
CLLP	0.000	0.000	0.000	
All Transmitters	**234,910.781**	**227,240.525**	**191,556.406**	
Transmitter	**Uniform Rates and Revenue Allocators**			
	Network	**Line Connection**	**Transformation Connection**	
Uniform Transmission Rates ($/kW-Month)	**6.32**	**1.00**	**3.39**	
	↓	↓	↓	
FNEI	0.00323	0.00364	0.00364	
CNPI	0.00188	0.00212	0.00212	
WPLP	0.02001	0.00000	0.00000	
UCT 2	0.05102	0.00000	0.00000	
H1N SSM	0.01753	0.01980	0.01980	
H1N	0.86286	0.97444	0.97444	
B2MLP	0.02538	0.00000	0.00000	
NRLP	0.00560	0.00000	0.00000	

CLLP	0.01249	0.00000	0.00000	
Sum of Allocation Factors	1.00000	1.00000	1.00000	

Table 3 – Changes in 2026 UTRs Resulting from this Application

Transmitter	**Change in Revenue Requirement ($)**			
	Network	**Line Connection**	**Transformation Connection**	**Total**
FNEI	$0	$0	$0	$0
CNPI	$0	$0	$0	$0
WPLP	($13,804,359)	$0	$0	($13,804,359)
UCT 2	$0	$0	$0	$0
H1N SSM	$0	$0	$0	$0
H1N	$0	$0	$0	$0
B2MLP	$0	$0	$0	$0
NRLP	$0	$0	$0	$0
CLLP	$0	$0	$0	$0
All Transmitters	**($13,804,359)**	**$0**	**$0**	**($13,804,359)**
Transmitter	**Change in Total Annual Charge Determinants (MW)**			
	Network	**Line Connection**	**Transformation Connection**	
FNEI	-	-	-	
CNPI	-	-	-	
WPLP	16.098	-	-	
UCT 2	-	-	-	
H1N SSM	-	-	-	
H1N	-	-	-	
B2MLP	-	-	-	
NRLP				
CLLP				
All Transmitters	**16.098**	**-**	**-**	
Transmitter	**Change in Uniform Rates and Revenue Allocators**			
	Network	**Line Connection**	**Transformation Connection**	
Uniform Transmission Rates ($/kW-Month)	**(0.05)**	**0.00**	**0.00**	
	↓	↓	↓	
FNEI	0.00003	-	-	
CNPI	0.00002	-	-	
WPLP	-0.00904	-	-	
UCT 2	0.00047	-	-	
H1N SSM	0.00016	-	-	
H1N	0.00796	-	-	
B2MLP	0.00024	-	-	
NRLP	0.00005	-	-	

CLLP	0.00011	-	-	▨
Total of Allocation Factors	**0.00000**	**-**	**-**	▨

D. Revenue Reconciliation

Table 4 below compares WPLP's forecasted 2026 revenue, based on the rates and charge determinants in Table 2, with the 2026 revenue requirement calculated in Exhibit I-2-1.

Table 4 – 2026 Revenue Reconciliation

2026 Network Charge Determinants (kW)	234,910,781
2026 Network UTR Rate ($/kW)	$6.32
2026 WPLP Network Allocation Factor	0.02001
2026 Revenue Forecast	$29,685,027
2026 WPLP LTPL Revenue Requirement	$29,685,502
Difference due to Rounding	($475) (0.002%)

Exhibit I, Tab 3, Schedule 2

Monthly Fixed Charge to Hydro One Remotes

MONTHLY FIXED CHARGE TO HYDRO ONE REMOTES

In accordance with the OEB's Decision and Order in EB-2018-0190 and consistent with the approach taken by WPLP and approved by the OEB in WPLP's prior rate proceedings (EB-2021-0134, EB-2022-0149, EB-2023-0168 and EB-2024-0176), WPLP will recover the portion of its revenue requirement associated with the Remote Connection Lines through a fixed monthly charge applicable to HORCI, effective from January 1, 2026.

WPLP's 2026 revenue requirement attributable to the Remote Connection Lines is $103,345,591. This amount includes an allocated base revenue requirement of $112,546,810, as detailed in Exhibit I-2-1, and disposition of deferral and variance accounts of ($9,201,219), as summarized in Exhibit H-2-1 and Exhibit I-2-1. Recovering this amount through a fixed charge to HORCI over the 12-month period from January to December 2026 results in a fixed monthly charge of $8,612,133 that would apply for each month from January 2026 to December 2026.

Exhibit I, Tab 4, Schedule 1

Bill Impacts

BILL IMPACTS

This schedule details the bill impacts for typical Ontario residential and general service distribution customers, as well as for an average transmission-connected customer, resulting from WPLP's proposed changes to its revenue requirement for 2026.

