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April 28, 2022

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 2023 Electricity Transmission Rates (EB-2022-0149)

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 2023 test year.

Please note that the application is being filed with a small number of redactions. Under separate cover, WPLP will be filing its request for confidential treatment of the underlying information in accordance with the OEB's *Practice Direction on Confidential Filings*.

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

EB-2022-0149

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

2023 ELECTRICITY TRANSMISSION REVENUE REQUIREMENT

WATAYNIKANEYAP POWER GP INC. on behalf of
WATAYNIKANEYAP POWER LP

April 28, 2022

Exhibit A, Tab 1, Schedule 1

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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"). This is WPLP's second application to the OEB seeking approval of an electricity transmission revenue requirement and is in respect of a single test year, commencing January 1, 2023.

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 1744[1] 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 First Nation communities by means of the "Remote Connection Lines", which extend north of Pickle Lake and north of Red Lake (collectively, the "Transmission System").[2]

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 second transmission revenue requirement application. WPLP filed its first such application on April 28, 2021 in EB-2021-0134 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. In that proceeding, the parties reached a complete settlement on all issues, which was approved by the OEB in its Decision and Order dated September 30, 2021. The approved Settlement Agreement provided for a total 2022 revenue requirement of $41.5 million, with recovery of $20.3 million through the UTR network rate pool effective April 1, 2022 in respect of the Line to Pickle Lake portion of WPLP's transmission system, and recovery of $21.3 million through a monthly fixed charge of $2.7 million to HORCI effective May 1, 2022 in respect of the Remote Connection Lines portion of WPLP's transmission system.

[1] Line length increased by 8 km or less than 1% as described on page 10 of Exhibit B-1-1

[2] WPLP's development, construction and operation of the Transmission System will also abide by the Guiding Principles which were approved by the leadership of the Participating First Nations.

The final Revenue Requirement and Change Determinant Order, dated December 2, 2021, reflected an updated total 2022 revenue requirement of $42 million, with recovery of $20.4 million through the UTR network rate pool effective April 1, 2022, and recovery of $21.5 million through fixed monthly charges of $2.7 million to HORCI effective May 1, 2022.

6. In the current application, WPLP is seeking approval of its revenue requirement for the 2023 test year using a cost of service approach. WPLP anticipates filing additional single-year cost of service revenue requirement applications for the 2024 and 2025 test years, followed by a multi-year revenue requirement application using an incentive-based regulatory method available to transmitters (i.e. Custom IR or Revenue Cap Index) for a period beginning with a 2026 test year. As WPLP's transmission system is expected to reach final completion during 2024, the 2026 test year represents the earliest opportunity to implement a multi-year revenue requirement framework following completion of the project.

7. Under WPLP's current project schedule, the Line to Pickle Lake is expected to come into service in June 2022. Given that the Line to Pickle Lake will be in-service for the full year in the 2023 test year, 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, 2023.

8. In respect of the Remote Connection Lines, under WPLP's current project schedule the initial segment is expected to come into service in June 2022, with two additional segments expected to come into service in August 2022. Four segments are expected to come into service between May and July of the 2023 test year, and all remaining segments are expected to come into service in the first half of 2024. Given that there will be assets in-service as of January 1, 2023, and additional assets will be coming into service in 2023, WPLP proposes to implement the proposed monthly fixed charge to HORCI effective January 1, 2023, to reflect (a) a full year of the 2022 in-service assets, and (b) for the new assets going into service during 2023, the relevant number of months those assets are

expected to be in-service in 2023, with the total resulting revenue requirement for those new assets divided by 12 months.

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

(a) A total revenue requirement of $92,931,065 for the 2023 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, on the basis set out in paragraph 7, above, to allow for recovery of $34,739,785, being the portion of the total revenue requirement attributed to transmission service provided by the Line to Pickle Lake for the 2023 test year; and

(ii) a fixed charge of $4,849,273/month, applicable to HORCI from January 1, 2023 to December 31, 2023, for recovery of $58,191,280, being the portion of the total revenue requirement attributed to transmission service provided by the Remote Connection Lines for the 2023 test year;

(b) Partial disposition of the 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, 2021, including applicable interest, and the addition of the corresponding costs to WPLP's revenue requirement in respect of the Line to Pickle Lake and the Remote Connection Lines for 2023, as detailed in Exhibit H-2-2 and I-2-1;

(c) Partial disposition of the 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, 2021, including applicable interest, and the addition of

the corresponding costs to WPLP's revenue requirement in respect of the Remote Connection Lines for 2023, as detailed in Exhibits H-2-1 and I-3-2; and

(d) The continuation of WPLP's current deferral and variance accounts as requested in Exhibit H-1-1.

10. 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.

11. 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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12. 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.

13. 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 28th day of April, 2022.

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 2023 electricity transmission rates (EB-2022-0149) is accurate, consistent and complete to the best of my knowledge.

Dated this 28th date of April, 2022.



_____

Duane Fecteau

Exhibit A, Tab 3, Schedule 1

Executive Summary

EXECUTIVE SUMMARY

This is WPLP's second transmission revenue requirement application. WPLP's Transmission System is currently under construction and is being brought into service in stages over the 2022 to 2024 period. Upon completion, the Transmission System will be comprised of 22 stations and approximately 1744[1] km of lines in northwestern Ontario, which will serve to reinforce the transmission system in the region and extend transmission service to connect 16 remote First Nation communities to the provincial electricity grid.[2] WPLP became a licensed transmitter in 2015, was granted approval to establish a deferral account to record development costs in 2017, received leave to construct for the Transmission Project in 2019, and had its initial transmission revenue requirement approved in 2021 for the 2022 rate year.

After receiving leave to construct, WPLP secured project financing and entered into an engineering, procurement and construction (EPC) contract following a rigorous competitive procurement process. Through those activities, the preliminary cost estimates that were presented in the leave to construct proceeding matured into cost forecasts, inclusive of significantly lower contingency amounts, which served as the foundation for its initial revenue requirement in EB-2021-0134. WPLP's initial revenue requirement application also described WPLP's extensive work with its construction contractor to manage the schedule and cost impacts during the first year of the COVID-19 pandemic.

As the pandemic has evolved, WPLP has continued to work tirelessly with its construction contractor and the First Nation communities over the past year to monitor and update its COVID-19 management plans to minimize the impacts on the project, the public, employees and First Nation communities. While these impacts have necessitated further updates to WPLP's construction schedule and community energization dates, the proactive management of COVID-

[1] As described on page 10 of Exhibit B-1-1, there have been a number of minor route changes that have increased the overall line length by approximately 8 km (less than 1%). As such, the total length indicated here has been adjusted by 8 km as compared to the previous application under EB-2021-0134.

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

19 has allowed construction of the project to continue. Over the past year, WPLP has also made significant progress on a number of other aspects of the project, including the implementation of several minor routing changes to reflect input received through engagement with First Nation communities, discussions with government agencies and to address constructability concerns; continued coordination with HONI and HORCI regarding procurement, construction and energization, as well as drafting transmission connection agreements; undertaking IESO registration processes and working towards completion of a Transmission Operating Agreement; as well as developing and implementing an interim operations strategy that involves the procurement of third-party O&M, emergency response and system control services on an interim basis, thereby enabling WPLP to continue its focus on construction activities while developing internal processes, systems and staffing to support operation of its transmission system in the future.

This Schedule summarizes WPLP's Application in respect of its transmission revenue requirement for the 2023 test year and other related approvals. Sections A and B below introduce the Applicant and the Application, with additional context related to the development, permitting and construction of WPLP's Transmission System. 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, not having any transmission assets currently in service, and having those assets come into service in stages over a multi-year period.

Historical costs presented in this Application are consistent with WPLP's December 31, 2021 audited financial statements. Cost and schedule forecasts for 2022-2024 reflect WPLP's revised forecasts as at January 2022. WPLP plans two updates to the Application. First, as WPLP is in the process of selecting third-party service providers to undertake certain O&M and SCADA support services, the outcomes of which have the potential to impact part of WPLP's forecast

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

OM&A costs (as described in Exhibit F-1-1), WPLP plans to file updates to its OM&A evidence prior to the OEB's issuance of its first Procedural Order. Second, as construction activities are expected to continue to progress at a significant pace during this proceeding, WPLP plans to update its capital cost and schedule forecasts, along with related in-service additions and rate base calculations, at an appropriate stage of the proceeding.

A. INTRODUCTION

1. Wataynikaneyap Power Limited Partnership

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 will be connected to WPLP's Transmission System between 2022 and 2024.[4] 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 are necessary to ensure successful project execution, construction and 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 ensure the successful construction and ongoing operation of the Transmission System.

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

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

2. WPLP's Transmission System

Upon completion of construction, WPLP's Transmission System will operate as a single transmission system in northwestern Ontario, one part of which will reinforce transmission to Pickle Lake (the "Line to Pickle Lake") and the balance of which will connect to the provincial power system 16 remote First Nation communities that are currently served by diesel generation (the "Remote Connection Lines").[5]

The Line to Pickle Lake consists of: (a) a 230 kV switching station (Wataynikaneyap SS) 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 (Wataynikaneyap TS) 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 consist of: (a) the Pickle Lake Remote Connection Lines, comprised of approximately 903[6] 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 Wataynikaneyap 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 538[7] km of single circuit 115 kV and 25 kV transmission lines,

[5] One of the 16 communities, Pikangikum First Nation, became grid-connected in 2018 through an interim 44 kV connection that will be converted to 115 kV and will subsequently form 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] Line length increased by 6 km or less than 1% as described on page 10 of Exhibit B-1-1.

[7] Line length increased by 2 km or less than 1% as described on page 10 of Exhibit B-1-1.

three additional switching stations and six transformer stations located generally to the north of the Red Lake SS.[8]

Upon completion of construction in 2024, the Remote Connection Lines will supply service to the 25 kV distribution systems that will be owned and operated by Hydro One Remote Communities Inc. ("HORCI") in each of the 16 connecting First Nation communities.[9] [10] Exhibit B-1-1 provides detailed descriptions of the components of WPLP's Transmission System as well as a map showing the geographical location and extent of the system.

3. Key Elements of the LTC and Initial Revenue Requirement Decisions

On April 1, 2019, the OEB issued its decision and order in respect of WPLP's application for leave to construct its Transmission System (the "LTC Decision").[11] On September 30, 2021, the OEB issued its decision and order in respect of WPLP's initial transmission revenue requirement application based on a 2022 test year (the "Initial Rate Decision"). References to the LTC Decision and to the Initial Rate Decision are included throughout this Application, however the following key elements of the LTC Decision and the Initial Rate Decision provide important context for WPLP's proposals in the current application.

(a) Asset Classification[12]

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.

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[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.*

[9] HORCI continues to work with the IPA communities. An update on progress has been provided in the Semi-Annual Report dated April 15, 2022, filed pursuant to EB-2018-0190.

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

[11] EB-2018-0190, Decision and Order, April 1, 2019 (Revised April 29, 2019)

[12] LTC Decision, p. 23

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.

(b) Cost Recovery and Rate Framework[13]

With respect to the Remote Connection Lines, in the LTC proceeding WPLP proposed an alternative cost recovery and rate framework that would be compatible with project-specific funding that it anticipates receiving from the federal government. The proposal also ensured that the Transmission Project, 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 required HORCI to make a capital contribution towards the cost of constructing the Remote Connection Lines. Instead, WPLP will calculate a distinct revenue requirement for the Remote Connection Lines and recover 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 will form part of HORCI's revenue requirement and thereby form 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 will not impact rates for customers in the connecting First Nation communities. Moreover, if funding is received under the Federal Funding Framework, some of that funding 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 Transmission System 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.

[13] LTC Decision, Section 5, pp. 24-28

The Federal Funding Framework is discussed further in Exhibit I-4-1. WPLP anticipates that any distribution of federal funds would occur in 2024 and that the impact of such federal funding will be incorporated into a future application.

(c) Contingency Deferral

In the Initial Rate Decision, the OEB approved a comprehensive settlement agreement, pursuant to which the parties agreed that WPLP would remove contingency amounts from its proposed rate base and establish 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. In the current application, WPLP is proposing to use an equivalent approach in respect of contingency amounts for the 2023 test year.

(d) COVID Cost Recovery

In the OEB-approved settlement agreement from the Initial Rate Decision, the parties also agreed that WPLP may recover its audited 2020 year-end balance of COVID 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 current application, WPLP is proposing to use an equivalent approach in respect of COVID costs for the 2023 test year and for the remainder of the construction period.

4. Approvals Requested

The primary purpose of this Application is to request approval of an electricity transmission revenue requirement for a single test year, commencing January 1, 2023. A number of related approvals are also explicitly requested, including:

- approval for the allocation of WPLP's 2023 revenue requirement between the Line to Pickle Lake and the Remote Connection Lines;

- approval for recovery of the portion of WPLP's 2023 revenue requirement allocated to the Line to Pickle Lake through adjustments to the 2023 Network UTR rate in the manner described in Exhibit A-2-1;

- approval for recovery of the portion of WPLP's 2023 revenue requirement allocated to the Remote Connection Lines through a fixed monthly charge applicable to HORCI effective from January 1, 2023, consistent with the cost recovery and rate framework described above;

- approvals for the continuation or discontinuation of existing regulatory accounts, as more particularly set out in Exhibit H-1-1;

- partial disposition of WPLP's Pikangikum Distribution System Deferral Account, based on the December 31, 2021 audited balance in that account, as more particularly set out in Exhibit H-2-1; and

- partial disposition of WPLP's incremental COVID-related construction costs, based on audited costs incurred in 2021, as more particularly set out in Exhibit H-2-2.

B. PROJECT EXECUTION

1. Project Execution and Controls

To provide an appropriate level of project controls, contract administration, risk mitigation, and general oversight during the construction phase, WPLP has developed a project execution structure that continues to leverage the strengths and experience of its partners (through WPPM and OSLP[14]), supplemented by Hatch in its role as WPLP's Owner's Engineer ("OE"), and Mott MacDonald in its role as Independent Engineer ("IE"). Exhibit B-1-4 describes the role of each party in the context of WPLP's organizational and project execution structure, along with the division of responsibilities between WPLP and its EPC Contractor (Valard) and the processes that

[14] WPPM and OSLP are service providers as further described in Exhibit B-1-4.

have been implemented in respect of project management, including risk management and project controls.

2. Project Schedule and COVID Impacts

Following receipt of the LTC Decision in April 2019, WPLP completed all outstanding items required to initiate construction of its Transmission System. Notably, between April 2019 and December 2019, WPLP executed its EPC contract, secured project financing and federal funding commitments, acquired the necessary outstanding permits and approvals (including EA approvals and *Far North Act* exemptions), and acquired the necessary land rights required to initiate construction. Exhibit B-1-2 provides additional detail on these pre-construction activities, while Exhibit B-1-3 summarizes the current Transmission Project schedule including the sequencing of in-service dates for all project components and segments.

In 2020 WPLP worked extensively with Valard to assess the schedule implications arising from the onset of the COVID-19 pandemic, as well as mitigation efforts and associated cost and operational impacts. Through extensive collaboration in 2020 and 2021, including regular engagement and communication with the Participating First Nations, appropriate COVID-19 health and safety measures were put in place and amended to address continuing changes to the COVID-19 environment, which has allowed construction to proceed while mitigating risks to workers and nearby communities. A revised project schedule was established and has continued to be amended in 2021 given the impact of COVID-19 on construction.

As described in the initial revenue requirement proceeding, WPLP received a series of schedule updates from its EPC Contractor in late June 2021. As a result, WPLP filed updated evidence that included the revised Transmission Project schedule as part of its responses to interrogatories.[15] The revised project schedule indicated that the Line to Pickle Lake as well as three communities (i.e. Pikangikum First Nation, North Caribou Lake First Nation and Kingfisher Lake First Nation) to be served by the Remote Connection Lines remained on-schedule and unchanged from the

[15] EB-2021-0134, Staff-8, Appendix A attaching Exhibit K.

application as originally filed. The in-service dates for all other communities were delayed until 2023 and 2024, but WPLP did not provide specific dates as those remained subject to WPLP's then ongoing discussions with the EPC Contractor.

Pursuant to the Settlement Agreement in EB-2021-0134, WPLP agreed to include information relating to expected community connection dates in its semi-annual reports that it files pursuant to the OEB's directions in EB-2018-0190. WPLP's Semi-Annual Report, filed on October 15, 2021, provided the most recent estimates then available regarding the energization dates for each community. Subsequently, in late January 2022, WPLP received a further updated project schedule from its EPC Contractor reflecting all factors known as of December 31, 2021.[16] That schedule represents the most current available project schedule and has therefore been used as the basis for the current Application. Table 1, below, presents WPLP's current estimates of the energization dates for each of the remote communities, along with comparisons to the estimated energization dates that were presented in the October 15, 2021 Semi-Annual Report.

Table 1 – Expected Energization Dates by Community

Community	Estimated Date from October 15, 2021 Semi Annual Report	Current Estimated Date	Difference (Months)
Pikangikum	Apr-22	Jun-22	2
North Caribou Lake	Jun-22	Aug-22	2
Kingfisher Lake	Jun-22	Aug-22	2
Muskrat Dam	May-23	May-23	-
Bearskin Lake	May-23	May-23	-
Wunnumin Lake	May-23	May-24	12
Wawakapewin	May-23	Jun-23	1
Kasabonika Lake	Jun-23	May-24	11
KI + Wapekeka	Jun-23	May-24	11
Sachigo Lake	Jun-23	Jul-23	1

[16] As of March 15, 2022, the EPC Contractor (Valard) and its subcontractors have experienced 450 cases of COVID-19 since January 1, 2022. The impact of these COVID-19 cases has not been reflected in the January 2022 schedule used to prepare this rate application. Any update to this rate application will reflect the impact, if any, to schedule.

Poplar Hill	Apr-24	Apr-24	-
Deer Lake	Apr-24	Apr-24	-
North Spirit Lake	May-24	May-24	-
Sandy Lake	May-24	May-24	-
Keewaywin	May-24	May-24	-

3. Project Costs and COVID Impacts

WPLP's cost estimate for the Transmission Project evolved into a mature cost forecast based on the further planning and development work it has carried out since the LTC proceeding, including the costs identified through the EPC contracting process and through securing project financing. Exhibit B-1-5 provides a detailed breakdown of its current cost forecasts for the Transmission Project, with variance analysis relative to the project cost forecasts presented in the initial revenue requirement application, excluding the impacts of COVID.

Excluding incremental COVID-related project costs that were not anticipated and other infrastructure costs[17] that were outside the scope of the LTC application, WPLP's current cost forecast, is $1,818 million, or approximately 2% lower than the Transmission Project cost estimate presented in the initial rate application, as amended. That amount is for the entire Transmission Project, not all of which will come into service in the test year.

Notwithstanding that WPLP's COVID-related costs are part of its construction costs for the Transmission Project, consistent with the approach in the approved Settlement Agreement from the initial revenue requirement application, WPLP proposes to recover its 2021 COVID-related project costs as an expense added to the calculation of its 2023 and future revenue requirements rather than through the recovery of capital costs added to its rate base, and to continue with the same approach to COVID-related project costs for the remainder of the construction period. WPLP's COVID-related project costs, including the proposed rate treatment for these amounts, are discussed in Exhibit H-2-2 in the context of WPLP's request to continue its COVID

[17] Other infrastructure costs have been deferred into future years given the interim OM&A implementation strategy. For additional information, please see Exhibit B-1-4 and Exhibit B-1-5.

Construction Costs Deferral Account for the remainder of the construction period to facilitate the continued recording and recovery of these costs in future years as an expense.

C. KEY ELEMENTS OF THE APPLICATION

1. Revenue Requirement and Materiality Threshold

This Application requests approval of a 2023 test year revenue requirement of $92,931,065. Table 2, 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 2 – 2023 Revenue Requirement Summary

	LTPL	RCL	Total	Reference
Gross Fixed Assets (avg)	290,439,412	580,144,361	870,583,773	C-3-1
Accumulated Depreciation (avg)	-5,823,087	-7,595,166	-13,418,252	C-3-1
Net Fixed Assets (avg)	284,616,325	572,549,196	857,165,521	C-1-1
Working Capital Allowance	0	0	0	C-4-1
Rate Base	284,616,325	572,549,196	857,165,521	C-1-1
Regulated Rate of Return	4.35%	4.35%	4.35%	G-2-1
Regulated Return on Rate Base	12,393,859	24,932,140	37,325,999	G-2-1
OM&A Expenses	7,098,009	14,771,400	21,869,409	F-2-1
Property Taxes	0	0	0	F-11-1
Depreciation Expense	5,846,793	11,419,648	17,266,442	F-10-1
Income Taxes	132,185	265,910	398,095	F-11-1
Service Revenue Requirement	**25,470,846**	**51,389,098**	**76,859,944**	
Other Revenue Offset	0	0	0	E-3-1
Base Revenue Requirement	**25,470,846**	**51,389,098**	**76,859,944**	
Disposition of Pikangikum Distribution System Deferral Account	0	1,196,963	1,196,963	H-2-1
Disposition of COVID Construction Costs Deferral Account (CCCDA)	9,268,939	5,605,220	14,874,159	H-2-2
Revenue Requirement for Rates	**34,739,785**	**58,191,280**	**92,931,065**	

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 2 above, WPLP's materiality threshold is approximately $465,000.

2. Budgeting Assumptions

WPLP's capital cost forecasts presented in Exhibit B-1-5 are largely related to its fixed price EPC contract, as well as its non-EPC costs and project development costs already incurred. Any non-EPC cost forecasts for the 2022 to 2024 period that are subject to inflationary pressures include annual inflationary adjustments of 2%.

3. Load Forecast Summary

WPLP forecasts that the Network UTR demand determinants will increase by 20.3 MW in 2023, based on the forecasted months during which 4 additional First Nation communities will become grid-connected in 2023,[18] and the electricity demand of those communities. 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,[19] WPLP has requested approval of a fixed monthly charge applicable to HORCI for service from the Remote Connection Lines. WPLP has therefore not included any Line Connection or Transformation Connection revenue requirements or charge determinants in its 2023 rate design.

4. Transmission System Plan

WPLP's Transmission Project is a major capital investment that includes the initial development, construction and in-servicing of its entire Transmission System. WPLP has carried out a

[18] Pikangikum First Nation is already grid-connected via Hydro One's distribution system. Its demand has therefore been excluded from WPLP's load forecast as this demand would already be incorporated into the UTR charge determinant forecasts through Hydro One's load forecast.

[19] See Section A.3 above, and Section E.9 below for additional detail on the Remote Connection Lines rate framework.

comprehensive Transmission Project planning and development process, engaged and continues to engage extensively with potentially impacted communities, land users and stakeholders, undertaken commercially prudent processes for construction contracting and securing necessary financing, and implemented appropriate organizational structures and processes to ensure that the Transmission Project is effectively executed.

The present Application seeks approval of WPLP's transmission revenue requirement on a cost of service basis for a single test year (2023), with capital expenditure forecasts covering the 2022-2024 period during which construction of the Transmission System will be completed and placed into service (in stages). The proposed revenue requirement for 2023 is therefore largely based on the costs of the Transmission Project and, in particular, on the elements of the Transmission Project that are expected to go into service in 2022 and at different points during 2023.

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. It is therefore unnecessary for the capital investments associated with the Transmission Project, including its initial development, construction and in-servicing, to be further approved through a Transmission System Plan ("TSP") or otherwise. As such, in lieu of a TSP and to support its revenue requirement request, WPLP uses Exhibit 'B' of this Application to provide a comprehensive description of the Transmission Project, including its scope, planning, schedule, execution approach, cost and the manner in which WPLP's organizational structure will evolve from construction to ongoing operation of the Transmission System. WPLP intends to file an initial TSP in conjunction with its first multi-year revenue requirement application following completion of the Transmission Project.

5. Rate Base

WPLP's forecasted rate base for the 2023 test year is summarized in Table 3. WPLP proposes to calculate its rate base for the 2023 test year using actual monthly in-service dates rather than using the half-year rule, due to the timing difference between different categories of assets that will be

coming into service.[20] Details of in-service additions and the derivation of WPLP's rate base are provided in Exhibit 'C'.

Table 3 – 2023 Rate Base Forecast

Item	2023 Forecast ($000's)		
	Opening	**Closing**	**12-Month Avg**
Gross Fixed Assets	679,733	1,021,065	870,584
Less Accumulated Depreciation	-5,618	-22,885	-13,418
Net Fixed Assets	**674,114**	**998,181**	**857,166**
Working Capital Allowance[21]			0

6. Performance and Reporting

WPLP does not yet have any transmission assets in service and therefore Section 2.6.2 of the Filing Requirements, which requires information about historical reliability performance is not applicable. However, in an effort to fulfill the Filing Requirements WPLP is able to report on its brief history of reliability performance in relation to its distribution system that is temporarily supplying the Pikangikum First Nation until such time as that system is converted to form part of the Transmission System. That information is summarized in Exhibit D-2-1.

WPLP proposes to begin tracking information for typical transmission scorecard measures related to safety, reliability and costs during the construction period so that this information can be used in setting future performance expectations, as discussed in Exhibit D-1-1. WPLP intends to file an initial draft scorecard in 2025 when applying for a multi-year revenue requirement for the period beginning with the 2026 test year. That scorecard will propose measures that will be tracked starting in 2025, which will be the first full year that WPLP's entire transmission system is in service.

[20] As permitted in Sections 2.5.1 and 2.8.10 of the Filing Requirements.

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

In addition, in accordance with the approved Settlement Agreement from the Initial Rate Decision, WPLP agreed, in respect of the Line to Pickle Lake and the portions of the Remote Connection Lines that will be placed into service in 2022, to monitor performance on the basis of five specific reliability metrics without establishing performance targets and to 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. WPLP in the current Application is proposing to continue to monitor performance on the same basis with respect to the additional portions of the Remote Connection Lines that will be placed into service in 2023.

7. OM&A Expense

WPLP's interim strategy for operating and maintaining its transmission assets as they come into service during the construction period is provided in Section F of Exhibit B-1-4. The interim O&M strategy focuses on scaling resources based on in-service timing, ensuring meaningful opportunities for Indigenous participation, evaluating alternative technologies and work methods in consideration of remoteness and access challenges, and obtaining a balance between leveraging construction resources already mobilized while recruiting and developing local operational resources for the longer term. WPLP's interim O&M strategy also involves the procurement of third-party O&M, emergency response and system control services on an interim basis, thereby enabling WPLP to continue its focus on construction activities while developing internal processes, systems and staffing to support operation of its transmission system in the future.

Table 4, below, summarizes the total operating costs included in WPLP's proposed 2023 revenue requirement.

Table 4 – Summary of Operating Costs

Operating Cost Category	2023 Test Year ($000's)
OM&A Expenses	21,869
Depreciation and Amortization	17,266
Income Taxes	398
Total Operating Costs	**39,534**

A portion of WPLP's OM&A expenses is directly related to operating and maintaining assets as they come into service, and provisions for outage or emergency response. These expenses will support the safe and reliable operation and maintenance of WPLP's Transmission System, with cost forecasts that are based on WPLP's experience operating its Pikangikum Distribution System since late 2018.[22] The balance of WPLP's OM&A expense results from WPLP's methodology for allocating overhead costs between capital costs and OM&A expenses, as detailed in Appendix 'A' of Exhibit B-1-5. Detailed analysis of WPLP's 2023 operating costs, as well as support for WPLP's 2023 depreciation/amortization expense and income taxes, are provided in Exhibit F.

8. Cost of Capital

WPLP's capital structure and cost of capital parameters are summarized in Table 5 below.

WPLP has followed the OEB's deemed 60/40 debt/equity structure,[23] using placeholder values for short-term debt and allowed ROE rates. Through extensive negotiations with a consortium of bank lenders and the Province of Ontario, WPLP has secured project financing with a relatively low effective interest rate that reduces costs for ratepayers, as further detailed in Exhibit G-2-1. Due to the variable nature of WPLP's financing facilities, WPLP has requested continuance of a variance account, approved in the Initial Rate Decision, to record the revenue requirement impact related to interest rate differentials on long-term debt, as summarized in Section 10 below.

[22] As described in Exhibit F-1-1, WPLP is in the process of selecting third-party service providers to undertake certain Operating and Maintenance activities and to provide SCADA support services. While WPLP's OM&A forecast has been reasonably forecast based on the best information available at the time of filing, the outcomes of these processes have the potential to impact part of WPLP's forecast OM&A costs. As such, WPLP plans to file updates to its OM&A evidence, along with an OM&A benchmarking report, prior to the OEB's issuance of its first Procedural Order.

[23] Through the federal funding framework, WPLP has agreed to contribute equity based on the forecasted total cost of the project, subject to restrictions that could limit WPLP's maximum equity contribution. Such limits do not limit WPLP's ability to contribute 40% equity during the 2023 Test Year. To the extent that WPLP's equity contribution is limited to less than 40% in a future year, this will be addressed in WPLP's revenue requirement application for the relevant Test Year.

Table 5 – Capital Structure and Cost of Capital

	Capitalization Ratio		Cost Rate[24]	Return
	(%)	**($)**	**(%)**	**($)**
Long-term Debt	56%	$480,012,692	1.51%	$7,232,632
Short-term Debt	4%	$34,286,621	1.17%	$401,153
Total Debt	*60%*	*$514,299,313*	*1.48%*	*$7,633,785*
Common Equity	*40%*	*$342,866,208*	*8.66%*	*$29,692,214*
Total	**100%**	**$857,165,521**	**4.35%**	**$37,325,999**

9. Cost Allocation and Rate Design

In consideration of WPLP's unique cost recovery and rate framework, which is summarized in Section A.3 above, WPLP's 2023 revenue requirement is allocated between the Line to Pickle Lake, and the Remote Connection Lines, as summarized in Table 6 below.

Table 6 – Allocation of 2023 Revenue Requirement

	LTPL	RCL	Total
Revenue Requirement for Rates	**$34,739,785**	**$58,191,280**	**$92,931,065**

Details supporting WPLP's 2023 revenue requirement allocation, rate design and bill impacts are presented in Exhibit 'I'.

WPLP has estimated that the UTR Network rate will increase by $0.04/kW resulting from the Line to Pickle Lake portion of its 2023 revenue requirement, as 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

[24] As indicated in Exhibit G-2-1, WPLP intends to update the rates applicable to short-term debt and return on equity to reflect the OEB's 2023 cost of capital parameters, once published.

Lines revenue requirement and 12 months of in-service assets, the proposed monthly fixed charge is $4,849,273, effective January 1, 2023.

10. Deferral and Variance Accounts

On March 23, 2017, the OEB in its Decision and Order in EB-2016-0262 approved WPLP's request to establish a deferral account to capture and record development costs associated with the Transmission Project up to the effective date of the initial transmission rate order for WPLP. Balances in this account were reported to the OEB semi-annually from July 2017 until July 2019. Pursuant to the OEB's decision in the LTC proceeding in EB-2018-0190, WPLP transferred the balance of this account to CWIP Account 2055 and has continued to report to the OEB on a semi-annual basis. The development costs transferred to CWIP will be allocated to fixed asset accounts in proportion to the direct capital costs of assets coming into service, as described in Exhibit C-2-1.

In EB-2018-0267, the OEB authorized WPLP to establish the Pikangikum Distribution System Deferral Account, consisting of six sub-accounts of Account 1508 to record OM&A costs, incremental capital costs and associated depreciation, and related carrying charges associated with its interim operation of the Pikangikum Distribution System. WPLP proposes to continue this account, as described in Exhibit H-1-1, and proposes to partially dispose of the December 31, 2021 audited account balance of $1,196,963, as described in Exhibit H-2-1.

In EB-2021-0134, the OEB authorized WPLP to establish four accounts. In the current Application, WPLP is proposing to continue each of these four accounts and partial disposition of the balance in one of these accounts, as follows.

The In-Service Date Variance Account ("ISDVA") is a symmetrical account that was established 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., as detailed in Section A.3 of Exhibit H-1-1. As no segments of the Transmission

Project were put into service during 2021, WPLP is not seeking disposition of any amounts from this account in the current Application. However, WPLP proposes to continue using the ISDVA in 2023, as the Transmission Project is still under construction and in-service date differences may continue to arise.

The Construction Period Interest Costs Variance Account ("CPICVA") is a symmetrical account that was established for the purpose of recording the revenue requirement impact attributable to the difference between the effective interest rate for long-term debt as approved and WPLP's actual effective interest rate on long-term debt during the construction period, as detailed in Section A.4 of Exhibit H-1-1. As no segments of the Transmission Project were put into service during 2021, WPLP is not seeking disposition of any amounts from this account in the current Application. However, WPLP proposes to continue using the CPICVA in 2023, as the Transmission Project is still under construction and interest rate differences may continue to arise.

The COVID Construction Costs Deferral Account ("CCCDA") was established to facilitate WPLP's recovery of COVID-related project costs as an expense rather than as a cost of capital in its revenue requirement, as described Section A.5 of Exhibit H-1-1 and further in Exhibit H-2-2. WPLP seeks recovery of $4,349,913, which represents 25% of the total audited 2020 year-end balance, plus applicable carrying costs. In addition, WPLP has recorded COVID construction costs of $42,096,982 incurred during 2021. Consistent with the approach approved in EB-2021-0134, WPLP seeks recovery of its incremental audited 2021 COVID construction costs in the CCCDA over a four-year period (i.e. 25% in each of 2023, 2024, 2025 and 2026). Accordingly, in 2023 WPLP seeks recovery of $10,524,246, which represents 25% of its total audited 2021 additions to the CCCDA, plus applicable carrying costs. Based on the foregoing, WPLP proposes to dispose of a total balance from the CCCDA of $14,874,159, of which $9,268,939 is in respect of the Line to Pickle Lake and $5,605,220 is in respect of the Remote Connection Lines, as detailed in Exhibit H-2-1.

The Deferred Contingency Deferral Account ("DCDA") was established as a result of the approved Settlement Agreement, in which 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"), and that WPLP would establish this account to track the revenue requirement impacts associated with the Deferred Contingency Amount, which WPLP will 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 from the initial rate proceeding is limited to the revenue requirement impact attributed to the Deferred Contingency Amount to a maximum of $48,075,777 for 2022. As the actual amount of contingency realized in 2022 is not yet available, and WPLP has additional forecasted contingency amounts associated with its planned 2023 in-service asset additions used to calculate year-end rate base, WPLP is not proposing disposition but is proposing to continue this account in 2023.

11. Bill Impacts

WPLP's proposed 2023 revenue requirement will result in bill increases from two perspectives. First, the Line to Pickle Lake portion of its revenue requirement will result in an increase of $0.04/kW to the Network UTR rate. Second, the Remote Connection Lines portion of its revenue requirement will result in increased costs to HORCI, which will ultimately be funded through an increase to the RRRP rate, which WPLP has calculated at $0.0002/kWh for 2023.

As detailed in Exhibit I-4-1, the combination of the increased Network UTR and RRRP rates arising from this Application is estimated to result in a total bill increase for a typical residential customer[25] of $0.20 per month, or 0.15%. Details of bill impacts for a typical general service customer and for transmission-connected customers are also provided in Exhibit I-4-1.

[25] In this context, the "typical" customer is 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 March 15, 2022. See Exhibit I-4-1 for details.

Exhibit A, Tab 4, Schedule 1

Corporate Structure

CORPORATE 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)[1]

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] As discussed in Exhibit A-5-2, WPLP currently holds an electricity distribution license (ED-2017-0236) in connection with the Pikangikum distribution line. Based on the current project schedule, further discussed in Exhibit B-1-3, it is anticipated that the Pikangikum First Nation will be connected to WPLP's transmission system on June 29, 2022, at which point the Pikangikum distribution line will form part of the Transmission System that is the subject of WPLP's electricity transmission licence. Once this conversion takes place, WPLP intends to request cancellation of its electricity distribution licence.

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 (as marked with an "*" below) have or will be connected to the WPLP Transmission System during the 2021-2024 construction period (the "Connecting 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 2021 revenue of $9.4 billion and total assets of $58 billion as at December 31, 2021. The company's 9,100 employees serve more than 3.4 million utility customers in five Canadian provinces, nine U.S. states and three Caribbean countries. Its regulated utilities account for approximately 99% of its total assets. FortisOntario Inc. is a wholly owned subsidiary of Fortis Inc.

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

WPLP's organizational structure, both for purposes of executing the Transmission System project and for transitioning into an operating utility, is described in Exhibit B, Tab 1, Schedule 4.

APPENDIX ‘A’

Applicant’s Corporate Structure

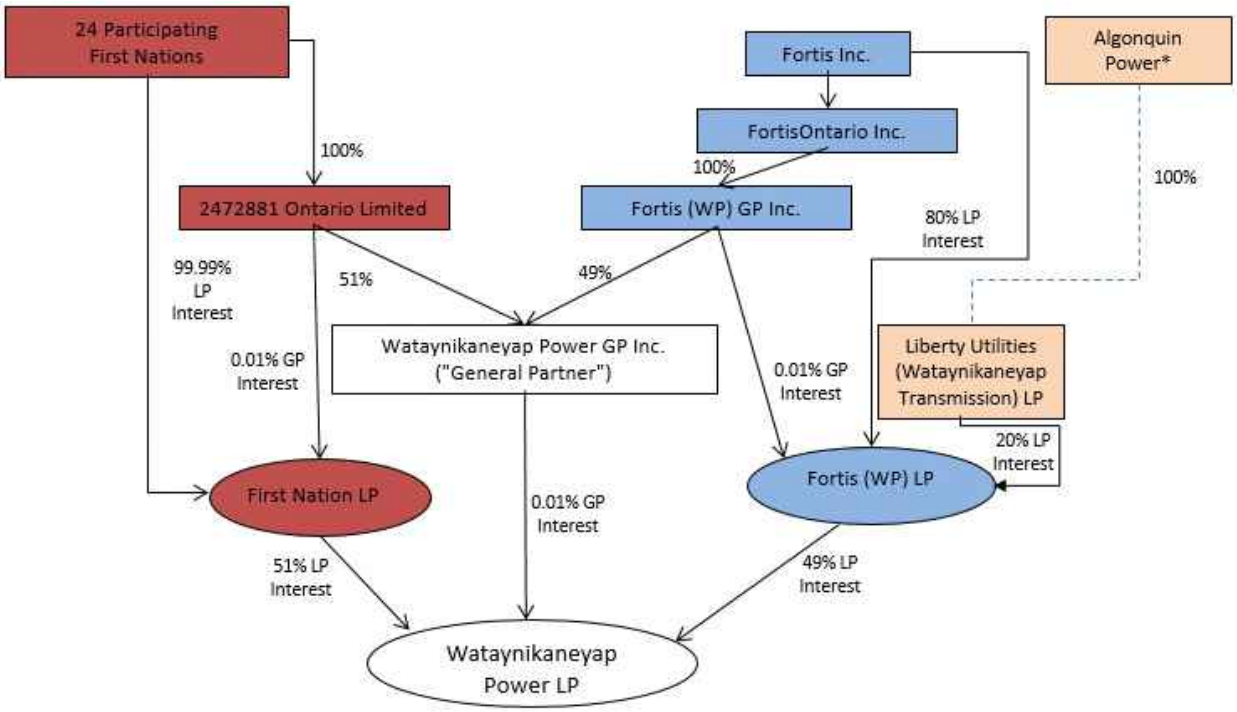

24 Participating First Nations
Fortis Inc.
Algonquin Power*
FortisOntario Inc.
100%
100%
100%
2472881 Ontario Limited
Fortis (WP) GP Inc.
80% LP Interest
99.99% LP Interest
51%
49%
0.01% GP Interest
Wataynikaneyap Power GP Inc. ("General Partner")
0.01% GP Interest
Liberty Utilities (Wataynikaneyap Transmission) LP
20% LP Interest
First Nation LP
Fortis (WP) LP
0.01% GP Interest
51% LP Interest
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 transmission system that is partly in service and which will continue to be put into service in segments during the test year and in the year following the test year, as well as 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 are summarized below and further addressed throughout the Application.

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"). WPLP's proposed revenue requirement is largely based on the costs of the Transmission Project and, in particular, on the elements of the Transmission Project that have gone or are going into service in 2022 and on the additional elements which are expected to go into service in 2023 and 2024. 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. It is therefore unnecessary for the capital investments associated with the Transmission Project, including its initial development, construction and in-servicing, to be further approved through a TSP or otherwise. As such, in lieu of a TSP and to support its revenue requirement request, WPLP uses Exhibit 'B' of the Application to provide a comprehensive description of the Transmission Project, including its scope, planning, schedule, execution approach, cost and the manner in which WPLP's organizational structure will evolve from one that is focused on construction and execution to one that is focused on operations by the time construction is complete.

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 Exhibit A-2-1, WPLP sets out its intention to file single-year cost of service revenue requirement applications for the 2023 test year that is the subject of the current application and for each of the 2024 and 2025 test years. During this time, WPLP's focus will be on completing construction of its transmission system and transitioning from construction to operation as additional assets come into service, with a focus on cost management, risk and performance management. In Exhibit D-1-1 of this application, WPLP addresses the OEB's performance and scorecard expectations relative to WPLP's circumstances. Exhibit D-1-1 also outlines WPLP's intention to file an initial draft scorecard in 2025 when applying for a multi-year revenue requirement for the period beginning with the 2026 test year, and notes that the scorecard would propose measures that will be tracked starting in 2025.

WPLP's transmission assets are only starting to be put into service in Q2 2022. It therefore expects to address transmission system reliability, including the Chapter 4 Transmission System Code requirements related to customer delivery point performance standards, in a future application. However, in an effort to be responsive to the Filing Requirements, Exhibit D-2-1 summarizes the historical reliability performance of WPLP's Pikangikum Distribution system. 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 will be placed into service in 2022, WPLP will monitor performance on the basis of the following reliability and operating performance metrics without establishing performance targets and report to the OEB on such performance, based on data as at Year End 2022, to be provided in or around April 2023:

- 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).

In accordance with the Settlement Agreement in EB-2021-0134, WPLP also agreed to prepare and file, as part of this application, benchmarking studies to compare:

- 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, and

- WPLP's compensation costs relative to Hydro One's compensation costs.

WPLP provides further details in connection with these benchmarking studies in Exhibit F-1-1.

Section 2.1 of the Filing Requirements states that the average of the opening and closing fiscal year balances must be used for items in rate base. However, for those portions of its transmission system that are expected to go into service during the 2023 test year, WPLP has instead used the average of twelve monthly values, as permitted in Sections 2.5.1 and 2.8.10 of the Filing Requirements. WPLP's rationale for this approach is provided in Exhibit C-3-1 and is consistent with the approach used by WPLP initial rate application.

Section 2.1 of the Filing Requirements also 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 generally applicable to WPLP's current transmission rate application given the expected in-service dates of assets in the 2022 bridge year. However, Exhibit A-5-2 provides context for the Application arising from prior OEB proceedings, and Exhibits B-1-3 and B-1-5 provide schedule and cost variance analysis relative to that which was presented in WPLP's application for its 2022 transmission revenue requirement application, as amended (EB-2021-0134).

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]

Finally, 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-11-1 show that WPLP's has a significant loss carryforward for 2023, primarily resulting from Capital Cost Allowance ("CCA") deductions. WPLP anticipates adding to its loss carryforwards in the coming years, due to the large CCA deductions allowable under the Accelerated Investment Incentive. WPLP does not expect to fully utilize its loss carryforwards prior to filing a multi-year revenue requirement application in 2025, and WPLP therefore proposes to address forecasting of loss carryforwards at that time.

[1] As detailed in Exhibit E-1-1, the change in Network UTR determinants resulting from WPLP's load forecast is 0.008%, and WPLP's load forecast is not included in the Line Connection or Transformation Connection UTR charge determinants.

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 second 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 Wataynikaneyap, amends schedule 1 of the licence to specify the transmission facilities to be owned and/or operated by Wataynikaneyap, 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 First Nation 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 decision approving the Settlement Agreement in EB-2021-0134.

D. Electricity Distribution Licence (EB-2017-0236)

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. 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 using 115 kV conductors, 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. Based on the current project schedule, it is anticipated that the Pikangikum distribution line will be converted to form part of the Transmission System on June 29, 2022, at which point, WPLP intends to request that the OEB cancel its electricity distribution licence. In the event that any updates to the project schedule indicate that the Pikangikum distribution line could remain connected to Hydro One's 44 kV distribution system beyond September 27, 2022, WPLP will file an application to extend the term of its electricity distribution licence.

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, based on the current project schedule, it is anticipated that the Pikangikum distribution line will be converted to form part of the Transmission System in Q2 2022. In WPLP's 2022 transmission rate proceeding (EB-2021-0134), the OEB approved the continuation of the Pikangikum Distribution

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

System Deferral Account, and the disposition of the audited December 31, 2020 account balance. 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 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 the 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]

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, with emphasis added to clarify applicability:[4]

[2] As a result of minor routing changes, the total estimated transmission line distance in the current Application is approximately 1,744 km. See Exhibit B-1-1 for a description of project changes.

[3] Details and status of backup power solutions for the 16 connecting First Nation 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, 2022.

[4] Bolded, italicized text indicates the relevance to the current Application and underlined text indicates relevance only to WPLP's initial application filed under EB-2021-0134.

- 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 addresses these requirements primarily in Exhibit B, Tab 1, Schedule 5 and Exhibit H, Tab 2, Schedule 2.

- 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[5], 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. See Exhibit C, Tab 3, Schedule 1 of the present Application.

- "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 the present Application.

- "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."[6] See Exhibit G, Tab 2, Schedule 1 of the present Application.

[5] 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.

[6] 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 Transmission System Code (TSC) in relation to the Remote Connection Lines. In particular, WPLP is exempt from all sections relating to connection procedures until the earlier of the date all Transmission System facilities are placed in service or December 31, 2023. WPLP must file Customer Connection Procedures (CCPs) by December 31, 2022, which will be effective on the earlier of the date all facilities are in service or January 1, 2024. WPLP is also exempt from all sections relating to customer capital contributions in respect of connection facilities.

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 will be 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 that relate to financial disclosure obligations in respect of the 2019 to 2023 reporting periods.

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 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 the present Application 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 a respective application and the values that were presented in the Leave to Construct proceeding (EB-2018-0190). See Exhibit B-1-5 of the present Application.

Exhibit A, Tab 6, Schedule 1

Indigenous, Métis 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 focused on issues relating to the design, development and construction of the Transmission System, including routing, land access, land sharing protocols and traditional protocols, through the significant Indigenous engagement activities related 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 First Nation communities, and OSLP[1] on behalf of WPLP and have been instrumental in the successful development and execution of WPLP's Transmission Project.

WPLP's extensive programs of consultation and 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.[2] WPLP's engagement efforts for the period from the leave to construct application until its initial rate application (EB-2021-0134) are summarized in Exhibits A-6-1 and B-1-2 of its initial rate application. WPLP's engagement efforts for the period since the initial rate application are summarized in Exhibit B-1-2 of the present application. In

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

[2] 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).

total, the record of engagement shows that, from 2012 to date, there have been more than 2,650 engagement activities with affected First Nation 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 otherwise affected First Nations, land users and private landowners affected by the Transmission System routing and construction, 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,[3] focused on identifying and supporting the need to connect remote First Nation communities to the transmission system as an alternative to the continued use of diesel generation. Discussions of electricity supply limitations related to diesel generators and the impacts on the First Nation communities are provided in WPLP's leave to construct application in EB-2018-0190.[4] Much of WPLP's engagement and consultation 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.

The Line to Pickle Lake portion of the Transmission System is expected to be connected to HONI's transmission system in Dinorwic and in Pickle Lake at the end of June 2022. This portion of the Transmission System reinforces transmission in the region but upon going into service will not serve any customers directly. The Remote Connection Lines directly serve one customer, HORCI, which is or will be the licensed distributor in respect of each of the sixteen connecting First Nation

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

[4] 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)

communities.[5][6] These connections are occurring over an approximately 3-year period as different segments of the Remote Connection Lines are completed and commissioned, with the first 3 communities connecting in 2022[7], 4 communities expected to connect in 2023 and the remaining 9 communities expected to connect in 2024.

WPLP has undertaken significant engagement with HONI and HORCI throughout the process of developing and constructing the Transmission System and in anticipation of placing the initial segments into service in 2022. This has included regular discussions in the context of developing and obtaining leave to construct and approval for the unique cost recovery and rate framework that will apply, as well as in the context of developing, obtaining approvals for and operating the Pikangikum Distribution Line.[8] In addition, during the course of the development and hearing of the initial transmission rate application, WPLP engaged with HORCI regarding matters such as the calculation and mechanics of the fixed monthly charge in respect of the Remote Connection Lines.

Since the 2022 revenue requirement application, WPLP has continued to coordinate with HONI on matters relating to construction, commissioning and energization at each of the three locations where WPLP's transmission system will connect with HONI's transmission system. Similarly, WPLP has worked with HORCI to coordinate procurement, construction, commissioning and energization activities for distribution delivery points, with a focus on the communities that will be connecting in 2022. WPLP's engagement and coordination activities with HONI and HORCI have also included the drafting of transmission connection agreements, confirmation of settlement processes, and completion of relevant IESO registration processes.

[5] HORCI continues to work with the Independent Power Authorities ("IPA") communities. WPLP has filed the latest IPA update provided by Indigenous Services Canada in connection with its Semi-Annual Report dated April 15, 2022 in EB-2018-0190.

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

[7] This includes Pikangikum, which is currently connected to WPLP's distribution system and will become transmission-connected during 2022.

[8] See EB-2018-0267.

As construction of various transmission line segments nears completion, WPLP has initiated community engagement activities that include, but are not limited to, engagement on permanent access for operational purposes for the project, 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 have 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 rights of way through a combination of a permanent access for operating purposes and temporary access methods. This process provides an opportunity for First Nations community members and land users to understand and comment on WPLP's access plans, and for WPLP to adjust its access plans based on the comments received.

As WPLP continues to transition into being an operating transmitter with connected customers, it will 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. Those processes and the customer needs and preferences identified through implementation of those processes will be described in connection with WPLP's first Transmission System Plan, which is expected to be included in a future transmission rate application by WPLP. In the interim, WPLP will continue to identify and take into consideration the customer, community and land user needs and preferences it identifies through its ongoing engagement with First Nation communities, HONI, HORCI and others.

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 2021
- Attachment 2 – WPLP Audited Financial Statements for 2020
- Attachment 3 – WPLP Tax Returns for 2020[1]
- Attachment 4 – 2021 Annual Report for Fortis Inc.[2]

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).[3]

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.[4]

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.

[1] WPLP's Tax Returns for 2021 will be filed when available.

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

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

[4] 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, and expects that its partners (First Nation LP and Fortis (WP) LP) are forecasted to make equity contributions in June and August 2022 as the initial assets go in service, as well as at different times in 2023 and 2024 coinciding with additional assets going in service. Filing Requirements related to rating agency reports, prospectuses and information circulars are therefore not applicable.

ATTACHMENT 1

WPLP Audited Financial Statements for 2021

Wataynikaneyap Power LP

Financial statements
December 31, 2021



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, 2021, and statements of income (loss), statement of partners' deficiency 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 financial statements present fairly, in all material respects, the financial position of the Partnership as at December 31, 2021, 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 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 25, 2022

Chartered Professional Accountants
Licensed Public Accountants

Wataynikaneyap Power LP

Balance sheet

As at December 31

	2021 $	2020 $
Assets		
Cash *[note 7]*	**35,980,389**	9,759,060
Accounts receivable	**227,528**	5,527
Inventory	**384,068**	396,804
HST receivable	**3,322,137**	4,957,221
Due from related parties *[note 3]*	**7,651**	82,657
Total current assets	**39,921,773**	15,201,269
Regulatory assets *[notes 1 and 2]*	**62,740,562**	2,046,966
Property, plant and equipment, net *[note 4]*	**968,527,983**	522,384,140
	1,071,190,318	539,632,375
Liabilities and partners' equity		
Current		
Accounts payable and accrued liabilities	**170,637,647**	116,158,333
Due to related parties *[note 3]*	**11,981,756**	1,704,345
Total current liabilities	**182,619,403**	117,862,678
Long-term debt *[note 5]*	**818,344,443**	350,716,664
Deferred contributions *[note 6]*	**53,285,819**	54,556,216
Total liabilities	**1,054,249,665**	523,135,558
Partners' equity	**16,940,653**	16,496,817
	1,071,190,318	539,632,375

See accompanying notes

Approved by the Directors:

Director

Director

Wataynikaneyap Power LP

Statement of partners' equity

Year ended December 31

	2021				2020
	First Nation LP 51.00%	Fortis (WP) LP 48.99%	Wataynikaneyap Power GP Inc. 0.01%	Total	Total
	$	$	$	$	$
Partners' equity, beginning of year	**9,069,523**	**7,427,666**	**(372)**	**16,496,817**	16,493,364
Net income for the year	**226,356**	**217,435**	**45**	**443,836**	3,453
Partners' equity, end of year	**9,295,879**	**7,645,101**	**(327)**	**16,940,653**	16,496,817

See accompanying notes

Wataynikaneyap Power LP

Statement of income

Year ended December 31

	2021	2020
	$	$
Revenue		
Pikangikum capital contribution amortization	**1,238,745**	1,228,605
Regulatory interest, net	**761,092**	30,387
Interest income	**1,035**	127
	2,000,872	1,259,119
Expenses		
General and administration	**318,291**	27,061
Amortization	**1,238,745**	1,228,605
	1,557,036	1,255,666
Net income for the year	**443,836**	3,453

See accompanying notes

Wataynikaneyap Power LP

Statement of cash flows

Year ended December 31

	2021	2020
	$	$
Operating activities		
Net income (loss) for the year	**443,836**	3,453
Deduct item not affecting cash		
Non-cash regulatory interest	**—**	(24,506)
Amortization of deferred contributions	**1,238,745**	1,228,605
Amortization of property, plant and equipment	**(1,238,745)**	(1,228,605)
Changes in non-cash working capital balances related to operations		
Accounts receivable	**(222,001)**	2,686,056
Inventory	**12,736**	(85,423)
HST receivable	**1,635,084**	(2,306,027)
Due from/to related parties	**10,352,417**	(1,365,003)
Accounts payable and accrued liabilities	**54,479,314**	94,933,982
Cash provided by operating activities	**66,701,386**	93,842,532
Investing activities		
Other assets	**—**	311,196
Regulatory assets	**(60,693,596)**	(705,527)
Purchases of property, plant and equipment	**(447,380,528)**	(365,556,779)
Cash used in investing activities	**(508,074,124)**	(365,951,110)
Financing activities		
Increase (decrease) in deferred contributions	**(33,712)**	397,829
Increase in long-term debt	**467,627,779**	278,537,992
Cash provided by financing activities	**467,594,067**	278,935,821
Net increase in cash during the year	**26,221,329**	6,827,243
Cash, beginning of year	**9,759,060**	2,931,817
Cash, end of year	**35,980,389**	9,759,060

See accompanying notes

Wataynikaneyap Power LP

Notes to financial statements

December 31, 2021

1. Basis of accounting and summary of significant accounting policies

Partnership

Wataynikaneyap Power LP ["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. 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, 2020. 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 totaling this same amount as consideration for the transfer.

The business of WPLP is the planning and development 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.

Notes to financial statements

December 31, 2021

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 Canadian accounting standards for private enterprises ["ASPE"], as per Part II of the *CPA Canada Handbook – Accounting*, 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 which 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 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 income. Future transmission rate proceedings will determine the proper disposition of all Project costs.

Notes to financial statements

December 31, 2021

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, Construction Period Interest Cost Variance Account, Deferred Contingency Deferral Account and the COVID Construction Costs Deferral Account.

Revenue recognition

WPLP's initial transmission rates have not yet been established and development costs for the Project have not been brought before the OEB for disposition. Consequently, WPLP does not currently record any transmission revenue. As noted above, WPLP is allowed regulatory carrying changes 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 collectability 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 depreciation.

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

	Method	Estimated Useful Life
Transmission plant		
Land rights	Straight-line	40 years
Station equipment – transformers and stations	Straight-line	50 years
Station equipment – switches and breakers	Straight-line	40 years
Station equipment – protection and control	Straight-line	20 years
Towers and fixtures	Straight-line	60 years
Poles and fixtures	Straight-line	45 years
Overhead conductors	Straight-line	45 years
General plant		
Office furniture and equipment	Straight-line	10 years
Computer hardware	Straight-line	5 years
Transportation equipment	Straight-line	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 due from related parties.

Use of estimates

The preparation of financial statements in conformity with ASPE requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities 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

Regulatory assets arise as a result of regulatory requirements established by the OEB and consist mainly of engineering, environmental assessments and project management project 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 – 3 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 COVID-19 costs incurred to December 31, 2020 to a deferral account in the Decision and Order EB-2021-0143. WPLP has recorded all coronavirus disease ["COVID-19"] construction costs in deferral account pending OEB approval.

Notes to financial statements

December 31, 2021

Long-term regulatory assets consist of the following:

	2021 $	2020 $
Distribution recoverable costs	**3,243,928**	2,046,966
COVID Construction costs deferral account	**59,496,634**	—
Total regulatory assets	**62,740,562**	2,046,966

3. Related party transactions

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

	2021 $	2020 $
Project costs paid on behalf of WPLP by		
FortisOntario Inc.	**1,325,445**	2,581,802
Newfoundland Power Inc.	**54,244**	368,165
Opiikapawiin Services LP	**5,238,526**	5,295,818
Wataynikaneyap Power PM Inc.	**3,558,977**	3,108,840
	10,177,192	11,354,625
Project costs recoverable by WPLP from		
Newfoundland Power	**—**	24,280
	—	24,280
Project engagement fees billed to WPLP by First Nation LP	**551,807**	547,791
Project management fees billed to WPLP by Wataynikaneyap Power PM Inc.	**551,807**	547,791

	2021 $	2020 $
Receipts (payments)		
Opiikapawiin Services LP	**(3,392,707)**	(5,526,524)
FortisOntario Inc.	**(1,264,723)**	(2,452,981)
Wataynikaneyap Power PM Inc.	**(4,046,407)**	(3,995,504)
Newfoundland Power Inc.	**(54,244)**	(760,708)
First Nation LP	**(622,786)**	(1,121,226)
Wataynikaneyap Power GP Inc.	**—**	13.
Fortis (WP) GP Inc.	**—**	331.
Fortis (WP) LP	**—**	390.
	(9,380,867)	(13,856,209)

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

December 31, 2021

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

	2021 $	2020 $
Current due from (to) related parties		
Opiikapawiin Services LP	**(2,680,311)**	(834,493)
First Nation LP	**(93,180)**	(97,233)
First Nation LP (Third Party Funding)	**(8,386,438)**	—
Wataynikaneyap Power PM Inc.	**(589,547)**	(601,060)
FortisOntario Inc.	**(232,280)**	(171,559)
	(11,981,756)	(1,704,345)

	2021 $	2020 $
Current due from related parties		
Wataynikaneyap Power GP Inc.	**2,506**	2,506
Fortis (WP) GP Inc.	**2,340**	2,503
Fortis (WP) LP	**2,805**	3,000
Wataynikaneyap Power PM Inc.	**—**	74,648
	7,651	82,657

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 sub-account without applying the amounts recorded in that subaccount as offsets to development and construction costs. The due to First Nation LP of $8,386,438 represents the third-party funding removed as an offset to CWIP construction costs and will be converted to preferred units in 2022.

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, 2021

4. Property, Plant and Equipment

	2021		2020	
	Cost	Accumulated amortization	Net book value	Net book value
	$	$	$	$
Transmission assets				
Land rights	**54,796**	**4,110**	50,686	52,056
Station equipment	**12,317,742**	**738,923**	11,578,819	11,825,177
Poles and fixtures	**22,057,899**	**1,470,527**	20,587,372	21,109,762
Overhead conductors and devices	**22,511,453**	**1,454,443**	21,057,010	21,557,290
Construction work-in-progress	**915,254,096**	**—**	915,254,096	467,839,855
	972,195,986	**3,668,003**	968,527,983	522,384,140

Included in the cost of property, plant and equipment is $915,254,096 [2020 – $467,839,855] of assets not being amortized because they are under construction. Within the balance of construction work-in-progress is $nil [2020 – $17,399,652] of COVID-19 incremental costs incurred due to the pandemic. Subsequent to 2020, all COVID-19 costs have been reclassed to the COVID deferral account for the purposes of recovery in accordance with the OEB Decision & Order EB-2021-0134.

5. Long-term debt

	2021	2020
	$	$
Senior banks [ii]	**547,800,000**	240,000,000
Ontario loan [i]	**278,000,000**	121,900,000
Unamortized financing costs, net of amortization of $8,149,231	**(7,455,557)**	(11,183,336)
	818,344,443	350,716,664

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 point. 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 0.64% [2020 – 1.02%]. 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 CDOR rate plus a spread of 1.5%. The average rate of interest for the year is 1.96% [2020 – 2.37%]. 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.

Notes to financial statements

December 31, 2021

6. Deferred contributions

Deferred contributions relate to government funding received for the construction of 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 $1,238,745 [2020 – 1,228,605] and is included under Pikangikum capital contribution amortization in the statement of income.

7. Cash

Bank balances are presented under cash.

8. Financial instruments and risk management

As at December 31, 2021, financial instruments recorded at amortized cost include cash, accounts receivable and due from related parties with a carrying value of $36,215,568 [2020 – $9,847,244].

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 minimized. 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.

Operating lease commitments

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

	$
2022	**141,092**
2023	**153,931**
2024	**160,251**
2025	**158,892**
2026	**166,461**
	780,627

9. COVID 19

In March 2020, the World Health Organization declared the spread of COVID-19 outbreak as a pandemic. As a result of this, on March 23, 2020, the Government of Ontario ordered the closure of all non-essential businesses effective March 24, 2020. In addition, the Canadian government imposed travel restrictions to Canada until further notice. These restrictions impacted the operations of WPLP and resulted in the closure of physical premises of the organization. Global stock markets have also experienced great volatility and a significant weakening. 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 financial impacts will depend on future developments, including the duration, spread and severity of the outbreak; physical distancing requirements; the duration and geographic scope of related travel advisories and restrictions; and the extent of disruptions to businesses globally and their related impact to the economy.

The duration and impact of the COVID-19 pandemic, as well as the effectiveness of Government and central bank responses, remains 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.

ATTACHMENT 2

WPLP Audited Financial Statements for 2020

Wataynikaneyap Power LP

Financial statements
December 31, 2020



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, 2020, and statement of operations, statement of partner's equity 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 financial statements present fairly, in all material respects, the financial position of the Partnership as at December 31, 2020, 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 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 14, 2021

Chartered Professional Accountants
Licensed Public Accountants

Wataynikaneyap Power LP

Balance sheet

As at December 31

	2020	2019
	$	$
Assets		
Cash *[note 7]*	**9,759,060**	2,931,817
Accounts receivable	**5,527**	2,691,583
Inventory	**396,804**	311,381
HST receivable	**4,957,221**	2,650,869
Due from related parties *[note 3]*	**82,657**	223,369
Total current assets	**15,201,269**	8,809,019
Other assets	**—**	311,196
Regulatory assets *[notes 1 and 2]*	**2,046,966**	1,316,933
Property, plant and equipment, net *[note 4]*	**522,384,140**	158,055,966
	539,632,375	168,493,114
Liabilities and partners' equity		
Current		
Accounts payable and accrued liabilities	**116,158,333**	21,224,351
Due to related parties *[note 3]*	**1,704,345**	3,209,735
Total current liabilities	**117,862,678**	24,434,086
Long-term debt *[note 5]*	**350,716,664**	72,178,672
Deferred contributions *[note 6]*	**54,556,216**	55,386,992
Total liabilities	**523,135,558**	151,999,750
Partners' equity	**16,496,817**	16,493,364
	539,632,375	168,493,114

See accompanying notes

Approved by the Directors:

Director

Director

Wataynikaneyap Power LP

Statement of operations

Year ended December 31

	2020	2019
	$	$
Revenue		
Pikangikum capital contribution amortization *[note 6]*	**1,228,605**	1,202,712
Regulatory interest, net	**30,387**	314,837
Interest income	**127**	153,263
	1,259,119	1,670,812
Expenses		
General and administration	**27,061**	564,813
Amortization	**1,228,605**	1,202,712
	1,255,666	1,767,525
Net income (loss) for the year	**3,453**	(96,713)

See accompanying notes

Wataynikaneyap Power LP

Statement of partners' equity

Year ended December 31

	2020				2019
	First Nation LP [51%]	Fortis (WP) LP [48.99%]	Wataynikaneyap Power GP Inc. [0.01%]	Total	Total
	$	$	$	$	$
Partners' equity (deficiency), beginning of year	**9,067,762**	**7,425,974**	**(372)**	**16,493,364**	(3,621,061)
Issuance of LP Units	**—**	**—**	**—**	**—**	20,211,138
Net income (loss) for the year	**1,761**	**1,692**	**—**	**3,453**	(96,713)
Partners' equity (deficiency), end of year	**9,069,523**	**7,427,666**	**(372)**	**16,496,817**	16,493,364

See accompanying notes

Wataynikaneyap Power LP

Statement of cash flows

Year ended December 31

	2020	2019
	$	$
Operating activities		
Net income (loss) for the year	**3,453**	(96,713)
Deduct items not affecting cash		
Non-cash regulatory interest	**(24,506)**	(314,837)
Amortization of deferred contributions	**1,228,605**	1,202,712
Amortization of property, plant and equipment	**(1,228,605)**	(1,202,712)
Changes in non-cash working capital balances related to operations		
Accounts receivable	**2,686,056**	(2,687,762)
Inventory	**(85,423)**	(311,381)
HST receivable	**(2,306,027)**	6,022,177
Due from/to related parties	**(1,365,003)**	(1,488,221)
Accounts payable and accrued liabilities	**94,933,982**	7,138,101
Cash provided by operating activities	**93,842,532**	8,261,364
Investing activities		
Other assets	**311,196**	58,613,866
Regulatory assets	**(705,527)**	55,703,963
Purchases of property, plant and equipment	**(365,556,779)**	(159,258,678)
Cash used in investing activities	**(365,951,110)**	(44,940,849)
Financing activities		
Increase (decrease) in deferred contributions	**397,829**	(859,302)
Increase in long-term debt	**278,537,992**	72,178,672
Decrease in promissory notes payable	**—**	(44,927,493)
Cash provided by financing activities	**278,935,821**	26,391,877
Net increase (decrease) in cash during the year	**6,827,243**	(10,287,608)
Cash, beginning of year	**2,931,817**	13,219,425
Cash, end of year	**9,759,060**	2,931,817

See accompanying notes

Wataynikaneyap Power LP

Notes to financial statements

December 31, 2020

1. Basis of accounting and summary of significant accounting policies

Partnership

Wataynikaneyap Power LP ["WPLP"] or the "Partnership" 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. The partnership ownership interests are the following:

First Nation LP	51.00%
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, 2020. 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 and development 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.

Notes to financial statements

December 31, 2020

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.

[a] Basis of accounting

These financial statements have been prepared in accordance with Canadian accounting standards for private enterprises ["ASPE"], as per Part II of the *CPA Canada Handbook – Accounting*, 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 which may be assessable to the partners. Further, no provision has been made in the accounts for any salaries or interest accruing to the partners.

[b] 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 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.

Revenue recognition

WPLP's initial transmission rates have not yet been established and development costs for the Project have not been brought before the OEB for disposition. Consequently, WPLP does not currently record any transmission revenue. As noted above, WPLP is allowed regulatory carrying changes 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 collectability 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 depreciation.

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

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

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 due from related parties.

Use of estimates

The preparation of financial statements in conformity with ASPE requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities 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

Regulatory assets arise as a result of regulatory requirements established by the OEB and consist mainly of engineering, environmental assessments and project management project 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 – 3 months plus 0.25 spread]. WPLP currently only accrues interest on regulatory costs that have been netted against third-party funding received. On April 1, 2019, the OEB approved the leave to construct application from WPLP, informing that all development costs incurred to date should be transferred to WPLP's CWIP account.

Long-term regulatory assets consist of the following:

	2020 $	2019 $
Distribution recoverable costs	**2,046,966**	1,316,933
Total regulatory assets	**2,046,966**	1,316,933

3. Related party transactions

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

	2020 $	2019 $
Project costs paid on behalf of WPLP by		
FortisOntario Inc.	**2,581,802**	3,339,910
Newfoundland Power Inc.	**368,165**	820,558
Opiikapawiin Services LP	**5,295,818**	5,357,477
Wataynikaneyap Power PM Inc.	**3,108,840**	2,628,296
	11,354,625	12,146,241

	2020 $	2019 $
Project costs recoverable by WPLP from		
Newfoundland Power	**24,280**	—
FortisOntario Inc.	**—**	141,223
Wataynikaneyap Power GP Inc.	**—**	2,844
Fortis (WP) GP Inc.	**—**	2,834
Fortis (WP) LP	**—**	3,390
Wataynikaneyap Power PM Inc.	**—**	74,648
	24,280	224,939
Project engagement fees billed to WPLP by First Nation LP	**547,791**	535,743
Project management fees billed to WPLP by Wataynikaneyap Power PM Inc.	**547,791**	535,743

Notes to financial statements

December 31, 2020

Receipts (payments)		
Opiikapawiin Services LP	**(5,526,524)**	(6,871,074)
FortisOntario Inc.	**(2,452,981)**	(4,406,727)
Wataynikaneyap Power PM Inc.	**(3,995,504)**	(2,533,201)
Newfoundland Power Inc.	**(760,708)**	(685,776)
First Nation LP	**(1,121,226)**	(593,590)
Wataynikaneyap Power GP Inc.	**13**	—
Fortis (WP) GP Inc.	**331**	—
Fortis (WP) LP	**390**	—
	(13,856,209)	(15,090,368)

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

	2020	**2019**
	$	$
Current due from (to) related parties		
Opiikapawiin Services LP	**(834,493)**	(1,065,198)
First Nation LP	**(97,233)**	(605,390)
Wataynikaneyap Power PM Inc.	**(601,060)**	(939,933)
FortisOntario Inc.	**(171,559)**	(182,391)
Newfoundland Power Inc.	**—**	(416,823)
	(1,704,345)	(3,209,735)

	2020	**2019**
	$	$
Current due from related parties		
FortisOntario Inc.	**—**	139,653
Wataynikaneyap Power GP Inc.	**2,506**	2,844
Fortis (WP) GP Inc.	**2,503**	2,834
Fortis (WP) LP	**3,000**	3,390
Wataynikaneyap Power PM Inc.	**74,648**	74,648
	82,657	223,369

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

Notes to financial statements

December 31, 2020

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 Nation.

4. Property, plant and equipment

Property, plant and equipment consist of the following:

	2020			2019
	Cost	**Accumulated amortization**	**Net book value**	**Net book value**
	$	$	$	$
Transmission assets				
Land rights	**54,796**	**2,740**	**52,056**	53,426
Station equipment	**12,317,742**	**492,565**	**11,825,177**	12,071,535
Poles and fixtures	**22,091,611**	**981,849**	**21,109,762**	21,600,686
Overhead conductors and devices	**22,511,453**	**954,163**	**21,557,290**	21,350,148
Construction work-in-progress	**467,839,855**	**—**	**467,839,855**	102,980,171
	524,815,457	**2,431,317**	**522,384,140**	158,055,966

Included in the cost of property, plant and equipment is $467,839,855 [2019 – $102,980,171] of assets not being amortized because they are under construction. Within the balance of construction work-in-progress is $17,399,652 [2019 – $ nil] of coronavirus disease [“COVID-19”] incremental costs incurred due the pandemic.

5. Long-term debt

Long-term debt consists of the following:

	2020	**2019**
	$	$
Ontario loan [i]	**240,000,000**	57,800,000
Senior banks [ii]	**121,900,000**	29,300,000
Unamortized financing costs, net of amortization of $4,421,452	**(11,183,336)**	(14,921,328)
	350,716,664	72,178,672

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 point. 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 1.02% [2019 – 2.26%]. 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 CDOR rate plus a spread of 1.5%. The average rate of interest for the year is 2.37% [2019 – 3.47%]. 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 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 $1,228,605 [2019 – $1,202,712] 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, 2020, financial instruments recorded at amortized cost include cash, accounts receivable and due from related parties with a carrying value of $9,847,244 [2019 – $5,846,769].

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 minimized. 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.

Operating lease commitments

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

	$
2021	135,678
2022	125,356
	261,034

9. COVID-19

In March 2020, the World Health Organization declared the spread of COVID-19 outbreak as a pandemic. As a result of this, on March 23, 2020, the Government of Ontario ordered the closure of all non-essential businesses effective March 24, 2020. In addition, the Canadian government imposed travel restrictions to Canada until further notice. These restrictions impacted the operations of WPLP and resulted in the closure of physical premises of the organization. Global stock markets have also experienced great volatility and a significant weakening. 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 is uncertain and difficult to assess. The financial impacts will depend on future developments, including the duration, spread and severity of the outbreak; physical distancing requirements; the duration and geographic scope of related travel advisories and restrictions; and the extent of disruptions to businesses globally and their related impact to the economy.

The duration and 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.

ATTACHMENT 3

WPLP Tax Returns for 2020

Canada Revenue Agency / Agence du revenu du Canada

Partnership Financial Return

Protected B when completed

T5013 Financial

055 For internal use only

Complete this financial return using the instructions in guide 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**.

Note: All legislative references on this form refer to the Income Tax Act.

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/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/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/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 2020-01-01
061 Fiscal period-end* Year Month Day: To 2020-12-31
*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: 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): **098** 237130

Client Copy. Do not Submit

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Partnership account number: **001** 78830 4327 RZ0001

Fiscal period end Year Month Day **061** 2020-12-31

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

1. Form T5013 SUM, Summary of Partnership Income, and a copy of each T5013, Statement of Partnership Income, issued to partners and nominees or agents
2. The General Index of Financial Information (GIFI) schedules; T5013SCH100, Balance Sheet Information; T5013SCH125, Income Statement Information; T5013SCH140, Summary Statement (when more than one schedule 125 is filed); and T5013SCH141, Financial Statement Notes Checklist, (not required for investment clubs)
3. Schedules: T5013SCH1, Net Income (Loss) for Income Tax Purposes; (If you are an inactive partnership, see line 280 in Guide T4068 for more information); and T5013SCH50, Partner's Ownership and Account Activity
4. For each **Yes** answer to the following questions, **attach** the related schedule or form to the partnership return, unless otherwise instructed

				Schedule or form
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	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	2
Does the partnership have a permanent establishment in more than one jurisdiction?	**205**	☐ Yes	☒ No	5
Has the partnership realized any capital gains or incurred any capital losses during the fiscal period?	**206**	☐ Yes	☒ No	6
Does the partnership have any property that is eligible for capital cost allowance?	**208**	☒ Yes	☐ No	8
Does the partnership have any resource-related deductions (not including renounced expenditures)?	**212**	☐ Yes	☒ No	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	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	58

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Partnership account number: **001** 78830 4327 RZ0001

Fiscal period end Year Month Day **061** 2020-12-31

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 Schedule 52:	307		
Amount of payment enclosed with this return:	308		

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Partnership account number: **001** 78830 4327 RZ0001

Fiscal period end Year Month Day **061** 2020-12-31

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, King Last name (print) **951** Glen First name (print) **954** CFO Position or title

certify that the information given on this form 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 2021-04-29 Year Month Day _____ Signature of the authorized partner **956** (905) 994-3643 Telephone number

Language of correspondence

Indicate your language of correspondence . . . . . **990** [X] English [ ] French

Privacy Statement

Personal information is collected for the purposes of the administration or enforcement of 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 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 interest payable, penalties, or 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 Info Source at **canada.ca/cra-info-source**.

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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	Original [X] Amended [ ]
Wataynikaneyap Power LP	78830 4327 RZ0001	2020-12-31	

Is this a NIL schedule? . . . . . 999 Yes [ ] No [X]

Balance sheet information

Account	Description	GIFI		Current year	Prior year
Assets					
	Total current assets	1599	+	15,201,269.00	8,809,019.00
	Total tangible capital assets	2008	+	524,760,661.00	159,203,882.00
	Total accumulated amortization of tangible capital assets	2009	–	2,428,577.00	1,201,342.00
	Total intangible capital assets	2178	+	54,796.00	54,796.00
	Total accumulated amortization of intangible capital assets	2179	–	2,740.00	1,370.00
	Total long-term assets	2589	+	2,046,966.00	1,628,129.00
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	539,632,375.00	168,493,114.00
Liabilities					
	Total current liabilities	3139	+	117,862,678.00	24,434,086.00
	Total long-term liabilities	3450	+	405,272,880.00	127,565,664.00
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	523,135,558.00	151,999,750.00
Partner's capital					
	Total partners' capital (mandatory field)	3575	+	16,496,817.00	16,493,364.00
	Total liabilities and partners' capital	3585	=	539,632,375.00	168,493,114.00

* Generic item

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Current Assets

SCHEDULE 100

Form Identifier 1599

Account	Description	GIFI		Current year	Prior year
Cash and deposits					
	* Cash and deposits	1000		9,759,060.00	2,931,817.00
	Cash and deposits		+	9,759,060.00	2,931,817.00
Accounts receivable					
	* Accounts receivable	1060		5,527.00	2,691,583.00
	Accounts receivable		+	5,527.00	2,691,583.00
Inventories					
	* Inventories	1120		396,804.00	311,381.00
	Inventories		+	396,804.00	311,381.00
Due from/investment in related parties					
	* Due from/investment in related parties	1400		82,657.00	223,369.00
	Due from/investment in related parties		+	82,657.00	223,369.00
Other current assets					
	* Other current assets	1480		4,957,221.00	2,650,869.00
	Other current assets		+	4,957,221.00	2,650,869.00
	Total current assets	1599	=	15,201,269.00	8,809,019.00

* Generic item

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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	+	56,920,806.00			56,223,711.00
	*Accumulated amortization of machinery, equipment, furniture, and fixtures	1741			–	2,428,577.00	1,201,342.00
	Total			56,920,806.00		2,428,577.00	
Other tangible capital assets							
	Other capital assets under construction	1920	+	467,839,855.00			102,980,171.00
	Total			467,839,855.00			
	Total tangible capital assets	2008	=	524,760,661.00			159,203,882.00
	Total accumulated amortization of tangible capital assets	2009			=	2,428,577.00	1,201,342.00

* Generic item

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Attached Schedule with Total

Tangible capital property – GIFI code 1740 – Machinery, equipment, furniture, and fixtures

Title Tangible capital property – GIFI code 1740 – Machinery, equipment, furnitu

Explanatory note

Description	Operator (Note)	Amount
Poles & Fixtures		22,091,611 00
Overhead Conuctors and devices	+	22,511,453 00
Station Equipment	+	12,317,742 00
	+	
	Total	56,920,806 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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Attached Schedule with Total

GIFI code 1741 – Accumulated amortization of machinery, equipment, furniture, and fixtures

Title GIFI code 1741 – Accumulated amortization of machinery, equipment, furn

Explanatory note

Description	Operator (Note)	Amount
Station Equipment		492,565 00
Poles & Fixtures	+	981,849 00
Overhead Conuctors and devices	+	954,163 00
	+	
	Total	2,428,577 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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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			–	2,740.00	1,370.00
		Total		54,796.00		2,740.00	
	Total intangible capital assets	2178	=	54,796.00			54,796.00
	Total accumulated amortization of intangible capital assets	2179			=	2,740.00	1,370.00

* Generic item

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Long-term Assets

SCHEDULE 100

Form identifier 2589

Account	Description	GIFI		Current year	Prior year
	Other long-term assets				
	* Other long-term assets	2420		2,046,966.00	1,628,129.00
	Other long-term assets		+	2,046,966.00	1,628,129.00
	Total long-term assets	2589	=	2,046,966.00	1,628,129.00

* Generic item

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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		116,158,333.00	21,224,351.00
	Amounts payable and accrued liabilities		+	116,158,333.00	21,224,351.00
Due to related parties					
	* Due to related parties	2860		1,704,345.00	3,209,735.00
	Due to related parties		+	1,704,345.00	3,209,735.00
	Total current liabilities	3139	=	117,862,678.00	24,434,086.00

* Generic item

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Long-term Liabilities

SCHEDULE 100

Form identifier 3450

Account	Description	GIFI		Current year	Prior year
Long-term debt					
	* Long-term debt	3140		350,716,664.00	72,178,672.00
	Long-term debt		+	350,716,664.00	72,178,672.00
Other long-term liabilities					
	* Other long-term liabilities	3320		54,556,216.00	55,386,992.00
	Other long-term liabilities		+	54,556,216.00	55,386,992.00
	Total long-term liabilities	3450	=	405,272,880.00	127,565,664.00

* Generic item

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Attached Schedule with Total

GIFI code 3140 – Long-term debt

Title GIFI code 3140 – Long-term debt

Explanatory note

Description	Operator (Note)	Amount
Senior Banks (G1-14)		121,900,000 00
Ontario Loan (G1-14)	+	240,000,000 00
Unamortized financing cost	+	-11,183,336 00
	+	
	Total	350,716,664 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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Partner's capital

SCHEDULE 100

GIFI Code 3575

Account	Description	GIFI		Current year	Prior year
Total net income/loss					
	Net income/loss	3545	+	3,453.00	-96,713.00
	Total net income/loss	3550	=	3,453.00	-96,713.00
General partners' capital					
	General partners' capital beginning balance	3551	+	-372.00	-362.00
	General partners' net income (loss)	3552	+		-10.00
	General partners' capital ending balance	3560	=	-372.00	-372.00
Limited partners' capital					
	Limited partners' capital beginning balance	3561	+	16,493,736.00	-3,620,699.00
	Limited partners' net income (loss)	3562	+	3,453.00	-96,703.00
	Limited partners' contributions during the fiscal period	3564	+		20,211,138.00
	Limited partners' capital ending balance	3571	+	16,497,189.00	16,493,736.00
	Total partners' capital	3575	=	16,496,817.00	16,493,364.00

* Generic item

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Attached Schedule with Total

GIFI code 3561 – Limited partners' capital beginning balance

Title GIFI code 3561 – Limited partners' capital beginning balance

Explanatory note

Description	Operator (Note)	Amount
First Nations LP		9,067,762 00
Fortis (WP) LP	+	7,425,974 00
	+	
	Total	16,493,736 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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Attached Schedule with Total

GIFI code 3564 – Limited partners' contributions during the fiscal period

Title GIFI code 3564 – Limited partners' contributions during the fiscal period

Explanatory note

Description	Operator (Note)	Amount
First Nation LP		
Fortis (WP) LP	+	
	+	
	Total	

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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T5013 SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Partnership name	Partnership account number	Fiscal period end (Year Month Day)	Original / Amended
Wataynikaneyap Power LP	78830 4327 RZ0001	2020-12-31	Original [X] Amended [ ]

Income statement information

Description	GIFI

Is this a NIL schedule? . . . . . 999 [ ] Yes [X] No

Operating 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	+		
	Cost of sales	8518	–		
	Gross profit/loss	8519	=		
	Cost of sales	8518	+		
	Total operating expenses	9367	+	1,255,666.00	1,767,525.00
	Total expenses (mandatory field)	9368	=	1,255,666.00	1,767,525.00
	Total revenue (mandatory field)	8299	+	1,259,119.00	1,670,812.00
	Total expenses (mandatory field)	9368	–	1,255,666.00	1,767,525.00
	Net non-farming income	9369	=	3,453.00	-96,713.00
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	=	3,453.00	-96,713.00
	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	=	3,453.00	-96,713.00

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Revenue

SCHEDULE 125

Form identifier 8299

Account	Description	GIFI		Current year	Prior year
Investment revenue					
	* Investment revenue	8090		30,387.00	314,837.00
	Interest from other Canadian sources	8094		127.00	153,263.00
	Investment revenue		+	30,514.00	468,100.00
Other revenue					
	* Other revenue	8230		1,228,605.00	1,202,712.00
	Other revenue		+	1,228,605.00	1,202,712.00
	Total revenue	8299	=	1,259,119.00	1,670,812.00

* Generic item

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Attached Schedule with Total

GIFI code 8094 – Amount – Interest from other Canadian sources

Title GIFI code 8094 – Amount – Interest from other Canadian sources

Explanatory note

Description	Operator (Note)	Amount
Interest Income		127 00
	+	
	+	
	Total	127 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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Operating Expenses

SCHEDULE 125

Form identifier 9367

Account	Description	GIFI		Current year	Prior year
	* Amortization of tangible assets	8670	+	1,228,605.00	1,202,712.00
	Other expenses				
	General and administrative expenses	9284		27,061.00	564,813.00
	Other expenses		+	27,061.00	564,813.00
	Total operating expenses	9367	=	1,255,666.00	1,767,525.00

* Generic item

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Canada Revenue Agency / Agence du revenu du Canada

Financial Statement Notes Checklist

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T5013
Schedule 141

Partnership name	Partnership account number	Fiscal period end (Year Month Day)	
Wataynikaneyap Power LP	78830 4327 RZ0001	2020-12-31	[X] Original [ ] Amended

- Fill out this schedule from the perspective of the person (referred to in this schedule as the "accountant") who prepared or reported on the financial statements.
- All the information requested in this form and in the documents supporting your information return is "prescribed information".
- For more information, see Guide T4068, *Guide for the Partnership Information Return (T5013 forms)*, and Guide RC4088, *General Index of Financial Information (GIFI)*.
- Attach the original copy of this completed schedule, along with any "Notes to the financial statements" and the auditor's or accountant's report, to Form T5013 FIN, *Partnership Financial Return*.

Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation?	095	1 Yes	[X]	2 No	[ ]
Is the accountant connected with the partnership? *	097	1 Yes	[ ]	2 No	[X]

Note: If the accountant does not have a professional designation or is connected with the partnership, you do not have to complete parts 2 and 3 below.

* 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 with the financial statements

Choose the option that represents the accountant's highest level of involvement: 198

Completed an auditor's report	1	[X]
Completed a review engagement report	2	[ ]
Conducted a compilation engagement	3	[ ]

Part 3 – Reservations

If you selected option 1 or option 2 **in part 2** above, answer the following question:

Has the accountant expressed a reservation?	099	1 Yes	[ ]	2 No	[X]

Part 4 – Other information (continued on page 2)

If you have a professional designation and are not the accountant associated with the financial statements in part 1 above, choose one of the following options: 110

Prepared the information return (financial statements prepared by client)	1	[X]
Prepared the information return and the financial information contained therein (financial statements have not been prepared)	2	[ ]

Were notes to the financial statements prepared?	101	1 Yes	[X]	2 No	[ ]
If **yes**, answer the following four questions:						
Are subsequent events mentioned in the notes?	104	1 Yes	[ ]	2 No	[X]
Is re-evaluation of asset information mentioned in the notes?	105	1 Yes	[ ]	2 No	[X]
Is contingent liability information mentioned in the notes?	106	1 Yes	[ ]	2 No	[X]
Is information regarding commitments mentioned in the notes?	107	1 Yes	[X]	2 No	[ ]
Does the partnership have investments in joint ventures? If **yes**, complete question 109 below	108	1 Yes	[ ]	2 No	[X]
Are you filing joint venture(s) financial statements?	109	1 Yes	[ ]	2 No	[ ]

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Partnership account number	Fiscal period end Year Month Day
78830 4327 RZ0001	2020-12-31

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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** 1 Yes ☐ 2 No ☒

If **yes**, enter the amount recognized:		**In net income** Increase (decrease)		**In other comprehensive income** Increase (decrease)
Property, plant and equipment	**210**		**211**	
Intangible assets	**215**		**216**	
Investment property	**220**			
Biological assets	**225**			
Financial instruments	**230**		**231**	
Other	**235**		**236**	

Financial instruments

Did the partnership derecognize any financial instrument(s) during the fiscal period (other than trade receivables)? . . . . . **250** 1 Yes ☐ 2 No ☒

Did the partnership apply hedge accounting during the fiscal period? . . . . . **255** 1 Yes ☐ 2 No ☒

Did the partnership discontinue hedge accounting during the fiscal period? . . . . . **260** 1 Yes ☐ 2 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** 1 Yes ☐ 2 No ☒

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

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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	2020-12-31

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

Assets – lines 1000 to 2599

1000	9,759,060.00	**1060**	5,527.00	**1120**	396,804.00
1400	82,657.00	**1480**	4,957,221.00	**1599**	15,201,269.00
1740	56,920,806.00	**1741**	-2,428,577.00	**1920**	467,839,855.00
2008	524,760,661.00	**2009**	-2,428,577.00	**2024**	54,796.00
2025	-2,740.00	**2178**	54,796.00	**2179**	-2,740.00
2420	2,046,966.00	**2589**	2,046,966.00	**2599**	539,632,375.00

Liabilities – lines 2600 to 3499

2620	116,158,333.00	**2860**	1,704,345.00	**3139**	117,862,678.00
3140	350,716,664.00	**3320**	54,556,216.00	**3450**	405,272,880.00
3499	523,135,558.00				

Partner's capital – lines 3540 to 3575

3545	3,453.00	**3550**	3,453.00	**3551**	-372.00
3560	-372.00	**3561**	16,493,736.00	**3562**	3,453.00
3571	16,497,189.00	**3575**	16,496,817.00	**3585**	539,632,375.00

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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	2020-12-31

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

Description

Sequence number **0003** 01

Revenue – lines 8000 to 8299

8090	30,387.00	**8094**	127.00	**8230**	1,228,605.00
8299	1,259,119.00				

Operating expenses – lines 8520 to 9369

8670	1,228,605.00	**9284**	27,061.00	**9367**	1,255,666.00
9368	1,255,666.00	**9369**	3,453.00		

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	3,453.00	**9999**	3,453.00

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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	2020-12-31	[X] 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 [X] 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		3,453.00
Add:					
Provision for Part IX.1 specified investment flow through (SIFT) taxes	101				
Amortization/depreciation of tangible assets	104	1,228,605.00			
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				
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				
Total (**Add** lines 101 to 199. Enter this amount on line 501)		1,228,605.00 ▶	501	+	1,228,605.00
Deduct: Amount from line 511 on page 3 of this schedule			502	–	4,353,335.83
Net income (loss) for income tax purposes – (line 500 **plus** line 501 **minus** line 502)			503	=	-3,121,277.83
Deduct: Net income (loss) for general partners			504	–	-312.13
Net income (loss) for income tax purposes for limited and non-active partners (line 503 **minus** line 504)			505	=	-3,120,965.70

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Canada

Partnership account number	Fiscal period end (Year Month Day)
78830 4327 RZ0001	2020-12-31

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		290	
601		291	
602		292	
603		293	
604		294	

Total (**Add** lines 290 to 294. Enter this amount on line 507) ▶ **507** +

Total (**Add** lines 506 and 507) **508** =

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

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Partnership account number	Fiscal period end (Year Month Day)
78830 4327 RZ0001	2020-12-31

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	1,228,605.25	
701	20(1)(e) Financing fees	391	3,120,958.00	
702		392		
703		393		
704		394		

Total (**Add** lines 300 to 394. Enter this amount on line 509) 4,349,563.25 ▶ **509** + 4,349,563.25

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	3,772.58
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) 3,772.58 ▶ **510** + 3,772.58

Total (**Add** lines 509 and 510) **511** = 4,353,335.83

Enter this amount on line 502 on page 1 of this schedule.