The bill impacts do not reflect any residual benefits that may be received by ratepayers as a result of the Federal Funding Framework (i.e. payments to RRRP Variance Account), as discussed in Part E of this Schedule.

The bill impacts discussed in this schedule are reflective of typical Hydro One customers and average transmission-connected customers, with references to the sources of information used to calculate each bill impact. Importantly, WPLP notes that Non-Standard A customers of HORCI in the connecting communities and other remote communities will not experience bill impacts resulting from WPLP's 2026 revenue requirement, because the rates for those customers are determined through relevant RRRP regulations and do not include components for Network UTR charges or RRRP charges. Additionally, Standard A customers in the connected communities have experienced significant bill reductions since grid connection, due to HORCI's Standard A rates being significantly lower for grid-connected communities as compared to air-access non-grid-connected communities.[1]

A. Bill Impacts for Distribution-Connected Customers

The total bill impact of this application for a typical residential customer is a decrease of approximately $0.26 per month, or 0.18%, and the total bill impact of this application for a typical General Service customer is a decrease of approximately $0.64 per month, or 0.15%, as summarized in Table 1.

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[1] HORCI's Standard A rates effective May 1, 2025 range from $1.1398-$1.2473 kWh for Air Access (non-grid-connected) communities vs. $0.3908/kWh for grid-connected communities.

Table 1 – Summary of Total 2026 Bill Impact

Item	Description	Amount[2]	
		Residential	General Service
A	Typical monthly bill	\$139.89[3]	\$433.78[4]
B	Increase related to Network RTSR	(\$0.10)	(\$0.21)
C	Increase related to RRRP rate	(\$0.16)	(\$0.44)
D = B + C	Total bill increase	(\$0.26)	(\$0.64)
E = D / A	Bill impact (%)	(0.18%)	(0.15%)

B. Bill Impact Resulting from Line to Pickle Lake

As calculated in Exhibit I-3-1, the portion of WPLP's 2026 revenue requirement associated with the Line to Pickle and allocated to the UTR Network rate pool results in a decrease in the UTR Network rate of \$0.05/kw, or 0.93%. The resulting bill impact of this application for a typical residential customer is a decrease of 0.07%, and the resulting bill impact of this application for a typical General Service customer is a decrease of 0.05%, as calculated in Table 2.

Table 2 – Bill Impact – Line to Pickle Lake

Item	Description	Amount	
		Residential	General Service
A	Typical monthly bill (see Table 1)	\$139.89	\$433.78
B	Portion of bill related to Network RTSR	\$10.32[5]	\$22.12[6]
C	Increase in Network UTR	(0.93%)	(0.93%)
D = B x C	Bill increase	(\$0.10)	(\$0.21)
E = D / A	Bill impact (%)	(0.07%)	(0.05%)

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[2] All amounts are inclusive of 13% HST and the Ontario Electricity Rebate.

[3] Total bill amount for a Hydro One R1 TOU customer (750 kWh per month), as indicated in the OEB's online bill calculator (https://www.oeb.ca/rates-and-your-bill/bill-calculator), as at April 30, 2025.

[4] Total bill amount for a Hydro One General Service Energy Billed TOU customer (2000 kWh per month), as indicated in the OEB's online bill calculator, as at April 30, 2025.

[5] HONI R1 Network RTSR Rate of \$0.0128/kWh * 750 kWh * 1.076 loss factor = \$10.3296 (\$10.32 after 13% HST and 13.1% Ontario Electricity Rebate).

[6] HONI GSe Network RTSR Rate of \$0.0101/kWh * 2000 kWh * 1.096 loss factor = \$22.1392 (\$22.12 after 13% HST and 13.1% Ontario Electricity Rebate)

C. Bill Impact Resulting from Remote Connection Lines

As described in Exhibit I-2-1, the OEB approved a cost recovery and rate framework whereby the portion of WPLP's revenue requirement allocated to the Remote Connection Lines will be recovered from HORCI, which in turn will add its cost for paying these amounts to its revenue requirement. In accordance with section 4(2.1) of the RRRP Regulation (O. Reg. 442/01), these incremental amounts in HORCI's revenue requirement will be recovered through RRRP funding. Importantly, WPLP expects that rates applicable to HORCI's non-Standard A customers will continue to be set based only on inflationary adjustments in accordance with the RRRP Regulation, such that HORCI's costs of receiving transmission service from WPLP will not result in an incremental bill impact for these customers. Table 3 calculates the 2026 RRRP rate, based on the assumption that the RRRP rate will be used for recovery by HORCI of 100% of the fixed charges that it pays to WPLP, and keeping all other values the same as 2025.

Table 3 – RRRP Rate Calculation

	2025	**2026**	**Change**
First Nations (O. Reg. 442/01, schedule 1)	$1,600,000	$1,600,000	$0
Algoma Power	$18,545,600	$18,545,600	$0
Hydro One Remote Communities Inc.	$50,138,000	$50,138,000	$0
Hydro One Remote Communities Inc. - WPLP	$132,731,158	$103,345,591	-$29,385,567
Total RRRP Funding Required[7]	***$203,014,758***	***$173,629,191***	***-$29,385,567***
Ontario TWh	140.5	140.5	0
RRRP Rate (Calculated)	$0.001445	$0.001236	-$0.000209
RRRP Rate (Rounded to 4 Decimals)	$0.0014	$0.0012	-$0.0002

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[7] RRRP variance account balances have been omitted from this analysis in order to isolate the impact of the RRRP funding requested in this application. Similarly, the 2026 RRRP funding requirements for parties other than WPLP have been held constant from 2025 to 2026 for the purpose of bill impact analysis. WPLP expects that the OEB will consider the RRRP variance account balance and changes to 2026 RRRP funding for other parties when it determines the 2026 RRRP rate in due course.

The calculation in Table 3 shows that the calculated RRRP rate rounded to 4 decimal places would decrease by $0.0002/kWh. WPLP has calculated the typical residential bill impact resulting from this change in Table 4 below.

Table 4 – RRRP Bill Impact Calculations

Item	Description	Amount	
		Residential	**General Service**
A	Typical monthly bill (see Table 1)	$139.89	$433.78
B	RRRP rate increase ($/kWh)	($0.0002)	($0.0002)
C = kWh * 1.076/1.096	Uplifted consumption (kWh)	807	2,192
D = B x C	Bill increase due to RRRP	($0.16)	($0.44)
E = D * (1+ 0.13 – 0.131)	Bill increase adjusted for HST and OER	($0.16)	($0.44)
F	Bill impact (%)	(0.12%)	(0.10%)

D. Bill Impacts for Transmission-Connected Customers

WPLP has calculated the estimated bill impact of this application for an average transmission-connected customer resulting from its 2026 revenue requirement, as detailed in Table 5, below. WPLP relied on the IESO's December 2024 Year-to-Date weighted average wholesale market electricity charges[8] and as such the calculated percentage increases reflect a customer with an Ontario-average demand profile.

Table 5 – Transmission-Connected Customer Bill Impacts

Item	Description	Amount
A	Total Wholesale Market Charges ($/MWh)	125.00
B	Total Wholesale Transmission Charges ($/MWh)	15.66
C = B / A	Transmission % of Total Bill	12.53%
D	% Increase in Transmission Revenue Requirement	(0.58%)
E = C * D	% Bill Increase from Line to Pickle Lake	(0.07%)
F	Total RRRP Charges ($/MWh)	1.40

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[8] https://www.ieso.ca/en/Power-Data/Monthly-Market-Report – Generated for December 2024

G = F / A	RRRP % of Total Bill	1.12%
H	% Increase in RRRP Rate	(14%)
I = G * H	% Bill Increase from Remote Connection Lines	(0.16%)
J = E + I	**Total % Bill Increase**	**(0.23%)**

E. Federal Funding Framework

In EB-2018-0190, WPLP described a contemplated Federal Funding Framework relating to the Project, resulting from a March 12, 2018 Memorandum of Understanding between WPLP, Canada and Ontario.[9] The mechanics and conditions of the contemplated funding, as well as clarifications resulting from interrogatories, were summarized in WPLP's February 15, 2019 Reply Submission.[10] The parties to the Federal Funding Framework agreed to an Amendment to the Trust Agreement dated June 6, 2024, as summarized below.

At a high level, based on the Federal Funding Framework as initially established, Canada was to provide $1.55 billion[11] in funding to the independent Trust in relation to the Project, which amount is unchanged by the Amendment, and will serve to reduce the resulting ratepayer impact in two ways:

a) a portion of the funding was to be applied as a Contribution in Aid of Construction ("CIAC"), reducing WPLP's rate base in respect of the Remote Connection Lines; and,

b) the remainder of the funding was to be provided to an independent Trust which will use the funding to help offset the impacts of the Remote Connection Lines on RRRP for Ontario ratepayers.

The portion of funding that was to be provided to WPLP as a CIAC was to be determined by WPLP's total Project costs. As WPLP's costs increased, the CIAC amount increased at a rate that

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[9] EB-2018-0190, Exhibit J-1-2.

[10] EB-2018-0190, WPLP Reply Submission, February 15, 2019, pp. 27-29.