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Capital Cost Allowance (CCA)

T5013 Schedule 8
Protected B when completed

Partnership's name	Partnership account number	Fiscal period end (Year Month Day)	
Wataynikaneyap Power LP	78830 4327 RZ0001	2020-12-31	[X] Original [ ] Amended

- Fill out this schedule to calculate the amount of capital cost allowance (CCA) the partnership is claiming for the fiscal period and to account for acquisitions and/or dispositions of depreciable 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 Schedule 8
- Attach the original copy of this completed schedule to form T5013 FIN, Partnership Financial Return

1 Class number (See note 1) 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 2) 203	4 Cost of acquisitions from column 3 that are accelerated investment incentive property (AIIP) or zero-emission vehicle (ZEV) (See note 3) 225	5 Adjustments and transfers (show amounts that reduce the UCC in brackets) (See note 4) 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 5) 221	7 Amount from column 5 that is repaid during the fiscal period for a property, subsequent to its disposition (See note 6) 222	8 Proceeds of dispositions (See note 7) 207	9 UCC (column 2 **plus** column 3 **plus** or **minus** column 5 **minus** column 8) (See note 8)
14.1	53,894.03							53,894.03
99	2,687,762.00						2,687,762.00	
99	102,980,170.00	364,847,754.01						467,827,924.01
Totals	105,721,826.03	364,847,754.01					2,687,762.00	467,881,818.04

10 Proceeds of disposition available to reduce the UCC of AIIP and ZEV (column 8 **plus** column 6 **minus** column 3 **plus** column 4 **minus** column 7) (if negative, enter "0")	11 Net capital cost additions of AIIP and ZEV acquired during the fiscal period (column 4 **minus** column 10) (if negative, enter "0")	12 UCC adjustment for AIIP and ZEV acquired during the fiscal period (column 11 **multiplied** by the relevant factor) (See note 9)	13 UCC adjustment for property acquired during the fiscal period other than AIIP and ZEV (0.5 **multiplied** by the result of column 3 **minus** column 4 **minus** column 6 **plus** column 7 **minus** column 8) (if negative, enter "0") (See note 10) 224	14 CCA rate % (See note 11) 212	15 Recapture of CCA (See note 12) 213	16 Terminal loss (See note 13) 215	17 CCA (for declining balance method, the result of column 9 **plus** column 12 **minus** column 13, **multiplied** by column 14 or a lower amount) (See note 14) 217	18 UCC at the end of the fiscal period (column 9 **minus** column 17) 220
				5.00			3,772.58	50,121.45
			182,423,877.01					467,827,924.01
			182,423,877.01		230	240	250	467,878,045.46
				Totals			3,772.58	

Enter the amount from line 230 on line 107 of the T5013 SCH1.
Enter the amount from line 240 on line 404 of the T5013 SCH1.
Enter the amount from line 250 on line 403 of the T5013 SCH1.

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T5013 SCH 8 E (19)

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Note 1. 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 2. Include any property acquired in previous fiscal periods that has now become available for use. 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.

Note 3. AIIP is a property (other than ZEV) that you acquired after November 20, 2018 and became available for use before 2028. ZEV is, subject to certain exceptions, a new motor vehicle included in Class 54 or 55 that you acquired after March 18, 2019 and became available for use before 2028. See Guide T4068 for more information.

Note 4. Enter in column 5, "Adjustments and transfers", amounts that increase or reduce the UCC (column 9). Items that increase the UCC include amounts transferred under subsection 97(2). Items that reduce the UCC include government assistance received or entitled to be received in the fiscal period. See the Guide T4068 for other examples of adjustments and transfers to include in column 5.
Also include the UCC of each 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 continuously owned by the transferor for at least 364 days before the end of your fiscal period.

Note 5. 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 6. Include all amounts you have repaid during the fiscal period with respect to 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 the UCC of each 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 continuously owned by the transferor for at least 364 days before the end of your fiscal period.

Note 7. 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).
The proceeds of disposition of a ZEV that has been included in Class 54 and that is subject to the $55,000 capital cost limit will be adjusted based on a factor equal to the capital cost limit of $55,000 as a proportion of the actual cost of the vehicle.

Note 8. If the amount in column 5 reduces the UCC (i.e. it is shown in brackets), you must subtract it for the purposes of the calculation. Otherwise, add the amount in column 5 for the purpose of the calculation.

Note 9. The relevant factors for property of a class in Schedule II, that is AIIP or ZEV, available for use before 2024 are:
- 2 1/3 for property in Classes 43.1 and 54
- 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 14 for additional information), and
- 0.5 for all other property that is AIIP

Note 10. The UCC adjustment for property other than AIIP or ZEV acquired during the fiscal period (formerly known as the half-year rule or 50% rule) does not apply to certain property. For special rules and exceptions, see Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance.

Note 11. 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 17.

Note 12. If the amount in column 9 is negative, you have a recapture of CCA. If applicable, enter the negative amount from column 9 in column 15 as a positive. The recapture rules do **not** apply to passenger vehicles in Class 10.1.

Note 13. If no property is left in the class at the end of the fiscal period and there is still a positive amount in column 9, you have a terminal loss. If applicable, enter the positive amount from column 9 in column 16. 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, or
- 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

Note 14. 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 paragraph 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 apply 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.

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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	2020-12-31	[X] 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**	-3,121,277.83

Partner 1

Ownership

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?	Fiscal period's income (loss) allocation: 220 Partner's share of the net income (loss)	Account activity: 300 Cost base
First Nation LP	722558525RZ0001	3	0	54.2464	[ ] Yes [X] No	-1,591,851.69	10963826.00

Account activity (continued)

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
	-1,643,081.05			

At-risk amount (ARA) (for limited partners only)

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

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?	Fiscal period's income (loss) allocation: 220 Partner's share of the net income (loss)	Account activity: 300 Cost base
Fortis (WP) LP	749436499RZ0001	3	0	45.7536	[ ] Yes [X] No	-1,529,114.01	9247312.00

Account activity (continued)

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
	-1,578,324.32			

At-risk amount (ARA) (for limited partners only)

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

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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		☐ Yes ☒ No	-312.13	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
	-322.17						

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

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List Detailing the Partner's Ownership and Account Activity

Partnership Wataynikaneyap Power LP

	Partner	Partner code	Percentage (%) of partner's interest	Line 220	Line 300	Line 320	Line 330	Line 340	Line 350
1	First Nation LP	0	54.2464	-1,591,851 69	10,963,826 00	-1,643,081 05			
2	Fortis (WP) LP	0	45.7536	-1,529,114 01	9,247,312 00	-1,578,324 32			
3	Wataynikaneyap Power GP Inc.	2		-312 13		-322 17			
			Total	-3,121,277 83	20,211,138 00	-3,221,727 54			

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Canada Revenue Agency | Agence du revenu du Canada

Fiscal period-end / Exercice se terminant le: YYYY-MM-DD / AAAA-MM-JJ: 2020-12-31

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	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: -1,591,851 69	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: 1,924 02

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
	104		-1,591,851 69		105		9,659,500 76
	106		9,659,500 76		118		642,150 69

Box – Case	Code	Other information – Autres renseignements	Box	Case	Code	Amount – Montant	Box	Case	Code	Amount – Montant

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Canada Revenue Agency | Agence du revenu du Canada

Fiscal period-end / Exercice se terminant le: YYYY-MM-DD / AAAA-MM-JJ: 2020-12-31

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	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: -1,529,114 01	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: 749436499RZ0001	005: 48.990000	030:	040: 1,848 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

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

Box	Case	Code	Amount – Montant	Box	Case	Code	Amount – Montant
104			-1,529,114 01	105			7,994,392 54
106			7,994,392 54	118			616,842 40

Box – Case	Code	Other information – Autres renseignements	Box	Case	Code	Amount – Montant	Box	Case	Code	Amount – Montant

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

Canada Revenue Agency | Agence du revenu du Canada

Fiscal period-end / Exercice se terminant le: YYYY-MM-DD / AAAA-MM-JJ: 2020-12-31

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	Country code / Code du pays	Recipient type / Genre de bénéficiaire
002: 2	003: CAN	004: 3

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: -312 13

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: 815046362RC0001	005: 0.010000	030:	040: 0 38

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	Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
116		-312 13	118		125 91

Client Copy. Do Not Submit

Canada Revenue Agency | Agence du revenu du Canada

Summary of Partnership Income
Sommaire des revenus d'une société de personnes

Protected B / Protégé B
when completed / une fois rempli

T5013 Summary / Sommaire

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

Remplissez ce sommaire et les feuillets connexes en suivant les instructions du guide T4068, *Guide pour la déclaration de renseignements des sociétés de personnes (formulaires T5013)*.

Do not use this area. N'inscrivez rien ici.

For the fiscal period – Pour l'exercice

Start / Début: 2020-01-01 (Year / Month / Day – Année / Mois / Jour)

End / Fin: 2020-12-31 (Year / Month / Day – Année / Mois / Jour)

Partnership's account number / Numéro de compte de la société de personnes: 78830 4327 RZ0001

Name of the partnership – Nom de la société de personnes: Wataynikaneyap Power LP

Postal or ZIP code / Code postal ou ZIP: L2A 5Y2

50 ____ 1616

Are you a nominee or agent? (tick if yes and provide the following information)
Êtes-vous un mandataire ou un agent? (cochez si oui et fournir les renseignements qui suivent) ☐

Name of the nominee or agent – Nom du mandataire ou de l'agent:

Postal or ZIP code / Code postal ou ZIP:

Nominee or agent's account number / Numéro de compte du mandataire ou de l'agent:

Is the partnership a tax shelter? (tick if yes)
La société de personnes est-elle un abri fiscal? (cochez si oui) ☐

If yes, provide the tax shelter identification number
Si oui, fournir le numéro d'identification de l'abri fiscal:

Totals from T5013 slips – Totaux des feuillets T5013

Total number of T5013 information slips attached:
Nombre total de feuillets de renseignements T5013 joints : **009** 3

Total limited partner's business income (loss) – Total du revenu (de la perte) d'entreprise du commanditaire	**010**	-3,120,965	70
Total business income (loss) – Total du revenu (de la perte) d'entreprise	**020**	-312	13
Total capital gains (losses) – Total des gains (pertes) en capital	**030**		
Capital cost allowance – Déduction pour amortissement	**040**	3,772	59

Complete the six generic boxes identified below taken from the T5013 slips – Remplissez les lignes ci-dessous pour les six cases génériques qui parviennent des feuillets T5013

Canadian and foreign net rental income (loss) – Revenu net (perte nette) de location canadien et étranger	**110**		
Professional income (loss) – Revenu (perte) de profession libérale	**120**		
Renounced Canadian exploration expenses – Frais renoncés d'exploration au Canada	**190**		
Renounced Canadian development expenses – Frais renoncés d'aménagement au Canada	**191**		
Expenses qualifying for an ITC – Frais admissibles aux fins du CII	**194**		
Total carrying charges – Total des frais financiers	**210**		

Person to contact about this return
Personne-ressource que nous pouvons contacter à propos de cette déclaration

076 Ernst & Young LLP

Area code / Indicatif régional | Telephone number / Numéro de téléphone | Extension / Numéro de poste

078 (416) 864-1234

Certification – Attestation

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

J'atteste que les renseignements fournis dans cette déclaration de renseignements et sur tous les feuillets connexes sont exacts et complets.

2021-04-29 (Date) | Signature of authorized person – Signature d'une personne autorisée | CFO (Position or office – Poste ou titre)

Prepared by – Préparé par: Ernst & Young LLP

Date: 2021-04-29

Personal information, including the social insurance number, is collected under the *Income Tax Act* to administer tax, benefits, and related programs. It may also be used for any purpose related to the administration or enforcement of the Act such as audit, compliance and the payment of debts owed to the Crown. It may be shared or verified with other federal, provincial/territorial government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties or other actions. Under the *Privacy Act*, individuals have the right to access their personal information and request correction if there are errors or omissions. Refer to Info Source **www.cra-arc.gc.ca/gncy/tp/nfsrc/nfsrc-eng.html**, personal information bank(s) CRA PPU 224.

Les renseignements personnels sont recueillis selon la *Loi de l'impôt sur le revenu* afin d'administrer les programmes fiscaux, de prestations et autres. Ils peuvent également être utilisés pour toute fin liée à l'application ou à l'exécution de la *Loi* telle que la vérification, l'observation et le recouvrement des sommes dues à l'État. Les renseignements peuvent être transmis à une autre institution gouvernementale fédérale, provinciale ou territoriale, ou vérifiés auprès de celles-ci, dans la mesure où la loi l'autorise. Cependant, le défaut de fournir ces renseignements pourrait entraîner des intérêts à payer, des pénalités ou d'autres mesures. Les particuliers ont le droit, selon la *Loi sur la protection des renseignements personnels*, d'accéder à leurs renseignements personnels et de demander une modification, s'il y a des erreurs ou omissions. Consultez Info Source en allant à **www.arc.gc.ca/gncy/tp/nfsrc/nfsrc-fra.html** et le(s) Fichier(s) de renseignements personnels ARC PPU 224.

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Canada

ATTACHMENT 4

2021 Annual Report for Fortis Inc.

Looking Forward



FORTIS

ANNUAL REPORT



One Strong Connection Throughout North America

PURPOSE

Delivering a cleaner energy future

VALUES

We value our **people**

We keep it **local**

We never compromise on **safety**

We act with **courage** and **integrity**

We are **community** champions

We aim for **excellence** every day

Quick Facts

TSX/NYSE: FTS

Unless otherwise specified, all financial information is referenced in Canadian dollars and all numbers are as at December 31, 2021.



3.4 million customers



9,100 employees strong



Corporate-wide emissions
reduction target of 75%
by 2035 compared to 2019 levels



48 consecutive years
of dividend payment increases



$58 billion in total assets



10 utilities in Canada, the U.S. and the Caribbean



The Fortis Board of Directors achieved **gender parity** and 60% of Fortis utilities have either a female CEO or Board Chair

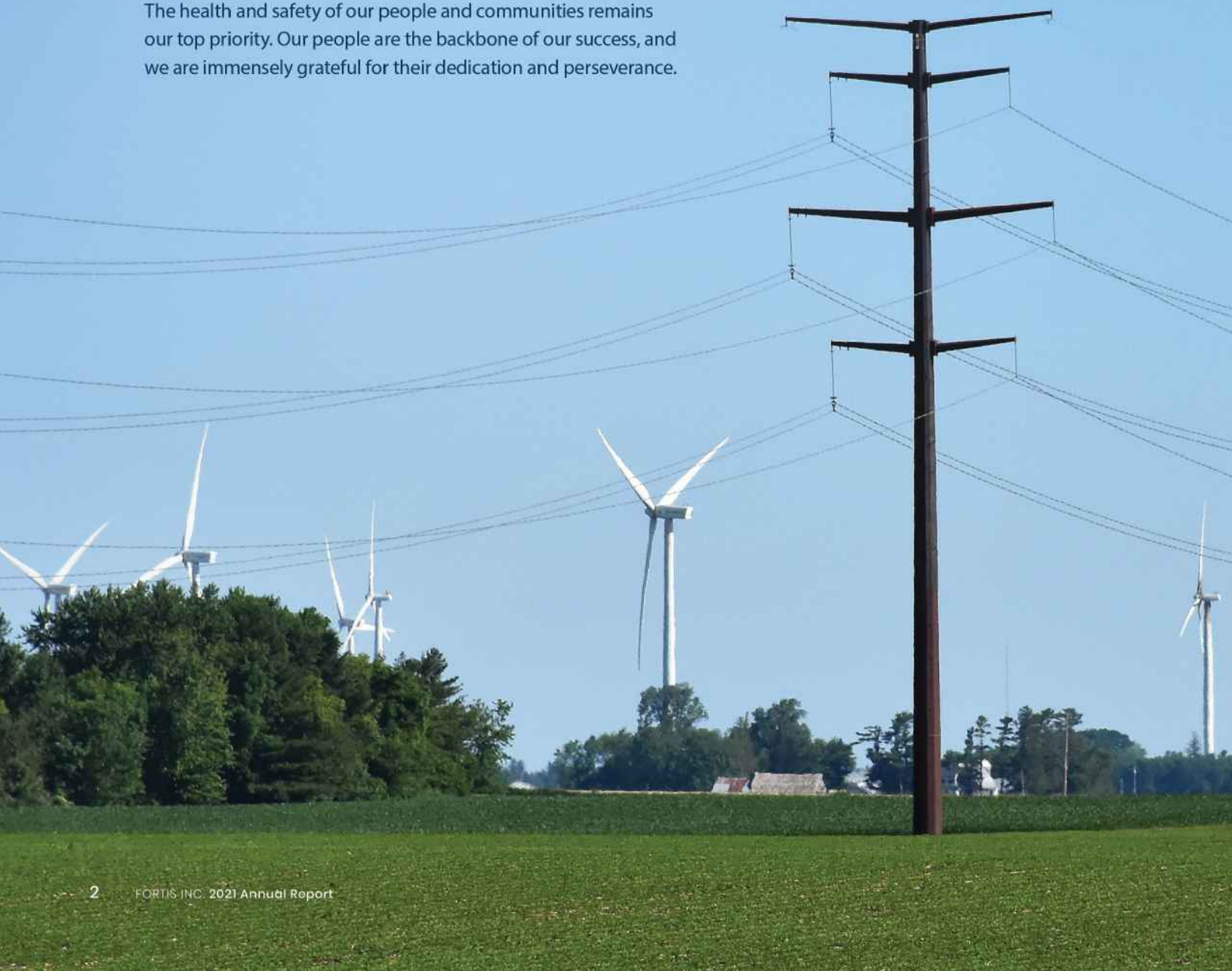


More than $10 million of
community investment in 2021

Advancing our Business Strategy

In 2021 we delivered steady growth and made significant progress on our long-term goals. We executed a $3.6 billion capital program; provided strong returns for our shareholders; further reduced our carbon emissions; outperformed industry averages for safety and reliability performance; and, achieved gender parity on our Board of Directors.

We advanced our business strategy and adapted to the challenges and uncertainties caused by the COVID-19 pandemic. The health and safety of our people and communities remains our top priority. Our people are the backbone of our success, and we are immensely grateful for their dedication and perseverance.



Delivering Returns to our Shareholders

Fortis delivered a strong one-year total shareholder return of 21.8% in 2021. Over a 20-year period, Fortis has delivered a total shareholder return of 975%, and an average annualized total return of 12.6%. Over the same 20-year period, the S&P/TSX Capped Utilities and S&P/TSX Composite indices delivered total returns of 549% and 373%, respectively.

For the past 48 consecutive years our company has delivered dividend increases to shareholders. In 2021 shareholders received $2.05 per common share, which is an increase of approximately 6% compared to 2020. We also reaffirmed our 6% average annual dividend growth guidance through 2025 supported by the long-term growth of our energy delivery businesses.

Superior 20-Year Total Shareholder Return



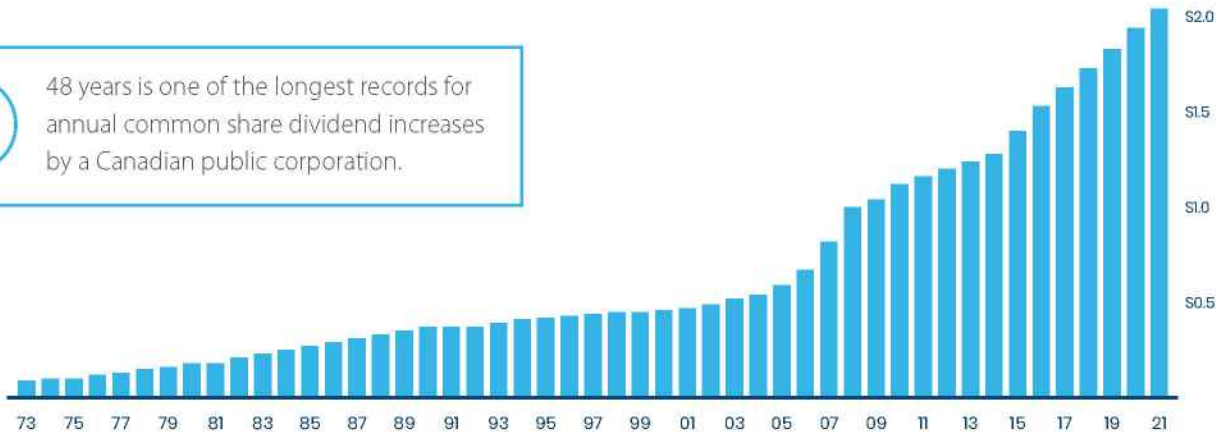
TOTAL SHAREHOLDER RETURNS (AVERAGE ANNUAL)	
1-Year	21.8%
5-Year	12.1%
10-Year	10.2%
20-Year	12.6%

Note: Cumulative 20-year total shareholder return as at December 31, 2021.

48 Years of Consecutive Dividend Increases

6% Average Annual Dividend Growth Guidance through 2025

48 years is one of the longest records for annual common share dividend increases by a Canadian public corporation.





Miranda Jackson, Civil Transmission Engineer

In 2021 net earnings attributable to common equity shareholders were $1,231 million, or $2.61 per common share, compared to $1,209 million, or $2.60 per common share, for 2020. We achieved adjusted net earnings per common share of $2.59 in 2021 compared to $2.57 in 2020.

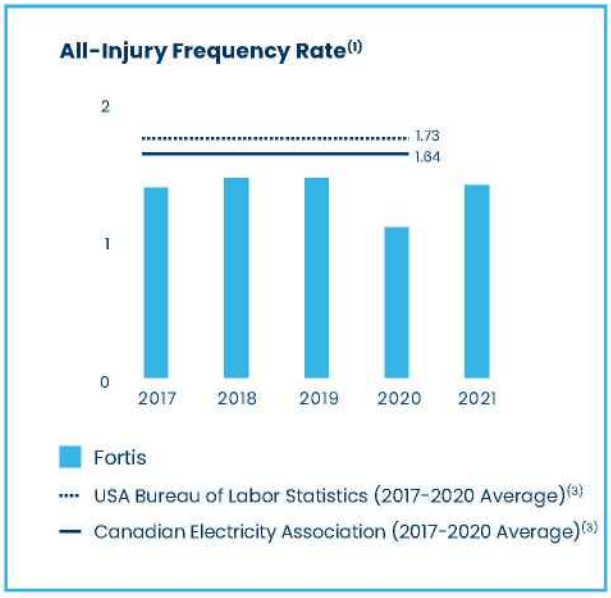
Rate base growth at our regulated utilities improved our earnings despite the unfavourable impact of foreign exchange of $48 million, or $0.10 per common share. Excluding foreign exchange, 2021 adjusted net earnings per common share increased by $0.12 or approximately 5% over 2020.

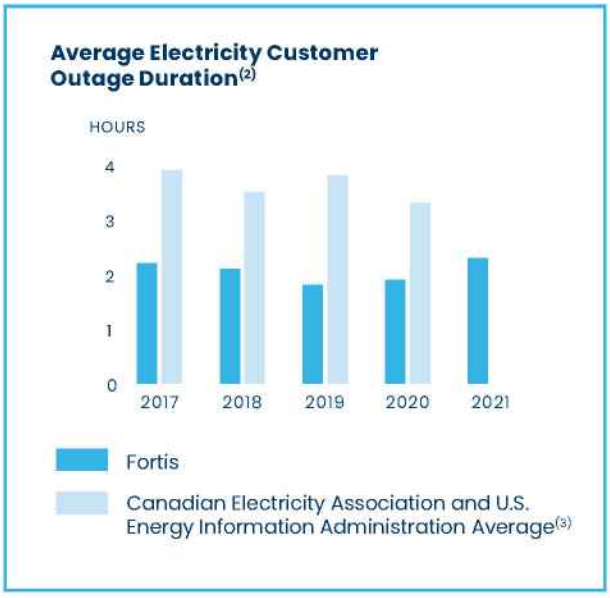
We raised more than $1 billion in long-term debt at attractive rates during 2021. Debt issued at Fortis Inc. was primarily used to refinance maturing debt, while our regulated utilities issued debt in support of their capital expenditure programs. Our continued focus on clean energy opened new financing options, with both ITC Holdings Corp. and Tucson Electric Power Company ("TEP") making use of green debt instruments in 2021. ITC Holdings Corp. priced US$150 million notes, of which half were green notes, while TEP amended its US$250 million revolving credit facility agreement that allows pricing adjustments linked to sustainability metrics.

Steadfast Focus on Safety and Reliability

Fortis continues to outperform industry averages for safety and reliability performance. Our utilities have a strong safety culture in delivering reliable electricity and natural gas to customers. We cannot have a safe and reliable system without a secure one. We deploy high cybersecurity standards and we have not had any reportable cybersecurity breaches since we began reporting this in 2018.

Our all-injury frequency rate, which represents the number of injuries for every 200,000 hours worked, was 1.40 in 2021. This compares to the Canadian and U.S. industry averages of 1.64 and 1.73, respectively. We continue to engage with employees on safety matters to further improve performance and, as always, will approach the future with a relentless focus on the safety of our employees, customers, and contractors.





(1) Injuries per 200,000 hours worked.
(2) Based on weighted average of Fortis' customer count in each jurisdiction.
(3) 2021 data not yet available.

Emergency response continues to be a hallmark of our operational excellence and enables us to minimize the interruption of service to customers. In 2021, our average hours of interruption per customer served was 2.3 hours, outperforming both Canadian and U.S. industry average outage durations.

2021 was another year of weather extremes across our service territories. From record heat and historic flooding in British Columbia, to a derecho storm in ITC's Midwest service area and a hurricane in Newfoundland and Labrador, nearly each of our jurisdictions was impacted by severe weather. Because of our operating model, our utilities were able to respond with the necessary local system knowledge, the best practices and resources provided under our Fortis umbrella to maintain the reliable provision of electricity and natural gas to our customers.

We are particularly proud of our teams at FortisAlberta and Newfoundland Power who received national recognition. FortisAlberta was awarded Excellence in the category of Canada's Safest Utilities and Electrical Employer at the 2021 Canada's Safest Employers Awards. Newfoundland Power was the recipient of the inaugural Reliability and Resiliency award from the Canadian Electricity Association.





TEP is making steady advances on its energy transition. In addition to bringing the 250-MW Oso Grande wind project online, the utility also now receives power from an additional 99-MW wind project, a 100-MW solar power system and a 30-MW battery energy storage system commissioned in 2021.

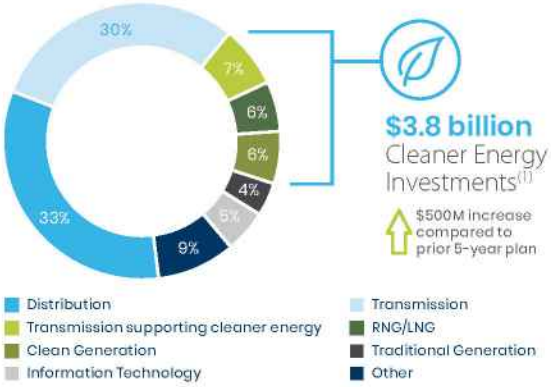
Investing in a Resilient Grid and Cleaner Energy

We executed a $3.6 billion capital program in 2021 while facing global supply chain challenges and pricing volatility. Our capital investments included resiliency, modernization, and sustainable energy projects.

Approximately $0.6 billion of our 2021 capital program was focused on delivering cleaner energy to customers. One significant achievement was the completion of the 250-MW Oso Grande Wind Project at TEP that will generate enough power each year to serve the annual electric needs of nearly 100,000 homes.

The Wataynikaneyap Transmission Power Project, which will bring many socio-economic benefits to 24 remote First Nations communities in Northern Ontario, was advanced in 2021. During peak construction periods, approximately 1,000 workers supported activities at various remote construction sites. The Wataynikaneyap Project was also chosen as a 2021 Clean50 Top Project award winner. Canada's Clean50 recognizes leaders in sustainability for contributions over the prior two years.

Five-Year (2022-2026) Capital Plan Supports Delivery of Cleaner Energy



(1) Cleaner energy investments defined as capital that reduces air emissions, water usage and/or increase customer energy efficiency.

Our new five-year capital plan calls for the investment of $20 billion from 2022 through 2026, showing our ability to sustain strong underlying organic growth. We expect to invest $3.8 billion in cleaner energy infrastructure over the next five years, representing a $500 million increase compared to the prior five-year plan. This balanced, low-risk plan is expected to increase midyear rate base from $31.1 billion in 2021 to $41.6 billion by 2026, translating into a five-year compound annual growth rate of approximately 6%.

46% of overall project complete

50% of transmission line construction complete

35% of substation construction complete

2021 Clean50 Exceptional Contributors to Clean Capitalism / Contributeurs Exceptionnels au Capitalisme Propre TOP PROJECT

Sustainability for our People and Planet

Together, our utilities are executing on the transition to a cleaner energy future. Through the end of 2021, we reduced our Scope 1 emissions by 20% relative to 2019 levels, supporting our target to reduce carbon emissions 75% by 2035.

Our goal represents avoided emissions equivalent to taking approximately two million cars off the road in 2035 compared to 2019 levels. Upon achieving this target, we expect 99% of our assets will be focused on energy delivery and renewable, carbon-free generation.

In 2021, we became a supporter of the Task Force on Climate-Related Financial Disclosures ("TCFD") and agreed to fully implement the TCFD recommendations, including a climate scenario analysis to assess the resiliency of our energy delivery businesses which will be completed in the first quarter of 2022.

As part of our 2021 Sustainability Update, we increased our sustainability disclosures by adding over 50 new key performance indicators, further aligning with standards set forth by the Sustainability Accounting Standards Board.

Newfoundland Power and Maritime Electric received the Canadian Electricity Association Sustainable Electricity Company designation in 2021.



Fortis Inc. was invited to participate in the official Canadian delegation for COP26 and was pleased to meet with CEA members and staff to discuss climate transition in the energy sector.



Megan Cutcliffe, Customer Service Representative



Caroline Astley, Environment Manager, Major Projects

Our commitments are helping us forge a path towards being a strong and reliable global partner in combatting climate change and creating a more diverse and inclusive society.

We have made great strides in advancing inclusion and diversity, including achieving gender parity on our Board of Directors. Throughout our utilities, we are also providing a more creative, innovative, and welcoming environment that allows our people and our company to be as successful as possible. We recognize this is a journey and are committed to continue making progress and better reflect the communities we serve with the guidance of our Diversity and Inclusion Council.

The Fortis Board of Directors achieved **gender parity** and 60% of Fortis utilities have either a female CEO or Board Chair.

Our corporate governance practices, which have earned us industry recognition, ensure we operate as a well-governed sustainable company today and into the future. In 2021 we introduced a new measure in executive compensation to link incentive compensation to carbon reduction and climate change priorities. We also established a new board diversity policy whereby the board will seek to maintain a minimum of 40% women, and have at least two board members who are visible minorities or Indigenous persons by 2023.

Our charitable giving totaled more than $10 million in 2021 making our communities better and stronger. Our utility and head office employees met numerous needs in their communities through both financial and hands-on support.

Leadership that Embraces our Goals

We welcomed two new directors to our Board at our annual meeting in May: Lisa Durocher, Executive Vice President, Financial and Emerging Services for Rogers Communications Inc., and Gianna Manes, the former President and Chief Executive Officer of ENMAX Corporation. Both bring extensive experience, diversity, and valuable contributions to our Board.

At the end of 2021, Jim Laurito, Executive Vice President, Business Development and Chief Technology Officer, retired after a distinguished career in the energy sector. We appreciate Jim's immense contributions to Fortis and wish him all the best in retirement.

Gary Smith's role was expanded with his appointment as Executive Vice President of Operations and Innovation. Gary leads our innovation priorities throughout the Fortis group of companies and continues to provide leadership in key areas such as safety, reliability, and capital investment across the entire organization. Gary also oversees the company's cybersecurity and technology functions.

Stakeholder Value

Our core values always have and always will underpin the way we do business. We are focused on all our stakeholders, including our people, customers, communities, shareholders, and planet. Our continued success demonstrates that we have the right strategy and people to ensure Fortis is a sustainable company that will provide long-term value.

We look forward to your continued support as we deliver a cleaner energy future for the benefit of all. Together we must – and will – do our part.

On behalf of the
Board of Directors,



Douglas J. Haughey
Chair of the Board, Fortis Inc.



David G. Hutchens
President and CEO, Fortis Inc.

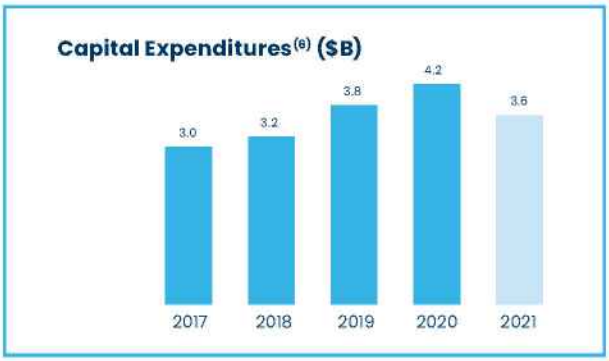




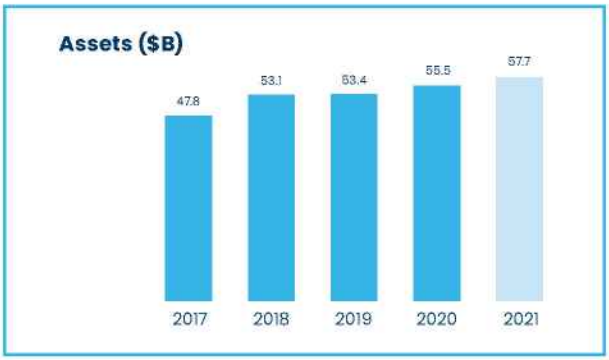
Financial Highlights

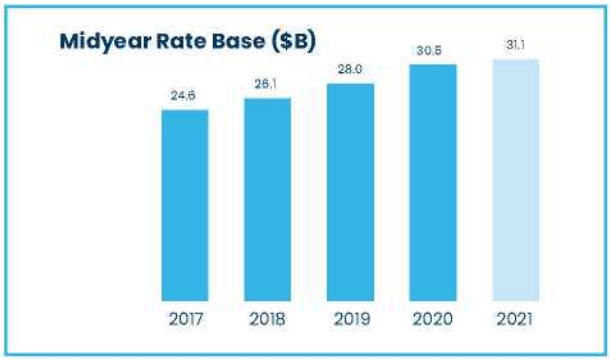












(1) Adjusted net earnings exclude the impact of U.S. tax reform and other non-operating items.

(2) Results were tempered by the ongoing impact of U.S. tax reform and a reduced independence incentive adder at ITC. Adjusted net earnings exclude certain non-operating items.

(3) Results were impacted by a gain on disposition of the Waneta Expansion and a favourable adjustment associated with a regulatory order at ITC. Adjusted net earnings exclude the gain on disposition, the favourable regulatory adjustment and other non-operating items.

(4) Results were impacted by a favourable adjustment associated with a regulatory order at ITC. Adjusted net earnings exclude the favourable regulatory adjustment and certain non-operating items.

(5) Results were tempered by the lower U.S.-to-Canadian dollar exchange rate. Adjusted net earnings exclude certain non-operating items.

(6) Non-U.S. GAAP financial measure.

All financial information is presented in Canadian dollars. Information is for the fiscal years ended December 31.

Highly Regulated, Low-Risk and Diversified Utility Business

Regulated

	CUSTOMERS			PEAK DEMAND		ELECTRIC	GAS		TOTAL	2022F[1] MIDYEAR	2022F[1] CAPITAL
	ELECTRIC (#)	GAS (#)	EMPLOYEES (#)	ELECTRIC (MW)	GAS (TJ)	SALES (GWh)	VOLUMES (PJ)	EARNINGS ($M)	ASSETS ($B)	RATE BASE ($B)	PROGRAM ($M)
ITC[2]	–	–	705	22,920	–	–	–	426	21.0	10.1	998
UNS Energy	538,000	165,000	2,028	3,164	108	16,842	16	292	11.1	6.5	704
Central Hudson	300,000	80,000	1,076	1,148	134	5,000	23	93	4.4	2.4	344
FortisBC[3]	185,000	1,065,000	2,594	777	1,399	3,460	228	244	10.7	6.9	778
FortisAlberta	577,000	–	1,087	2,751	–	16,643	–	141	5.2	4.0	445
Other Electric[4]	474,000	–	1,479	1,956	–	9,266	–	118	4.3	3.6	621
	2,074,000	**1,310,000**	**8,969**	**32,716**	**1,641**	**51,211**	**267**	**1,314**	**56.7**	**33.5**	**3,890**

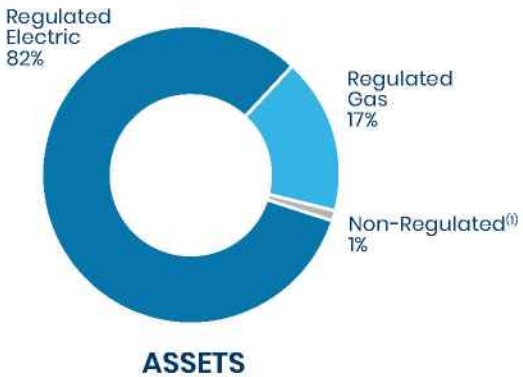
(1) Forecast

(2) Data reflects 100% of ITC's operations except for earnings, which represent the Corporation's 80.1% ownership interest. ITC has no retail customers.

(3) Includes FortisBC Energy and FortisBC Electric.

(4) Data reflects 100% of Caribbean Utilities' operations except earnings, which represent the Corporation's 60% ownership interest. Also includes Newfoundland Power, Maritime Electric, FortisOntario, a 39% equity investment in Wataynikaneyap Power Limited Partnership, Fortis Turks and Caicos, and a 33% equity investment in Belize Electricity.

99% Regulated Utilities



ASSETS

(1) Comprising of energy infrastructure investments in British Columbia and Belize.



Total Assets of
$58 billion
as at December 31, 2021.

Management Discussion and Analysis

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Dated February 10, 2022

This MD&A has been prepared in accordance with National Instrument 51-102 - *Continuous Disclosure Obligations*. It should be read in conjunction with the 2021 Annual Financial Statements and is subject to the cautionary statement and disclaimer provided under "Forward-Looking Information" on page 52. Further information about Fortis, including its Annual Information Form filed on SEDAR, can be accessed at www.fortisinc.com, www.sedar.com, or www.sec.gov.

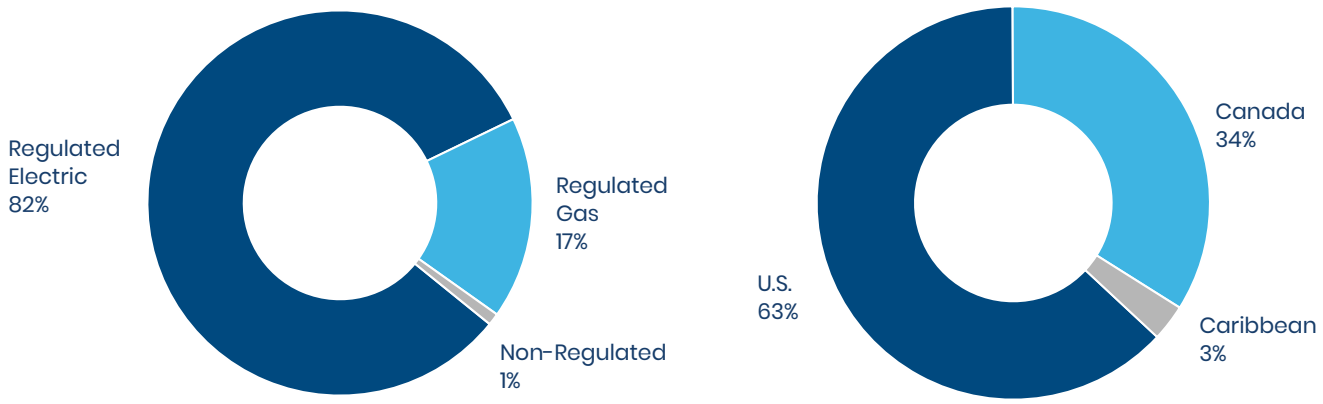
Financial information herein has been prepared in accordance with U.S. GAAP (except for indicated Non-U.S. GAAP Financial Measures) and, unless otherwise specified, is presented in Canadian dollars based, as applicable, on the following U.S. dollar-to-Canadian dollar exchange rates: (i) average of 1.25 and 1.34 for the years ended December 31, 2021 and 2020, respectively; (ii) 1.26 and 1.27 as at December 31, 2021 and 2020, respectively; (iii) average of 1.26 and 1.30 for the quarters ended December 31, 2021 and 2020, respectively; and (iv) 1.25 for all forecast periods. Certain terms used in this MD&A are defined in the "Glossary" on page 53.

ABOUT FORTIS

Fortis (TSX/NYSE: FTS) is a well-diversified leader in the North American regulated electric and gas utility industry, with revenue of $9.4 billion in 2021 and total assets of $58 billion as at December 31, 2021.

Regulated utilities account for 99% of the Corporation's assets with the remainder primarily attributable to non-regulated energy infrastructure. The Corporation's 9,100 employees serve 3.4 million utility customers in five Canadian provinces, nine U.S. states and three Caribbean countries. As at December 31, 2021, 66% of the Corporation's assets were located outside Canada and 57% of 2021 revenue was derived from foreign operations.

TOTAL ASSETS AT DECEMBER 31, 2021



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 and Oklahoma); 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 the Wataynikaneyap Partnership (electric transmission - Ontario) and Belize Electricity (integrated electric - Belize).

Non-regulated energy infrastructure consists of BECOL (three hydroelectric generation facilities - Belize) and Aitken Creek (natural gas storage facility - British Columbia).

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 strives to provide safe, reliable and cost-effective energy service to customers while focusing on sustainability policies and practices. The Corporation has established delivering a cleaner energy future as its 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 2021 Annual Financial Statements.

KEY DEVELOPMENTS

COVID-19 Pandemic

The Corporation's utilities continue to reliably and safely deliver an essential service during the COVID-19 Pandemic. Developments are monitored and commensurate measures taken, particularly with respect to the health and safety of our employees and the public. The Corporation's utilities are monitoring the impact of the pandemic on commodity prices and the supply chain, and are advancing procurement and hedging activities to mitigate the impact on customer rates. These and other potential impacts of the pandemic, including labour disruption risk, are evaluated and actions are taken to ensure that Fortis and its utilities can continue to provide safe, reliable and cost-effective service while supporting public health.

The Corporation continues to assess economic conditions in its service territories and the associated impacts on: (i) energy sales, particularly for UNS Energy and the Other Electric segment as revenue in these segments is not protected by regulatory mechanisms; (ii) the ability of customers to pay their energy bills and the related impact on Operating Cash Flow; (iii) the progress of regulatory proceedings and the ability to recover costs in a timely manner; and (iv) the execution of the Capital Plan. Except for the delay in TEP's general rate application in 2020, the COVID-19 Pandemic did not have a significant impact on financial performance for the years ended December 31, 2021 and 2020.

There continues to be uncertainty surrounding the pandemic, particularly with respect to the emergence of new variants of the virus, the long-term efficacy and global distribution of COVID-19 vaccines, the impact of vaccine mandates and isolation requirements on labour availability, potential government action to mitigate public health effects, and disruptions to the global supply chain. Potential financial and operating impacts of the COVID-19 Pandemic on Fortis are discussed under "Business Risks" on page 36.

U.S. Infrastructure Spending and Tax Proposals

In November 2021, the U.S. government approved significant infrastructure spending, including investments in transmission, electrification and economic development, as well as electrical grid resilience. Fortis continues to review the intended spending, as details become available, in order to assess the impact on its business.

The Biden administration has also been drafting significant tax proposals including, amongst other things, amendments to rules associated with international and minimum taxation, the introduction of a transmission investment tax credit, and the extension of clean energy tax credits. Proposals continue to evolve and while it is unknown when legislation incorporating these tax proposals could be enacted, it is currently expected in 2022.

In February 2022, the Department of Finance Canada released draft legislation including a proposal on interest deductibility. The proposal is open for public comment until May 2022 and it is unknown when the legislation may be enacted. In addition, in April 2021, the Canadian federal budget was released which proposed changes in relation to international taxation. There has been no significant update on this proposal, and it is unknown when draft legislation may be available.

Changes in tax legislation could affect the results of operations, financial condition and cash flows of the Corporation. Potential impacts of changes in tax laws are discussed under "Business Risks" on page 36. Fortis will continue to assess the impacts as more details on the U.S. and Canadian tax proposals become available.

PERFORMANCE AT A GLANCE

Key Financial Metrics

($ millions, except as indicated)	**2021**	2020	Variance
Common Equity Earnings			
Actual	**1,231**	1,209	22
Adjusted [(1)]	**1,219**	1,195	24
Basic EPS *($)*			
Actual	**2.61**	2.60	0.01
Adjusted [(1)]	**2.59**	2.57	0.02
Dividends			
Paid per common share *($)*	**2.0500**	1.9375	0.1125
Actual Payout Ratio *(%)*	**78.5**	74.5	4.0
Adjusted Payout Ratio *(%)* [(1)]	**79.2**	75.4	3.8
Weighted average number of common shares outstanding *(# millions)*	**470.9**	464.8	6.1
Operating Cash Flow	**2,907**	2,701	206
Capital Expenditures [(1)]	**3,564**	4,177	(613)

[(1)] *See "Non-U.S. GAAP Financial Measures" on page 24*

Earnings and EPS

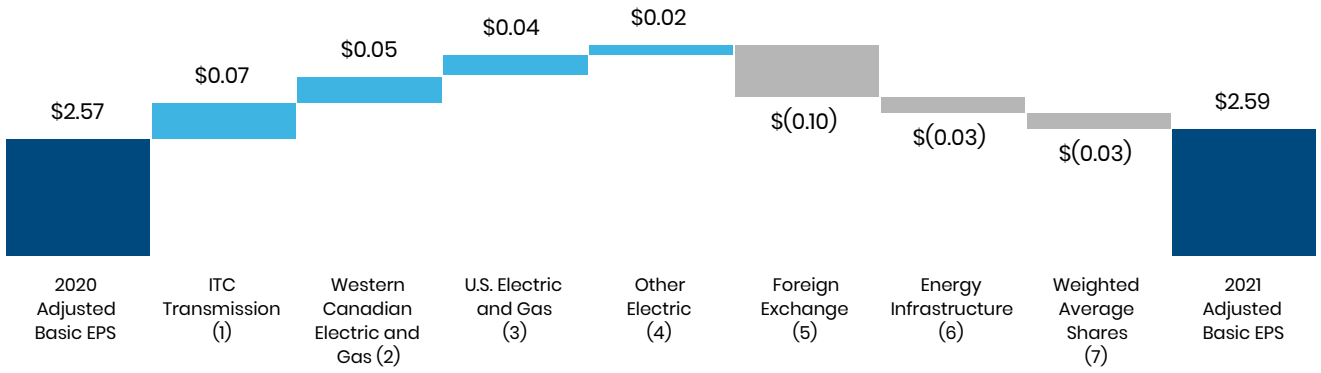
Common Equity Earnings increased by $22 million compared to 2020. Growth in Common Equity Earnings was tempered by the unfavourable impact of foreign exchange of $48 million, and significant one-time items recognized in 2020 of $14 million. The significant items in 2020 included an adjustment to ITC's base ROE, partially offset by the finalization of U.S. tax reform. These impacts were partially offset by unrealized mark-to-market gains of $12 million in 2021 on natural gas derivatives at Aitken Creek.

The Corporation delivered earnings growth of $72 million excluding the impact of the above noted items. Operational growth in 2021 reflected: (i) Rate Base growth; (ii) higher earnings in Arizona primarily due to new customer rates at TEP effective January 1, 2021, partially offset by lower sales due to unfavourable weather and higher operating costs; (iii) continued recovery in the Caribbean from economic conditions experienced in 2020 associated with the COVID-19 Pandemic; and (iv) higher sales at FortisAlberta associated with favourable weather, partially offset by a higher effective income tax rate. This growth was partially offset by lower hydroelectric production in Belize, and lower earnings at Aitken Creek due to realized losses on natural gas contracts.

In addition to the above-noted items impacting earnings, the change in EPS 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 $24 million and $0.02, respectively. Refer to "Non-U.S. GAAP Financial Measures" on page 24 for a reconciliation of these measures. The changes in Adjusted Basic EPS, including the unfavourable impact of foreign exchange described above, are illustrated in the chart below.

CHANGES IN ADJUSTED BASIC EPS



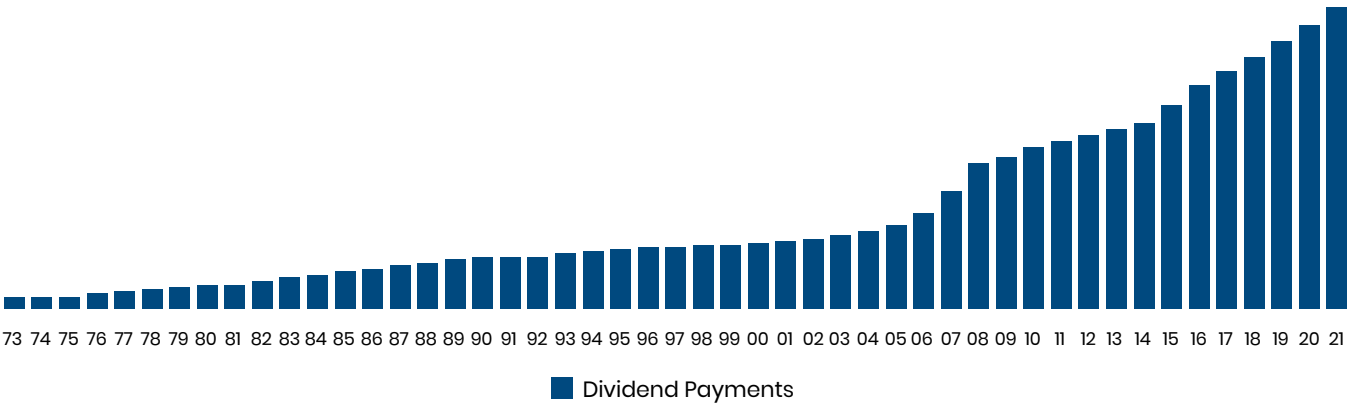
(1) *Primarily reflects Rate Base growth and an adjustment related to interest rate swaps, partially offset by higher non-recoverable expenses*
(2) *Includes FortisBC Energy, FortisAlberta and FortisBC Electric. Primarily reflects Rate Base growth, as well as higher sales due to favourable weather partially offset by a higher effective income tax rate at FortisAlberta*
(3) *Includes UNS Energy and Central Hudson. Increase at UNS Energy primarily reflects the impact of new customer rates at TEP partially offset by lower sales driven by unfavourable weather and higher operating costs mainly related to planned generation maintenance. Earnings at Central Hudson reflects the finalization of its general rate application effective July 1, 2021, partially offset by the impact of regulatory mechanisms and higher operating costs*
(4) *Primarily reflects higher earnings in the Caribbean, related to the continued recovery from economic conditions in 2020 associated with the COVID-19 Pandemic*
(5) *Average foreign exchange rate of 1.25 in 2021 compared to 1.34 in 2020*
(6) *Primarily reflects variations in hydroelectric production in Belize associated with rainfall levels, and lower earnings at Aitken Creek due to realized losses on natural gas contracts, as certain contracts were settled in 2021 in consideration of favourable forward curves*
(7) *Weighted average shares of 470.9 million in 2021 compared to 464.8 million in 2020*

Dividends

Fortis paid a dividend of $0.535 per common share in the fourth quarter of 2021, up 5.9% from $0.505 paid in each of the previous four quarters and in line with the Corporation's dividend guidance. The Actual Payout Ratio was 78.5% in 2021 compared to 74.5% in 2020 and an annual average of 65.9% over the five-year period of 2017 through 2021.

Fortis has increased its common share dividend for 48 consecutive years. In September 2021, Fortis reaffirmed its targeted average annual dividend growth of approximately 6% through 2025.

48 YEARS OF CONSECUTIVE DIVIDEND INCREASES



Growth of dividends and the market price of the Corporation's common shares have together yielded the following TSR.

TSR [1] (%)	1-Year	5-Year	10-Year	20-Year
Fortis	**21.8**	**12.1**	**10.2**	**12.6**

[1] *Annualized TSR per Bloomberg, as at December 31, 2021*

Operating Cash Flow

The $206 million increase in Operating Cash Flow was due to higher cash earnings, reflecting Rate Base growth and new customer rates at TEP effective January 1, 2021, partially offset by higher operating costs at TEP and an upfront payment received by FortisAlberta in 2020 associated with a long-term energy retailer agreement. Favourable changes in regulatory deferrals due to the timing of flow-through costs in customer rates and lower transmission payments at FortisAlberta also contributed to the increase. The increase was partially offset by the lower U.S.-to-Canadian dollar exchange rate in 2021.

Capital Expenditures

Capital Expenditures were $3.6 billion, broadly consistent with the 2021 Capital Plan. For a detailed discussion of the Corporation's capital expenditure program, see "Capital Plan" on page 31. Capital Expenditures in 2021 were $0.6 billion lower than 2020 primarily due to the timing of costs associated with the construction of the Oso Grande generating facility at UNS Energy, and the impact of the lower average foreign exchange rate.

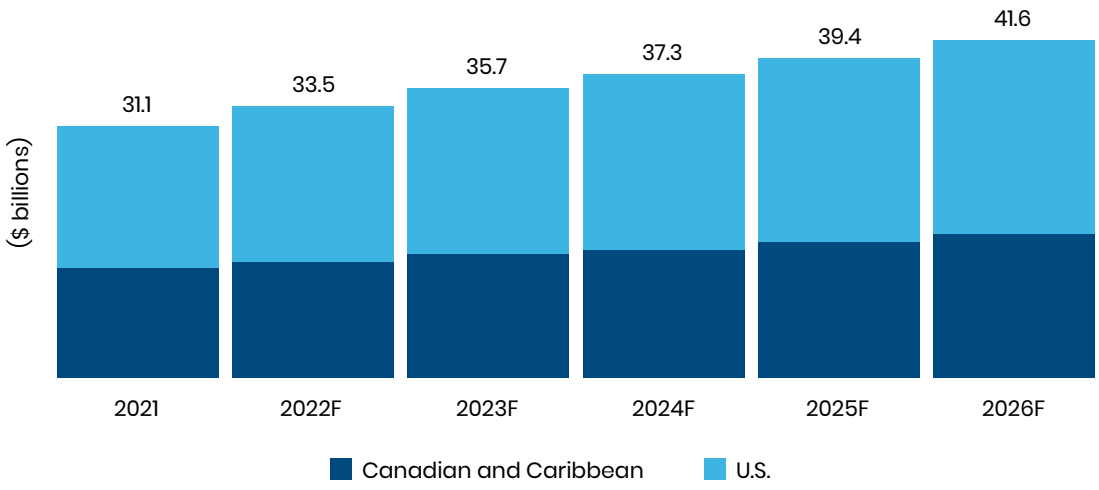
The Corporation's five-year 2022-2026 Capital Plan of $20.0 billion reflects $1.0 billion of additional capital investment at the Corporation's regulated utilities in comparison to the 2021-2025 Capital Plan disclosed in the 2020 MD&A. The increase largely reflects customer growth, enhancements to transmission reliability and capacity, and investments in cleaner energy. This growth is tempered by $600 million associated with the lower assumed foreign exchange rate of 1.25, down from a rate of 1.32 assumed in the Corporation's previous five-year Capital Plan.

Overall, the COVID-19 Pandemic did not have a material impact on capital expenditures in 2021. While the Corporation does not expect the COVID-19 Pandemic to materially impact its overall five-year Capital Plan, the timing of forecast capital expenditures will continue to be evaluated. Depending on the length and severity of the pandemic, including any impacts of supply chain disruptions, certain planned expenditures may shift within the 2022-2026 Capital Plan. Funding of the Capital Plan is expected to be primarily through Operating Cash Flow, regulated utility debt and common equity from the Corporation's DRIP.

The five-year Capital Plan is expected to increase midyear Rate Base from $31.1 billion in 2021 to $41.6 billion by 2026, representing a five-year CAGR of approximately 6%. Fortis expects this growth in Rate Base will support earnings and dividend growth.

Capital Expenditures and Capital Plan reflect Non-U.S. GAAP financial measures. Refer to "Non-U.S. GAAP Financial Measures" on page 24 and "Capital Plan" on page 31.

PROJECTED RATE BASE GROWTH



Additional opportunities to expand and extend growth include: further expansion of the electric transmission grid in the U.S. to facilitate the interconnection of cleaner energy, including infrastructure investments associated with MISO's long-range transmission plan; natural gas resiliency investments in pipelines and LNG infrastructure in British Columbia; the fully permitted, cross-border, Lake Erie Connector electric transmission project in Ontario; and the acceleration of cleaner energy infrastructure investments across our jurisdictions.

THE INDUSTRY

The North American energy industry's transformation is accelerating at a rapid pace, driven by the impacts of climate change and the need for a cleaner energy future. This creates a growing need for the development of cleaner energy sources and the deployment of energy conservation measures to preserve the planet for future generations. The goal of carbon emission reduction creates the need for increased innovation, and associated advancements in technology have attracted interest from investors and customers. Renewable generation continues to be a key element in a decarbonized future, with electric transmission seen as a critical enabler of large-scale renewables. Natural gas also continues to be an important part of the energy mix, as supplemental generation to the intermittency of renewables, and as a cost-effective heating source. Longer term, advancements in the use of hydrogen and RNG may also contribute to carbon reduction. Each of these factors, as well as the increasing affordability of cleaner energy, is driving significant investment opportunity in the utility sector.

Energy policies at the federal, state, and provincial levels continue to reflect the rising focus on climate change, with clean energy and carbon reduction goals and initiatives at the forefront. In the U.S., legislation has been approved for significant infrastructure investments, including those in the energy sector involving renewables, transmission and storage. Additional legislation is under consideration, which would further increase the investments required to meet new and aggressive federal carbon reduction goals. With states and provinces also setting ambitious carbon reduction targets, the regulatory and compliance environment continues to evolve and become increasingly complex. These changes are creating opportunities to expand investment in new, renewable generation sources, including solar and wind, as well as transmission infrastructure to interconnect renewable energy sources to the grid. As the amount of renewables grow, investment opportunities in energy storage are also being created, driven by the decreasing costs of energy storage technology. The electrification of the transportation sector is gaining momentum and represents a significant opportunity to reduce GHG emissions while increasing the output and efficiency of the grid. The Corporation's utilities are well positioned and actively involved in pursuing these opportunities which will drive significant investment well into the future.

New technology is stimulating change across all service territories. Energy delivery systems are becoming more intelligent, with upgraded advanced meters, additional grid automation and more capable operational technology, providing utilities with detailed usage data and predictive maintenance information to improve cost efficiency and safety. Energy management capabilities are expanding through emerging storage and demand response systems, and customers have been enabled with options to manage and reduce energy usage and access more affordable distributed generation technology. Grid resilience is growing in importance with the increasing frequency of extreme weather events such as hurricanes, wildfires, tornadoes and storms. As a result, investments in grid hardening and resiliency are increasing in importance to improve the grid's ability to withstand and recover from these climate events.

Fortis' culture of innovation underlies a continuous drive to find a better way to safely, reliably and affordably deliver the energy and services that customers need. To further advance innovation, Fortis is a partner in the Energy Impact Partners utility coalition, which is a strategic private equity fund that invests in emerging technologies, products, services and business models that are transforming the industry. The Corporation is also involved in the Electric Power Research Institute's Low Carbon Resources Initiative, along with other major North American utilities. By leveraging these strengths and partnerships, Fortis expects to remain at the forefront of this ever-changing industry.

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 services. They also expect personalized service, customized self-service offerings and more real-time, digital communication. Fortis' utilities are capitalizing on this as an opportunity to provide enhanced customer information systems and digital technologies to improve customer service.

On the security front, with the advent of new and increasing cyber threats to our information and operational technology systems, increased focus and investment on protection and response to these events is an ongoing effort. Upgrades to the physical security environment is also required to keep pace with evolving challenges. All these technological advancements and challenges offer strategic investment opportunities for improving and expanding customer service and enhancing security.

Fortis is positioned to capitalize on evolving industry opportunities. The Corporation's decentralized structure and customer-focused business culture support the efforts required to meet changing customer expectations. Each of the utilities work constructively with regulators and all stakeholders on policy, energy and service solutions, and are an integral partner in all the communities they serve. Fortis is committed to be an industry leader in the clean energy transition.

FOCUS ON SUSTAINABILITY

Fortis is dedicated to being a strong energy partner for its communities by operating in an environmentally and socially responsible manner. Fortis believes that responsible environmental and sustainability management not only creates business value, but it is also good for our customers and the planet.

To bring focus and accountability to sustainability, oversight is coordinated at the most senior levels of Fortis and is a priority at each of our operating subsidiaries. Sustainability efforts are managed at the utility level to address applicable federal, provincial/state and municipal laws and regulations, which may differ in each service territory. Fortis' Executive Vice-President, Sustainability and Chief Human Resource Officer reports to the President and CEO and collectively they are responsible for enterprise-wide sustainability and stewardship at the executive level. The Board is responsible for risk management oversight and ensuring that business is conducted to meet high standards of environmental and social responsibility. The governance and sustainability committee of the Board is responsible for overseeing governance structure and sustainability programs and practices.

Key aspects of Fortis' sustainability program and practices are outlined below. Additional information may be found in the Corporation's Annual Information Form.

Climate Change and Environmental Matters

Fortis is primarily an energy delivery company with 93% of its assets dedicated to the movement of energy through our wires and natural gas lines. This presents a unique opportunity for Fortis to facilitate the delivery of cleaner energy to its customers and limits its impact on the environment when compared to energy generation-intensive businesses. Although Fortis has limited fossil-fuel generation exposure, it has a plan to transition to more sustainable energy for its customers.

The Corporation's direct GHG emissions come primarily from its generation assets, and largely include fossil fuel-based generation at TEP representing 5% of the Corporation's total assets. Fortis continues to build on its low emissions profile and is committed to achieve its corporate-wide target to reduce carbon emissions by 75% by 2035 from a 2019 base year. Fortis expects to achieve this target through delivering on TEP's plan to reduce carbon emissions, as well as clean energy initiatives across the Corporation's other utilities.

In 2021, Fortis' Scope 1 emissions were 20% lower relative to 2019 levels, equivalent to taking approximately 540,000 vehicles off the road in one year and marking significant progress to our 75% target. Closure of Navajo at TEP in late 2019 as well as recently commissioned renewable projects, such as the 250-MW Oso Grande wind project, the 99-MW Borderlands wind project and the 100-MW Wilmot solar project, have supported our carbon emissions reduction target to date.

The Corporation's environmental statement sets out its commitment to comply with all applicable laws and regulations relating to the protection of the environment, regularly conduct monitoring and audits of environmental management systems, seek feasible, cost-effective opportunities to decrease GHG emissions and increase renewable energy sources. Each operating subsidiary has extensive environmental compliance programs aligned with the ISO 14001 standard, regularly reviews its environmental management systems and protocols, strives for continual performance improvement and sets and reviews its own environmental objectives, targets and programs. Fortis' most recent sustainability update was released in July 2021 and included information on: (i) the Corporation's progress on reducing carbon emissions; (ii) updated sustainability key indicators; (iii) alignment with standards issued by the Sustainability Accounting Standards Board; and (iv) the Corporation's support of the Task Force on Climate-related Financial Disclosures. The Corporation is currently completing a climate scenario analysis to assess the resiliency of our energy delivery businesses with a progress update planned in 2022.

Safety and Reliability

Fortis is an industry leader in safety and reliability, with the Corporation consistently performing above industry averages. Fortis leverages its unique operating model and utility experience to deliver safe and reliable service to its customers and the communities it serves. Senior operational executives from all Fortis utilities meet regularly to share best practices and identify opportunities for collaboration on a range of operational areas including health and safety.

In 2021, $600 million in Capital Expenditures were focused on the delivery of cleaner energy to customers. In addition, in the development of the Corporation's five-year Capital Plan, each of the utilities consider investment required to deliver cleaner energy to customers, strengthen infrastructure, and improve network resiliency, with the intent of maintaining customer reliability, while also mitigating the expected impacts of climate change, such as more frequent and intense weather events, on utility infrastructure. Additional information on the Corporation's Capital Plan can be found in the "Capital Plan" section on page 31.

Customer Service and Community Efforts

Fortis' utilities work closely with their customers and communities to drive enhancements and improve the overall customer service experience. Customer satisfaction targets are established and customer service surveys are completed regularly focusing on customer satisfaction, reliability and accuracy of billing and metering, contact centre services and reliability of energy supply.

Fortis and its utilities consistently look for opportunities for growth, innovation and energy efficiency in the communities served. Regular community engagement through donations to local charities, partnerships with educational institutions, and participation on local boards, amongst other initiatives, enables Fortis to remain a meaningful contributor to our local communities.

Cybersecurity

Fortis' CRMP aims to continually improve information sharing and the culture of security. Fortis has an enterprise-wide CRMP that allows for the identification, measurement, monitoring and management of cybersecurity risks. Further, the Corporation and each of the utilities continually consider investments required in security, in both the corporate and grid environments, during the development of the five-year Capital Plan. Oversight of cybersecurity is the responsibility of Fortis' Vice President, Chief Information Officer and the respective boards and executive committees at Fortis and at each utility.

Human Capital Management

Fortis values its 9,100 employees and recognizes that success is dependent on a strong workforce which is safe, supported and empowered. Fortis has compensation and benefit programs designed to attract and retain talent. Fortis believes that the foundation for a healthy work environment starts with leadership from the most senior levels of the organization and must be reflected throughout the organization. The Corporation has established delivering a cleaner energy future as its core purpose, driven by values embedded at all levels of the organization.

Governance

Fortis has a Code of Conduct which is guided by the Corporation's purpose and values and sets out standards for the ethical conduct of its business, including all of its directors, officers, employees, consultants, contractors and representatives, as applicable. The core principles of the Fortis Code of Conduct apply universally across the organization, with each operating subsidiary adopting its own substantially similar Code. Fortis and its utilities hold regular Code of Conduct employee training and all Fortis employees annually certify compliance.

The Code of Conduct is supported by other policies that outline the behaviour expected from management and employees, including the Anti-Corruption Policy and Respectful Workplace Policy. All Fortis operating subsidiaries have policies in place that uphold the Corporation's values as contained in these policies and demonstrate their commitment to ensuring equal opportunity and providing safe, respectful work environments.

Fortis and each of its operating subsidiaries have a Speak Up Policy to support and facilitate the reporting of conduct that may breach the Code of Conduct or other workplace policies.

Diversity, Equity and Inclusion

The Corporation's Board and Executive Diversity Policy describes the principles and objectives for diversity among the Board and executive leadership, including a commitment to maintaining a Board where at least 40% of independent directors are women. Currently, 50% of the Board and 45% of its executive leadership team are women. 60% of Fortis utilities have either a female president or female board chair. Fortis has also recently introduced a target of two directors identifying as a visible minority or indigenous by 2023.

Advancing diversity, equity and inclusion is a priority at Fortis. The Corporation has a formal Inclusion and Diversity Commitment that applies to all employees at Fortis and its operating subsidiaries. The commitment is supported by a framework built upon three pillars - talent, culture and community. A Diversity, Equity and Inclusion Advisory Council with diverse, senior level representation from across the Fortis organization guides the inclusion and diversity strategy and its implementation.

OPERATING RESULTS

			Variance	
($ millions)	**2021**	2020	FX	Other
Revenue	**9,448**	8,935	(345)	858
Energy supply costs	**2,951**	2,562	(77)	466
Operating expenses	**2,523**	2,437	(107)	193
Depreciation and amortization	**1,505**	1,428	(52)	129
Other income, net	**173**	154	—	19
Finance charges	**1,003**	1,042	(40)	1
Income tax expense	**234**	231	(14)	17
Net earnings	**1,405**	1,389	(55)	71
Net earnings attributable to:				
Non-controlling interests	**111**	115	(7)	3
Preference equity shareholders	**63**	65	—	(2)
Common equity shareholders	**1,231**	1,209	(48)	70
Net Earnings	**1,405**	1,389	(55)	71

Revenue

The increase in revenue, net of foreign exchange, was due primarily to: (i) higher flow-through costs in customer rates; (ii) Rate Base growth; (iii) new customer rates, effective January 1, 2021 and higher wholesale sales at TEP; and (iv) higher retail electricity sales, primarily in Western Canada and the Caribbean, partially offset by lower sales in Arizona due to unfavourable weather. The increase was partially offset by a $40 million favourable base ROE adjustment recognized at ITC in 2020 as a result of the May 2020 FERC Decision.

Energy Supply Costs

The increase in energy supply costs, net of foreign exchange, was due primarily to overall higher commodity costs due to pricing and volumes, and the impact of higher wholesale sales at TEP.

Operating Expenses

The increase in operating expenses, net of foreign exchange, was due primarily to: (i) higher flow-through costs, particularly at ITC; (ii) higher operating costs mainly related to planned generation maintenance at UNS Energy; and (iii) general inflationary and employee-related cost increases. The increase was partially offset by lower credit loss expense.

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.

Other Income, Net

The increase, net of foreign exchange, was due primarily to non-service benefit costs and higher mark-to-market gains on total returns swaps associated with share price growth, partially offset by lower equity income from Belize Electricity.

Finance Charges

Finance charges, net of foreign exchange, were consistent with 2020. The impact of higher debt levels to support the Corporation's Capital Plan was largely offset by the benefit of refinancing debt at lower interest rates.

Income Tax Expense

The increase in income tax expense, net of foreign exchange, was driven by: (i) a higher consolidated state tax rate associated with changes in regional sales mix; and (ii) a higher effective income tax rate at FortisAlberta, partially offset by the reversal of a $13 million tax recovery in 2020 resulting from the finalization of U.S. tax reform and associated anti-hybrid regulations.

Net Earnings

See "Performance at a Glance - Earnings and EPS" on page 14.

BUSINESS UNIT PERFORMANCE

Common Equity Earnings

($ millions)	**2021**	2020	Variance FX [1]	Variance Other
Regulated Utilities				
ITC	**426**	449	(31)	8
UNS Energy	**292**	302	(20)	10
Central Hudson	**93**	91	(4)	6
FortisBC Energy	**185**	175	—	10
FortisAlberta	**141**	133	—	8
FortisBC Electric	**59**	56	—	3
Other Electric [2]	**118**	112	(2)	8
	1,314	1,318	(57)	53
Non-Regulated				
Energy Infrastructure [3]	**38**	39	—	(1)
Corporate and Other [4]	**(121)**	(148)	9	18
Common Equity Earnings	**1,231**	1,209	(48)	70

[1] The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, FortisTCI and BECOL 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. The Corporate and Other segment includes certain transactions denominated in U.S. dollars.

[2] Consists of the utility operations in eastern Canada and the Caribbean: Newfoundland Power; Maritime Electric; FortisOntario; Caribbean Utilities; FortisTCI; and Belize Electricity

[3] Primarily consists of long-term contracted generation assets in Belize and Aitken Creek in British Columbia

[4] Includes Fortis net corporate expenses and non-regulated holding company expenses

ITC

($ millions)	2021	2020	Variance FX	Variance Other
Revenue [1]	**1,691**	1,744	(117)	64
Earnings [1]	**426**	449	(31)	8

[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, reflected higher flow-through costs in customer rates and Rate Base growth. The increase was partially offset by a $40 million favourable base ROE adjustment recognized in 2020 as a result of the May 2020 FERC Decision.

Earnings

The increase in earnings, net of foreign exchange, reflected Rate Base growth and an adjustment related to the amortization of interest rate swaps. The increase was partially offset by a $27 million favourable base ROE adjustment as a result of the May 2020 FERC Decision, discussed above, and higher non-recoverable operating expenses related to an increase in stock-based compensation costs due to the Corporation's share price growth.

UNS Energy

($ millions, except as indicated)	2021	2020	Variance FX	Variance Other
Retail electricity sales *(GWh)*	**10,559**	10,920	—	(361)
Wholesale electricity sales *(GWh)* [1]	**6,283**	5,843	—	440
Gas sales *(PJ)*	**16**	15	—	1
Revenue	**2,334**	2,260	(147)	221
Earnings	**292**	302	(20)	10

[1] *Primarily short-term wholesale sales*

Sales

The decrease in retail electricity sales was largely due to unfavourable weather as compared to 2020.

The increase in wholesale electricity sales was due primarily to favourable market conditions, including customer demand in the first quarter of 2021 resulting from a severe winter storm in southwestern U.S. in February 2021. Revenue from short-term wholesale sales is primarily credited to customers through regulatory deferral mechanisms and, therefore, does not materially impact earnings.

Gas sales were consistent with 2020.

Revenue

The increase in revenue, net of foreign exchange, was due primarily to: (i) new customer rates effective January 1, 2021 at TEP; (ii) higher wholesale electricity sales reflecting favourable market conditions; (iii) higher transmission revenue; and (iv) the recovery of higher fuel and non-fuel costs through the normal operation of regulatory mechanisms. The increase was partially offset by lower retail electricity sales, discussed above.

Earnings

The increase in earnings, net of foreign exchange, was due to the impact of new customer rates and higher transmission revenue at TEP, partially offset by: (i) higher operating costs mainly related to planned generation maintenance in 2021, including outages at the Springerville and Sundt generating facilities; and (ii) lower retail electricity sales driven by unfavourable weather.

Central Hudson

($ millions, except as indicated)	2021	2020	Variance FX	Variance Other
Electricity sales *(GWh)*	**5,000**	4,969	—	31
Gas sales *(PJ)*	**23**	23	—	—
Revenue	**1,000**	953	(60)	107
Earnings	**93**	91	(4)	6

Sales

Electricity and gas sales were largely consistent with 2020.

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 increase in revenue, net of foreign exchange, was due primarily to: (i) the flow through of higher energy supply costs driven by higher commodity prices; and (ii) the finalization of Central Hudson's general rate application including an increase in gas and electricity delivery rates with retroactive effect to July 1, 2021, reflecting a return on increased Rate Base assets, the recovery of higher operating and finance expenses, and the recovery of finance charges which had not been billed to customers since the second quarter of 2020. See "Regulatory Highlights" on page 25 for further details. The increase in revenue was partially offset by the normal operation of regulatory mechanisms to be reflected in future customer rates.

Earnings

The increase in earnings, net of foreign exchange, was due primarily to the finalization of Central Hudson's general rate application, partially offset by the operation of regulatory mechanisms, discussed above, as well as higher operating costs.

FortisBC Energy

($ millions, except as indicated)	2021	2020	Variance
Gas sales *(PJ)*	**228**	219	9
Revenue	**1,715**	1,385	330
Earnings	**185**	175	10

Sales

The increase in gas sales was due primarily to higher consumption by residential and commercial customers due to colder temperatures in the fourth quarter of 2021 as compared to the same period in 2020.

Revenue

The increase in revenue was due primarily to a higher cost of natural gas recovered from customers, Rate Base growth, and the normal operation of regulatory deferrals.

Earnings

The increase in earnings was due primarily to Rate Base growth.

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)	2021	2020	Variance
Electricity deliveries *(GWh)*	**16,643**	16,092	551
Revenue	**644**	596	48
Earnings	**141**	133	8

Deliveries

The increase in electricity deliveries was due to: (i) higher average consumption by residential and small commercial customers due to favourable weather largely in the first and third quarters of 2021; (ii) customer additions; and (iii) higher load from 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 and Earnings

The increases in revenue and earnings were due to: (i) Rate Base growth and customer additions; (ii) higher revenue associated with significantly colder and warmer temperatures in the first and third quarters of 2021, respectively; and (iii) higher revenue associated with a long-term energy retailer agreement. The increase in earnings was partially offset by the impact of a higher effective income tax rate associated with lower available tax deductions in 2021 as compared to 2020, and higher operating costs.

FortisBC Electric

($ millions, except as indicated)	**2021**	2020	Variance
Electricity sales *(GWh)*	**3,460**	3,291	169
Revenue	**468**	424	44
Earnings	**59**	56	3

Sales

The increase in electricity sales was due primarily to: (i) higher average consumption, as a result of warmer temperatures in the second quarter of 2021 and colder temperatures in the fourth quarter of 2021 compared to the same periods in 2020; and (ii) higher average consumption by commercial and industrial customers due, in part, to the impact of the COVID-19 Pandemic, which resulted in tighter public health restrictions during 2020 as compared to 2021.

Revenue

The increase in revenue was due primarily to: (i) higher electricity sales, partially offset by the normal operation of regulatory deferrals; (ii) Rate Base growth; and (iii) an increase in third-party contract work.

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)	**2021**	2020	FX	Other
Electricity sales *(GWh)*	**9,266**	9,175	—	91
Revenue	**1,498**	1,485	(21)	34
Earnings	**118**	112	(2)	8

Sales

The increase in electricity sales was due primarily to overall higher average consumption, reflecting the continued recovery from the impacts of the COVID-19 Pandemic in 2020, including the temporary closure of non-essential businesses and lower tourism-related activities in the Caribbean.

Revenue

The increase in revenue, net of foreign exchange, reflected higher sales, the flow through of overall higher energy supply costs, and Rate Base growth.

Earnings

The increase in earnings, net of foreign exchange, primarily reflected the continued recovery of economic conditions in the Caribbean and Rate Base growth, partially offset by lower equity income from Belize Electricity.

Energy Infrastructure

($ millions, except as indicated)	**2021**	2020	Variance
Electricity sales *(GWh)*	**147**	229	(82)
Revenue	**98**	88	10
Earnings	**38**	39	(1)

Sales

The change in electricity sales reflected variations in hydroelectric production in Belize associated with rainfall levels.

Revenue

The increase in revenue was due to year-over-year changes at Aitken Creek, including unrealized gains associated with mark-to-market accounting of natural gas derivatives partially offset by realized losses on natural gas contracts, as certain contracts were settled in 2021 in consideration of favourable forward curves. The increase in revenue was also partially offset by lower hydroelectric production in Belize.

Earnings

The decrease in earnings was primarily due to lower hydroelectric production in Belize, partially offset by higher earnings at Aitken Creek as discussed above.

Aitken Creek is subject to commodity price risk, as it purchases and holds natural gas in storage to earn a profit margin from its ultimate sale. Aitken Creek mitigates this risk by using derivatives to materially lock in the profit margin that will be realized upon the sale of natural gas. The fair value accounting of these derivatives creates timing differences and the resultant earnings volatility can be significant.

Corporate and Other

			Variance	
($ millions)	**2021**	2020	FX	Other
Net expenses	**(121)**	(148)	9	18

The decrease in net expenses, net of foreign exchange, was due primarily to: (i) the reversal of a $13 million tax recovery in 2020, originally recognized in 2019, resulting from the finalization of U.S. tax reform and associated anti-hybrid regulations; (ii) lower operating expenses; and, (iii) higher mark-to-market gains on total returns swaps associated with share price growth. The decrease was partially offset by a lower income tax recovery resulting from a higher consolidated state tax rate associated with changes in regional sales mix.

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 includes 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 this Major Capital Project.

Non-U.S. GAAP Reconciliation

($ millions, except as indicated)	**2021**	2020	Variance
Adjusted Common Equity Earnings, Adjusted Basic EPS and Adjusted Payout Ratio			
Common Equity Earnings	**1,231**	1,209	22
Adjusting items:			
Unrealized gain on mark-to-market of derivatives [1]	**(12)**	—	(12)
May 2020 FERC decision [2]	**—**	(27)	27
U.S. tax reform [3]	**—**	13	(13)
Adjusted Common Equity Earnings	**1,219**	1,195	24
Adjusted Basic EPS [4] *($)*	**2.59**	2.57	0.02
Adjusted Payout Ratio [5] *(%)*	**79.2**	75.4	3.8
Capital Expenditures			
Additions to property, plant and equipment	**3,189**	3,857	(668)
Additions to intangible assets	**197**	182	15
Adjusting item:			
Wataynikaneyap Transmission Power Project [6]	**178**	138	40
Capital Expenditures	**3,564**	4,177	(613)

[1] *Represents timing differences related to the accounting of natural gas derivatives at Aitken Creek, net of income tax expense of $5 million in 2021 (2020 - $nil), included in the Energy Infrastructure segment*
[2] *Represents prior period impacts of the May 2020 FERC Decision, net of income tax expense of $11 million, included in the ITC segment*
[3] *Represents income tax expense resulting from the finalization of U.S. tax reform and associated anti-hybrid regulations, included in the Corporate and Other segment*
[4] *Calculated using Adjusted Common Equity Earnings divided by weighted average common shares of 470.9 million in 2021 (2020 - 464.8 million)*
[5] *Calculated using dividends paid per common share of $2.05 in 2021 (2020 - $1.9375) divided by Adjusted Basic EPS*
[6] *Represents Fortis' 39% share of capital spending for the Wataynikaneyap Transmission Power Project, included in the Other Electric segment*

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 regulatory 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 generally depends 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 reflected in customer rates.

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 governmental authorities.

Additional information about regulation and the regulatory matters discussed below is provided in Note 2 in the 2021 Annual Financial Statements. Also refer to "Business Risks - Utility Regulation" on page 36.

Significant Regulatory Developments

ITC

Transmission Incentives: In April 2021, FERC issued a supplemental NOPR on transmission incentives modifying the proposal in the initial NOPR released in March 2020. The supplemental NOPR proposes to eliminate the 50-basis point RTO ROE incentive adder for existing RTO members that have been members longer than three years, like ITC. In June 2021, ITC filed its comments on the supplemental NOPR supporting the continuation of the ROE incentive adder for RTO members. The timeline for FERC to issue a final rule in this proceeding and the likely outcome cannot be determined at this time. Although any potential impact to Fortis remains uncertain, every 10-basis point change in ROE at ITC impacts Fortis' annual EPS by approximately $0.01.

UNS Energy

FERC Rate Case: In 2019, FERC issued an order accepting formula transmission rates proposed by TEP, subject to refund following hearing and settlement procedures. A settlement in principle was reached in August 2021, and a settlement agreement including an ROE of 9.79% was filed with FERC in December 2021. Until conclusion of the proceeding, customer rates continue to be charged under the 2019 FERC order and remain subject to refund pending the final order. The timing and outcome of this proceeding remains unknown.

Central Hudson

General Rate Application: In November 2021, the PSC approved a three-year rate plan for Central Hudson with retroactive application to July 1, 2021, including an ROE of 9.0%, and a common equity component of capital structure of 50% declining by 1% annually to 48% in the third rate year. The three-year rate plan also reflects the use of existing regulatory balances and other measures to reduce customer bill impacts, the recovery of finance charges which had not been billed to customers since the second quarter of 2020, as well as initiatives to support New York State's climate goals.

FortisBC Energy and FortisBC Electric

GCOC Proceeding: In January 2021, the BCUC announced the initiation of a GCOC proceeding including a review of the common equity component of capital structure and the allowed ROE. The timing and outcome of this proceeding, including the effective date of any change in the cost of capital for 2022 or beyond, remains unknown.

FortisAlberta

2022 GCOC Proceeding: In March 2021, the AUC concluded the 2022 GCOC proceeding and extended the existing allowed ROE of 8.5% using a 37% equity component of capital structure through 2022.

2023 COS Application: The final year of FortisAlberta's second PBR term is 2022. In June 2021, the AUC issued a decision confirming the approach to be adopted by Alberta distribution utilities for the COS rebasing year in 2023. In November 2021, FortisAlberta filed its 2023 COS application and a decision is expected in the third quarter of 2022.

2023/2024 GCOC Proceeding: In January 2022, the AUC initiated proceedings to establish the cost of capital parameters for 2023 and to consider a formula-based approach to setting the allowed ROE for 2024 and beyond. The AUC is considering extending the existing allowed ROE of 8.5% using a 37% equity component of capital structure through 2023. Comments on this proposal are due in February 2022 and a decision is expected in the first quarter of 2022. The GCOC proceeding for 2024 and beyond is expected to commence in the third quarter of 2022, with a decision expected in 2023.

Third PBR Term: In July 2021, the AUC issued a decision confirming that Alberta distribution utilities will be subject to a third PBR term commencing in 2024 with going-in rates based on the 2023 COS rebasing. The AUC also initiated a new proceeding to consider the design of the third PBR term. FortisAlberta will submit comments with respect to the design of the third PBR term in 2022 and a decision from the AUC is expected in 2023.

Independent System Operator Tariff Proceeding: In April 2021, the AUC issued a decision confirming that distribution facility owners, such as FortisAlberta, will no longer be permitted to earn a return on AESO contributions made on a prospective basis from the date of the decision. Contributions made prior to that date are not impacted. The decision did not have a material financial impact on the Corporation in 2021 and it is not expected to materially impact future periods. In January 2022, the Alberta Court of Appeal granted a full appeal on this matter. In doing so, the Alberta Court of Appeal also permitted a related appeal regarding the legality of the AUC's AESO customer contribution policy. FortisAlberta will fully participate in the appeal regarding the legality of the AESO customer contribution policy and will closely monitor the preceding related to earned returns on future AESO contributions.

FINANCIAL POSITION

Significant Changes between December 31, 2021 and 2020

Balance Sheet Account	Variance		
($ millions)	FX	Other	Explanation
Cash and cash equivalents	(1)	(117)	Reflects the timing of debt issuances, and the related reinvestment in capital and operating requirements.
Accounts receivable and other current assets	(5)	147	Due primarily to the flow through of higher energy supply costs and an increase in the fair value of energy contracts, partially offset by a lower income tax receivable.
Other assets	(4)	289	Due primarily to an increase in employee future benefit assets, largely at Central Hudson, driven by higher discount rates.
Property, plant and equipment, net	(156)	1,974	Due to capital expenditures, partially offset by depreciation.

Significant Changes between December 31, 2021 and 2020

Balance Sheet Account	Variance		
($ millions)	FX	Other	Explanation
Short-term borrowings	(1)	116	Reflects the issuance of commercial paper at ITC to finance working capital and capital investment requirements.
Accounts payable & other current liabilities	(8)	257	Due to higher energy supply costs at FortisBC Energy and UNS Energy.
Other liabilities	(6)	(184)	Due primarily to a decrease in employee future benefit liabilities driven by higher discount rates.
Regulatory liabilities (current and long-term)	(15)	134	Due to the normal operation of regulatory mechanisms including employee future benefits, largely at Central Hudson, and the fair value of energy contracts at UNS Energy, partially offset by a reduction in deferred income taxes.
Deferred income tax liabilities	(13)	296	Due to higher temporary differences associated with ongoing capital investment.
Long-term debt (including current portion)	(112)	1,080	Reflects debt issuances, partially offset by debt repayments, at Corporate and the regulated utilities, as well as higher borrowings under committed credit facilities.
Shareholders' equity	(82)	673	Due primarily to: (i) Common Equity Earnings for 2021, 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 committed credit facility, the operation of the DRIP and issuances of common shares, preference equity and long-term debt. The subsidiaries pay dividends to Fortis and receive equity injections from Fortis when required. Both Fortis and its subsidiaries initially borrow through their committed 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 total facilities. Approximately $4.6 billion of the total credit facilities are committed with maturities ranging from 2022 through 2026. Available credit facilities are summarized in the following table.

Credit Facilities

As at December 31	Regulated	Corporate		
($ millions)	Utilities	and Other	**2021**	2020
Total credit facilities [1]	3,466	1,380	**4,846**	5,581
Credit facilities utilized:				
Short-term borrowings	(247)	—	**(247)**	(132)
Long-term debt (including current portion)	(1,019)	(286)	**(1,305)**	(980)
Letters of credit outstanding	(70)	(45)	**(115)**	(130)
Credit facilities unutilized	2,130	1,049	**3,179**	4,339

[1] *Additional information about the Corporation's credit facilities is provided in Note 14 in the 2021 Annual Financial Statements*

In April 2021, the Corporation's unsecured $500 million revolving one-year term committed credit facility expired and was not renewed, and in June 2021 the Corporation extended its unsecured $1.3 billion revolving term committed credit facility to July 2026. In October 2021, UNS Energy terminated a US$150 million revolving credit facility and entered into an arrangement with Fortis.

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, 2021, consolidated fixed-term debt maturities/repayments are expected to average $1,209 million annually over the next five years and approximately 75% of the Corporation's consolidated long-term debt, excluding credit facility borrowings, had maturities beyond five years.

In December 2020, 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. In May 2021, the Corporation issued 7-year $500 million unsecured senior notes at 2.18% and, as at December 31, 2021, $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 2022.

Fortis and its subsidiaries were in compliance with debt covenants as at December 31, 2021 and are expected to remain compliant in 2022.

Cash Flow Summary

Summary of Cash Flows

Years ended December 31 *($ millions)*	**2021**	2020	Variance
Cash and cash equivalents, beginning of year	**249**	370	(121)
Cash from (used in):			
Operating activities	**2,907**	2,701	206
Investing activities	**(3,488)**	(4,132)	644
Financing activities	**451**	1,327	(876)
Effect of exchange rate changes on cash and cash equivalents	**12**	(17)	29
Cash and cash equivalents, end of year	**131**	249	(118)

Operating Activities

See "Performance at a Glance - Operating Cash Flow" on page 16.

Investing Activities

The decrease in cash used in investing activities reflects higher capital expenditures in 2020, largely related to the Oso Grande generating facility at UNS Energy, as well as the lower U.S.-to-Canadian dollar exchange rate. See "Performance at a Glance - Capital Expenditures" on page 16 and "Capital Plan" on page 31.

Financing Activities

Cash flow 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 27.

Debt Financing

Long-Term Debt Issuances

Year ended December 31, 2021	Month Issued	Interest Rate (%)	Maturity	Amount ($ millions)	Use of Proceeds
ITC					
Series A secured senior notes [1]	August	2.90	2051	US 75	[2]
UNS Energy					
Unsecured senior notes	May	3.25	2051	US 325	[3][4]
Central Hudson					
Unsecured senior notes	March	3.29	2051	US 75	[3][4]
Unsecured senior notes	October	3.22	2051	US 55	[3][5]
FortisBC Energy					
Unsecured debentures	April	2.42	2031	150	[5]
Maritime Electric					
Secured first mortgage bonds	December	3.40	2051	40	[5]
Fortis					
Unsecured senior notes	May	2.18	2028	500	[3][4][5]

[1] *US$75 million Series B secured senior notes were priced at 3.05% with issuance expected in May 2022*
[2] *Fund or refinance a portfolio of eligible green projects*
[3] *General corporate purposes*
[4] *Repay maturing long-term debt*
[5] *Repay credit facility borrowings*

In January 2022, ITC issued 30-year US$150 million secured first mortgage bonds at 2.93%. The net proceeds are expected to be used to repay credit facility borrowings, fund or refinance a portfolio of eligible green projects, fund capital expenditures and for other general corporate purposes.

In January 2022, Central Hudson issued 5-year US$50 million unsecured senior notes at 2.37% and 7-year US$60 million unsecured senior notes at 2.59%. The net proceeds are expected to be used to repay maturing long-term debt and for general corporate purposes.

Common Equity Financing

Common Equity Issuances and Dividends Paid

Years ended December 31 ($ millions, except as indicated)	2021	2020	Variance
Common shares issued:			
Cash [1]	**60**	58	2
Non-cash [2]	**358**	116	242
Total common shares issued	**418**	174	244
Number of common shares issued *(# millions)*	**8.0**	3.5	4.5
Common share dividends paid:			
Cash	**(608)**	(786)	178
Non-cash [3]	**(356)**	(114)	(242)
Total common share dividends paid	**(964)**	(900)	(64)
Dividends paid per common share *($)*	**2.0500**	1.9375	0.1125

[1] *Includes common shares issued under stock option and employee share purchase plans*
[2] *Common shares issued under the DRIP and stock option plan. The 2% discount offered on common share issuances under the DRIP was reinstated effective December 1, 2020.*
[3] *Common share dividends reinvested under the DRIP*

On November 18, 2021 and February 10, 2022, Fortis declared a dividend of $0.535 per common share payable on March 1, 2022 and June 1, 2022, respectively. The payment of dividends is at the discretion of the Board and depends on the Corporation's financial condition and other factors.