[11] The actual contribution to the independent Trust is $1,491,868,309 as Canada has previously funded $63,131,691 for the construction of the Pikangikum system.

reduced WPLP's deemed equity position in the Project, thereby providing a strong incentive to control and reduce costs during construction. Reductions to WPLP's rate base in respect of the Remote Connection Lines resulting from the CIAC treatment of federal funding have therefore resulted in a reduction to the fixed monthly charges that WPLP will recover from HORCI, which will in turn result in HORCI needing to collect less revenue from the RRRP pool. Funding provided to the independent Trust will further reduce rate impacts for Ontario ratepayers because the independent Trust will be required to provide funds to the IESO to be applied against the total RRRP funding that the IESO needs to collect from Ontario ratepayers each month, until such time as the independent Trust's funds are exhausted.

On July 3, 2019, WPLP, Canada and Ontario signed the definitive documents regarding the Federal Funding Framework for the Project. Until March 21, 2024, when the appropriation of funds occurred through the 2024-2025 "interim supply" spending authorization received Royal Assent, the funding remained conditional on appropriation by Parliament. The definitive documents solidified the mechanics by which the funding is being provided.

The Amendment to the Trust Agreement under the Federal Funding Framework was made by the parties thereto to lessen the impact of COVID-19 for Ontario electricity ratepayers. Ontario and Canada executed the Amendment to the Trust Agreement on June 6, 2024. As described above, the independent Trust was initially designed to provide for a single CIAC to WPLP, with that CIAC to be determined based on WPLP's "Nominal OEB-Approved Capital Costs" for the Project as determined under the Trust Agreement, and with the remaining funds in the independent Trust (after payment of the CIAC to WPLP) used to help offset the impacts of the Remote Connection Lines on RRRP for Ontario ratepayers. Prior to the Amendment of the Trust Agreement, the $68.71M in COVID-19 costs that were added to rate base in EB-2023-0168 would have been included in the determination of the Nominal OEB-Approved Capital Costs and would have reduced WPLP's available Owner Equity to $458M[12] as compared to available Owner Equity of

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[12] Under Federal Funding Framework, WPLP's available equity is determined using a sliding scale based on the Nominal OEB-Approved Capital Cost as determined under the Trust Agreement.

$520M had no COVID-19 costs been added to rate base.[13] In addition to impacting WPLP's available Owner Equity, the independent Trust only provided for one CIAC to WPLP. As a result, any future settlement or resolution with Valard would need to be added to WPLP's rate base in a future transmission revenue requirement application.[14]

The Amendment of the Trust Agreement involved two primary changes:

(1) Excludes the $68.71M in COVID-19 costs, which were added to rate base in EB-2023-0168, in determining WPLP's available Owner Equity. This change increased WPLP's available Owner Equity under the Trust from $458M to $520M as reflected in the 2025 rate application.

(2) Requires the independent Trust to make an additional CIAC to WPLP once (i) WPLP has settled or otherwise resolved the amounts that are the subject of ongoing commercial discussions with the EPC Contractor, (ii) WPLP has recorded such amounts in the EPC COVID-Related Costs Deferral Account, and (iii) the OEB has reviewed and approved the prudence of the amounts that may be added to WPLP's rate base on disposition of the balance in the EPC COVID-Related Costs Deferral Account in a future application, inclusive of accumulated carrying costs. For greater certainty, it was the intention of the parties to the Amendment to the Trust Agreement that the OEB would review and consider the disposition to rate base of the balance in the EPC COVID-Related Costs Deferral Account in the normal course, as though such approved amount would in fact be added to WPLPs rate base, but on the understanding that once the amount of such rate base addition is approved that this would trigger the requirement for the independent Trust to then make an additional CIAC to WPLP for

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[13] The calculation of WPLP's available equity and implied rate base is determined based on the Decision and Order in EB-2023-0168, dated November 30, 2023, as per the Trust Agreement.

[14] See EB-2023-0168, Exhibit H-2-2 and Response to Board Staff IR 33(c).

the approved amount[15] such that there would not ultimately be a rate base addition in respect of the disposition from the EPC COVID-Related Costs Deferral Account.

The impact of the two changes to the Trust Agreement was to materially reduce the financial impact of the Project for Ontario ratepayers.[16]

The distribution of funds from Canada to the independent Trust occurred on June 25, 2024, and the initial CIAC was provided by the independent Trust to WPLP on July 11, 2024. In EB-2023-0168, based on its forecast that it would receive the CIAC on December 31, 2024, WPLP proposed and obtained approval to establish the Federal CIAC Variance Account to record the revenue requirement impact of receiving the CIAC earlier or later than that forecast date, as further discussed in Exhibit H-1-1.

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[15] Inclusive of costs related to Line to Pickle Lake and Remote Connection Lines.

[16] Further details of this amendment can be found in Exhibit G-1-1 of the 2025 rate application (EB-2024-0176).