Contractual Obligations

Contractual Obligations

As at December 31, 2021

($ millions)	**Total**	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Long-term debt:							
Principal [1]	**25,482**	1,628	1,275	1,750	101	2,595	18,133
Interest	**15,859**	982	951	892	859	836	11,339
Finance leases [2]	**1,202**	35	34	34	34	35	1,030
Other obligations [3]	**532**	168	106	101	36	37	84
Other commitments: [4]							
Waneta Expansion capacity agreement	**2,525**	53	54	55	56	58	2,249
Gas and fuel purchase obligations	**2,464**	787	446	252	169	121	689
Renewable power purchase agreements	**1,918**	122	122	122	122	122	1,308
Power purchase obligations	**1,783**	288	254	194	184	185	678
ITC easement agreement	**366**	13	13	13	13	13	301
Debt collection agreement	**109**	3	3	3	3	3	94
Renewable energy credit purchase agreements	**87**	17	16	11	8	6	29
Other	**158**	66	7	7	6	4	68
	52,485	4,162	3,281	3,434	1,591	4,015	36,002

[1] Amounts not reduced by unamortized deferred financing and discount costs of $147 million. Additional information is provided in Note 14 in the 2021 Annual Financial Statements.

[2] Additional information is provided in Note 15 in the 2021 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 26 in the 2021 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 $4.0 billion for 2022 and approximately $20.0 billion over the five-year 2022-2026 Capital Plan. See "Capital Plan" on page 31.

Under a funding framework with the Governments of Ontario and Canada, Fortis will contribute a minimum of approximately $155 million of equity capital to the Wataynikaneyap Partnership based on Fortis' proportionate 39% ownership interest and the final regulatory-approved capital cost of the related project. The Wataynikaneyap Partnership has loan agreements in place to finance the project during construction. 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.

Development projects at ITC may result in payments to developers that are contingent on the projects reaching certain milestones indicating that the projects are financially viable. It is reasonably possible that ITC will be required to make these contingent development payments up to a maximum amount of $88 million upon financial close of the projects. In the event it becomes probable that these payments will be made, the liability and the corresponding intangible asset would be recognized.

UNS Energy has joint generation performance guarantees with participants at San Juan, Four Corners, and Luna, with agreements expiring in 2022 through 2046, and at 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 Navajo, participants would seek financial recovery from the defaulting party. There is no maximum amount under these guarantees, except for a maximum of $318 million for Four Corners. As at December 31, 2021, there was no obligation under these guarantees.

Central Hudson is a participant in an investment with other utilities to jointly develop, own and operate electric transmission projects in New York State. Central Hudson's maximum commitment is $83 million, for which it has issued a parental guarantee. As at December 31, 2021, there was no obligation under this guarantee.

As at December 31, 2021, FortisBC Holdings Inc., a non-regulated holding company, had $69 million of parental guarantees outstanding to support storage optimization activities at Aitken Creek.

Off-Balance Sheet Arrangements

With the exception of letters of credit outstanding of $115 million as at December 31, 2021 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	2021		2020	
As at December 31	*($ millions)*	*(%)*	*($ millions)*	*(%)*
Debt [1]	**25,784**	**55.2**	24,581	54.8
Preference shares	**1,623**	**3.5**	1,623	3.6
Common shareholders' equity and non-controlling interests [2]	**19,293**	**41.3**	18,661	41.6
	46,700	**100.0**	44,865	100.0

[1] *Includes long-term debt and finance leases, including current portion, and short-term borrowings, net of cash*
[2] *Includes shareholders equity, net of preference shares, and non-controlling interests. Non-controlling interests represented 3.5% as at December 31, 2021 (December 31, 2020 - 3.5%)*

Outstanding Share Data

As at February 10, 2022, the Corporation had issued and outstanding 474.9 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.

Only 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 10, 2022, an additional 2.8 million common shares would be issued and outstanding.

Credit Ratings

The Corporation's credit ratings shown below reflect its low 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, 2021	**Rating**	Type	Outlook
S&P	A-	Corporate	Stable
	BBB+	Unsecured debt	
DBRS Morningstar	A (low)	Corporate	Stable
	A (low)	Unsecured debt	
Moody's	Baa3	Issuer	Stable
	Baa3	Unsecured debt	

In January 2022, S&P revised Central Hudson's outlook to negative from stable in consideration of the PSC's order on the company's general rate application, projected elevated capital expenditures, and the resulting impact on the company's financial measures.

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 of $3.6 billion were slightly lower than the 2021 Capital Plan of $3.8 billion as disclosed in the 2020 MD&A. The reduction reflected: (i) a lower-than-planned U.S.-to-Canadian dollar exchange rate; and (ii) the timing of Capital Expenditures, including delays at the Wataynikaneyap Transmission Power Project and at Caribbean Utilities due to the COVID-19 Pandemic. This decrease was partially offset by higher-than-anticipated Capital Expenditures at ITC, largely reflecting various incremental projects as well as restoration costs following a derecho storm in the Midwestern U.S. in December 2021.

2021 Capital Expenditures [1]

	Regulated Utilities										
($ millions, except as indicated)	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	**Total Regulated Utilities**	**Non-Regulated [2]**	**Total**	***(%)***
Generation	—	177	1	—	—	18	62	**258**	**—**	**258**	**7**
Transmission	939	161	33	200	—	44	211	**1,588**	**—**	**1,588**	**45**
Distribution	—	205	160	203	320	43	187	**1,118**	**—**	**1,118**	**31**
Other [3]	107	167	97	72	69	29	39	**580**	**20**	**600**	**17**
Total	1,046	710	291	475	389	134	499	**3,544**	**20**	**3,564**	**100**
(%)	29	20	8	13	11	4	14	**99**	**1**	**100**	

[1] See "Non-U.S. GAAP Financial Measures" on page 24
[2] Energy Infrastructure segment
[3] Includes facilities, equipment, vehicles and information technology assets

Capital Expenditures of $600 million in 2021 were focused on delivering cleaner energy to customers.

Forecast 2022 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**	**Total**	***(%)***
Generation	—	85	9	—	—	15	162	**271**	**60**	**331**	**8**
Transmission	948	243	45	270	—	14	205	**1,725**	**—**	**1,725**	**44**
Distribution	—	244	184	185	358	98	193	**1,262**	**—**	**1,262**	**32**
Other	50	132	106	167	87	29	61	**632**	**17**	**649**	**16**
Total	998	704	344	622	445	156	621	**3,890**	**77**	**3,967**	**100**
(%)	25	18	9	16	11	4	15	**98**	**2**	**100**	

[1] Represents a forward-looking non-GAAP financial measure calculated in the same manner as Capital Expenditures. See "Non-U.S. GAAP Financial Measures" on page 24.
[2] Excludes the non-cash equity component of AFUDC

2022–2026 Capital Plan [1]

($ billions)	2022	2023	2024	2025	2026	**Total [2][3]**
Five-year capital plan	4.0	3.8	4.0	4.0	4.2	**20.0**

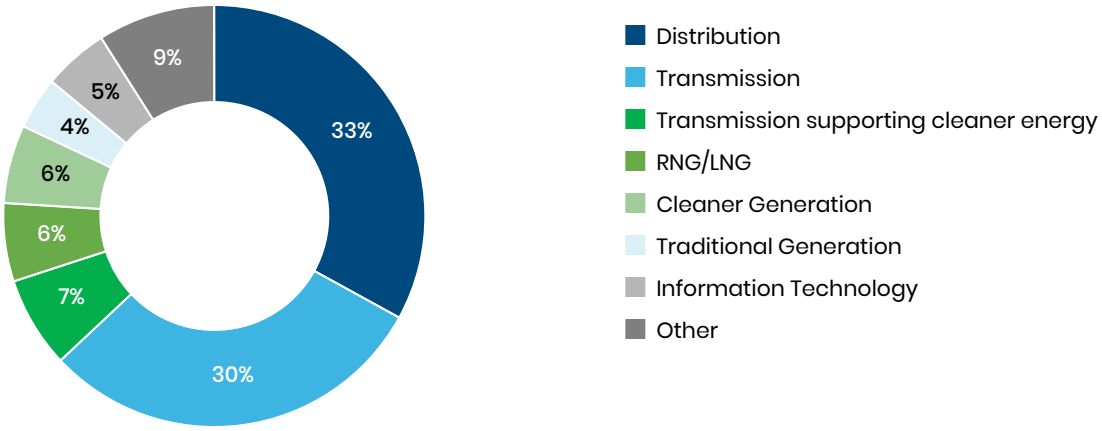
[1] Capital Plan is a forward-looking non-GAAP financial measure calculated in the same manner as Capital Expenditures. See "Non-U.S. GAAP Financial Measures" on page 24.
[2] Reflects an assumed U.S.:CAD foreign exchange rate of 1.25. On average, Fortis estimates that a five-cent increase or decrease in the U.S. dollar relative to the Canadian dollar would increase or decrease Capital Expenditures by approximately $450 million over the five-year planning period
[3] Excludes the non-cash equity component of AFUDC

In comparison to the prior five-year plan totaling $19.6 billion as disclosed in the 2020 MD&A, the 2022-2026 Capital Plan reflects $1.0 billion of additional capital investments at the Corporation's regulated utilities, largely reflecting customer growth, enhancements to transmission reliability and capacity, and investments in cleaner energy. This growth is tempered by $600 million associated with the lower assumed foreign exchange rate of 1.25, down from a rate of 1.32 assumed in the Corporation's previous five-year plan.

The Capital Plan is low risk and highly executable, with 99% of planned expenditures to occur at the regulated utilities and only 15% related to Major Capital Projects. The composition of the 2022-2026 Capital Plan includes 27% related to growth, 56% sustaining and 17% for other areas. Geographically, 53% of planned expenditures are expected in the U.S., including 25% at ITC, with 43% in Canada and the remaining 4% in the Caribbean.

The investments included in the 2022-2026 Capital Plan are summarized as follows:

FIVE-YEAR CAPITAL PLAN



Planned capital expenditures are based on detailed forecasts of energy demand, labour and material costs, general economic conditions, foreign exchange rates and other factors. These could change and cause actual expenditures to differ from forecast or plan. While the Corporation does not expect the COVID-19 Pandemic to impact its overall five-year Capital Plan, the timing of forecast capital expenditures will continue to be evaluated. Depending on the length and severity of the pandemic, including any impact of supply chain disruptions, certain planned expenditures may shift within the 2022-2026 Capital Plan.

Midyear Rate Base [1]

($ billions)	**2021**	2022	2026
ITC	**9.5**	10.1	12.6
UNS Energy	**5.8**	6.5	8.0
Central Hudson	**2.2**	2.4	3.1
FortisBC Energy	**5.2**	5.4	7.1
FortisAlberta	**3.8**	4.0	4.7
FortisBC Electric	**1.5**	1.5	1.8
Other Electric	**3.1**	3.6	4.3
Total	**31.1**	33.5	41.6

[1] *Simple average of Rate Base at beginning and end of the year*

Total midyear Rate Base is forecast to grow to $41.6 billion by 2026 under the five-year Capital Plan, representing a CAGR of approximately 6%, which is supportive of continuing growth in earnings and dividends.

Major Capital Projects [1] ($ millions)	Pre-2021	**Actual 2021**	Forecast 2022	Forecast 2023-2026	Expected Completion
ITC [2]					
Multi-Value Regional Transmission Projects	642	**68**	81	73	2023
34.5 to 69kV Transmission Conversion Project	445	**37**	68	77	Post-2026
UNS Energy					
Vail-to-Tortolita Project	—	**21**	58	182	2025
Oso Grande Generating Facility	554	**39**	—	—	2021
FortisBC Energy					
Lower Mainland Intermediate Pressure System Upgrade	411	**16**	—	—	2021
Eagle Mountain Woodfibre Gas Line Project [3]	—	**—**	—	350	2026
Transmission Integrity Management Capabilities Project	21	**9**	10	212	Post-2026
Inland Gas Upgrade Project	59	**69**	79	65	2025
Okanagan Capacity Upgrade	9	**7**	16	185	2024
Tilbury 1B Project	20	**9**	33	322	Post-2026
Tilbury LNG Storage Expansion	10	**6**	8	449	Post-2026
AMI Project	—	**—**	5	375	Post-2026
Other Electric					
Wataynikaneyap Transmission Power Project [4]	178	**177**	248	109	2024
Total		**458**	606	2,399	

[1] *Includes applicable AFUDC*
[2] *Pre-2021 capital expenditures are from the date of the ITC acquisition on October 14, 2016*
[3] *Net of forecast customer contributions*
[4] *Fortis' share of estimated capital spending. Under the funding framework, Fortis will be funding its equity component only.*

Multi-Value Regional Transmission Projects
Four regional electric transmission projects that have been identified by MISO to address system capacity needs and reliability in various states. Three projects were completed pre-2021. The fourth project is expected to be placed in service in 2023.

34.5 to 69kV Transmission Conversion Project
Multiple projects designed to convert the 34.5kV system to 69kV operating voltage. Projects include construction of new 69kV lines, rebuild of existing 34.5kV lines to 69kV, and substation conversions. In service dates range from pre-2021 to post-2026.

Vail-to-Tortolita Project
Construction and upgrades to connect existing TEP substations to a new 230kV line within TEP's service territory. Construction is expected to begin in 2023 with an in service date of 2025.

Oso Grande Generating Facility
In May 2021, construction of UNS Energy's 250 MW wind-powered electric generating facility was completed.

Lower Mainland Intermediate Pressure System Upgrade
Addresses system capacity and pipeline condition issues for the gas supply system in the Lower Mainland of British Columbia. The project has been completed, with the final pipeline segment replaced in 2021. Final allowable project costs are subject to review by the BCUC.

Eagle Mountain Woodfibre Gas Line Project
Gas line expansion to a proposed LNG site in Squamish, British Columbia. FortisBC Energy's proposed pipeline expansion remains contingent on Woodfibre LNG Limited making a final decision to proceed with construction of the LNG facility.

Transmission Integrity Management Capabilities Project
This project improves gas line safety and transmission system integrity, including gas line modifications and looping. In February 2021, FortisBC Energy filed a CPCN application with the BCUC for the coastal transmission system section of this project.

Inland Gas Upgrades Project
Gas line modifications and replacements to enable in-line integrity inspection capabilities. In January 2020, the CPCN application was approved by the BCUC.

Okanagan Capacity Upgrade
Construction of a new section of pipeline and associated facilities to address expected load growth in the Okanagan region. In November 2020, FortisBC Energy filed a CPCN application with the BCUC for this project.

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. The project received an Order in Council from the Government of British Columbia in 2017. In February 2020, an initial project scope was filed with regulators to begin the federal impact assessment and provincial environmental assessment required to further expand the Tilbury site. Engineering design and related studies will continue in 2022.

Tilbury LNG Storage Expansion
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. In December 2020, FortisBC Energy filed a CPCN application for this project with the BCUC, and if approved, the project is expected to begin in 2022.

AMI Project
Replacement of residential and small commercial meters with advanced meters and installation of bypass valves to support the safety, resiliency, and efficient operation of the gas distribution system. In May 2021, FortisBC Energy filed a CPCN application with the BCUC for this project.

Wataynikaneyap Transmission Power Project
Construction of a 1,800 kilometre, OEB-regulated transmission line to connect 17 remote First Nations communities in Northwestern Ontario to the main electricity grid, in which Fortis holds a 39% equity interest. FortisOntario is responsible for construction management and operation of the transmission line. The project is expected to be completed in 2024.

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 - Lake Erie Connector
Proposed 1,000 MW, bi-directional, high-voltage direct current underwater transmission line to directly link the markets of the Ontario IESO and PJM Interconnection, LLC. The project would enable transmission customers to more efficiently access energy, capacity and renewable energy credit opportunities in both markets. The project is fully permitted in the U.S. and Canada and continues to advance through regulatory, operational and economic milestones. In 2021, the Canada Infrastructure Bank announced it would fund 40% of the approximate $1.7 billion project and the Ontario government authorized IESO to commence contract negotiations. Negotiation of transmission service agreements is required to advance to the construction phase. Completion would take approximately four years from the commencement of construction.

ITC - MISO LRTP
A comprehensive effort by MISO is underway to identify and construct the regional transmission required in the MISO region to support the ongoing evolution of the electric industry. ITC has a large footprint in the MISO region, specifically including but not limited to wind-rich regions in Iowa and Minnesota. MISO is currently requesting FERC authorization for cost allocation and finalizing planning for an initial tranche of LRTP projects.

UNS Energy - TEP 2020 IRP
Outlines the resource energy transition required at TEP to meet its customers' energy needs through 2035 as it exits coal-fired resources by 2032 and replaces it with wind and solar resources as part of a cleaner energy portfolio that will reduce carbon emissions 80 percent by 2035. This plan supports reliable and affordable service from sustainable resources and is expected to provide capital investment opportunities that extends beyond the Capital Plan. The IRP may be impacted by various federal and state energy policies, including policies currently under consideration.

FortisBC Energy - LNG
Pursuit of additional LNG infrastructure opportunities in British Columbia, including further expansion of the Tilbury LNG facility, which is uniquely positioned to meet customer demand for clean-burning natural gas. The site is scalable and can accommodate additional storage and liquefaction equipment and is relatively close to international shipping lanes. FortisBC Energy continues to have discussions with potential export customers.

Other Opportunities
Includes incremental regulated transmission investment and grid modernization projects at ITC; energy storage projects, grid modernization, infrastructure resiliency, and transmission investments at UNS Energy; further gas infrastructure opportunities at FortisBC Energy; and cleaner energy infrastructure investments across our jurisdictions.

BUSINESS RISKS

Fortis has established an ERM program to identify and evaluate risks by both severity of impact and probability of occurrence. Materiality thresholds are reviewed and, if necessary, updated annually. Financial risks, as well as risks that may impact the safety of employees, customers or the general public, as well as reputational risks, are evaluated. Systems of internal controls are used to monitor and manage identified risks. The ERM program at the subsidiary level is overseen by each subsidiary's board of directors and any material risks identified are communicated to Fortis management and form part of Fortis' ERM program. The Fortis Board, through the audit committee, oversees Fortis' ERM program ensuring that management has an effective risk management system to support strategic planning.

A summary of the Corporation's significant business risks follows.

Utility Regulation

Regulated utility assets represented approximately 99% of the Corporation's total assets as at December 31, 2021. Regulatory jurisdictions include five Canadian provinces, nine 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 and the underlying 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 is particularly significant for UNS Energy given the use of historical test years in setting rates.

The ability to recover the actual cost of service and earn the approved ROE or ROA typically depends on achieving the forecasts established in the rate-setting process. Failure to do so could have a Material Adverse Effect. For those utilities subject to PBR mechanisms, rates reflect assumed inflation rates and productivity improvement factors, and variances therefrom could have a Material Adverse Effect. FortisAlberta's PBR mechanism gives rise to added risk that incremental incurred capital expenditures may not be approved for recovery in rates.

For transmission operations, the underlying elements of FERC-established formula rates can be, and have been, challenged by third parties which could result in, and has resulted in, lowered rates and customer refunds. These underlying elements include the ROE, ROE adders for independent transmission ownership and deemed capital structure, as well as operating and capital expenditures.

Additionally, 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.

The political and economic environments as well as their effect on energy laws and governmental energy policies have had, and may continue to have, negative impacts on regulatory decisions. While Fortis is well positioned to maintain constructive regulatory relationships through local management teams and boards comprised mostly of independent local members, it cannot predict future legislative or regulatory changes, whether caused by economic, political or other factors, or its ability to respond thereto in an effective and timely manner, or the resulting compliance costs. Any of the foregoing potential regulatory changes could have a Material Adverse Effect.

Climate Change and Physical Risks

The provision of electric and gas service is subject to risks, including severe weather and natural disasters, wars, terrorism, critical equipment failure and other catastrophic events within and outside the Corporation's service territories. Resultant service disruption and repair and replacement costs 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.

Climate change is predicted to lead to more frequent and intense weather events, changing air temperatures and changing seasonal variations, and the Corporation expects that regulatory responses to such changes will occur in the coming years (see "Environmental Regulation" on page 37). Severe weather impacts the Corporation's service territories, primarily in the form of thunderstorms, flooding, wildfires, hurricanes and snow or ice storms. Increased frequency of extreme weather events could increase the cost of providing service through increased repairs and use of contingency plans. Changes in precipitation that 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. Extreme weather conditions in general require system backup and can contribute to increased system stress, including service interruptions. Changing air temperatures could also result in system stress and decreased efficiency of operating facilities over time. Longer-term climate change impacts, such as sustained higher temperatures, higher sea levels and larger storm surges, could result in service disruption, repair and replacement costs, and costs associated with strengthened design standards and systems.

The electricity and gas systems are designed to service customers under various contingencies in accordance with good utility practice. 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. The impacts of climate change and the transition to a cleaner energy future will require the Corporation's utilities to effectively manage evolving regulatory and legislative requirements, new resiliency standards, the integration of new technologies and impacts on customer demand and rates. Failure to do so may disrupt the ability of the utilities to provide safe and cost-effective service, which could cause reputational harm and other impacts. Any of the foregoing potential impacts of climate change could have a Material Adverse Effect.

The operation of transmission and distribution assets has the potential to cause fires, mainly as a result of equipment failure, falling trees and lightning strikes to lines or equipment. Also, certain utilities operate in remote and mountainous terrain that can be difficult to access for timely repairs and maintenance, or otherwise face risk of loss or damage from forest fires, floods, washouts, landslides, earthquakes, avalanches and other acts of nature.

The 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, and other accidents and issues that can lead to service disruption, spills and commensurate environmental liability, or other liability.

Generating equipment and facilities are subject to risks, including equipment breakdown and flood and fire damage, that may result in the uncontrolled release of water, interruption of fuel supply, lower-than-expected operational efficiency or performance, and service disruption. There is no assurance that generating equipment and facilities will continue to operate in accordance with expectations and climate changes may increase the frequency of such failures occurring.

Risks associated with fire damage vary depending on weather, forestation, the proximity of habitation and third-party facilities to utility facilities, and other factors. The utilities may become liable for fire-suppression costs, regeneration and timber value costs, and third-party claims if their facilities are held responsible for a fire.

Electricity and gas systems require ongoing maintenance, improvement and replacement. Service disruption, other effects and liability caused by the failure to properly implement or complete approved maintenance and capital expenditures, the occurrence of significant unforeseen equipment failures, or the inability to recover requisite costs in customer rates, could result in loss. Any of the foregoing potential impacts of physical risk could have a Material Adverse Effect.

Environmental Regulation

The Corporation's businesses are subject to environmental risks and environmental laws and regulations, including those which: (i) impose limitations or restrictions on the discharge of pollutants into the air, soil and water; (ii) establish standards for the management, treatment, storage, transportation and disposal of hazardous wastes; and/or (iii) impose obligations to investigate and remediate contamination.

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.

Liabilities relating to contamination investigation and remediation, and 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 or whether it resulted from non-compliance with applicable environmental laws. Under some environmental laws, such liabilities may be joint and several, meaning that a party can be held responsible for more than its share of the liability involved or even the entire liability. These liabilities could lead to litigation and administrative proceedings that could result in substantial monetary judgments for clean-up costs, damages, fines and/or penalties. To the extent not fully covered by insurance, these costs could have a Material Adverse Effect.

The Corporation's businesses have incurred substantial expenses for environmental compliance, and they anticipate continuing to do so in the future. In particular, the management of GHG emissions is a major concern due to new and emerging federal, state and provincial GHG laws, regulations and guidelines. Future legislation relating to GHG emissions could impact generation assets, operations, energy supply, operational costs, reporting obligations and other material aspects of the Corporation's business.

The Corporation's businesses continue to develop compliance strategies and assess the impact of emerging legislative changes, but significant uncertainties remain. Increased compliance costs or additional operating restrictions from revised or additional regulation could have a Material Adverse Effect.

Pandemics and Public Health Crises, including the COVID-19 Pandemic

The Corporation could be negatively impacted by a widespread outbreak of communicable diseases or other public health crises that cause economic and/or other disruptions, including the disruption of global supply chains. The outbreak of communicable diseases, as well as efforts to reduce the health impacts and control disease spread can lead to worldwide 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 42).

There continues to be uncertainty surrounding the duration and severity of the COVID-19 Pandemic, particularly with respect to the emergence of new variants of the virus, the long-term efficacy and global distribution of COVID-19 vaccines, the impact of vaccine mandates and isolation requirements on labour availability, potential government action to mitigate public health effects, disruptions to the global supply chain, and other factors beyond the Corporation's control. An extended period of economic or supply chain disruption could have a Material Adverse Effect.

Growth

Fortis has a history of growth through acquisitions and organic growth from capital investment in existing service territories. Acquisitions include inherent risks that some or all of the expected benefits may fail to materialize, or may not occur within the time periods anticipated, and material unexpected costs may arise.

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 described under "Capital Plan" on page 31. Projects, particularly Major Capital Projects, are subject to risks of delay and cost overruns during construction caused by inflation, commodity price fluctuations, supply and labour costs, 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. These risks could impact the successful execution of a project by preventing the project from proceeding, delaying its completion, increasing its projected costs or negatively impacting its financing.

Cybersecurity

As operators of critical energy infrastructure, the Corporation's utilities face the risk of cybercrime, which has increased in frequency, scope and potential impact in recent years. 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 electric generation, transmission and distribution facilities, including 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 may be vulnerable to unauthorized access due to hacking, computer viruses, acts of war or terrorism, acts of vandalism and other causes. This can result in the disruption of energy service and other business operations, system failures and grid disturbances, property damage, corruption or unavailability of critical data, and the misappropriation and/or disclosure of sensitive, confidential and proprietary business, customer and employee information.

A material cybersecurity breach could adversely affect the financial performance of the Corporation, its reputation and standing with customers, regulators and financial markets, and expose it to claims for third-party damage. 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.

Technology Advances

The emergence of initiatives designed to reduce GHG emissions and control or limit the effects of climate change has increased the incentive for the development of new technologies that produce power, enable more efficient storage of energy and reduce power consumption.

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.

Weather Variability and Seasonality

Electricity consumption varies significantly in response to climate change and seasonal weather changes (see "Climate Change and Physical Risks" on page 36). In central and western Canada, Arizona and New York State, cool summers may reduce the use of air conditioning and other cooling equipment, while less severe winters may reduce heating load. Alternatively, severe weather could unexpectedly increase heating and cooling loads, negatively impacting system reliability.

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.

Hydroelectric generation is sensitive to rainfall levels.

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. Both the discontinuance of key regulatory mechanisms and their absence at other Fortis entities could result in significant and prolonged weather variations from seasonal norms having a Material Adverse Effect.

Natural Gas Competitiveness

Approximately 22% of the Corporation's revenue is derived from the delivery of natural gas. A decrease in the competitiveness of natural gas due to pricing, government policy or other factors could have a Material Adverse Effect.

In British Columbia, which accounts for 83% of the Corporation's natural gas revenue, natural gas primarily competes with electricity for space and hot water heating. Upfront capital costs for gas service continue to present competitive challenges for natural gas compared to electricity service. If gas becomes less competitive, 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, whereby system costs must be recovered from a smaller customer and sales base, leading to reductions in competitiveness.

Government policy could also impact the competitiveness of natural gas in British Columbia. In October 2021, the provincial government released an update to its economic and climate action plan, including a series of actions designed to achieve GHG emission reduction targets and the transition to a low-carbon economy. As all levels of government become more active in the development of policies to address climate change, any resultant changes to energy policy may impact the competitiveness of natural gas relative to non-carbon based energy sources.

There are other competitive challenges that are impacting the penetration of natural gas into new housing stock such as green attributes of the energy source and the type of housing stock being built. In addition, 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.

Commodity Price Volatility

Purchased power 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 (see "Business Unit Performance" on page 20); and (ii) price-risk management strategies such as the use of derivative contracts that effectively fix costs (see "Financial Instruments - Derivatives" on page 45).

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. These 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 generated 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, which could have a Material Adverse Effect.

Required Approvals

The acquisition, ownership and operation of electric and gas businesses require numerous licences, permits, agreements, orders, certificates and other approvals from various levels of government, regulators, government agencies, Indigenous Peoples and/or third parties. The external environment has become more complex with heightened expectations from permitting agencies, local municipalities and Indigenous Peoples to be able to review and provide feedback on projects, largely driven by policy responses to climate change. There is no assurance that: (i) all of these 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* 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, Alberta and Ontario. 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, such as 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 TransAlta Utilities Corporation. To acquire these permits, FortisAlberta requires approval 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.

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.

Wataynikaneyap Partnership, which is owned 51% by 24 First Nations communities and 49% by a partnership between Fortis (80%) and Algonquin Power & Utilities Corp. (20%), is responsible for the Wataynikaneyap Transmission Power Project. Fortis does not have sole discretion on decisions for the project and divergence in the interest of Fortis and the other partners could delay the project's completion, increase its anticipated cost, or adversely affect the reputation of Fortis.

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.

UNS Energy, Central Hudson, FortisBC Energy, Aitken Creek and Fortis may be exposed to credit risk from non-performance by counterparties to derivatives. Credit risk is managed by net settling payments, when possible, and dealing only with counterparties that have investment-grade credit ratings. At UNS Energy and Central Hudson, certain contractual arrangements require counterparties to post collateral.

There is no assurance that management strategies will continue to be effective. Significant counterparty defaults could have a Material Adverse Effect.

Interest Rates

Generally, the market price of the Corporation's common shares is inversely sensitive to interest rate changes. Additionally, allowed ROEs are exposed to changes in long-term interest rates such that a low interest rate environment could reduce allowed ROEs. If interest rates rise, regulatory lag may cause delays in any compensatory ROE increases. Borrowings under variable-rate credit facilities and long-term debt, as well as new debt issuances, are also exposed to interest rate changes.

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 future 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.

Foreign Exchange Exposure

The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, FortisTCI, BECOL 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.

Fortis has limited this U.S. dollar currency exposure through hedging. As at December 31, 2021, US$2.2 billion (2020 - US$2.3 billion) of corporately issued U.S. dollar-denominated long-term debt had been designated as an effective hedge of foreign net investments, leaving US$10.8 billion (2020 - US$10.2 billion) in foreign net investments unhedged. Fortis has also entered into foreign exchange contracts to manage a portion of its exposure to foreign currency risk.

Given only partial hedging, consolidated earnings and cash flow continue to be impacted by exchange rate fluctuations. On average, Fortis estimates that a five-cent increase or decrease in the U.S. dollar relative to the Canadian dollar exchange rate of US$1.00=CA$1.25 as at December 31, 2021 would increase or decrease average annual EPS by approximately six cents, which reflects the Corporation's hedging program.

The Corporation's $20.0 billion five-year Capital Plan for 2022 through 2026 also includes exposure to foreign exchange. 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 $450 million over the five-year planning period.

There is no assurance that existing hedging strategies will continue to be effective and any resultant financial impacts 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 regulatory 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.

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 27.

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.

Talent Management

The delivery of safe, reliable and cost-effective service depends on the attraction, development and retention of skilled workforces. 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 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 the regulator disallows full recovery in rates, and could have a Material Adverse Effect.

Post-Retirement Obligations

Fortis and most of its subsidiaries maintain a combination of defined benefit pension 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. Market disruptions, significant declines in the market values of investments held to meet plan obligations, discount rate changes, participant demographics, and changes in laws and regulations may require additional plan funding. Significant increases in plan expenses and funding requirements 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 may lower energy demand and reduce sales both directly and through reduced capital spending, particularly that related to new customer growth, which would affect Rate Base growth. A severe and prolonged economic downturn could have a Material Adverse Effect, including making it more difficult for customers to pay their bills.

Reputation, Relationships and Stakeholder Activism

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.

Additionally, external stakeholders, including shareholders and investors, are increasingly challenging utilities regarding climate change, sustainability, diversity, returns including ROEs, 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 maintain or respond to stakeholder activism could have a Material Adverse Effect.

Legal, Administrative and Other Proceedings

These 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

Critical Accounting Estimates

General

The preparation of the 2021 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, 2021, Fortis recognized regulatory assets of $3.6 billion (2020 - $3.6 billion) and regulatory liabilities of $3.2 billion (2020 - $3.1 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	**Defined Benefit Pension Plans**		**OPEB Plans**	
Years ended December 31				
($ millions, except as indicated)	**2021**	2020	**2021**	2020
Funded status: [1]				
Benefit obligation [2]	**(3,922)**	(3,995)	**(747)**	(789)
Plan assets	**3,722**	3,528	**440**	391
	(200)	(467)	**(307)**	(398)
Net benefit cost [2]	**64**	67	**35**	32
Key assumptions: *(weighted average %)*				
Discount rate: [3]				
During the year	**2.60**	3.16	**2.60**	3.22
As at December 31	**3.00**	2.63	**2.97**	2.64
Expected long-term rate of return on plan assets [4]	**5.40**	5.52	**4.88**	5.28
Rate of compensation increase	**3.30**	3.34	**—**	—
Health care cost trend increase rate [5]	**—**	—	**4.49**	4.61

[1] *Periodic actuarial valuations determine funding contributions for the pension 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*

[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 2022 rate is 5.75% and is assumed to decrease over the next 11 years to the ultimate rate of 4.49% in 2032 and thereafter.*

Sensitivity Analysis	**Rate of Return**		**Discount Rate**		**Health Care Costs Trend Rate**	
Year ended December 31, 2021	**1% change**		**1% change**		**1% change**	
($ millions)	**Increase**	**Decrease**	**Increase**	**Decrease**	**Increase**	**Decrease**
Defined benefit pension plans:						
Net benefit cost	**(33)**	**28**	**(48)**	**65**	**n/a**	**n/a**
Projected benefit obligation	**32**	**(75)**	**(520)**	**649**	**n/a**	**n/a**
OPEB plans:						
Net benefit cost	**(4)**	**4**	**(10)**	**12**	**16**	**(14)**
Accumulated benefit obligation	**—**	**—**	**(112)**	**135**	**100**	**(91)**

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.

At FortisAlberta, cash contributions are expensed and reflected in customer rates with any difference between the cash contributions and the net benefit cost deferred as a regulatory asset/liability. 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, 2021, Fortis recognized property, plant and equipment and intangible assets of $39.2 billion (2020 - $37.3 billion) representing 68% of total assets (2020 - 67%). Depreciation and amortization of these assets totalled $1.4 billion for 2021 (2020 - $1.4 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, 2021, this regulatory liability was $1.2 billion (2020 - $1.2 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, 2021, Fortis recognized goodwill of $11.7 billion (2020 - $11.8 billion), representing 20% of total assets (2020 - 21%). The decrease in goodwill was due to the impact of foreign exchange associated with the translation of U.S. dollar-denominated goodwill.

Goodwill at each of the Corporation's 11 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 necessary, 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, 2021, deferred income tax liabilities, current income tax payable included in accounts payable, deferred income taxes included in regulatory assets, and deferred income taxes included in regulatory liabilities totalled $3.6 billion, $31 million, $1.8 billion and $1.3 billion, respectively (2020 - $3.3 billion, current income tax receivable of $72 million, $1.7 billion and $1.4 billion, respectively). Income tax expense was $234 million in 2021 (2020 - $231 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 2013 to 2021 taxation years are still open for audit in Canadian jurisdictions, and its 2011 to 2021 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's financial statements (see "Business Risks - Taxation" on page 41).

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 - Indigenous Peoples' Land Claims" on page 40, for which no amounts have been accrued because the outcomes currently cannot be reasonably determined. Further information is provided in Note 26 in the 2021 Annual Financial Statements.

While Fortis currently believes that these matters are unlikely to have a Material Adverse Effect, there is no assurance that this will be the case.

FINANCIAL INSTRUMENTS

Long-Term Debt and Other

As at December 31, 2021, the carrying value of long-term debt, including the current portion, was $25.5 billion (2020 - $24.5 billion) compared to an estimated fair value of $28.8 billion (2020 - $29.1 billion). Since Fortis does not intend to settle long-term debt prior to maturity, the excess of fair value over carrying value does not represent an actual liability.

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, 2021, unrealized losses of $20 million (2020 - $73 million) were recognized as regulatory assets and unrealized gains of $52 million (2020 - $17 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 holds gas swap contracts to manage its exposure to changes in natural gas prices, capture natural gas price spreads, and manage the financial risk posed by physical transactions. Fair values are measured using forward pricing from published market sources.

Unrealized gains or losses associated with changes in the fair value of these energy contracts are recognized in revenue. In 2021, unrealized gains of $21 million (2020 - $3 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 settlements of certain stock-based compensation obligations. The swaps have a combined notional amount of $112 million and terms of one to three years expiring at varying dates through January 2024. 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 2021, unrealized gains of $17 million (2020 - unrealized losses of $9 million) 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 November 2022 and have a combined notional amount of $161 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 2021, unrealized losses of $11 million (2020 - unrealized gains of $11 million) were recognized in other income, net.

Interest rate swaps

In 2021, ITC entered into interest rate swaps with a total notional value of US$375 million to manage the interest rate risk associated with the refinancing of long-term debt due in November 2022. The swaps have five-year terms, include mandatory early termination provisions, and will be terminated no later than the effective date of November 15, 2022. Fair value was measured using a discounted cash flow method based on LIBOR rates. Unrealized gains and losses associated with the changes in fair value are recognized in other comprehensive income, will be reclassified to earnings as a component of interest expense over the life of the debt, and were not material for 2021.

Other investments

ITC and Central Hudson hold investments in trust associated with supplemental retirement benefit plans for select employees. These investments include mutual funds and money market accounts, which are recorded at fair value based on quoted market prices in active markets. Gains and losses are recognized in other income, net. In 2021, unrealized gains of $9 million (2020 - $7 million) were recognized in other income, net.

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, 2021				
Assets [2]				
Energy contracts subject to regulatory deferral	**—**	**78**	**—**	**78**
Energy contracts not subject to regulatory deferral	**—**	**16**	**—**	**16**
Foreign exchange contracts, total return and interest rate swaps	**23**	**2**	**—**	**25**
Other investments	**137**	**—**	**—**	**137**
	160	**96**	**—**	**256**
Liabilities [3]				
Energy contracts subject to regulatory deferral	**—**	**(46)**	**—**	**(46)**
Energy contracts not subject to regulatory deferral	**—**	**(3)**	**—**	**(3)**
	—	**(49)**	**—**	**(49)**
As at December 31, 2020				
Assets [2]				
Energy contracts subject to regulatory deferral	—	38	—	38
Energy contracts not subject to regulatory deferral	—	6	—	6
Foreign exchange contracts and total return swaps	16	—	—	16
Other investments	126	—	—	126
	142	44	—	186
Liabilities [3]				
Energy contracts subject to regulatory deferral	—	(94)	—	(94)
Energy contracts not subject to regulatory deferral	—	(12)	—	(12)
	—	(106)	—	(106)

[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] *Current portion is included in accounts receivable and other current assets, with the remainder included in other assets*

[3] *Current portion is included in accounts payable and other current liabilities, with the remainder included in other liabilities*

Derivative Volumes

As at December 31	2021	2020
Energy contracts subject to regulatory deferral [1]		
Electricity swap contracts *(GWh)*	**509**	522
Electricity power purchase contracts *(GWh)*	**731**	2,781
Gas swap contracts *(PJ)*	**151**	156
Gas supply contract premiums *(PJ)*	**144**	203
Energy contracts not subject to regulatory deferral [1]		
Wholesale trading contracts *(GWh)*	**1,886**	1,588
Gas swap contracts *(PJ)*	**29**	36

[1] *Energy contracts settle on various dates through 2029*

SELECTED ANNUAL FINANCIAL INFORMATION

Years ended December 31 *($ millions, except as indicated)*	2021	2020	2019
Revenue	**9,448**	8,935	8,783
Net earnings	**1,405**	1,389	1,852
Common Equity Earnings	**1,231**	1,209	1,655
EPS: *($)*			
Basic	**2.61**	2.60	3.79
Diluted	**2.61**	2.60	3.78
Total assets	**57,659**	55,481	53,404
Long-term debt (excluding current portion)	**23,707**	23,113	21,501
Dividends declared: *($)*			
Per common share	**2.080**	1.965	1.855
Per first preference share:			
Series F	**1.2250**	1.2250	1.2250
Series G	**1.0983**	1.0983	1.0983
Series H [1]	**0.4588**	0.5003	0.6250
Series I [2]	**0.3926**	0.4987	0.7771
Series J	**1.1875**	1.1875	1.1875
Series K	**0.9823**	0.9823	0.9823
Series M [3]	**0.9783**	0.9783	1.0133

[1] *The annual dividend per share was reset to $0.4588 for the five-year period from June 1, 2020 up to but excluding June 1, 2025.*
[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 to $0.9783 for the five-year period from December 1, 2019 up to but excluding December 1, 2024.*

2021/2020

For a discussion of the changes in revenue, net earnings, Common Equity Earnings, EPS, total assets and long-term debt see "Performance at a Glance" on page 14, "Operating Results" on page 19, and "Financial Position" on page 26.

2020/2019

The increase in revenue reflected: (i) overall higher flow-through costs in customer rates; (ii) Rate Base growth; (iii) higher electricity sales driven by favourable weather in Arizona; and (iv) a $40 million favourable base ROE adjustment at ITC related to prior periods as a result of the May 2020 FERC Decision. The increase was partially offset by: (i) a $91 million favourable base ROE adjustment at ITC in 2019 related to prior periods as a result of the November 2019 FERC decision; and (ii) lower short-term wholesale sales at UNS Energy.

The decrease in Common Equity Earnings reflected significant one-time items: (i) a $484 million gain on the disposition of the Waneta Expansion in April 2019; and (ii) the $56 million net impact associated with the reversal of prior period liabilities as a result of the November 2019 and May 2020 FERC Decisions at ITC.

Excluding the significant one-time items, the Corporation delivered higher earnings of $94 million in 2020 reflecting: (i) Rate Base growth of 8.2%; (ii) increased retail electricity sales at UNS Energy, driven largely by weather, and (iii) higher earnings from Belize, mainly from increased hydroelectric production. Earnings were also favourably impacted by mark-to-market accounting of natural gas derivatives at Aitken Creek. This growth was tempered by: (i) the delay in TEP's general rate application, resulting in approximately $1 billion of Rate Base not reflected in customer rates in 2020; and (ii) the impact of the COVID-19 Pandemic, reflecting lower sales in the Caribbean and higher net operational expenses, including increased credit loss expense, largely at Central Hudson and UNS Energy.

In addition to the above-noted items impacting earnings, the change in EPS reflected an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's $1.2 billion common equity issuance in the fourth quarter of 2019.

The increase in total assets was due to 2020 capital expenditures, partially offset by unfavourable foreign exchange on the translation of U.S. dollar-denominated assets.

FOURTH QUARTER RESULTS

Sales

(Gwh, except as indicated)	**2021**	2020	Variance
Regulated Utilities			
UNS Energy			
Retail Electricity	**2,206**	2,345	(139)
Wholesale Electricity	**1,749**	1,871	(122)
Gas *(P.J)*	**5**	5	—
Central Hudson			
Electricity	**1,203**	1,200	3
Gas *(P.J)*	**6**	7	(1)
FortisBC Energy *(P.J)*	**74**	67	7
FortisAlberta	**4,147**	4,138	9
FortisBC Electric	**927**	894	33
Other Electric	**2,449**	2,362	87
Non-Regulated			
Energy Infrastructure	**13**	103	(90)

The decrease in electricity sales was driven by: (i) UNS Energy, due to lower retail electricity sales resulting from milder weather and lower wholesale sales; and (ii) BECOL, due to lower hydroelectric production in Belize caused by variations in rainfall levels. The decrease was partially offset by higher electricity sales in the Caribbean reflecting the continued recovery from the impacts of the COVID-19 Pandemic in 2020.

The increase in gas volumes was due to higher consumption by residential and commercial customers at FortisBC Energy due to colder temperatures.

Revenue and Common Equity Earnings

	Revenue			**Earnings**		
($ millions, except as indicated)	**2021**	2020	Variance	**2021**	2020	Variance
Regulated Utilities						
ITC	**418**	419	(1)	**103**	109	(6)
UNS Energy	**540**	525	15	**33**	45	(12)
Central Hudson	**283**	242	41	**39**	35	4
FortisBC Energy	**592**	476	116	**78**	74	4
FortisAlberta	**156**	139	17	**23**	33	(10)
FortisBC Electric	**133**	117	16	**14**	13	1
Other Electric	**401**	381	20	**29**	32	(3)
Non-regulated						
Energy Infrastructure	**60**	47	13	**40**	27	13
Corporate and Other	**—**	—	—	**(31)**	(37)	6
Total	**2,583**	2,346	237	**328**	331	(3)
Weighted average number of common shares outstanding *(# millions)*				**473.7**	465.8	7.9
Basic EPS *($)*				**0.69**	0.71	(0.02)

The increase in revenue was driven by: (i) overall higher flow-through costs, mainly at FortisBC Energy and Central Hudson; (ii) Rate Base growth; (iii) higher electricity sales in the Caribbean reflecting the impact of the COVID-19 Pandemic in 2020; and, (iv) unrealized gains on the mark-to-market of natural gas derivatives at Aitken Creek. New customer rates and higher transmission revenue at TEP also contributed to the increase. These factors were partially offset by the unfavourable impact of foreign exchange.

The decrease in Common Equity Earnings was driven by: (i) lower earnings in Arizona, due to the reduction in sales as noted above, and lower gains on certain investments that support retirement benefits, partially offset by higher transmission revenue; (ii) the timing of earnings at FortisAlberta, due the reversal of income tax expense in the fourth quarter of 2020; (iii) the operation of regulatory mechanisms at Central Hudson; and, (iv) higher non-recoverable costs at ITC. Lower earnings in Belize and the impact of foreign exchange also unfavourably impacted earnings for the quarter. The decrease in earnings was partially offset by growth in Rate Base, the finalization of Central Hudson's rate application with retroactive application to July 1, 2021, and the favourable impact of mark-to-market accounting at Aitken Creek.

The decrease in basic EPS reflects lower Common Equity Earnings and an increase in the weighted average number of common shares outstanding, largely associated with the Corporation's DRIP.

Cash Flows

($ millions)	**2021**	2020	Variance
Cash and cash equivalents, beginning of period	**225**	494	(269)
Cash from (used in):			
Operating activities	**717**	700	17
Investing activities	**(985)**	(1,235)	250
Financing activities	**174**	308	(134)
Effect of exchange rate changes on cash and cash equivalents	**—**	(18)	18
Cash and cash equivalents, end of period	**131**	249	(118)

Operating Activities

Operating Cash Flow increased during the quarter due to: (i) Rate Base growth; (ii) new customer rates at TEP effective January 1, 2021; and, (iii) favourable changes in regulatory deferrals due to the timing of flow-through costs in customer rates. These increases were largely offset by an upfront payment received by FortisAlberta in the fourth quarter of 2020 associated with a long-term energy retailer agreement, and the lower foreign exchange rate in 2021.

Investing Activities

The variance reflects lower capital expenditures in accordance with the Corporation's 2021 Capital Plan.

Financing Activities

See "Cash Flow Summary" on page 28.

SUMMARY OF QUARTERLY RESULTS

Quarter ended	**Revenue** *($ millions)*	**Common Equity Earnings** *($ millions)*	**Basic EPS** *($)*	**Diluted EPS** *($)*
December 31, 2021	**2,583**	**328**	**0.69**	**0.69**
September 30, 2021	**2,196**	**295**	**0.63**	**0.62**
June 30, 2021	**2,130**	**253**	**0.54**	**0.54**
March 31, 2021	**2,539**	**355**	**0.76**	**0.76**
December 31, 2020	2,346	331	0.71	0.71
September 30, 2020	2,121	292	0.63	0.63
June 30, 2020	2,077	274	0.59	0.59
March 31, 2020	2,391	312	0.67	0.67

Generally, within each calendar year, quarterly results fluctuate primarily in accordance with seasonality. Given the diversified nature of the Corporation's subsidiaries, seasonality varies. Most of the annual earnings of the gas utilities are realized in the first and fourth quarters due to space-heating requirements. Earnings for the electric distribution utilities in the U.S. are generally 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 timing and significance of any regulatory decisions; (iv) changes in the U.S.-to-Canadian dollar exchange rate; (v) any acquisitions and dispositions; (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 2021/December 2020

See "Fourth Quarter Results" on page 48.

September 2021/September 2020

Common Equity Earnings and basic EPS were relatively consistent with the same period in 2020. Growth in Common Equity Earnings was tempered by a lower U.S.-to-Canadian dollar exchange rate, unfavourably impacting earnings by $13 million.

Excluding the impact of foreign exchange, Common Equity Earnings increased by $16 million due to: (i) Rate Base growth; (ii) higher sales, largely associated with favourable weather, and the timing of expenditures at FortisAlberta; (iii) continued recovery in the Caribbean from economic conditions experienced in 2020 associated with the COVID-19 Pandemic; and (iv) an adjustment related to the amortization of interest rate swaps at ITC. New customer rates effective January 1, 2021 at TEP also contributed to results. The increase in earnings was partially offset by: (i) lower sales in Arizona due to cooler weather; (ii) realized losses on natural gas contracts at Aitken Creek; and (iii) the delay in Central Hudson's general rate application. The change in basic EPS also reflected an increase in the weighted average number of common shares outstanding, largely associated with the DRIP.

June 2021/June 2020

Common Equity Earnings decreased by $21 million and basic EPS decreased by $0.05 due primarily to: (i) a lower U.S.-to-Canadian dollar exchange rate, resulting in a $24 million unfavourable variance; and (ii) significant one-time items totalling $14 million recognized in the second quarter of 2020. The significant items included an adjustment to ITC's base ROE, partially offset by the finalization of U.S. tax reform and associated regulations.

Excluding the impact of foreign exchange and the one-time items, Common Equity Earnings increased by $17 million due to: (i) Rate Base growth; (ii) higher earnings in Arizona driven by warmer weather and new customer rates at TEP, partially offset by higher operating expenses; and (iii) higher earnings in the Caribbean, reflecting the continued recovery from economic conditions experienced in 2020 associated with the COVID-19 Pandemic. This growth was partially offset by a lower income tax recovery at Corporate and the impact of mark-to-market accounting of natural gas derivatives at Aitken Creek. The change in basic EPS also reflected an increase in weighted average number of common shares outstanding, largely associated with the DRIP.

March 2021/March 2020

Common Equity Earnings increased by $43 million and basic EPS increased by $0.09, due primarily to Rate Base growth, new customer rates at TEP effective January 1, 2021 and higher hydroelectric production in Belize. The impact of losses on retirement investments and foreign exchange contracts recognized in March 2020 at UNS Energy and Corporate, respectively, also favourably impacted the year-over-year change. The increase was partially offset by higher operating expenses mainly related to planned generation maintenance at UNS Energy and unfavourable foreign exchange. The change in basic EPS also reflected an increase in the weighted average number of common shares outstanding, largely associated with the 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 2021 or 2020.

Inter-company transactions between non-regulated and regulated entities not eliminated on consolidation include the lease of gas storage capacity and gas sales by Aitken Creek to FortisBC Energy. These transactions did not have a material impact on consolidated earnings, financial position or cash flows.

As at December 31, 2021, accounts receivable included $22 million due from Belize Electricity (2020 - $28 million).

Fortis periodically provides short-term financing, the impacts of which are eliminated on consolidation, to subsidiaries to support capital expenditures, acquisitions and seasonal working capital requirements. In October 2021, Fortis entered into a non-revolving term credit facility with UNS Energy to lend a maximum of US$175 million, maturing December 2022. As at December 31, 2021, inter-segment loans of $126 million were outstanding related to this agreement. Interest charged on inter-segment loans was not material in 2021 and 2020.

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, 2021, 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, 2021.

Internal Controls 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 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 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, 2021, 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, 2021, the Corporation's ICFR was effective.

During the year ended December 31, 2021, 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

The Corporation's long-term outlook remains unchanged. Fortis continues to enhance shareholder value through the execution of its Capital Plan, the balance and strength of its diversified portfolio of utility businesses, and growth opportunities within and proximate to its service territories. While uncertainty exists due to the COVID-19 Pandemic, the Corporation does not currently expect it to have a material financial impact in 2022.

Fortis is executing on the transition to a cleaner energy future and is on plan to achieve its corporate-wide target to reduce carbon emissions by 75% by 2035. Upon achieving this target, 99% of the Corporation's assets will be focused on energy delivery and renewable, carbon-free generation.

The Corporation's $20 billion five-year Capital Plan is expected to increase midyear Rate Base from $31.1 billion in 2021 to $41.6 billion by 2026, translating into a five-year CAGR of approximately 6%. Above and beyond the five-year Capital Plan, Fortis continues to pursue additional energy infrastructure opportunities.

Additional opportunities to expand and extend growth include: further expansion of the electric transmission grid in the U.S. to facilitate the interconnection of cleaner energy including infrastructure investments associated with MISO's long-range transmission plan; natural gas resiliency investments in pipelines and LNG infrastructure in British Columbia; the fully permitted, cross-border, Lake Erie Connector electric transmission project in Ontario; and the acceleration of cleaner energy infrastructure investments across our jurisdictions.

Fortis expects long-term growth in Rate Base will support earnings and dividend growth. Fortis is targeting average annual dividend growth of approximately 6% through 2025. This dividend growth guidance is premised on the assumptions listed under "Forward-Looking Information".

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: targeted average annual dividend growth through 2025; forecast capital expenditures for 2022-2026; the expectation that the COVID-19 Pandemic will not have a material financial impact in 2022 and will not impact the five-year capital plan; forecast Rate Base and Rate Base growth for 2022 through 2026; the expectation that long-term growth in Rate Base will support earnings and dividend growth; the expectation that Fortis is well positioned to capitalize on evolving industry opportunities, including additional investment opportunities beyond the Capital Plan; the 2035 carbon emission reduction target, how that target is expected to be achieved and the projected asset mix upon achieving the target; the expected timing of updates on climate scenario analysis work; the expected timing for achieving new board diversity targets; the expected timing, outcome and impact of regulatory decisions; the expected or potential funding sources for operating expenses, interest costs and capital plans; 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 access to long-term capital and will remain compliant with debt covenants in 2022; the expected uses of proceeds from debt financings; the targeted capital structure; and the nature and expected timing, benefits and costs of certain capital projects including the Multi-Value Regional Transmission Projects, Transmission Conversion Project, Vail-to-Tortolita Project, Lower Mainland Intermediate Pressure System Upgrade, Okanagan Capacity Upgrade, Eagle Mountain Woodfibre Gas Line Project, Transmission Integrity Management Capabilities Project, Inland Gas Upgrades Project, Tilbury 1B Project, Tilbury LNG Storage Expansion, AMI Project, Wataynikaneyap Transmission Power Project and additional opportunities beyond the capital plan.

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: no material impact from the COVID-19 Pandemic; reasonable regulatory decisions and the expectation of regulatory stability; the successful execution of the five-year 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; the Board exercising its discretion to declare dividends, taking into account the financial performance and condition of the Corporation; no significant variability in interest rates; 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 2022 include, but are not limited to: uncertainty regarding the outcome of regulatory proceedings at the Corporation's utilities; risks associated with climate change, physical risks and service disruption, including cybersecurity risk; risks related to environmental laws and regulations; the impact of weather variability and seasonality on heating and cooling loads, gas distribution volumes and hydroelectric generation; risks associated with the competitiveness of natural gas; the impact of pandemics and public health crises, including the COVID-19 Pandemic; risks associated with capital projects and the impact on the Corporation's continued growth; risks associated with commodity price volatility and supply of purchased power; and interest rate and foreign exchange risks.

All forward-looking information herein is given as of February 10, 2022. 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

2021 Annual Financial Statements: the Corporation's audited consolidated financial statements and notes thereto for the year ended December 31, 2021

Actual Payout Ratio: dividends 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 24

Adjusted Payout Ratio: dividends per common share divided by Adjusted Basic EPS as shown under "Non-U.S. GAAP Financial Measures" on page 24

AESO: Alberta Electric System Operator

AFUDC: allowance for funds used during construction

Aitken Creek: Aitken Creek Gas Storage ULC, a direct 93.8%-owned subsidiary of FortisBC Holdings Inc.

AMI: Advanced Metering Infrastructure

AUC: Alberta Utilities Commission

BCUC: British Columbia Utilities Commission

BECOL: Belize Electric Company Limited, an indirect wholly owned subsidiary of Fortis

Belize Electricity: Belize Electricity Limited, in which Fortis indirectly holds a 33% equity interest

Board: Board of Directors of the Corporation

CAGR(s): compound average 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 2021 Annual Financial Statements, as well as Fortis' 39% share of capital spending for the Wataynikaneyap Transmission Power Project. See "Non-US GAAP Financial Measures" on page 24

Capital Plan: forecast Capital Expenditures. Represents a non-U.S. GAAP financial measure calculated in the same manner as Capital Expenditures

Caribbean Utilities: Caribbean Utilities Company, Ltd., an indirect approximately 60%-owned (as at December 31, 2021) 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

COVID-19 Pandemic: declared by the World Health Organization in March 2020 as a result of a novel coronavirus

CPCN: Certificate of Public Convenience and Necessity

CRMP: Cybersecurity Risk Management Program

DBRS Morningstar: DBRS Limited

DCP: disclosure controls and procedures

DRIP: dividend reinvestment plan

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 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

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.-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 controls over financial reporting

IESO: Independent Electricity System Operator

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

LIBOR: London Interbank Offered Rate

LNG: liquefied natural gas

LRTP: MISO Long Range Transmission Plan

Luna: Luna Energy Facility

kV: kilovolt

Major Capital Projects: projects, other than ongoing maintenance projects, individually costing $200 million or more

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

May 2020 FERC Decision: a FERC order issued in May 2020, on rehearing of the FERC's November 2019 decision, increasing the base ROE for ITC's MISO Subsidiaries from that determined in November 2019

MD&A: the Corporation's management discussion and analysis for the year ended December 31, 2021

MISO: Midcontinent Independent System Operator, Inc.

Moody's: Moody's Investor Services, Inc.

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

OEB: Ontario Energy Board

OPEB: other post-employment benefits

Operating Cash Flow: cash from operating activities

PBR: performance-based rate-setting

PJ: petajoule(s)

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

RNG: renewable natural gas

ROA: rate of return on Rate Base

ROE: rate of return on common equity

RTO: regional transmission organization

S&P: Standard & Poor's Financial Services LLC

San Juan: San Juan Generating Station Unit 1

SEDAR: Canadian System for Electronic Document Analysis and Retrieval

Springerville: Springerville Generating Station

Sundt: H. Wilson Sundt Generating Station

TEP: Tucson Electric Power Company, a direct wholly owned subsidiary of UNS Energy

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 Energy: UNS Energy Corporation, an indirect wholly owned subsidiary of Fortis, together with its subsidiaries, including TEP, UNS Electric, Inc. and 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, in which Fortis held a 51% controlling interest prior to April 2019

Wataynikaneyap Partnership: Wataynikaneyap Power Limited Partnership

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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, 2021, 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, 2021, the Corporation's ICFR was effective.

The Corporation's ICFR as of December 31, 2021 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, 2021. Deloitte LLP issued an unqualified opinion for both audits.

February 10, 2022



David G. Hutchens
President and Chief Executive Officer, Fortis Inc.
St. John's, Canada



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, 2021 and 2020, 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, 2021, 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, 2021 and 2020, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2021, 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, 2021, 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 10, 2022, 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 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 growth rates and discount rates. Auditing these estimates and assumptions required a high degree of audit judgment and effort, including the need to involve a fair value specialist.

How the Critical Audit Matter was Addressed in the Audit

Our audit procedures related to the growth rate and discount rate used by management to estimate the fair value of more recently acquired reporting units included the following:

- Evaluating the effectiveness of controls over the estimated fair value of the reporting units, including the review and approval of the growth rate and discount rate selected by management.
- Evaluating management's ability to accurately forecast the growth rate by:
  - Assessing the methodology used in management's determination of the growth rate; and
  - Comparing management's assumptions to historical data and available market trends.
- 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.



Deloitte LLP

Chartered Professional Accountants

St. John's, Canada
February 10, 2022

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, 2021, 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, 2021, 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, 2021, of the Corporation and our report dated February 10, 2022, 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.



Deloitte LLP
Chartered Professional Accountants

St. John's, Canada
February 10, 2022

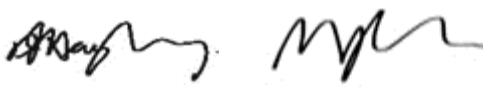
CONSOLIDATED BALANCE SHEETS

FORTIS INC.

As at December 31 (in millions of Canadian dollars)	2021	2020
ASSETS		
Current assets		
Cash and cash equivalents	**$ 131**	$ 249
Accounts receivable and other current assets (Note 6)	**1,511**	1,369
Prepaid expenses	**116**	102
Inventories (Note 7)	**478**	422
Regulatory assets (Note 8)	**492**	470
Total current assets	**2,728**	2,612
Other assets (Note 9)	**955**	670
Regulatory assets (Note 8)	**3,097**	3,118
Property, plant and equipment, net (Note 10)	**37,816**	35,998
Intangible assets, net (Note 11)	**1,343**	1,291
Goodwill (Note 12)	**11,720**	11,792
Total assets	**$ 57,659**	$ 55,481
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings (Note 14)	**$ 247**	$ 132
Accounts payable and other current liabilities (Note 13)	**2,570**	2,321
Regulatory liabilities (Note 8)	**357**	441
Current installments of long-term debt (Note 14)	**1,628**	1,254
Total current liabilities	**4,802**	4,148
Regulatory liabilities (Note 8)	**2,865**	2,662
Deferred income taxes (Note 22)	**3,627**	3,344
Long-term debt (Note 14)	**23,707**	23,113
Finance leases (Note 15)	**333**	331
Other liabilities (Note 16)	**1,409**	1,599
Total liabilities	**36,743**	35,197
Commitments and contingencies (Note 26)		
Equity		
Common shares [(1)]	**14,237**	13,819
Preference shares (Note 18)	**1,623**	1,623
Additional paid-in capital	**10**	11
Accumulated other comprehensive (loss) income (Note 19)	**(40)**	34
Retained earnings	**3,458**	3,210
Shareholders' equity	**19,288**	18,697
Non-controlling interests	**1,628**	1,587
Total equity	**20,916**	20,284
Total liabilities and equity	**$ 57,659**	$ 55,481

[(1)] No par value. Unlimited authorized shares. 474.8 million and 466.8 million issued and outstanding as at December 31, 2021 and 2020, respectively

Approved on Behalf of the Board



Douglas J. Haughey, Director

Maura J. Clark, 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)		2021		2020
Revenue (Note 5)	**$**	**9,448**	$	8,935
Expenses				
Energy supply costs		**2,951**		2,562
Operating expenses		**2,523**		2,437
Depreciation and amortization		**1,505**		1,428
Total expenses		**6,979**		6,427
Operating income		**2,469**		2,508
Other income, net (Note 21)		**173**		154
Finance charges		**1,003**		1,042
Earnings before income tax expense		**1,639**		1,620
Income tax expense (Note 22)		**234**		231
Net earnings	**$**	**1,405**	$	1,389
Net earnings attributable to:				
Non-controlling interests	**$**	**111**	$	115
Preference equity shareholders		**63**		65
Common equity shareholders		**1,231**		1,209
	$	**1,405**	$	1,389
Earnings per common share (Note 17)				
Basic	**$**	**2.61**	$	2.60
Diluted	**$**	**2.61**	$	2.60

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 (in millions of Canadian dollars)		2021		2020
Net earnings	**$**	**1,405**	$	1,389
Other comprehensive loss				
Unrealized foreign currency translation losses, net of hedging activities and income tax expense of $2 million and $3 million, respectively		**(93)**		(311)
Other, net of income tax expense (recovery) of $3 million and $(9) million, respectively		**8**		(27)
		(85)		(338)
Comprehensive income	**$**	**1,320**	$	1,051
Comprehensive income attributable to:				
Non-controlling interests	**$**	**100**	$	79
Preference equity shareholders		**63**		65
Common equity shareholders		**1,157**		907
	$	**1,320**	$	1,051

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

FORTIS INC.

For the year ended December 31 (in millions of Canadian dollars)	2021	2020
Operating activities		
Net earnings	**$ 1,405**	$ 1,389
Adjustments to reconcile net earnings to net cash provided by operating activities:		
Depreciation - property, plant and equipment	**1,313**	1,282
Amortization - intangible assets	**136**	131
Amortization - other	**56**	15
Deferred income tax expense (Note 22)	**147**	226
Equity component, allowance for funds used during construction (Note 21)	**(77)**	(78)
Other	**71**	170
Change in working capital (Note 24)	**(144)**	(434)
Cash from operating activities	**2,907**	2,701
Investing activities		
Additions to property, plant and equipment	**(3,189)**	(3,857)
Additions to intangible assets	**(197)**	(182)
Contributions in aid of construction	**93**	68
Other	**(195)**	(161)
Cash used in investing activities	**(3,488)**	(4,132)
Financing activities		
Proceeds from long-term debt, net of issuance costs (Note 14)	**1,324**	3,470
Repayments of long-term debt and finance leases	**(634)**	(1,251)
Borrowings under committed credit facilities	**5,082**	5,648
Repayments under committed credit facilities	**(4,749)**	(5,299)
Net change in short-term borrowings	**115**	(413)
Issue of common shares, net of costs, and dividends reinvested	**60**	58
Dividends		
Common shares, net of dividends reinvested	**(608)**	(786)
Preference shares	**(63)**	(65)
Subsidiary dividends paid to non-controlling interests	**(58)**	(65)
Other	**(18)**	30
Cash from financing activities	**451**	1,327
Effect of exchange rate changes on cash and cash equivalents	**12**	(17)
Change in cash and cash equivalents	**(118)**	(121)
Cash and cash equivalents, beginning of year	**249**	370
Cash and cash equivalents, end of year	**$ 131**	$ 249

Supplementary Cash Flow Information (Note 24)

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, 2020	**466.8**	**$ 13,819**	**$ 1,623**	**$ 11**	**$ 34**	**$ 3,210**	**$ 1,587**	**$ 20,284**
Net earnings	**—**	**—**	**—**	**—**	**—**	**1,294**	**111**	**1,405**
Other comprehensive loss	**—**	**—**	**—**	**—**	**(74)**	**—**	**(11)**	**(85)**
Common shares issued	**8.0**	**418**	**—**	**(2)**	**—**	**—**	**—**	**416**
Subsidiary dividends paid to non-controlling interests	**—**	**—**	**—**	**—**	**—**	**—**	**(58)**	**(58)**
Dividends declared on common shares ($2.08 per share)	**—**	**—**	**—**	**—**	**—**	**(983)**	**—**	**(983)**
Dividends on preference shares	**—**	**—**	**—**	**—**	**—**	**(63)**	**—**	**(63)**
Other	**—**	**—**	**—**	**1**	**—**	**—**	**(1)**	**—**
As at December 31, 2021	**474.8**	**$ 14,237**	**$ 1,623**	**$ 10**	**$ (40)**	**$ 3,458**	**$ 1,628**	**$ 20,916**
As at December 31, 2019	463.3	$ 13,645	$ 1,623	$ 11	$ 336	$ 2,916	$ 1,582	$ 20,113
Net earnings	—	—	—	—	—	1,274	115	1,389
Other comprehensive loss	—	—	—	—	(302)	—	(36)	(338)
Common shares issued	3.5	174	—	(3)	—	—	—	171
Advances to non-controlling interests	—	—	—	—	—	—	(13)	(13)
Subsidiary dividends paid to non-controlling interests	—	—	—	—	—	—	(65)	(65)
Dividends declared on common shares ($1.965 per share)	—	—	—	—	—	(915)	—	(915)
Dividends on preference shares	—	—	—	—	—	(65)	—	(65)
Other	—	—	—	3	—	—	4	7
As at December 31, 2020	466.8	$ 13,819	$ 1,623	$ 11	$ 34	$ 3,210	$ 1,587	$ 20,284

See accompanying Notes to Consolidated Financial Statements

For the years ended December 31, 2021 and 2020

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 and Oklahoma.

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 in Pima County and parts of Cochise County, as well as in Santa Cruz and Mohave counties. TEP also sells wholesale electricity to other entities in the western United States. Together they own generating capacity of 3,485 megawatts ("MW"), including 53 MW of solar capacity and 252 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 Arizona's Mohave, Yavapai, Coconino, Navajo and Santa Cruz counties.

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 65 MW.

FortisBC Energy: FortisBC Energy Inc., which is the largest regulated distributor of natural gas in British Columbia, provides transmission and distribution services in over 135 communities. FortisBC Energy obtains 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. It 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 Partnership"); 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 143 MW, of which 97 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 130 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 5 MW. Wataynikaneyap Partnership is a partnership between 24 First Nations communities, Fortis and Algonquin Power & Utilities Corp. with a mandate to connect remote First Nations communities to the electricity grid in Ontario through the development of new transmission lines.

Caribbean Utilities is an integrated regulated electric utility and the sole electricity provider on Grand Cayman with a diesel-powered generating capacity of 161 MW. FortisTCI consists of two integrated regulated electric utilities that provide electricity to certain Turks and Caicos Islands and has a diesel-powered generating capacity of 94 MW. Belize Electricity is an integrated electric utility and the principal distributor of electricity in Belize.

1. DESCRIPTION OF BUSINESS (cont'd)

Non-Regulated

Energy Infrastructure: Long-term contracted generation assets in Belize and the Aitken Creek natural gas storage facility ("Aitken Creek") in British Columbia. Generation assets in Belize consist of three hydroelectric generating facilities with a combined generating capacity of 51 MW, held through the Corporation's indirectly wholly owned subsidiary Belize Electric Company Limited ("BECOL"). The output is sold to Belize Electricity under 50-year power purchase agreements ("PPAs"). Fortis indirectly owns 93.8% of Aitken Creek, with the remainder owned by BP Canada Energy Company. Aitken Creek is the only underground natural gas storage facility in British Columbia and has a working gas capacity of 77 billion cubic feet.

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, including net corporate expenses of Fortis and non-regulated holding company expenses.

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 regulatory 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. There can be varying degrees of regulatory lag between when costs are incurred and when they are reflected in customer rates.

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).

2. *REGULATION (cont'd)*

Nature of Regulation

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed ROE [1] (%) 2021	Allowed ROE [1] (%) 2020	Significant Features
ITC [2]	Federal Energy Regulatory Commission ("FERC")	60.0	**10.77**	10.77	Cost-based formula rates, with annual true-up mechanism [3] Incentive adders
TEP	Arizona Corporation Commission ("ACC") [4]	53.0	**9.15**	9.75	COS regulation Historical test year
	FERC	[5]	**[5]**	[5]	Formula transmission rates
UNS Electric	ACC	52.8	**9.50**	9.50	
UNS Gas	ACC	50.8	**9.75**	9.75	
Central Hudson [6]	New York State Public Service Commission ("PSC")	50.0	**9.00**	8.80	COS regulation Future test year
FortisBC Energy	British Columbia Utilities Commission ("BCUC")	38.5	**8.75**	8.75	COS regulation with formula components and incentives [7]
FortisBC Electric	BCUC	40.0	**9.15**	9.15	Future test year
FortisAlberta	Alberta Utilities Commission ("AUC")	37.0	**8.50**	8.50	PBR [8]
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 [9]	Ontario Energy Board	40.0	**8.52-9.30**	8.52-9.30	COS regulation with incentive mechanisms
Caribbean Utilities [10]	Utility Regulation and Competition Office	N/A	**6.00-8.00**	6.75-8.75	COS regulation Rate-cap adjustment mechanism based on published consumer price indices
FortisTCI [11]	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] *Includes the allowed common equity and base ROE plus incentive adders for ITCTransmission, METC, and ITC Midwest. See "Significant Regulatory Developments" below*
[3] *Annual true-up collected or refunded in rates within a two-year period*
[4] *Effective January 1, 2021, an approved ROE of 9.15% with a 0.20% return on the fair value increment. The common equity component of capital structure for 2020 was 50%*
[5] *The allowed common equity component for FERC transmission rates is formulaic, and is updated annually based on TEP's actual equity ratio. See "Significant Regulatory Developments" below*
[6] *Allowed common equity percentage is updated annually on July 1st. See "Significant Regulatory Developments" below*
[7] *Formula and incentives have been set through 2024. See "Significant Regulatory Developments" below*
[8] *FortisAlberta is subject to PBR including mechanisms for flow-through costs and capital expenditures not otherwise recovered through customer rates. FortisAlberta's current PBR term expires as of December 31, 2022. See "Significant Regulatory Developments" below*
[9] *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*
[10] *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*
[11] *Operates under 50-year licences from the Government of the Turks and Caicos Islands, which expire in 2036 and 2037*

Significant Regulatory Developments

ITC

Transmission Incentives: In April 2021, FERC issued a supplemental notice of proposed rulemaking ("NOPR") on transmission incentives modifying the proposal in the initial NOPR released in March 2020. The supplemental NOPR proposes to eliminate the 50-basis point regional transmission organization ("RTO") ROE incentive adder for existing RTO members that have been members longer than three years, like ITC. In June 2021, ITC filed its comments on the supplemental NOPR supporting the continuation of the ROE incentive adder for RTO members. The timeline for FERC to issue a final rule in this proceeding as well as the likely outcome and potential impacts to Fortis cannot be determined at this time.

2. REGULATION (cont'd)

UNS Energy

FERC Rate Case: In 2019, FERC issued an order accepting formula transmission rates proposed by TEP, subject to refund following hearing and settlement procedures. A settlement in principle was reached in August 2021, and a settlement agreement including an ROE of 9.79% was filed with FERC in December 2021. Until conclusion of the proceeding, customer rates continue to be charged under the 2019 FERC order and remain subject to refund pending the final order. The timing and outcome of this proceeding remains unknown.

Central Hudson

General Rate Application: In November 2021, the PSC approved a three-year rate plan for Central Hudson with retroactive application to July 1, 2021, including an ROE of 9.0%, and a common equity component of capital structure of 50% declining by 1% annually to 48% in the third rate year. The three-year rate plan also reflects the use of existing regulatory balances and other measures to reduce customer bill impacts, the recovery of finance charges which had not been billed to customers since the second quarter of 2020, as well as initiatives to support New York State's climate goals.

FortisBC Energy and FortisBC Electric

Generic Cost of Capital ("GCOC") *Proceeding:* In January 2021, the BCUC announced the initiation of a GCOC proceeding including a review of the common equity component of capital structure and the allowed ROE. The timing and outcome of this proceeding, including the effective date of any change in the cost of capital for 2022 or beyond, remains unknown.

FortisAlberta

2022 GCOC Proceeding: In March 2021, the AUC concluded the 2022 GCOC proceeding and extended the existing allowed ROE of 8.5% using a 37% equity component of capital structure through 2022.

2023 COS Application: The final year of FortisAlberta's second PBR term is 2022. In June 2021, the AUC issued a decision confirming the approach to be adopted by Alberta distribution utilities for the COS rebasing year in 2023. In November 2021, FortisAlberta filed its 2023 COS application and a decision is expected in the third quarter of 2022.

2023/2024 GCOC Proceeding: In January 2022, the AUC initiated proceedings to establish the cost of capital parameters for 2023 and to consider a formula-based approach to setting the allowed ROE for 2024 and beyond. The AUC is considering extending the existing allowed ROE of 8.5% using a 37% equity component of capital structure through 2023. Comments on this proposal are due in February 2022 and a decision is expected in the first quarter of 2022. The GCOC proceeding for 2024 and beyond is expected to commence in the third quarter of 2022, with a decision expected in 2023.

Third PBR Term: In July 2021, the AUC issued a decision confirming that Alberta distribution utilities will be subject to a third PBR term commencing in 2024 with going-in rates based on the 2023 COS rebasing. The AUC also initiated a new proceeding to consider the design of the third PBR term. FortisAlberta will submit comments with respect to the design of the third PBR term in 2022 and a decision from the AUC is expected in 2023.

Independent System Operator Tariff Proceeding: In April 2021, the AUC issued a decision confirming that distribution facility owners, such as FortisAlberta, will no longer be permitted to earn a return on contributions made to the Alberta Electric System Operator ("AESO") on a prospective basis from the date of the decision. Contributions made prior to that date are not impacted. The decision did not have a material financial impact on the Corporation in 2021 and it is not expected to materially impact future periods. In January 2022, the Alberta Court of Appeal granted a full appeal on this matter. In doing so, the Alberta Court of Appeal also permitted a related appeal regarding the legality of the AUC's AESO customer contribution policy. FortisAlberta will fully participate in the appeal regarding the legality of the AESO customer contribution policy and will closely monitor the preceding related to earned returns on future AESO contributions.

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. Intercompany transactions have been eliminated, except for transactions between non-regulated and regulated entities in accordance with U.S. GAAP for rate-regulated 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.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

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 accounted for using the equity method are reviewed annually for potential impairment in value. Impairments are recognized when identified.

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 2021 totalled $39 million (2020 - $41 million) and is reported as a reduction of finance charges and the equity component is reported as other income (Note 21). Both components are recorded to earnings through depreciation expense over the estimated service lives of the applicable PPE.

At FortisAlberta, through December 31, 2020, the cost of PPE includes contributions to AESO toward funding the construction of transmission facilities (Note 2).

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. Depreciation rates for 2021 ranged from 0.9% to 39.8% (2020 - 0.9% to 39.8%). The weighted average composite rate of depreciation, before reduction for amortization of contributions in aid of construction, was 2.6% for 2021 (2020 – 2.5%).

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

The service life ranges and weighted average remaining service life of PPE as at December 31 were as follows.

	2021		2020	
(years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Distribution				
Electric	**5-80**	**32**	5-80	32
Gas	**18-95**	**38**	18-95	38
Transmission				
Electric	**20-90**	**42**	20-90	43
Gas	**10-85**	**35**	10-85	35
Generation	**5-95**	**23**	1-85	24
Other	**3-70**	**13**	2-70	14

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 2021 (2020 – 1.0% to 33.0%).

The service life ranges and weighted average remaining service life of finite-life intangible assets as at December 31 were as follows.

	2021		2020	
(years)	**Service Life Ranges**	**Weighted Average Remaining Service Life**	Service Life Ranges	Weighted Average Remaining Service Life
Computer software	**3-15**	**4**	3-15	4
Land, transmission and water rights	**34-90**	**55**	43-90	56
Other	**10-100**	**11**	10-100	12

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.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

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 11 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 necessary, 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 plans 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 defined benefit pension 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.

Defined benefit pension 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 defined benefit pension 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.

For most of the Corporation's regulated utilities, any difference between defined benefit pension 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 (Note 8).

For most of the Corporation's regulated utilities, any unamortized balances related to net actuarial gains and losses, past service costs and transitional obligations associated with defined benefit pension 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 all 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.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

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 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.

Revenue is disaggregated by geography, regulatory status, and substantially autonomous utility operations (Note 5). This represents the level of disaggregation used by the Corporation's President and Chief Executive Officer ("CEO") to allocate resources and evaluate performance.

Stock-Based Compensation

Compensation expense related to stock options is measured at the grant date using the Black-Scholes fair value option-pricing model and each grant is amortized to compensation expense as a single award 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.

Fortis recognizes liabilities associated with its directors' Deferred Share Unit ("DSU"), Performance Share Unit ("PSU") and Restricted Share Unit ("RSU") Plans. DSUs and PSUs, as well as RSUs issued through 2019 represent cash-settled awards. Effective January 1, 2020, new RSU issuances represent cash or share-settled awards, depending on settlement elections and the share ownership requirements of the executive. 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 VWAP as at December 31, 2021 was $61.08 (2020 - $52.36). 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 the PSU and RSU Plans is over the lesser of three years or the period to retirement eligibility and for the DSU Plan is at the time of grant. Forfeitures are accounted for as they occur.

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, 2021 was US$1.00=CA$1.26 (2020 – US$1.00=CA$1.27).

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$1.25 for 2021 (2020 - US$1.00=CA$1.34).

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.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

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; (ii) UNS Energy, to meet forecast load and reserve requirements; and (iii) Aitken Creek, to manage commodity price risk, capture natural gas price spreads, and manage the financial risk of physical transactions. These 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 UNS Energy 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 BECOL 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).

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 $4.1 billion as at December 31, 2021 (2020 - $3.4 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.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (cont'd)

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.

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.

4. SEGMENTED INFORMATION

General

Fortis segments its business based on regulatory jurisdiction and service territory, as well as the information used by its CEO in deciding how to allocate resources. Segment performance is evaluated principally on net earnings attributable to common equity shareholders.

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 2021 or 2020.

The lease of gas storage capacity and gas sales from Aitken Creek to FortisBC Energy of $38 million in 2021 (2020 - $25 million) are inter-company transactions between non-regulated and regulated entities, which were not eliminated on consolidation.

As at December 31, 2021, accounts receivable included $22 million due from Belize Electricity (2020 - $28 million).

Fortis periodically provides short-term financing, the impacts of which are eliminated on consolidation, to subsidiaries to support capital expenditures, acquisitions and seasonal working capital requirements. In October 2021, Fortis entered into a non-revolving term credit facility with UNS Energy to lend a maximum of US$175 million, maturing December 2022. As at December 31, 2021, inter-segment loans of $126 million were outstanding related to this agreement. Interest charged on inter-segment loans was not material in 2021 and 2020 .

4. SEGMENTED INFORMATION (cont'd)

($ millions)	Regulated								Non-Regulated			
	ITC	UNS Energy	Central Hudson	FortisBC Energy	Fortis Alberta	FortisBC Electric	Other Electric	**Sub-total**	**Energy Infra-structure**	**Corporate and Other**	**Inter-segment eliminations**	**Total**
Year ended December 31, 2021												
Revenue	1,691	2,334	1,000	1,715	644	468	1,498	**9,350**	**98**	**—**	**—**	**9,448**
Energy supply costs	—	919	285	713	—	136	895	**2,948**	**3**	**—**	**—**	**2,951**
Operating expenses	466	648	498	355	157	128	201	**2,453**	**33**	**37**	**—**	**2,523**
Depreciation and amortization	291	345	91	281	231	65	181	**1,485**	**17**	**3**	**—**	**1,505**
Operating income	934	422	126	366	256	139	221	**2,464**	**45**	**(40)**	**—**	**2,469**
Other income, net	42	41	34	12	2	5	5	**141**	**1**	**31**	**—**	**173**
Finance charges	300	120	46	144	106	73	71	**860**	**—**	**143**	**—**	**1,003**
Income tax expense	156	51	21	48	11	12	21	**320**	**8**	**(94)**	**—**	**234**
Net earnings	520	292	93	186	141	59	134	**1,425**	**38**	**(58)**	**—**	**1,405**
Non-controlling interests	94	—	—	1	—	—	16	**111**	**—**	**—**	**—**	**111**
Preference share dividends	—	—	—	—	—	—	—	**—**	**—**	**63**	**—**	**63**
Net earnings attributable to common equity shareholders	426	292	93	185	141	59	118	**1,314**	**38**	**(121)**	**—**	**1,231**
Additions to property, plant and equipment and intangible assets	1,046	710	291	475	389	134	321	**3,366**	**20**	**—**	**—**	**3,386**
As at December 31, 2021												
Goodwill	7,755	1,746	570	913	228	235	246	**11,693**	**27**	**—**	**—**	**11,720**
Total assets	21,020	11,126	4,356	8,135	5,201	2,540	4,357	**56,735**	**777**	**295**	**(148)**	**57,659**
Year ended December 31, 2020												
Revenue	1,744	2,260	953	1,385	596	424	1,485	8,847	88	—	—	8,935
Energy supply costs	—	847	232	468	—	119	893	2,559	3	—	—	2,562
Operating expenses	438	627	503	341	148	117	194	2,368	30	39	—	2,437
Depreciation and amortization	295	330	90	237	212	61	183	1,408	16	4	—	1,428
Operating income	1,011	456	128	339	236	127	215	2,512	39	(43)	—	2,508
Other income, net	40	40	31	8	2	5	10	136	5	13	—	154
Finance charges	324	125	48	142	104	72	77	892	—	150	—	1,042
Income tax expense	179	69	20	29	1	4	21	323	5	(97)	—	231
Net earnings	548	302	91	176	133	56	127	1,433	39	(83)	—	1,389
Non-controlling interests	99	—	—	1	—	—	15	115	—	—	—	115
Preference share dividends	—	—	—	—	—	—	—	—	—	65	—	65
Net earnings attributable to common equity shareholders	449	302	91	175	133	56	112	1,318	39	(148)	—	1,209
Additions to property, plant and equipment and intangible assets	1,182	1,200	339	471	420	135	273	4,020	19	—	—	4,039
As at December 31, 2020												
Goodwill	7,810	1,758	574	913	228	235	247	11,765	27	—	—	11,792
Total assets	20,358	10,802	3,939	7,695	5,084	2,441	4,261	54,580	745	209	(53)	55,481

5. REVENUE

($ millions)	**2021**	2020
Electric and gas revenue		
United States		
ITC	**1,694**	1,726
UNS Energy	**2,071**	2,019
Central Hudson	**962**	941
Canada		
FortisBC Energy	**1,645**	1,336
FortisAlberta	**622**	580
FortisBC Electric	**404**	358
Newfoundland Power	**701**	707
Maritime Electric	**223**	215
FortisOntario	**211**	222
Caribbean		
Caribbean Utilities	**248**	238
FortisTCI	**89**	77
Total electric and gas revenue	**8,870**	8,419
Other services revenue [1]	**382**	325
Revenue from contracts with customers	**9,252**	8,744
Alternative revenue [2]	**(18)**	64
Other revenue	**214**	127
Total revenue	**9,448**	8,935

[1] *Includes $260 million and $227 million from regulated operations for 2021 and 2020, respectively*
[2] *2020 includes a $40 million favourable base ROE adjustment associated with the May 2020 FERC decision, which set the all-in ROE for ITC's subsidiaries operating in the Midcontinent Independent System Operator, Inc. "MISO" region at 10.77%*

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: (i) management fee revenue at UNS Energy for the operation of Springerville Units 3 and 4; (ii) revenue from storage optimization activities at Aitken Creek; and (iii) revenue from other services that reflect the ordinary business activities of Fortis' utilities.

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. UNS Energy's demand side management surcharge, which is approved by the ACC annually, compensates for the costs to design and implement cost-effective energy efficiency and demand response programs until such costs, along with a performance incentive, are reflected in non-fuel base rates.

FortisBC Energy and FortisBC Electric have an earnings sharing mechanism that provides for a 50/50 sharing of variances from the allowed ROE. This mechanism is in place until the expiry of the current multi-year rate plan in 2024. 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 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 reflecting cost recovery variances from forecast.

6. ACCOUNTS RECEIVABLE AND OTHER CURRENT ASSETS

($ millions)	**2021**	2020
Trade accounts receivable	**621**	595
Unbilled accounts receivable	**701**	571
Allowance for credit losses	**(53)**	(64)
	1,269	1,102
Income tax receivable	**—**	72
Other [1]	**242**	195
	1,511	1,369

[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 25)*

Allowance for Credit Losses

The allowance for credit losses changed as follows.

($ millions)	**2021**	2020
Balance, beginning of year	**(64)**	(35)
Credit loss expensed	**(7)**	(36)
Credit loss deferral	**—**	(6)
Write-offs, net of recoveries	**18**	14
Foreign exchange	**—**	(1)
Balance, end of year	**(53)**	(64)

7. INVENTORIES

($ millions)	**2021**	2020
Materials and supplies	**318**	297
Gas and fuel in storage	**131**	101
Coal inventory	**29**	24
	478	422

8. REGULATORY ASSETS AND LIABILITIES

($ millions)	**2021**	2020
Regulatory assets		
Deferred income taxes (Notes 3 and 22)	**1,806**	1,697
Employee future benefits (Notes 3 and 23)	**388**	588
Deferred energy management costs [1]	**384**	334
Rate stabilization and related accounts [2]	**339**	213
Deferred lease costs [3]	**127**	122
Manufactured gas plant site remediation deferral (Note 16)	**96**	107
Generation early retirement costs [4]	**48**	55
Derivatives (Notes 3 and 25)	**20**	73
Other regulatory assets [5]	**381**	399
Total regulatory assets	**3,589**	3,588
Less: Current portion	**(492)**	(470)
Long-term regulatory assets	**3,097**	3,118
Regulatory liabilities		
Deferred income taxes (Notes 3 and 22)	**1,289**	1,361
Future cost of removal (Note 3)	**1,217**	1,206
Employee future benefits (Notes 3 and 23)	**196**	43
Rate stabilization and related accounts [2]	**116**	104
Renewable energy surcharge [6]	**107**	100
Energy efficiency liability [7]	**83**	83
Derivatives (Notes 3 and 25)	**52**	17
Other regulatory liabilities [5]	**162**	189
Total regulatory liabilities	**3,222**	3,103
Less: Current portion	**(357)**	(441)
Long-term regulatory liabilities	**2,865**	2,662

[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 two 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] ***Generation Early Retirement Costs:*** TEP and the co-owners of Navajo Generating Station ("Navajo") retired Navajo in 2019, with related decommissioning activities continuing through 2054. TEP also retired Sundt Generating Facility Units 1 and 2 ("Sundt") in 2019. In 2020, the ACC approved the recovery of the retirement costs of Navajo and Sundt over a 10-year period.

[5] ***Other Regulatory Assets and Liabilities:*** Comprised of regulatory assets and liabilities individually less than $40 million.

[6] ***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.

8. REGULATORY ASSETS AND LIABILITIES (cont'd)

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.

(7) ***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.

Regulatory assets not earning a return: (i) totalled $1,727 million and $1,678 million as at December 31, 2021 and 2020, 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)	**2021**	2020
Employee future benefits (Note 23)	**259**	66
Supplemental Executive Retirement Plan ("SERP")	**165**	155
RECs (Note 8)	**112**	106
Other investments	**86**	66
Equity investment - Belize Electricity	**80**	80
Deferred compensation plan	**42**	36
Operating leases (Note 15)	**40**	40
Derivatives	**40**	4
Equity investment - Wataynikaneyap Partnership	**12**	12
Other	**119**	105
	955	670

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 25).

10. PROPERTY, PLANT AND EQUIPMENT

($ millions)	**Cost**	**Accumulated Depreciation**	**Net Book Value**
2021			
Distribution			
Electric	**12,321**	**(3,359)**	**8,962**
Gas	**5,838**	**(1,504)**	**4,334**
Transmission			
Electric	**17,104**	**(3,610)**	**13,494**
Gas	**2,453**	**(756)**	**1,697**
Generation	**7,014**	**(2,691)**	**4,323**
Other	**4,362**	**(1,454)**	**2,908**
Assets under construction	**1,759**	**—**	**1,759**
Land	**339**	**—**	**339**
	51,190	**(13,374)**	**37,816**

10. PROPERTY, PLANT AND EQUIPMENT (cont'd)

($ millions)	Cost	Accumulated depreciation	Net Book Value
2020			
Distribution			
Electric	11,921	(3,223)	8,698
Gas	5,546	(1,422)	4,124
Transmission			
Electric	15,888	(3,413)	12,475
Gas	2,360	(719)	1,641
Generation	6,441	(2,550)	3,891
Other	4,178	(1,347)	2,831
Assets under construction	2,012	—	2,012
Land	326	—	326
	48,672	(12,674)	35,998

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")) or a hoop stress of less than 20% of standard minimum yield strength. 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) or a hoop stress of 20% or more of standard minimum yield strength. 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, information technology assets and assets associated with natural gas storage at Aitken Creek.

As at December 31, 2021, assets under construction largely reflect ongoing transmission projects at ITC and UNS Energy.

The cost of PPE under finance lease as at December 31, 2021 was $323 million (2020 - $322 million) and related accumulated depreciation was $113 million (2020 - $111 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, 2021, interests in jointly owned facilities consisted of the following.

($ millions, except as indicated)	**Ownership** *(%)*	**Cost**	**Accumulated Depreciation**	**Net Book Value**
Transmission Facilities	1.0-80.0	**958**	**(290)**	**668**
Springerville Common Facilities	86.0	**504**	**(262)**	**242**
San Juan Unit 1 ("San Juan")	50.0	**361**	**(340)**	**21**
Springerville Coal Handling Facilities	83.0	**264**	**(120)**	**144**
Four Corners Units 4 and 5 ("Four Corners")	7.0	**243**	**(102)**	**141**
Gila River Common Facilities	50.0	**109**	**(38)**	**71**
Luna Energy Facility ("Luna")	33.3	**76**	**(4)**	**72**
		2,515	**(1,156)**	**1,359**

For the years ended December 31, 2021 and 2020

11. INTANGIBLE ASSETS

($ millions)	Cost	Accumulated Amortization	Net Book Value
2021			
Computer software	**952**	**(518)**	**434**
Land, transmission and water rights	**941**	**(154)**	**787**
Other	**113**	**(69)**	**44**
Assets under construction	**78**	**—**	**78**
	2,084	**(741)**	**1,343**
2020			
Computer software	932	(524)	408
Land, transmission and water rights	898	(142)	756
Other	114	(64)	50
Assets under construction	77	—	77
	2,021	(730)	1,291

Included in the cost of land, transmission and water rights as at December 31, 2021 was $137 million (2020 - $136 million) not subject to amortization. Amortization expense was $136 million for 2021 (2020 - $131 million). Amortization is estimated to average approximately $82 million for each of the next five years.

12. GOODWILL

($ millions)	2021	2020
Balance, beginning of year	**11,792**	12,004
Foreign currency translation impacts [(1)]	**(72)**	(212)
Balance, end of year	**11,720**	11,792

[(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 2021 or 2020.

13. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

($ millions)	2021	2020
Trade accounts payable	**774**	707
Employee compensation and benefits payable	**283**	248
Gas and fuel cost payable	**269**	188
Dividends payable	**259**	241
Accrued taxes other than income taxes	**238**	224
Customer and other deposits	**222**	214
Interest payable	**218**	215
Derivatives (Note 25)	**43**	56
Income taxes payable	**31**	—
Employee future benefits (Note 23)	**26**	26
Manufactured gas plant site remediation (Note 16)	**13**	31
Other	**194**	171
	2,570	2,321

14. LONG-TERM DEBT

($ millions)	Maturity Date	**2021**	2020
ITC			
Secured U.S. First Mortgage Bonds -			
4.31% weighted average fixed rate (2020 - 4.31%)	2024-2055	**2,736**	2,755
Secured U.S. Senior Notes -			
3.90% weighted average fixed rate (2020 - 4.00%)	2040-2055	**1,011**	923
Unsecured U.S. Senior Notes -			
3.61% weighted average fixed rate (2020 - 3.61%)	2022-2043	**4,108**	4,136
Unsecured U.S. Shareholder Note -			
6.00% fixed rate (2020 - 6.00%)	2028	**252**	253
UNS Energy			
Unsecured U.S. Tax-Exempt Bonds - 4.34% weighted			
average fixed and variable rate (2020 - 4.34%)	2029-2030	**359**	362
Unsecured U.S. Fixed Rate Notes -			
3.62% weighted average fixed rate (2020 - 3.86%)	2023-2051	**2,780**	2,704
Central Hudson			
Unsecured U.S. Promissory Notes - 3.83% weighted			
average fixed and variable rate (2020 - 3.94%)	2022-2060	**1,177**	1,078
FortisBC Energy			
Unsecured Debentures -			
4.61% weighted average fixed rate (2020 - 4.72%)	2026-2050	**3,145**	2,995
FortisAlberta			
Unsecured Debentures -			
4.49% weighted average fixed rate (2020 - 4.49%)	2024-2052	**2,360**	2,360
FortisBC Electric			
Secured Debentures -			
8.80% fixed rate (2020 - 8.80%)	2023	**25**	25
Unsecured Debentures -			
4.77% weighted average fixed rate (2020 - 4.87%)	2035-2050	**760**	785
Other Electric			
Secured First Mortgage Sinking Fund Bonds -			
5.61% weighted average fixed rate (2020 - 5.61%)	2022-2060	**627**	634
Secured First Mortgage Bonds -			
5.31% weighted average fixed rate (2020 - 5.66%)	2025-2061	**260**	220
Unsecured Senior Notes -			
4.45% weighted average fixed rate (2020 - 4.45%)	2041-2048	**152**	152
Unsecured U.S. Senior Loan Notes and Bonds -			
4.36% weighted average fixed and variable rate (2020 - 4.41%)	2022-2049	**609**	648
Corporate and Other			
Unsecured U.S. Senior Notes and Promissory Notes -			
3.82% weighted average fixed rate (2020 - 3.81%)	2023-2044	**2,509**	2,685
Unsecured Debentures -			
6.50% fixed rate (2020 - 6.50%)	2039	**200**	200
Unsecured Senior Notes -			
2.52% weighted average fixed rate (2020 - 2.85%)	2023-2028	**1,000**	500
Long-term classification of credit facility borrowings		**1,305**	980
Fair value adjustment - ITC acquisition		**107**	119
Total long-term debt (Note 25)		**25,482**	24,514
Less: Deferred financing costs and debt discounts		**(147)**	(147)
Less: Current installments of long-term debt		**(1,628)**	(1,254)
		23,707	23,113

14. LONG-TERM DEBT (cont'd)

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.

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%.

Long-Term Debt Issuances in 2021	**Month Issued**	**Interest Rate** *(%)*	**Maturity**	**Amount** *($ millions)*	**Use of Proceeds**
ITC					
Series A secured senior notes [1]	August	2.90	2051	**US 75**	[2]
UNS Energy					
Unsecured senior notes	May	3.25	2051	**US 325**	[3][4]
Central Hudson					
Unsecured senior notes	March	3.29	2051	**US 75**	[3][4]
Unsecured senior notes	October	3.22	2051	**US 55**	[3][5]
FortisBC Energy					
Unsecured debentures	April	2.42	2031	**150**	[5]
Maritime Electric					
Secured first mortgage bonds	December	3.40	2051	**40**	[5]
Fortis					
Unsecured senior notes	May	2.18	2028	**500**	[3][4][5]

[1] *US$75 million Series B secured senior notes were priced at 3.05% with issuance expected in May 2022*
[2] *Fund or refinance a portfolio of eligible green projects*
[3] *General corporate purposes*
[4] *Repay maturing long-term debt*
[5] *Repay credit facility borrowings*

In January 2022, ITC issued 30-year US$150 million secured first mortgage bonds at 2.93%. The net proceeds are expected to be used to repay credit facility borrowings, fund or refinance a portfolio of eligible green projects, fund capital expenditures and for other general corporate purposes.

In January 2022, Central Hudson issued 5-year US$50 million unsecured senior notes at 2.37% and 7-year US$60 million unsecured senior notes at 2.59%. The net proceeds are expected to be used to repay maturing long-term debt and for general corporate purposes.

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**
2022	1,628
2023	1,275
2024	1,750
2025	101
2026	2,595
Thereafter	18,133
	25,482

In December 2020, 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. In May 2021, the Corporation issued $500 million unsecured senior notes as shown above and, as at December 31, 2021, $1.5 billion remained available under the short-form base shelf prospectus.

14. LONG-TERM DEBT (cont'd)

Credit Facilities

($ millions)	Regulated Utilities	Corporate and Other	**2021**	2020
Total credit facilities	3,466	1,380	**4,846**	5,581
Credit facilities utilized:				
Short-term borrowings [1]	(247)	—	**(247)**	(132)
Long-term debt (including current portion) [2]	(1,019)	(286)	**(1,305)**	(980)
Letters of credit outstanding	(70)	(45)	**(115)**	(130)
Credit facilities unutilized	2,130	1,049	**3,179**	4,339

[1] *The weighted average interest rate was approximately 0.6% (2020 - 0.8%).*
[2] *The weighted average interest rate was approximately 0.9% (2020 - 0.9%). The current portion was $888 million (2020 - $651 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 total facilities. Approximately $4.6 billion of the total credit facilities are committed facilities with maturities ranging from 2022 through 2026.

Consolidated credit facilities of approximately $4.8 billion as at December 31, 2021 are itemized below. In April 2021, the Corporation's unsecured $500 million revolving one-year term committed credit facility expired and was not renewed. In October 2021, UNS Energy terminated a US$150 million revolving credit facility and entered into an arrangement with Fortis (Note 4).

($ millions)		**Amount**	Maturity
Unsecured committed revolving credit facilities			
Regulated utilities			
ITC [1]	**US**	**900**	2024
UNS Energy	**US**	**375**	2026
Central Hudson	**US**	**200**	2025
FortisBC Energy		**700**	2026
FortisAlberta		**250**	2026
FortisBC Electric		**150**	2026
Other Electric		**215**	[2]
Other Electric	**US**	**70**	2025
Corporate and Other		**1,350**	[3]
Other facilities			
Regulated utilities			
Central Hudson - uncommitted credit facility	**US**	**30**	n/a
FortisBC Energy - uncommitted credit facility		**55**	2023
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**	**60**	2022
Corporate and Other - unsecured non-revolving facility		**30**	n/a

[1] *ITC also has a US$400 million commercial paper program, under which US$155 million was outstanding as at December 31, 2021 (2020 - US$67 million) , as reported in short-term borrowings.*
[2] *$50 million in 2024, $65 million in 2024 and $100 million in 2026*
[3] *$50 million in 2023 and $1.3 billion in 2026*

15. LEASES

The Corporation and its subsidiaries lease office facilities, utility equipment, land, and communication tower space with remaining terms of up to 20 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 34 years.

Leases were presented on the consolidated balance sheets as follows.

($ millions)	**2021**	2020
Operating leases		
Other assets	**40**	40
Accounts payable and other current liabilities	**(8)**	(7)
Other liabilities	**(32)**	(33)
Finance leases [1]		
Regulatory assets	**127**	122
PPE, net	**210**	211
Accounts payable and other current liabilities	**(4)**	(2)
Finance leases	**(333)**	(331)

[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.*

The components of lease expense were as follows.

($ millions)	**2021**	2020
Operating lease cost	**8**	10
Finance lease cost:		
Amortization	**2**	14
Interest	**32**	34
Variable lease cost	**19**	20
Total lease cost	**61**	78

As at December 31, 2021, the present value of minimum lease payments was as follows.

($ millions)	Operating Leases	Finance Leases	**Total**
2022	8	35	**43**
2023	7	34	**41**
2024	6	34	**40**
2025	5	34	**39**
2026	3	35	**38**
Thereafter	20	1,030	**1,050**
	49	1,202	**1,251**
Less: Imputed interest	(9)	(865)	**(874)**
Total lease obligations	40	337	**377**
Less: Current installments	(8)	(4)	**(12)**
	32	333	**365**

15. LEASES (cont'd)

Supplemental lease information follows.

($ millions, except as indicated)	**2021**	2020
Weighted average remaining lease term *(years)*		
Operating leases	**10**	10
Finance leases	**34**	35
Weighted average discount rate *(%)*		
Operating leases	**3.8**	4.0
Finance leases	**5.1**	5.1
Cash payments related to lease liabilities		
Operating cash flows used for operating leases	**(8)**	(10)
Operating cash flows used for finance leases	**—**	(2)
Financing cash flows used for finance leases	**(2)**	(25)
Investing cash flows used for finance leases	**—**	(87)

16. OTHER LIABILITIES

($ millions)	**2021**	2020
Employee future benefits (Note 23)	**740**	905
AROs (Note 3)	**184**	130
Customer and other deposits	**99**	132
Stock-based compensation plans (Note 20)	**96**	86
Manufactured gas plant site remediation [(1)]	**83**	69
Deferred compensation plan (Note 9)	**50**	43
Mine reclamation obligations [(2)]	**44**	47
Retail energy contract [(3)]	**40**	46
Operating leases	**32**	33
Derivatives (Note 25)	**7**	50
Other	**34**	58
	1,409	1,599

[(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. As at December 31, 2021, an obligation of $91 million was recognized, including a current portion of $8 million recognized in accounts payable and other current liabilities (Note 13). 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 $56 million upon expiry of the coal agreements between 2022 and 2031. The present value of the estimated future liability is shown in the table above.

[(3)] In 2020, FortisAlberta entered into an eight-year agreement with an existing retail energy provider to continue 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 life of the agreement.

17. EARNINGS PER COMMON SHARE

Diluted earnings per share ("EPS") was calculated using the treasury stock method for stock options.

	2021			2020		
	Net Earnings to Common Shareholders *($ millions)*	**Weighted Average Shares** *(# millions)*	**EPS** *($)*	Net Earnings to Common Shareholders *($ millions)*	Weighted Average Shares *(# millions)*	EPS *($)*
Basic EPS	**1,231**	**470.9**	**2.61**	1,209	464.8	2.60
Potential dilutive effect of stock options	**—**	**0.5**	**—**	—	0.6	—
Diluted EPS	**1,231**	**471.4**	**2.61**	1,209	465.4	2.60

18. PREFERENCE SHARES

Authorized

An unlimited number of first preference shares and second preference shares, without nominal or par value.

Issued and Outstanding

	2021		2020	
First Preference Shares	**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

Characteristics of the first preference shares are as follows.

First Preference Shares [1] [2]	**Initial Yield** *(%)*	**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	5.25	1.0983	2.13	September 1, 2023	25.00	—
Series H [5]	4.25	0.4588	1.45	June 1, 2025	25.00	Series I
Series K	4.00	0.9823	2.05	March 1, 2024	25.00	Series L
Series M	4.10	0.9783	2.48	December 1, 2024	25.00	Series N
Floating rate reset [4] [6]						
Series I	2.10	—	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 annual dividend per share for the First Preference Shares, Series H was reset from $0.6250 to $0.4588 for the five-year period from June 1, 2020 up to but excluding June 1, 2025.*

[6] *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.*

18. PREFERENCE SHARES *(cont'd)*

On June 1, 2020, 267,341 First Preference Shares, Series H were converted on a one-for-one basis into First Preference Shares, Series I, and 907,577 First Preference Shares, Series I were converted on a one-for-one basis into First Preference Shares, Series H.

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**
2021			
Unrealized foreign currency translation gains (losses)			
Net investments in foreign operations	**377**	**(104)**	**273**
Hedges of net investments in foreign operations	**(299)**	**23**	**(276)**
Income tax expense	**(6)**	**(2)**	**(8)**
	72	**(83)**	**(11)**
Other			
Cash flow hedges (Note 25)	**(4)**	**(1)**	**(5)**
Unrealized employee future benefits (losses) gains (Note 23)	**(49)**	**13**	**(36)**
Income tax recovery (expense)	**15**	**(3)**	**12**
	(38)	**9**	**(29)**
Accumulated other comprehensive income	**34**	**(74)**	**(40)**
2020			
Unrealized foreign currency translation gains (losses)			
Net investments in foreign operations	713	(336)	377
Hedges of net investments in foreign operations	(359)	60	(299)
Income tax expense	(3)	(3)	(6)
	351	(279)	72
Other			
Cash flow hedges (Note 25)	17	(21)	(4)
Unrealized employee future benefits losses (Note 23)	(38)	(11)	(49)
Income tax recovery	6	9	15
	(15)	(23)	(38)
Accumulated other comprehensive income	336	(302)	34

20. STOCK-BASED COMPENSATION PLANS

Stock Options

Officers and certain key employees of Fortis and its subsidiaries are eligible for grants of options to purchase common shares of the Corporation. Options 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.

20. STOCK-BASED COMPENSATION PLANS (cont'd)

The following options were granted in 2021 and 2020.

	2021	2020
Options granted *(thousands)*	**431**	686
Exercise price *($)* [1]	**50.33**	58.40
Grant date fair value *($)*	**4.91**	4.20
Valuation assumptions:		
Dividend yield *(%)* [2]	**3.8**	3.7
Expected volatility *(%)* [3]	**20.0**	15.8
Risk-free interest rate *(%)* [4]	**0.9**	1.2
Weighted average expected life *(years)* [5]	**5.0**	5.2

[1] *Five-day VWAP immediately preceding the grant date*
[2] *Reflects average annual dividend yield up to the grant date and the weighted average expected life of the options*
[3] *Reflects historical experience over a period equal to the weighted average expected life of the options*
[4] *Government of Canada benchmark bond yield at the grant date that covers the weighted average expected life of the options*
[5] *Reflects historical experience*

The following table summarizes information related to stock options for 2021.

	Total Options		Non-vested Options [1]	
(thousands, except as indicated)	Number of Options	Weighted Average Exercise Price *($)*	Number of Options	Weighted Average Grant Date Fair Value *($)*
Options outstanding, beginning of year	**3,262**	**45.26**	**1,772**	**3.81**
Granted	**431**	**50.33**	**431**	**4.91**
Exercised	**(777)**	**40.80**	**n/a**	**n/a**
Vested	**n/a**	**n/a**	**(715)**	**3.67**
Cancelled/Forfeited	**—**	**—**	**—**	**—**
Options outstanding, end of year	**2,916**	**47.20**	**1,488**	**4.20**
Options vested, end of year [2]	**1,428**	**42.76**		

[1] *As at December 31, 2021, there was $6 million of unrecognized compensation expense related to stock options not yet vested, which is expected to be recognized over a weighted average period of approximately three years.*
[2] *As at December 31, 2021, the weighted average remaining term of vested options was six years with an aggregate intrinsic value of $26 million.*

The following table summarizes additional stock option information.

($ millions)	2021	2020
Stock options exercised:		
Cash received for exercise price	**32**	32
Intrinsic value realized by employees	**11**	15

DSU Plan

Directors of the Corporation who are not officers are eligible for grants of DSUs representing the equity portion of their annual compensation. Directors can further 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.

20. STOCK-BASED COMPENSATION PLANS (cont'd)

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.

The following table summarizes information related to DSUs.

	2021	2020
Number of units *(thousands)*		
Beginning of year	**147**	165
Granted	**30**	25
Notional dividends reinvested	**6**	6
Paid out	**—**	(49)
End of year	**183**	147

The accrued liability has been recognized at the respective December 31st VWAP (Note 3) and included in other liabilities (Note 16). The accrued liability, compensation expense and cash payout were not material for 2021 or 2020.

PSU Plans

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, is entitled to commensurate notional common share dividends, and is settled in cash. At the end of the three-year vesting period, cash payouts are the product of: (i) the numbers 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%.

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; and (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.

The following table summarizes information related to PSUs.

	2021	2020
Number of units *(thousands)*		
Beginning of year	**1,976**	2,118
Granted	**587**	586
Notional dividends reinvested	**60**	71
Paid out	**(697)**	(735)
Cancelled/forfeited	**(28)**	(64)
End of year	**1,898**	1,976
Additional information *($ millions)*		
Compensation expense recognized	**74**	58
Compensation expense unrecognized [(1)]	**33**	32
Cash payout	**50**	54
Accrued liability as at December 31 [(2)]	**132**	108
Aggregate intrinsic value as at December 31 [(3)]	**165**	140

[(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)

RSU Plans

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 or immediately upon retirement eligibility of the holder, 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, beginning with the 2020 grant, common shares of the Corporation. Effective January 1, 2020, new RSU issuances may be settled in cash, common shares, or an equal proportion of cash and common shares depending on an executives' settlement election and whether their share ownership requirements have been met.

The following table summarizes information related to RSUs.

	2021	2020
Number of units *(thousands)*		
Beginning of year	**1,048**	1,050
Granted	**378**	356
Notional dividends reinvested	**32**	37
Paid out	**(371)**	(355)
Cancelled/forfeited	**(27)**	(40)
End of year	**1,060**	1,048
Additional information *($ millions)*		
Compensation expense recognized	**26**	20
Compensation expense unrecognized [(1)]	**17**	15
Cash payout	**21**	19
Accrued liability as at December 31 [(2)]	**46**	39
Aggregate intrinsic value as at December 31 [(3)]	**63**	54

[(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*

21. OTHER INCOME, NET

($ millions)	**2021**	2020
Equity component of AFUDC	**77**	78
Non-service benefit cost	**45**	31
Derivative gains	**30**	13
Equity income	**7**	20
Interest income	**5**	13
Other	**9**	(1)
	173	154

22. INCOME TAXES

Deferred Income Tax Assets and Liabilities

The significant components of deferred income tax assets and liabilities consisted of the following.

($ millions)	**2021**	2020
Gross deferred income tax assets		
Regulatory liabilities	**560**	527
Tax loss and credit carryforwards	**556**	494
Employee future benefits	**169**	175
Other	**91**	116
	1,376	1,312
Valuation allowance	**(23)**	(22)
Net deferred income tax asset	**1,353**	1,290
Gross deferred income tax liabilities		
PPE	**(4,571)**	(4,253)
Regulatory assets	**(283)**	(263)
Intangible assets	**(126)**	(118)
	(4,980)	(4,634)
Net deferred income tax liability	**(3,627)**	(3,344)

Unrecognized Tax Benefits

($ millions)	**2021**	2020
Beginning of year	**33**	36
Additions related to current year	**2**	3
Adjustments related to prior years [(1)]	**(33)**	(6)
End of year	**2**	33

(i) UNS Energy received approval from the Internal Revenue Service to change its accounting method related to an uncertain tax position which resulted in a decrease in uncertain tax benefits..

Unrecognized tax benefits, if recognized, would reduce income tax expense by $1 million in 2021. Fortis has not recognized interest expense in 2021 and 2020 related to unrecognized tax benefits.

Income Tax Expense

($ millions)	**2021**	2020
Canadian		
Earnings before income tax expense	**427**	333
Current income tax	**84**	20
Deferred income tax	**(35)**	(16)
Total Canadian	**49**	4
Foreign		
Earnings before income tax expense	**1,212**	1,287
Current income tax	**3**	(15)
Deferred income tax	**182**	242
Total Foreign	**185**	227
Income tax expense	**234**	231

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.

22. INCOME TAXES (cont'd)

The following is a reconciliation of consolidated statutory taxes to consolidated effective taxes.

($ millions, except as indicated)	**2021**	2020
Earnings before income tax expense	**1,639**	1,620
Combined Canadian federal and provincial statutory income tax rate *(%)*	**30.0**	30.0
Expected federal and provincial taxes at statutory rate	**492**	486
Decrease resulting from:		
Foreign and other statutory rate differentials	**(157)**	(145)
AFUDC	**(16)**	(20)
Effects of rate-regulated accounting:		
Difference between depreciation claimed for income tax and accounting purposes	**(47)**	(56)
Items capitalized for accounting purposes but expensed for income tax purposes	**(13)**	(26)
Other	**(25)**	(8)
Income tax expense	**234**	231
Effective tax rate *(%)*	**14.3**	14.3

Income Tax Carryforwards

($ millions)	Expiring Year	**2021**
Canadian		
Capital loss	n/a	**15**
Non-capital loss	2028-2041	**308**
Other tax credits	2026-2041	**2**
		325
Unrecognized		**(15)**
		310
Foreign		
Federal and state net operating loss	2022-2041	**3,070**
Other tax credits	2023-2041	**90**
		3,160
Total income tax carryforwards recognized		**3,470**

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 2013 to 2021 taxation years are still open for audit in Canadian jurisdictions, and its 2011 to 2021 taxation years are still open for audit in United States jurisdictions.

23. EMPLOYEE FUTURE BENEFITS

For defined benefit pension 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, 2018 for FortisBC Energy and FortisBC Electric (plan covering unionized employees); December 31, 2019 for the remaining FortisBC Electric plans, Newfoundland Power, FortisAlberta and FortisOntario; December 31, 2020 for the Corporation; and December 31, 2021 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 defined benefit pension 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.

23. EMPLOYEE FUTURE BENEFITS (cont'd)

Allocation of Plan Assets *(weighted average %)*	**2021 Target Allocation**	**2021**	2020
Equities	**47**	**48**	48
Fixed income	**46**	**45**	45
Real estate	**6**	**6**	6
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**
2021				
Equities	**749**	**1,271**	**—**	**2,020**
Fixed income	**219**	**1,642**	**—**	**1,861**
Real estate	**—**	**—**	**235**	**235**
Private equities	**—**	**—**	**21**	**21**
Cash and other	**10**	**15**	**—**	**25**
	978	**2,928**	**256**	**4,162**
2020				
Equities	713	1,163	—	1,876
Fixed income	197	1,580	—	1,777
Real estate	—	17	204	221
Private equities	—	—	20	20
Cash and other	8	17	—	25
	918	2,777	224	3,919

[1] *See Note 25 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)	**2021**	2020
Balance, beginning of year	**224**	229
Return (loss) on plan assets	**32**	(2)
Foreign currency translation	**—**	(1)
Purchases, sales and settlements	**—**	(2)
Balance, end of year	**256**	224

23. EMPLOYEE FUTURE BENEFITS (cont'd)

Funded Status

	Defined Benefit Pension Plans		OPEB Plans	
($ millions)	**2021**	2020	**2021**	2020
Change in benefit obligation [1]				
Balance, beginning of year	**3,995**	3,632	**789**	712
Service costs	**109**	98	**35**	32
Employee contributions	**18**	17	**2**	2
Interest costs	**98**	113	**19**	22
Benefits paid	**(170)**	(162)	**(25)**	(27)
Actuarial (gains) losses	**(111)**	350	**(70)**	62
Past service credits/plan amendments	**(2)**	—	**—**	(3)
Foreign currency translation	**(15)**	(53)	**(3)**	(11)
Balance, end of year [2]	**3,922**	3,995	**747**	789
Change in value of plan assets				
Balance, beginning of year	**3,528**	3,208	**391**	343
Actual return on plan assets	**291**	444	**48**	55
Benefits paid	**(158)**	(155)	**(21)**	(27)
Employee contributions	**18**	17	**2**	2
Employer contributions	**55**	62	**22**	28
Foreign currency translation	**(12)**	(48)	**(2)**	(10)
Balance, end of year	**3,722**	3,528	**440**	391
Funded status	**(200)**	(467)	**(307)**	(398)
Balance sheet presentation				
Other assets (Note 9)	**204**	58	**55**	8
Other current liabilities (Note 13)	**(13)**	(13)	**(13)**	(13)
Other liabilities (Note 16)	**(391)**	(512)	**(349)**	(393)
	(200)	(467)	**(307)**	(398)

[1] *Amounts reflect projected benefit obligation for defined benefit pension plans and accumulated benefit obligation for OPEB plans.*
[2] *The accumulated benefit obligation, which excludes assumptions about future salary levels, for defined benefit pension plans was $3,586 million as at December 31, 2021 (2020 - $3,679 million).*

For those defined benefit pension plans for which the projected benefit obligation exceeded the fair value of plan assets as at December 31, 2021, the obligation was $2,188 million compared to plan assets of $1,799 million (2020 - $3,290 million and $2,777 million, respectively).

For those defined benefit pension plans for which the accumulated benefit obligation exceeded the fair value of plan assets as at December 31, 2021, the obligation was $1,243 million compared to plan assets of $1,063 million (2020 - $3,037 million and $2,741 million, respectively).

For those OPEB plans for which the accumulated benefit obligation exceeded the fair value of plan assets as at December 31, 2021, the obligation was $398 million compared to plan assets of $36 million (2020 - $589 million and $183 million, respectively).

Net Benefit Cost [1]

	Defined Benefit Pension Plans		OPEB Plans	
($ millions)	**2021**	2020	**2021**	2020
Service costs	**109**	98	**35**	32
Interest costs	**98**	113	**19**	22
Expected return on plan assets	**(177)**	(176)	**(19)**	(19)
Amortization of actuarial losses (gains)	**36**	33	**(2)**	(5)
Amortization of past service credits/plan amendments	**(1)**	(1)	**(1)**	(2)
Regulatory adjustments	**(1)**	—	**3**	4
	64	67	**35**	32

[1] *The non-service benefit cost components of net periodic benefit cost are included in other income, net in the consolidated statements of earnings.*

23. 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.

	Defined Benefit Pension Plans		OPEB Plans	
($ millions)	**2021**	2020	**2021**	2020
Unamortized net actuarial losses (gains)	**33**	42	**(5)**	(1)
Unamortized past service costs	**1**	1	**7**	7
Income tax recovery	**(8)**	(10)	**—**	(1)
Accumulated other comprehensive income	**26**	33	**2**	5
Net actuarial losses (gains)	**260**	517	**(81)**	12
Past service credits	**(5)**	(7)	**(6)**	(8)
Other regulatory deferrals	**10**	13	**14**	18
	265	523	**(73)**	22
Regulatory assets (Note 8)	**376**	523	**12**	65
Regulatory liabilities (Note 8)	**(111)**	—	**(85)**	(43)
Net regulatory assets (liabilities)	**265**	523	**(73)**	22

The following table summarizes the components of net benefit cost recognized in comprehensive income or as regulatory assets or liabilities.

	Defined Benefit Pension Plans		OPEB Plans	
($ millions)	**2021**	2020	**2021**	2020
Current year net actuarial (gains) losses	**(10)**	9	**(4)**	1
Amortization of actuarial losses	**1**	1	**—**	—
Income tax expense (recovery)	**2**	(2)	**1**	—
Total recognized in comprehensive income	**(7)**	8	**(3)**	1
Current year net actuarial (gains) losses	**(220)**	69	**(95)**	25
Past service credits/plan amendments	**—**	—	**—**	(3)
Amortization of actuarial (losses) gains	**(35)**	(31)	**2**	5
Amortization of past service credits	**2**	2	**2**	3
Foreign currency translation	**(2)**	(7)	**—**	—
Regulatory adjustments	**(3)**	(2)	**(4)**	(1)
Total recognized in regulatory (liabilities) assets	**(258)**	31	**(95)**	29

Significant Assumptions

	Defined Benefit Pension Plans		OPEB Plans	
(weighted average %)	**2021**	2020	**2021**	2020
Discount rate during the year [1]	**2.60**	3.16	**2.60**	3.22
Discount rate as at December 31	**3.00**	2.63	**2.97**	2.64
Expected long-term rate of return on plan assets [2]	**5.40**	5.52	**4.88**	5.28
Rate of compensation increase	**3.30**	3.34	**—**	—
Health care cost trend increase as at December 31 [3]	**—**	—	**4.49**	4.61

[1] *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 2022 weighted average health care cost trend rate is 5.75% and is assumed to decrease over the next 11 years to the weighted average ultimate health care cost trend rate of 4.49% in 2032 and thereafter.*

23. EMPLOYEE FUTURE BENEFITS (cont'd)

Expected Benefit Payments *($ millions)*	**Defined Benefit Pension Payments**	**OPEB Payments**
2022	$ 168	$ 28
2023	172	29
2024	176	30
2025	181	32
2026	189	33
2027-2031	1,019	175

During 2022, the Corporation expects to contribute $49 million for defined benefit pension plans and $27 million for OPEB plans.

In 2021, the Corporation expensed $44 million (2020 - $42 million) related to defined contribution pension plans.

24. SUPPLEMENTARY CASH FLOW INFORMATION

($ millions)	**2021**	2020
Cash paid (received) for		
Interest	**986**	1,027
Income taxes	**(13)**	(26)
Change in working capital		
Accounts receivable and other current assets	**(88)**	(84)
Prepaid expenses	**(15)**	(15)
Inventories	**(56)**	(36)
Regulatory assets - current portion	**(99)**	(49)
Accounts payable and other current liabilities	**164**	(100)
Regulatory liabilities - current portion	**(50)**	(150)
	(144)	(434)
Non-cash investing and financing activities		
Accrued capital expenditures	**432**	400
Common share dividends reinvested	**356**	114
Contributions in aid of construction	**13**	13

25. 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.

The Corporation records all derivatives 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.

Cash flow associated with the settlement of all derivatives is included in operating activities on the consolidated statements of cash flows.

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.

25. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (cont'd)

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, 2021, unrealized losses of $20 million (2020 - $73 million) were recognized as regulatory assets and unrealized gains of $52 million (2020 - $17 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 holds gas swap contracts to manage its exposure to changes in natural gas prices, capture natural gas price spreads, and manage the financial risk posed by physical transactions. Fair values are measured using forward pricing from published market sources.

Unrealized gains or losses associated with changes in the fair value of these energy contracts are recognized in revenue. In 2021, unrealized gains of $21 million (2020 - $3 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 settlements of certain stock-based compensation obligations. The swaps have a combined notional amount of $112 million and terms of one to three years expiring at varying dates through January 2024. 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 2021, unrealized gains of $17 million (2020 - unrealized losses of $9 million) 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 November 2022 and have a combined notional amount of $161 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 2021, unrealized losses of $11 million (2020 - unrealized gains of $11 million) were recognized in other income, net.

Interest Rate Swaps

In 2021, ITC entered into interest rate swaps with a total notional value of US$375 million to manage the interest rate risk associated with the refinancing of long-term debt due in November 2022. The swaps have five-year terms, include mandatory early termination provisions, and will be terminated no later than the effective date of November 15, 2022. Fair value was measured using a discounted cash flow method based on LIBOR rates. Unrealized gains and losses associated with the changes in fair value are recognized in other comprehensive income, will be reclassified to earnings as a component of interest expense over the life of the debt, and were not material for 2021.

Other Investments

ITC and Central Hudson hold investments in trust associated with supplemental retirement benefit plans for select employees. These investments include mutual funds and money market accounts, which are recorded at fair value based on quoted market prices in active markets. Gains and losses are recognized in other income, net. In 2021, unrealized gains of $9 million (2020 - $7 million) were recognized in other income, net.

25. 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, 2021				
Assets				
Energy contracts subject to regulatory deferral [2][3]	**—**	**78**	**—**	**78**
Energy contracts not subject to regulatory deferral [2]	**—**	**16**	**—**	**16**
Foreign exchange contracts, total return and interest rate swaps [2]	**23**	**2**	**—**	**25**
Other investments [4]	**137**	**—**	**—**	**137**
	160	**96**	**—**	**256**
Liabilities				
Energy contracts subject to regulatory deferral [3][5]	**—**	**(46)**	**—**	**(46)**
Energy contracts not subject to regulatory deferral [5]	**—**	**(3)**	**—**	**(3)**
	—	**(49)**	**—**	**(49)**
As at December 31, 2020				
Assets				
Energy contracts subject to regulatory deferral [2][3]	—	38	—	38
Energy contracts not subject to regulatory deferral [2]	—	6	—	6
Foreign exchange contracts and total return swaps [2]	16	—	—	16
Other investments [4]	126	—	—	126
	142	44	—	186
Liabilities				
Energy contracts subject to regulatory deferral [3][5]	—	(94)	—	(94)
Energy contracts not subject to regulatory deferral [5]	—	(12)	—	(12)
	—	(106)	—	(106)

[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] *Included in other assets*

[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 Received/Posted	Net Amount
As at December 31, 2021				
Derivative assets	**94**	**25**	**7**	**62**
Derivative liabilities	**(49)**	**(25)**	**—**	**(24)**
As at December 31, 2020				
Derivative assets	44	26	10	8
Derivative liabilities	(106)	(26)	(9)	(71)

25. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (cont'd)

Volume of Derivative Activity

As at December 31, 2021, 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.

	2021	2020
Energy contracts subject to regulatory deferral [1]		
Electricity swap contracts *(GWh)*	**509**	522
Electricity power purchase contracts *(GWh)*	**731**	2,781
Gas swap contracts *(PJ)*	**151**	156
Gas supply contract premiums *(PJ)*	**144**	203
Energy contracts not subject to regulatory deferral [1]		
Wholesale trading contracts *(GWh)*	**1,886**	1,588
Gas swap contracts *(PJ)*	**29**	36

[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. The 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 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.

UNS Energy, Central Hudson, FortisBC Energy, Aitken Creek and the Corporation may be exposed to credit risk in the event of non-performance by counterparties to derivatives. Credit risk is managed by net settling payments, when possible, and dealing only with counterparties that have investment-grade credit ratings. At UNS Energy and Central Hudson, 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 $59 million as at December 31, 2021 (2020 - $88 million).

Hedge of Foreign Net Investments

The reporting currency of ITC, UNS Energy, Central Hudson, Caribbean Utilities, FortisTCI, Belize Electric Company 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 limited this exposure through hedging.

As at December 31, 2021, US$2.2 billion (2020 - US$2.3 billion) of corporately issued U.S. dollar-denominated long-term debt has been designated as an effective hedge of net investments, leaving approximately US$10.8 billion (2020 - US$10.2 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, 2021, the carrying value of long-term debt, including current portion, was $25.5 billion (2020 - $24.5 billion) compared to an estimated fair value of $28.8 billion (2020 - $29.1 billion).

26. COMMITMENTS AND CONTINGENCIES

As at December 31, 2021, unconditional minimum purchase obligations were as follows.

($ millions)	**Total**	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Waneta Expansion capacity agreement [1]	**2,525**	53	54	55	56	58	2,249
Gas and fuel purchase obligations [2]	**2,464**	787	446	252	169	121	689
Renewable PPAs [3]	**1,918**	122	122	122	122	122	1,308
Power purchase obligations [4]	**1,783**	288	254	194	184	185	678
ITC easement agreement [5]	**366**	13	13	13	13	13	301
Debt collection agreement [6]	**109**	3	3	3	3	3	94
Renewable energy credit purchase agreements [7]	**87**	17	16	11	8	6	29
Other [8]	**158**	66	7	7	6	4	68
	9,410	1,349	915	657	561	512	5,416

[1] FortisBC Electric is a party to an agreement to purchase capacity from the Waneta Expansion hydroelectric generating facility for forty-years, beginning April 2015.

[2] ***FortisBC Energy ($1,686 million):*** includes contracts 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, 2021. The renewable gas supply obligations disclosed reflect the contracted price per GJ between the Corporation and the suppliers.

UNS Energy ($670 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, 2021. 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 2040.

[3] 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. Amounts are the estimated future payments.

[4] ***Maritime Electric ($815 million):*** includes an energy purchase agreement and transmission capacity contract for 30MW 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 ($544 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 ($276 million): includes 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.

UNS Energy ($118 million): an agreement with Salt River Project Agricultural Improvement and Power District to purchase up to 300 MW of capacity, power and ancillary services through 2023. TEP will pay monthly capacity charges and variable power charges.

[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] 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.

[7] UNS Energy and Central Hudson are party to renewable energy credit 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.

[8] Includes AROs and joint-use asset and shared service agreements.

Other Commitments

Under a funding framework with the Governments of Ontario and Canada, Fortis will contribute a minimum of approximately $155 million of equity capital to the Wataynikaneyap Partnership, based on Fortis' proportionate 39% ownership interest and the final regulatory-approved capital cost of the related project.

The Wataynikaneyap Partnership has loan agreements in place to finance the project during construction. 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.

26. COMMITMENTS AND CONTINGENCIES (cont'd)

Development projects at ITC may result in payments to developers that are contingent on the projects reaching certain milestones indicating that the projects are financially viable. It is reasonably possible that ITC will be required to make these contingent development payments up to a maximum amount of $88 million upon financial close of the projects. In the event it becomes probable that these payments will be made, the liability and the corresponding intangible asset would be recognized.

UNS Energy has joint generation performance guarantees with participants at San Juan, Four Corners, and Luna, with agreements expiring in 2022 through 2046, and at 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 Navajo, participants would seek financial recovery from the defaulting party. There is no maximum amount under these guarantees, except for a maximum of $318 million for Four Corners. As at December 31, 2021, there was no obligation under these guarantees.

Central Hudson is a participant in an investment with other utilities to jointly develop, own and operate electric transmission projects in New York State. Central Hudson's maximum commitment is $83 million, for which it has issued a parental guarantee. As at December 31, 2021, there was no obligation under this guarantee.

As at December 31, 2021, FortisBC Holdings Inc. ("FHI") had $69 million of parental guarantees outstanding to support storage optimization activities at Aitken Creek.

Contingency

In April 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 right-of-way on reserve lands. The pipeline was transferred by FHI (then Terasen Inc.) to Kinder Morgan Inc. in 2007. 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 May 2016 the Federal Court dismissed the Band's application for judicial review of the ministerial consent. In September 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.

Historical Financial Summary

Statements of Earnings *(in $ millions)*	**2021**	2020	2019[1]
Revenue	**9,448**	8,935	8,783
Energy supply costs and operating expenses	**5,474**	4,999	4,972
Depreciation and amortization	**1,505**	1,428	1,350
Gain on disposition	**–**	–	577
Other income, net	**173**	154	138
Finance charges	**1,003**	1,042	1,035
Income tax expense	**234**	231	289
Earnings from continuing operations	**1,405**	1,389	1,852
Earnings from discontinued operations, net of tax	**–**	–	–
Extraordinary gain, net of tax	**–**	–	–
Net earnings	**1,405**	1,389	1,852
Net earnings attributable to non-controlling interests	**111**	115	130
Net earnings attributable to preference equity shareholders	**63**	65	67
Net earnings attributable to common equity shareholders	**1,231**	1,209	1,655
Balance Sheets *(in $ millions)*			
Current assets	**2,728**	2,612	2,574
Property, plant and equipment, non-utility capital assets[2] and intangible assets	**39,159**	37,289	35,248
Goodwill	**11,720**	11,792	12,004
Other long-term assets	**4,052**	3,788	3,578
Total assets	**57,659**	55,481	53,404
Current liabilities	**4,802**	4,148	4,176
Long-term debt (excluding current portion)	**23,707**	23,113	21,501
Other long-term liabilities	**8,234**	7,936	7,614
Total liabilities	**36,743**	35,197	33,291
Total equity	**20,916**	20,284	20,113
Cash Flows *(in $ millions)*			
Operating activities	**2,907**	2,701	2,663
Investing activities	**(3,488)**	(4,132)	(2,768)
Financing activities, excluding dividends	**1,180**	2,243	788
Dividends	**(729)**	(916)	(634)
Financial Statistics			
Return on average book common shareholders' equity *(%)*	**7.09**	7.12	10.40
Capitalization Ratios *(%)* (year end)			
Total debt and finance leases (net of cash)	**57.2**	56.8	55.1
Preference shares	**3.6**	3.7	4.0
Common shareholders' equity	**39.2**	39.5	40.9
Interest Coverage *(x)*			
Debt	**2.5**	2.4	2.9
All fixed charges	**2.5**	2.4	2.9
Capital Expenditures *(in $ millions)*	**3,564**	4,177	3,818
Common share data			
Book value per share (year end) *($)*	**37.21**	36.58	36.49
Average common shares outstanding *(in millions)*	**470.9**	464.8	436.8
Basic earnings per common share *($)*	**2.61**	2.60	3.79
Dividends declared per common share *($)*	**2.08**	1.965	1.855
Dividends paid per common share *($)*	**2.05**	1.9375	1.8275
Dividend payout ratio *(%)*	**78.5**	74.5	48.2
Price earnings ratio *(x)*	**23.4**	20.0	14.2
Share trading summary (TSX)			
High price *($)*	**61.54**	59.28	56.94
Low price *($)*	**48.97**	41.52	44.00
Closing price *($)*	**61.03**	52.00	53.88
Volume *(in thousands)*	**386,673**	441,457	297,490

[1] Results were impacted by non-recurring items, largely associated with the disposition of the Waneta Expansion in 2019, the acquisition of ITC in 2016, the sale of non-core assets in 2015, the acquisition of UNS Energy in 2014 and the acquisition of Central Hudson in 2013.

[2] Non-utility capital assets were sold as part of the sale of commercial real estate and hotel assets in 2015.

2018	2017	2016[1]	2015[1]	2014[1]	2013[1]	2012
8,390	8,301	6,838	6,757	5,401	4,047	3,654
4,782	4,611	4,372	4,465	3,690	2,654	2,390
1,243	1,179	983	873	688	541	470
–	–	–	–	–	–	–
60	116	53	197	(25)	(31)	4
974	914	678	553	547	389	366
165	588	145	223	66	32	61
1,286	1,125	713	840	385	400	371
–	–	–	–	5	–	–
–	–	–	–	–	20	–
1,286	1,125	713	840	390	420	371
120	97	53	35	11	10	9
66	65	75	77	62	57	47
1,100	963	585	728	317	353	315
3,261	2,207	2,166	1,857	1,787	1,296	1,093
33,957	30,749	30,348	20,136	18,304	12,612	10,574
12,530	11,644	12,364	4,173	3,732	2,075	1,568
3,303	3,222	3,026	2,638	2,410	1,925	1,715
53,051	47,822	47,904	28,804	26,233	17,908	14,950
4,252	3,504	3,944	2,638	2,676	2,084	1,350
23,159	20,691	20,817	10,784	9,911	6,424	5,741
7,184	6,878	6,693	5,029	4,534	3,024	2,449
34,595	31,073	31,454	18,451	17,121	11,532	9,540
18,456	16,749	16,450	10,353	9,112	6,376	5,410
2,604	2,756	1,884	1,673	982	899	992
(3,252)	(3,025)	(6,891)	(1,368)	(4,199)	(2,164)	(1,096)
1,254	932	5,491	(14)	3,627	1,434	396
(610)	(593)	(441)	(332)	(266)	(248)	(225)
7.78	7.31	5.56	9.75	5.45	8.06	8.06
59.7	59.2	60.6	54.8	56.4	56.2	55.3
3.9	4.4	4.4	8.3	9.1	9.0	9.7
36.4	36.4	35.0	36.9	34.5	34.8	35.0
2.3	2.7	2.1	2.7	1.6	1.9	2.0
2.3	2.7	2.1	2.7	1.6	1.9	2.0
3,218	3,024	2,061	2,243	1,725	1,175	1,146
34.80	31.77	32.31	28.62	24.89	22.38	20.84
424.7	415.5	308.9	278.6	225.6	202.5	190.0
2.59	2.32	1.89	2.61	1.41	1.74	1.66
1.75	1.65	1.55	1.43	1.30	1.25	1.21
1.725	1.625	1.525	1.40	1.28	1.24	1.20
66.6	70.0	80.7	53.6	90.8	71.3	72.3
17.6	19.9	21.9	14.3	27.6	17.5	20.6
47.36	48.73	44.87	42.23	40.83	35.14	34.98
39.38	40.59	35.53	34.16	29.78	29.51	31.70
45.51	46.11	41.46	37.41	38.96	30.45	34.22
269,284	205,261	293,991	172,038	174,566	120,470	115,962

Investor Information

Expected Dividend* and Earnings Release Dates

Dividend Record Dates

May 17, 2022	August 19, 2022
November 17, 2022	February 15, 2023

Dividend Payment Dates

June 1, 2022	September 1, 2022
December 1, 2022	March 1, 2023

Earnings Release Dates

May 4, 2022	July 28, 2022
October 28, 2022	February 10, 2023

* *The setting of dividend record dates and the declaration and payment of dividends are subject to the Board of Directors' approval.*

Transfer Agent and Registrar

Computershare Trust Company of Canada ("Computershare" or "Transfer Agent") is responsible for the maintenance of shareholder records and the issuance, transfer and cancellation of stock certificates. Transfers can be effected at its Montreal and Toronto offices in Canada and at the co-transfer agent's Canton, MA, Jersey City, NJ, and Louisville, KY offices in the United States. Computershare also distributes dividends and shareholder communications. Inquiries with respect to these matters and corrections to shareholder information should be addressed to the Transfer Agent.

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Direct Deposit of Dividends

Shareholders may arrange for automatic electronic deposit of dividends to their designated Canadian and U.S. financial institutions by contacting the Transfer Agent.

Duplicate Annual Reports

While every effort is made to avoid duplications, some shareholders may receive extra reports as a result of multiple share registrations. Shareholders wishing to consolidate these accounts should contact the Transfer Agent.

Eligible Dividend Designation

For purposes of the enhanced dividend tax credit rules contained in the Income Tax Act (Canada) and any corresponding provincial and territorial tax legislation, all dividends paid on common and preferred shares after December 31, 2005 by Fortis to Canadian residents are designated as "eligible dividends." Unless stated otherwise, all dividends paid by Fortis hereafter are designated as "eligible dividends" for the purposes of such rules.

Annual and Special Meeting

Thursday, May 5, 2022 – 10:30 a.m. NDT

Dividend Reinvestment Plan

Fortis offers a Dividend Reinvestment Plan ("DRIP") as a convenient method for Common Shareholders to increase their investments in Fortis. Participants have dividends plus any optional contributions (minimum of $100, maximum of $30,000 annually) automatically deposited in the plan to purchase additional Common Shares. Shares can be purchased quarterly on March 1, June 1, September 1 and December 1 at the average market price then prevailing on the Toronto Stock Exchange. The DRIP currently offers a 2% discount on the purchase of Common Shares, issued from treasury, with the reinvested dividends. Inquiries should be directed to the Transfer Agent.

Share Listings

The Common Shares; First Preference Shares, Series F; First Preference Shares, Series G; First Preference Shares, Series H; First Preference Shares, Series I; First Preference Shares, Series J; First Preference Shares, Series K; and First Preference Shares, Series M of Fortis Inc. are listed on the Toronto Stock Exchange and trade under the ticker symbols FTS, FTS.PR.F, FTS.PR.G, FTS.PR.H, FTS.PR.I, FTS.PR.J, FTS.PR.K and FTS.PR.M, respectively. The Common Shares are also listed on the New York Stock Exchange and trade under the ticker symbol FTS.

Valuation Day

For capital gains purposes, the valuation day prices are as follows:

December 22, 1971	**$1.531**
February 22, 1994	**$7.156**

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Executive Vice President, Chief Legal Officer and Corporate Secretary

Gary J. Smith
Executive Vice President, Operations and Innovation

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Exhibit B, Tab 1, Schedule 1

Transmission System Project Plan

TRANSMISSION SYSTEM PROJECT PLAN

A. Introduction

WPLP's Transmission Project is a major capital investment that includes the initial development, construction and in-servicing of its entire Transmission System. WPLP has carried out a comprehensive Transmission Project planning and development process, engaged and continues to engage extensively with potentially impacted Indigenous and Métis communities, land users and other relevant stakeholders, undertaken commercially prudent processes for construction contracting and secured necessary financing, and implemented appropriate organizational structures and processes to ensure that the Transmission Project is effectively executed.

The present Application seeks approval of WPLP's transmission revenue requirement on a cost of service basis for a single test year (2023), with capital expenditure forecasts covering the 2022-2024 period during which the Transmission System will be constructed and placed into service (in stages). The proposed revenue requirement is therefore largely based on the costs of the Transmission Project and, in particular, on the elements of the Transmission Project that are expected to be in-service in 2022 and additional elements that are expected to go into service in 2023. Furthermore, the proposed revenue requirement includes operating expenses relating to the assets that are in service or expected to be going into service in 2022 and 2023.

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. It is therefore unnecessary for the capital investments associated with the Transmission Project, including its initial development, construction and in-servicing, to be further approved through a Transmission System Plan ("TSP") or otherwise. As such, in lieu of a TSP and to support its revenue requirement request, WPLP uses this Exhibit 'B' to provide a comprehensive description of the Transmission Project, including its scope, planning, schedule, execution approach, cost and the manner in which WPLP's organizational structure will evolve from construction to ongoing operation of the Transmission System. WPLP has updated this Exhibit 'B' since its last transmission rate application (EB-2021-0134) and intends to further

update it in its subsequent single-year revenue requirement applications during the construction period. WPLP anticipates that it will file an initial TSP in conjunction with its first multi-year revenue requirement application following completion of the Transmission Project.

The majority of WPLP's forecasted investments, during the 2023 test year and in 2024 when it also plans to seek approval of a single-year revenue requirement, are related to the initial construction of the Transmission System and General Plant investments for facilities, equipment and systems that are required to enable and support the ongoing operation of the Transmission System. Due to WPLP's focus on constructing the Transmission System and supporting facilities, connecting HORCI's distribution systems in each of the 16 connecting First Nation communities[1] and commencing operation of the Transmission System assets, WPLP does not anticipate having significant capital investment needs, incremental to its initial construction costs, during the 2023 test year or during the balance of the construction period. System Renewal and System Service needs are expected to be *de minimus* due to the Transmission System being newly built and designed to meet anticipated operational needs and customer service requirements.

The General Plant investments referred to above include fleet, facilities and business systems. Most of these investments are planned for post-2024, with in-service dates that coincide with WPLP's gradual transition from construction and project management to system operation as more assets are placed in service, as discussed in Exhibit B-1-4.

Regarding the in-service schedule for the Transmission Project, in 2022 WPLP plans to put into service the entirety of the Line to Pickle Lake including its 2 associated substations, and for the Remote Connection Lines, WPLP plans to put into service 5 of the 20 substations and 7 of the 34 line segments[2], as well as to convert the Pikangikum Distribution System to form part of the Transmission System (discussed below). In 2023, WPLP plans to put into service 4 of the

[1] While a 17th community, McDowell Lake First Nation, is not forecasted to be connected during this initial construction period, WPLP's Transmission System is designed to permit the future connection of this community.

[2] These counts include line segments and substations associated with the Pikangikum Distribution System that are already in service and will transition to a transmission supply in 2022.

substations and 8 of the line segments associated with the Remote Connection Lines. In total, these 2022 and 2023 in-service additions reflect approximately 57% of the total forecast Transmission Project cost.[3] The remainder of the Transmission Project, comprised of 11 substations and 19 line segments associated with the Remote Connection Lines, is expected to be completed and put into service by Q3 2024.

Following the completion of the Transmission Project in 2024, WPLP anticipates receiving a significant capital contribution from the Federal Government, as discussed in Exhibit I-4-1. WPLP also expects to transition from project financing to long-term debt financing in 2024. Accordingly, WPLP anticipates filing its first multi-year incentive-based rate application (for a 2026 Test Year) in 2025, once the amount of the federal capital contribution and interest rate(s) applicable to WPLP's long-term debt are more certain.

B. Roadmap

WPLP's Transmission System Project Plan, which comprises Exhibit 'B', is organized as follows:

- The balance of this Exhibit B-1-1 describes the scope of the Transmission Project, including the physical components of the Transmission System as approved in the Leave to Construct Proceeding, as well as changes made subsequent to that proceeding and further changes that are being contemplated.

- Exhibit B-1-2 describes the key elements of WPLP's project planning and development process and provides an overview of the key development activities that have been carried out by WPLP, both following the granting of Leave to Construct and since the 2022 revenue requirement application.

- Exhibit B-1-3 describes the current Transmission Project schedule, including the sequencing of in-service dates for project components and segments. In addition, WPLP

[3] As noted in Exhibit A-3-1, WPLP intends to update its schedule and cost forecasts at an appropriate stage in this proceeding.

identifies and explains any changes in the project schedule relative to that which was presented in the 2022 revenue requirement application, as amended, and associated schedule risks and mitigation.

- Exhibit B-1-4 sets out WPLP's approach to organizing and executing the Transmission Project, including its structure during the construction period, the manner in which it is coordinating and providing oversight of key contractors, change management processes, cost and performance management, project tracking and reporting, as well as the company's efforts and plans for evolving its organization to support operations as additional segments come into service and to ensure it is prepared for ongoing utility operations following project completion.

- Exhibit B-1-5 provides detailed Transmission Project cost information, as well as information on other infrastructure capital costs and operating costs, and explanations for variances between estimated project costs presented in the 2022 revenue requirement application, as amended, and current forecasts. In addition, this schedule describes how overhead costs are assigned to or allocated between capital and OM&A for each of the Line to Pickle Lake and Remote Connection Line portions of the Transmission System over the construction period.

C. Transmission Project Scope

1. Transmission System Components

Upon completion of construction, WPLP's Transmission System will operate as a single transmission system in northwestern Ontario, one part of which will reinforce transmission to Pickle Lake (the "Line to Pickle Lake") and the balance of which will connect to the provincial power system 16 remote First Nation communities that are currently served by diesel generation

(the "Remote Connection Lines").[4] These two components of WPLP's Transmission System are depicted in the Transmission System Map provided in **Appendix 'A'** and are described as follows.

(a) Line to Pickle Lake

The Line to Pickle Lake will be 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 will reinforce 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 approximately 8 km southeast of Dinorwic ("Wataynikaneyap SS");
- an approximately 303 km single circuit, overhead, 230 kV transmission line running from the Wataynikaneyap SS generally in a northeasterly direction to the Wataynikaneyap 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 ("Wataynikaneyap TS").

In addition, immediately next to WPLP's Wataynikaneyap SS there will be a small, separate fenced area called Dinorwic Junction ("Dinorwic JCT") to support the connection of WPLP's 230 kV tap from Wataynikaneyap SS to Hydro One's existing 230 kV transmission line D26A. Dinorwic JCT will be designed, installed, owned and operated by Hydro One and will house two new 230 kV motor-operated switches on transmission line D26A on either side of WPLP's 230 kV tap. Similarly, immediately next to WPLP's Wataynikaneyap TS will be a separately fenced 115 kV switching station called Pickle Lake SS, which will support the connection of WPLP's

[4] One of the 16 communities, Pikangikum First Nation became grid-connected in 2018 through an interim 44 kV connection that will be converted to 115 kV and will subsequently form 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.

Wataynikaneyap TS to Hydro One's existing 115 kV transmission line E1C. Pickle Lake SS will be designed, installed, owned and operated by Hydro One and will house two 115 kV circuit breakers, as well as associated switches and protection and control facilities. The existing Hydro One customers at Crow River DS and Musselwhite CSS, near the end of transmission line E1C, will remain connected to Hydro One's transmission system via Pickle Lake SS, but will benefit from the increased available capacity and the improved system reliability resulting from WPLP's Line to Pickle Lake.

(b) Remote Connection Lines

The connection of remote First Nations communities will be achieved by means of approximately 903[5] km of new 115 kV, 44 kV and 25 kV transmission lines north of Pickle Lake (the "Pickle Lake Remote Connection Lines"), and approximately 538[6] km of new 115 kV and 25 kV transmission lines north of Red Lake (the "Red Lake Remote Connection Lines"), including associated stations and ancillary facilities (together, the "Remote Connection Lines"). By the time the construction period concludes in 2024, a total of 16 remote First Nations communities, all of which are Participating First Nations, will connect to the Transmission System, and thereby to the provincial electricity system.[7] In EB-2018-0190, the OEB approved WPLP's request under subsection 84(b) of the OEB Act for the 44 kV and 25 kV segments of the Remote Connection Lines to be deemed to be transmission facilities that are part of WPLP's Transmission System notwithstanding that these segments will have voltages less than 50 kV.[8]

The Pickle Lake Remote Connection Lines include the following elements:

- approximately 903 km of single circuit, overhead, 115 kV, 44 kV and 25 kV transmission lines running from the Wataynikaneyap TS generally in a northerly direction to one

[5] Line length increased by 6 km or less than 1% as described on page 10 of this Exhibit.

[6] Line length increased by 2 km or less than 1% as described on page 10 of this Exhibit.

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

[8] OEB, Decision and Order in EB-2018-0190, April 1, 2019, p. 30.

switching station and subsequently to a series of nine transformer stations from which transmission service will be provided by WPLP to Hydro One Remote Communities Inc., and from which Hydro One Remote Communities Inc. will provide distribution service to customers in ten remote First Nation communities.[9]

The Red Lake Remote Connection Lines include the following elements:

- a 115 kV switching station located approximately 4 km southeast of Hydro One's Red Lake TS adjacent to Hydro One's existing circuit E2R (the "Red Lake SS"); and

- approximately 538 km of single circuit, overhead, 115 kV and 25 kV transmission lines running from the Red Lake SS generally in a northerly direction to a series of three switching stations and six transformer stations from which transmission service will be provided by WPLP to Hydro One Remote Communities Inc., and from which Hydro One Remote Communities Inc. will provide distribution service to customers in six remote First Nation communities.[10,11]

The Remote Connection Lines will help address the significant limitations associated with the current electricity supply in the remote First Nation communities, which severely impacts

[9] (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 Carribou Lake First Nation, (8) Muskrat Dam First Nation, (9) Bearskin Lake First Nation, and (10) Sachigo Lake First Nation.

[10] (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.

[11] The Red Lake Remote Connection Lines include approximately 113 km of an approximately 117 km line that the Applicant constructed and is currently operating, 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 has been constructed to a 115 kV standard but, during the interim period, is being supplied by Hydro One's 44 kV system and is therefore only capable of operating at 44 kV. Approximately 18 km of the 113 km portion of the line has been constructed to a 25 kV standard. As contemplated by the OEB's Decision and Order in EB-2018-0190, the 18 km segment will be deemed to be part of the Transmission System, and the 95 km portion of the line will be converted to a transmission voltage 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 will not form part of the WPLP Transmission System.

community infrastructure, economic development and quality of life, and leads to significant environmental and health risks.

2. Project Design Changes

As a condition of approval, the LTC Decision required WPLP to advise the OEB of any proposed material changes in the Transmission Project. WPLP has advised the OEB of two changes, first relating to the relocation of a substation, and second to a change in the type of structure to be used for the 230 kV and 115 kV line segments. As noted below, the OEB confirmed that neither of these changes was material.

(i) Relocation of Wataynikaneyap SS

On July 22, 2019, WPLP advised the OEB that following additional engineering and coordination with HONI, it had decided to shift the location of the Wataynikaneyap SS (which is located at the south end of the Line to Pickle Lake near Dinorwic) by approximately 620 meters to the northwest. This relocation required a corresponding extension of the 230 kV Line to Pickle Lake by the same distance, running parallel to HONI's existing D26A 230 kV circuit. This change in scope was made in consideration of constructability, soil conditions and site access and did not affect any new landowners or additional land parcels. On August 8, 2019, the OEB confirmed that the change was not material.[12]

(ii) Use of Lattice Steel Structures

The physical design of the transmission lines, as set out in the LTC Application, contemplated the use of H-frame wood pole structures for the 230 kV Line to Pickle Lake, as well as for most 115 kV segments of the Remote Connection Lines, with single-pole wood structures for the 44 kV and 25 kV segments. Through the competitive EPC contracting process (see Exhibit B-1-2), it became evident to WPLP that the use of lattice steel structures for the 230 kV and 115 kV components of the project would be comparable in cost to the use of H-frame wood pole structures, which was

[12] Letter from OEB to WPLP re Post-Approval Modifications (EB-2018-0190), August 8, 2019 (https://www.rds.oeb.ca/CMWebDrawer/Record/649128/File/document).

not previously expected. In addition to a small initial cost savings as compared to the wood structures, the use of lattice steel structures offered WPLP important advantages in terms of reduced construction schedule risk (due to the ability to assemble the structures at centralized locations), reliability benefits and reduced land disturbance. On August 16, 2019, WPLP advised the OEB of its proposed use of lattice steel structures and on August 23, 2019, the OEB confirmed that this proposed change was not material.[13] This change occurred during the course of negotiating the EPC contract with the preferred proponent and enabled the contract to ultimately be executed based on the planned use of the lattice structures.

3. Additional Project Changes

In the LTC Decision, the Board recognized that WPLP would complete final engineering, procurement, construction and commissioning of the Transmission Project through a competitively tendered EPC contract. While the overall scope of work and the design basis for the Transmission Project are set out in the EPC contract, the EPC contractor is required to complete final engineering and design activities as part of its scope of work. Throughout this process, and in consideration of ongoing engagement efforts during this stage of the project, a number of additional project changes have been identified, as discussed below. Further changes are expected to arise as final engineering and design activities continue to progress in parallel with ongoing engagement efforts for segments of the transmission system with later in-service dates.

(a) Changes to Design

As a result of the EPC contractor's detailed design and engineering efforts progressing through typical stages of design and review to date, a small number of design changes have occurred. These changes include additional grounding switches, changes to reactor sizing and placement within substations, which will improve the future operability and maintainability of the Transmission System, including operation during contingencies. Minor changes to specific steel lattice tower types and anchoring components have also been made as line design engineering has

[13] Letter from OEB to WPLP re Post OEB Approval Design Modifications (EB-2018-0190), August 23, 2019 (https://www.rds.oeb.ca/CMWebDrawer/Record/650616/File/document).

progressed from initial design to "Issued for Construction" status. Given that OEB staff did not consider WPLP's earlier design change from wood pole to steel lattice towers to be material, WPLP does not consider any of these further design changes to date to be material.

(b) Changes to Routing

In the Leave to Construct proceeding, WPLP presented its comprehensive process to initially select and subsequently refine the routing for the Transmission Project.[14] This routing process integrated technical and constructability considerations with a comprehensive EA process, informed by continued engagement with potentially impacted Indigenous communities, land users, government agencies and other relevant stakeholders. WPLP maintains a comprehensive engagement program, as described in Exhibit B-1-2, to ensure that Indigenous knowledge and land use protocols are appropriately accounted for during the detailed design and construction phases of the project. WPLP also continues to communicate with a number of government agencies, including the MNRF, MECP and MTO. WPLP has processes in place to ensure that appropriate approvals are received from First Nation communities and appropriate government agencies, prior to committing to any routing refinements.

As a result of continuous efforts to engage with the affected Indigenous communities, certain routing refinements have been made, primarily in five locations: (i) near McInnes Lake (between Poplar Hill SS – Substation R and Deer Lake SS – Substation T); (ii) near Critchell Lake (between Poplar Hill SS – Substation R and Deer Lake SS – Substation T), (iii) between Muskrat Dam TS - Substation E and Sachigo Lake TS - Substation G, (iv) near the Muskrat Dam peninsula, and (v) near the Fawn River in the vicinity of Kitchenuhmaykoosib Inninuwug (KI) to avoid culturally sensitive areas, which were not previously identified. These changes represent a total net increase of approximately 8 km (or less than 1%) relative to the total project length. The revised transmission line rights-of-way were permitted through a multi-site land use permit issued by the MNRF and through section 28(2) permit amendments where First Nation reserve lands were

[14] See for example: (a) EB-2018-0190, Exhibit D-3-1, as amended October 5, 2018; (b) WPLP's January 28, 2019 letter advising the OEB of minor routing amendments; and (c) the OEB's January 31, 2019 reply to WPLP, agreeing that the realignments were minor in nature.

impacted. Moreover, given that these routing refinements remained within the limits of work identified in the EA process, and did not impact any new land rights holders or landowners, WPLP did not consider the refinements to be material in the context of the obligation to notify OEB staff as set out in the LTC Decision.

Please see Exhibit B-1-4 for a description of WPLP's change management and control process.

Appendix ‘A’ – Transmission System Map

N

Sachigo Lake First Nation
Bearskin Lake First Nation
Kitchenuhmaykoosib Inninuwug
Wapekeka First Nation
Kasabonika Lake First Nation
Wawakapewin First Nation
OPASQUIA PROVINCIAL PARK
Muskrat Dam Lake First Nation
Sandy Lake First Nation
Keewaywin First Nation
North Caribou Lake First Nation
Wunnumin Lake First Nation
Kingfisher Lake First Nation
Deer Lake First Nation
North Spirit Lake First Nation
Poplar Hill First Nation
McDowell Lake First Nation
Pikangikum First Nation
Cat Lake First Nation
Pickle Lake
Red Lake
Mishkeegogamang First Nation
WABAKIMI PROVINCIAL PARK
Ear Falls
Wabauskang First Nation
Lac Seul First Nation
Ojibway Nation of Saugeen
Whitesand First Nation
Asubpeeschoseewagong First Nation
Sioux Lookout
Kiashke Zaaging Anishinaabek
Dryden
Dinorwic
Wabigoon Lake First Nation
Ignace

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

ᐊ·Uσbσᔦ Wataynikaneyap Power

PROJECT 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

Project Planning and Development

PROJECT PLANNING AND DEVELOPMENT

This schedule describes the key elements of WPLP's project planning and development process and provides an overview of the development activities that have been carried out by WPLP since the decision approving WPLP's 2022 revenue requirement was issued on September 30, 2021.

A. Leave to Construct Proceeding

WPLP's Transmission Project planning and development activities were described and considered in detail during the Leave to Construct proceeding. WPLP demonstrated that it had undertaken a comprehensive and rigorous planning and development process to define and execute the Transmission Project, the key elements of which included:

- Comprehensive environmental assessment processes for all aspects of the Transmission Project to identify, minimize and mitigate potential environmental impacts;

- Extensive First Nations and Métis engagement and stakeholder consultation processes, which provided multiple opportunities for meaningful review and input from affected persons over an extended period;

- Thorough review and in-depth analysis of transmission line routing and facility location options to determine optimal routing and facility locations using best available information, taking into account input received through engagement and consultations, as well as environmental, constructability and cost considerations;

- Rigorous engineering analysis, including from internal resources and with support from a third-party Owner's Engineer, as well as in consultation with the IESO and Hydro One Networks Inc. (HONI), to arrive at a detailed and considered system design that is consistent with the IESO's recommended and supported scope, compatible with the neighboring systems to which it will be connected, and that appropriately balances the needs for safety, reliability, efficiency, operational flexibility and cost minimization;

- System Impact Assessment Reports from the IESO and Customer Impact Assessment Reports from HONI, which have been obtained for all project components to ensure that connection of the Transmission System facilities to the provincial electricity grid will result in no material adverse impacts on the reliability of the integrated power system, or on existing customers connected to HONI' s transmission system; and

- Efforts to minimize the number of directly affected landowners and the impacts of the Transmission Project on those landowners through considerations of routing and design, and providing fair offers to such landowners where needed to enable WPLP to secure in a timely manner all of the land rights required to construct, own and operate the Transmission Project facilities.

The OEB, in the LTC Decision, found that:

- WPLP demonstrated that its cost estimates were developed through an appropriate process according to a well-defined scope, and that it took appropriate steps to find cost efficiency measures and ensure that the costs of the Project would be well managed;[1]

- WPLP's approach to the Transmission Project, including its competitive tendering of the EPC contract and the retention of a third-party Owner's Engineer to assist with procurement and project management processes, was a reasonable way to manage the risks associated with the Transmission Project costs;[2]

- there will be no adverse impacts on the integrated power system and consumers with respect to the reliability and the quality of electricity service from the Transmission Project, provided that the requirements specified in the Final System Impact Assessments and Customer Impact Assessments are implemented;[3] and

[1] OEB, LTC Decision and Order, EB-2018-0190, April 1, 2019 (Revised April 29, 2019), p. 12.
[2] LTC Decision, p. 12.
[3] LTC Decision, p. 14.

- there were no concerns with respect to WPLP's land requirements or land rights acquisition process.[4]

B. Post-Leave to Construct Planning and Development Activities

WPLP has continued to progress in all areas of project planning and development since completion of the Leave to Construct proceeding in April 2019, and since completion of the 2022 revenue requirement proceeding in September 2021. The following describes WPLP's key activities and achievements during each of these periods, including with respect to EPC contracting, financing, federal funding arrangements, permits and approvals, land rights acquisition, coordination with HONI and HORCI, engagement with Indigenous and Métis communities, the facilitation of back-up generation, and coordination with the IESO.

1. EPC Contracting

In the LTC Decision, the Board recognized that: (i) WPLP would complete final engineering, procurement, construction and commissioning of the Transmission Project through a competitively tendered Engineering, Procurement and Construction ("EPC") contract, (ii) WPLP had retained an Owner's Engineer to provide increased granularity and accuracy of the cost estimate in preparation for the EPC tendering, evaluation and selection process, and (iii) the Owner's Engineer's mandate would include a requirement to refine the contingency. On that basis, the OEB found that competitive tendering of the EPC contract and the retention of a third-party Owner's Engineer to assist with procurement and project management processes was a reasonable way to manage the risks associated with the Project costs.[5]

More particularly, WPLP's Owner's Engineer, Hatch Ltd. ("Hatch"), was engaged through a competitive process in Spring 2018. With assistance from Hatch, WPLP ran a pre-qualification process to identify qualified and interested firms to participate in its EPC contracting process. The pre-qualification process included the issuance of a Request for Expressions of Interest and

[4] LTC Decision, p. 19.
[5] LTC Decision, pp. 6 and 12.

Qualifications, which identified eight potential proponents. This was followed by safety, performance and bench strength reviews, which narrowed the group down to four pre-qualified proponents.[6] The pre-qualification process was completed in September 2018. The four pre-qualified proponents were then permitted to participate in WPLP's Request for Proposals ("RFP") process for EPC services.

In parallel with running the pre-qualification process, with Hatch's assistance, WPLP developed its RFP, which was issued to the four pre-qualified proponents on November 2, 2018. Through Wataynikaneyap Power PM Inc. (the "Project Manager"), WPLP was also assisted in developing and administering the RFP by Fortis subsidiary ITC Holdings Corp. ("ITC"), which is the largest independent electricity transmission company in the United States, as well as by the technical departments of the Tribal Councils representing member First Nation communities within the Participating First Nations. Following a number of RFP addendums to enable proponents to develop higher quality and more competitive proposals, WPLP granted a two-month extension that allowed proponents to submit their responses in mid-April 2019.

The review process included a comprehensive set of evaluation criteria for all components of the RFP and an executive review team, along with sub-teams of experts that included representatives from Hatch, the Project Manager (including ITC) and Opiikapawiin Services LP ("OSLP"). The RFP was structured to enable proponents to bid separately for each of (a) the Line to Pickle Lake (Group 1), (b) the Pickle Lake Remote Connection Lines (Group 2), and (c) the Red Lake Remote Connection Lines (Group 3), and to propose pricing for developing one group, two groups or all three groups. All of the pre-qualified proponents bid for all three portions of the Transmission Project. Valard LP was identified as the preferred proponent for all three groups in early July

[6] As described in a September 18, 2018 news release, the pre-qualified proponents were Forbes Bros. Ltd. (Pennecon), Power North Contractors JV (PowerTel, Kiewit and SNC-L), Valard Construction LP, and Voltage Power Ltd. (Sigfusson, Anishnawabe Construction Corporation). See WPLP News Release https://www.wataypower.ca/updates/wataynikaneyap-power-lp-announces-pre-qualified-proponents-to-receive-engineering-procurement-construction-request-for-proposal-packages-epc-rfp-for-phase-1-2-of-the-project

2019, at which point the other proponents were notified and contract negotiations with Valard LP commenced.

Valard LP made the lowest cost proposal for all three groups. In part, this contributed to the selection of Valard LP as the preferred proponent for all three portions of the Transmission Project. Upon receiving confirmation from OEB staff on August 23, 2019, that changing to a lattice tower design was not a material change under the LTC Decision[7], the final EPC contract was executed with Valard LP and was announced on September 10, 2019.[8]

On October 25, 2019, coinciding with its achievement of financial close (see below), WPLP issued a formal Notice to Proceed to Valard LP under the EPC contract. WPLP notes that, as described in Exhibit B-1-2 in EB-2021-0134, between execution of the EPC contract and October 31, 2020[9], nine change orders were approved related to design changes and routing refinements. Since October 31, 2020 there have been an additional 32 change orders related to design changes and routing refinements that are described in Sections C.2 of Exhibit B-1-1. The project schedule and cost changes resulting from completion of the EPC procurement process, as well as change orders and other factors, are discussed in Exhibits B-1-3 and B-1-5, respectively. Incremental COVID costs are discussed separately in Exhibit H-2-2.

2. Financing

As noted above, coinciding with its issuance of Notice to Proceed to Valard LP under the EPC contract on October 25, 2019, WPLP achieved another significant development milestone when it closed on its project financing. Financial close reflected the completion of a negotiated Common Terms and Inter-Creditor Agreement ("CTIA") with the Province of Ontario and a group of Senior

[7] OEB Letter, August 23, 2019 (EB-2018-0190) http://www.rds.oeb.ca/HPECMWebDrawer/Record/650616/File/document.

[8] See WPLP News Release https://www.wataypower.ca/updates/wataynikaneyap-power-lp-awards-engineering-procurement-construction-contract-to-valard-lp.

[9] This cut-off date was chosen in consideration of revisions to the in-service schedule to reflect COVID-19 impacts being completed in September 2020 (as detailed in Exhibit B-1-3), and associated in-service additions being re-estimated in October 2020 to support the capital cost forecast included in Exhibit B-1-5 and the in-service addition forecast included in exhibit C-2-1.

Bank 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. However, it has secured financing that would cover a combination of worst-case scenarios in consideration of cost increases, interest rate increases and construction delays. WPLP's financing process and arrangements are described in greater detail as part of the evidence on WPLP's cost of capital in Exhibit G, Tab 2, Schedule 1.

3. Federal Funding Arrangements

In EB-2018-0190, WPLP described the federal funding contemplated for the Transmission Project, which resulted from a March 12, 2018 Memorandum of Understanding between WPLP, Canada, and Ontario.[10] Subsequent to the LTC Decision, on July 3, 2019, WPLP, Canada and Ontario signed definitive documents regarding the funding framework for the Transmission Project and a formal announcement was made on July 22, 2019.[11] While the provision of funding remains conditional on appropriation by Parliament, the definitive documents solidify the mechanics by which the funding would be provided upon appropriation. WPLP anticipates that the distribution of funds will occur in 2024, following the later of: (a) the OEB's Decision and Order in respect of WPLP's 2023 application for approval of a 2024 test year revenue requirement; or (b) completion of construction and receipt of funds by the Trustee. Further details about how the federal funding will be applied are set out in Exhibit I, Tab 4, Schedule 1.

4. Permits and Approvals

WPLP's progress with respect to permits and approvals since the LTC and since completing the 2022 revenue requirement proceeding in September 2021 has been focused on the environmental assessments for the Line to Pickle Lake and Remote Connection Lines, species protection and the *Far North Act*, as follows.

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[10] EB-2018-0190, Exhibit J-1-2.

[11] See WPLP News Release https://www.wataypower.ca/updates/wataynikaneyap-power-lp-and-government-of-canada-formalize-support-for-provinces-largest-first-nations-led-transmission-project.

(a) Environmental Assessment

In EB-2018-0190, WPLP described the two distinct environmental assessment ("EA") processes for the Transmission Project: (i) an Individual EA process under the provincial *Environmental Assessment Act* ("EA Act") for the Line to Pickle Lake, and (ii) a comprehensive engagement plan and effects assessment for the Remote Connection Lines to address, in an integrated manner, all provincial class EA requirements under the EA Act and certain additional federal environmental requirements from Indigenous Services Canada (formerly Indian and Northern Affairs Canada) ("ISC") based on its consideration of environmental effects.[12]

On June 21, 2019, following multiple rounds of community engagement and comments from various government ministries and Indigenous and Métis communities, the Minister of the Environment, Conservation and Parks ("MECP"), with support from the Lieutenant Governor in Council ("LGIC"), approved the Individual EA for the Line to Pickle Lake with conditions. Following the MECP's decision, WPLP identified changes to optimize the design and reduce the overall footprint of the Line to Pickle Lake. Generally, these changes had the effect of reducing potentially adverse environmental effects. To give effect to the changes, WPLP amended the final EA Report for the Line to Pickle Lake and, on September 12, 2019, the MECP accepted the changes. With the acceptance of the changes, the EA for the Line to Pickle Lake was deemed complete.

Following multiple rounds of community engagement and comments from various government ministries and Indigenous and Métis communities, WPLP satisfied all provincial class EA requirements for the Remote Connection Lines and, in July 2019, the Minister of Natural Resources and Forestry ("MNRF") and the MECP issued their respective Statements of Completion, thereby approving the EA for the Remote Connection Lines. Following this provincial approval, but before obtaining federal approval from ISC, WPLP identified certain refinements to the Remote Connection Line's 115 kV corridors that had the effect of reducing the overall footprint of the project and optimizing the design to align with future community

[12] EB-2018-0190, Exhibit I-1-1

infrastructure projects. To implement these changes, WPLP issued an Addendum to the Final Environmental Study Report ("ESR") for public comment and for MNRF, MECP and ISC approval. On August 2, 2019, WPLP received provincial approval for the Addendum. Following this provincial approval, in September 2019, ISC completed its environmental review of the Remote Connection Lines, inclusive of the changes set out in the Addendum, and concluded that, taking into account the proposed mitigation measures, the Remote Connection Lines portion of the Transmission Project is not likely to cause significant adverse environment effects. With this approval, the EA for the Remote Connection Lines was deemed complete.

As the Project continues to evolve through community engagement and detailed design, WPLP continues to engage with First Nation communities, land users, other relevant stakeholders and agencies. As a result of these engagements, WPLP may receive input that may require amendments to its EA permits. In 2021, as a result of input received from First Nation communities in connection with the Remote Connection Lines, WPLP made three amendments to its ESR. First, in April 2021, WPLP amended its ESR to reflect minor routing changes in the vicinity of McInnes Lake and Critchell Lake within the Whitefeather Forest area northeast of Pikangikum First Nation and Poplar Hill First Nation, and changes to the line leading towards Sachigo Lake First Nation. Second, in June 2021, WPLP amended its ESR to reflect minor routing changes at two locations along the connections approaching Muskrat Dam First Nation and Bearskin Lake First Nation. Third, in July 2021, WPLP amended its ESR to reflect minor routing changes along the connection approaching Kasabonika Lake First Nation and a minor relocation of the substation at Kasabonika Lake First Nation. For each of these changes, WPLP sought and received MECP's approval to amend its ESR permit. While these changes necessitated the ESR permit amendments, they are not considered material in the context of the LTC decision as these changes did not affect any new landowners or materially impact the overall cost of the Project.

(b) Species Protection

During the EA processes, WPLP determined that construction, operation and maintenance activities associated with the Transmission Project might affect certain species at risk or their

habitats. This triggered application of the Ontario *Endangered Species Act* ("ESA") and the federal *Species at Risk Act* ("SARA") as each Act is applicable within the Transmission Project footprint. WPLP was required to apply for authorization in order to proceed with construction activities that might otherwise be prohibited under the ESA and/or SARA. In October 2019, WPLP received the ESA and SARA permits, with conditions aimed at protecting and mitigating the effects of the Transmission Project on certain species at risk. As the Transmission Project progresses, WPLP continues to update its ESA permit by way of minor amendments, where required, to reflect the most up to date information available in relation to its activities aimed at protecting and mitigating the effects of the Transmission Project on certain species at risk and habitats.

(c) Far North Act

As discussed in EB-2018-0190, WPLP and the MNRF established a technical working group to consider how WPLP could meet the requirements of the *Far North Act* ("FNA") and to determine an appropriate approach for meeting those requirements.[13] Given the scale and scope of the Transmission Project, and the number and geographic range of areas that had and had not started their FNA planning processes, the technical working group determined that an appropriate approach to meeting the requirements of the FNA was for WPLP to request an Order from the LGIC, pursuant to subsection 12(4) of the FNA, declaring the Transmission Project to be in the social and economic interests of Ontario. WPLP followed this approach and submitted its request, along with supporting information. On August 16, 2019, the LGIC determined that the Transmission Project is in the social and economic interests of Ontario. In doing so, the LGIC exempted WPLP from the further application of the FNA. There have been no further developments regarding this aspect of the project.

5. Land Rights Acquisition

Following the Leave to Construct and 2022 revenue requirement proceedings, WPLP continued with its efforts to acquire the land rights required for purposes of the Transmission Project. As discussed in EB-2018-0190, these include various land rights required from private landowners,

[13] EB-2018-0190, Exhibit F-2-1.

as well as rights in respect of public lands over which various federal, provincial and municipal authorities assert jurisdiction.[14]

To date, WPLP has acquired: (i) all required easements on private lands; (ii) all required permits under section 28(2) of the *Indian Act*, which have been signed off on by the affected First Nations and the federal government; (iii) all required Land Use Permits for transmission line rights-of-way and substations located on lands over which the Province of Ontario, through the MNRF and the Ministry of Transportation ("MTO"), asserts authority;[15] and (iv) a required easement on land owned by the Corporation of the Municipality of Red Lake. In addition, upon further investigation, WPLP and its EPC contractor, Valard LP, have verified that no other municipally owned lands or roads under the control of local roads boards are affected by the Transmission Project.

Independent of the conventional land rights discussed above, WPLP has followed the Anishinabe and Anishinninuwug land sharing and traditional protocols, in respect of WPLP's use of land covered by Treaties 3, 5 and 9.[16]

WPLP has also worked with Valard LP, the MECP and the MNRF to secure all Water Crossing Permits and Work Permits that are required for access roads based on the EPC contractor's work schedule. In addition, Valard LP has prepared all detailed engineering design drawings required to secure the necessary MTO Encroachment Permits and crossing agreements in respect of Canadian National Railway and Canadian Pacific Railway crossings. The MTO has determined that license agreements will not be required for WPLP's planned crossings of MTO controlled roads and, instead, Encroachment Permits have been issued.

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[14] EB-2018-0190, Exhibit F-2-1.

[15] Although all required Land Use Permits have been secured, due to the fact that Land Use Permits are not assignable to WPLP's lenders, WPLP was required to convert its Land Use Permits into a License of Occupation to finalize its financing arrangements. Upon completion of construction, the License of Occupation will be converted into an easement. WPLP has secured a Multisite Land Use Permit to capture minor routing refinements as they are finalized for different segments of the Transmission Project. License of Occupation mapping for these minor routing refinements will be produced to add these locations to WPLP's License of Occupation. To the extent that any of the changes being contemplated may be material, WPLP will notify the Board in accordance with the conditions of its LTC.

[16] Please refer to Exhibit F-1-1 of EB-2018-0190 for additional discussion of land sharing and traditional protocols.

As further discussed in Exhibit B-1-1, since the 2022 revenue requirement proceedings, WPLP made certain routing refinements to incorporate input received from the affected First Nation communities and avoid culturally sensitive areas, which may not have been previously identified. The revised transmission line rights-of-way were permitted through a multi-site land use permit issued by the MNRF and through section 28(2) permit amendments where First Nation reserve lands were impacted.

6. Coordination with HONI and HORCI

In parallel with the EPC contracting process described above, WPLP worked with Hatch (its Owner's Engineer) and various representatives of HONI to advance a number of project development milestones including: (a) completing preliminary engineering of substation layouts and interconnections between the HONI and WPLP transmission systems at each of Dinorwic, Pickle Lake, and Red Lake; (b) coordinating land rights, access requirements and EA approvals in relation to these stations; and (c) refining station locations and footprints in consideration of permitting and approval requirements.

Following WPLP's selection of Valard LP as the preferred proponent in the EPC RFP, WPLP and Hatch continued to coordinate engineering efforts with HONI, further advancing station engineering efforts in consideration of enhanced and updated information available from the EPC proposal, as well as consideration of preliminary construction schedules provided in the proposal. After issuing the Notice to Proceed to Valard LP, formal project teams were established to finalize engineering and design with respect to interconnections with HONI.

Coordination with HORCI following the LTC Decision primarily focused on facilitating backup supply arrangements (see Section 8 below) and advancing agreements and arrangements for the transfer of distribution system assets to HORCI for communities currently served by Independent Power Authorities (IPAs). IPA transfer work has focused on advancing contractual agreements and permitting, as well as preparing and issuing design and construction tender packages for the necessary distribution system and facilities upgrades in each community. OSLP, in collaboration with ISC and HORCI, completed the development of template Asset Transfer Agreements and

template permits under Section 28(2) of the *Indian Act* in January 2020.[17] Those templates were reviewed with all IPA communities and their respective Tribal Councils. Design and construction tendering processes have been completed for all six communities that are currently served by IPAs. Target completion dates for all construction activities and other transfer requirements and conditions are aligned with the target in-service dates for each community, and the Asset Transfer Agreements and Section 28(2) permits will be finalized on a rolling basis in parallel with the completion of those activities for each community.

Since the 2022 revenue requirement application, WPLP has continued to coordinate with HONI on matters relating to construction, commissioning and energization at each of the three locations where WPLP's transmission system will connect with HONI's transmission system. Similarly, WPLP has worked with HORCI to coordinate procurement, construction, commissioning and energization activities for distribution delivery points, with a focus on the communities that will be connecting in 2022. WPLP's engagement and coordination activities with HONI and HORCI have also included the drafting of transmission connection agreements, confirmation of settlement processes, and completion of relevant IESO registration processes.

7. Indigenous and Métis Engagement

An overview of WPLP's First Nation and Métis engagement is provided in Exhibit A-6-1. The following summarizes key developments relating to First Nation and Métis engagement since the 2022 transmission rate application.

Throughout 2021, WPLP with the assistance of OSLP continued to engage and communicate with potentially impacted Indigenous and Métis communities on a variety of issues, including but not limited to routing changes, permanent land access plans, permitting work, back-up power, employment and training opportunities, and IPA transfers. In particular, during 2021 WPLP with support from OSLP held:

[17] HORCI continues to work with the IPA communities on their respective Asset Transfer Agreements. A copy of the most recent Indigenous Services Canada report on IPA and Backup Power was filed by WPLP as part of its Semi-Annual Report dated April 15, 2022, pursuant to EB-2018-0190.

- seven in-person meetings with communities, during which the discussions related to topics that included, but were not limited to, the proposed permanent access for operational purposes for the project, 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;

- eight community-specific radio shows (some with Microsoft Teams option) to provide updates on the Transmission Project, land protocols, COVID protocols, and Indigenous participation. Participating First Nation members had the opportunity to call in to ask questions;

- over a dozen teleconferences to address community-specific project related issues, including, but not limited to, routing, substation locations, and COVID impact;

- monthly meetings with Community leadership on COVID-19; and

- four videoconferences for the Community Liaisons presenting information and Indigenous participation opportunities associated with the right of way and access, tower preparation and assembly, tower erection and stringing, and substations.

In addition, WPLP and OSLP continue to produce a monthly update newsletter and provide information, updates and opportunities via their respective websites and social media pages. WPLP continues to engage with Indigenous communities and the Métis Nation on regulatory requirements as required, including the circulation of documents for review and input (archaeology, environmental assessment, permitting), circulation of quarterly environmental updates, and notification of sightings of species at risk.

8. Facilitation of Back-up Supply

Further to the OEB's decision in EB-2018-0190, WPLP is required to provide regular updates to the Board, through its semi-annual reports, on its efforts to facilitate the development of back-up electricity supplies to the connecting communities. Please refer to WPLP's most recent semi-

annual report (dated April 15, 2022) for a description of the status of those efforts and the activities most recently undertaken by WPLP (through OSLP) to facilitate back-up supplies.

WPLP also notes that, in response to its semi-annual report filed on April 15, 2021, the OEB requested that WPLP file a copy of its finalized backup power plan (the "Backup Power Plan") and that WPLP provide opinions on the sufficiency of the backup power plan from HORCI and the IESO. The OEB's letter further requested explanations as to (a) why the Backup Power Plan provides for backup supply coverage only of critical assets in three communities, and (b) the plans for funding the long-term costs associated with the supply of back-up power to the connecting communities. On July 15, 2021, WPLP responded to the OEB's request and provided the requested information. The OEB subsequently requested, by way of a letter dated July 23, 2021, that WPLP facilitate a request to the Backup Power Working Group ("BPWG") for confirmations in respect of certain aspects of the Backup Power Plan. WPLP has requested that the BPWG provide confirmation of those aspects, which relate to reliability levels and the ability to supply load identified in each community's Emergency Response Plan. WPLP continues to work with BPWG to address the OEB's request for additional information. The BPWG has provided information to assist in responding to the OEB's request. An update is provided as part of the semi-annual report dated April 15, 2022.

9. Coordination with the IESO

Over the past year, WPLP has worked with the IESO to draft a Transmission Operating Agreement, which is substantially similar to the terms of the operating agreements the IESO has entered into with all other Ontario transmitters. This agreement defines those of WPLP's transmission facilities that are part of the IESO-Controlled Grid, and sets forth the various responsibilities of the IESO and WPLP with respect to the secure and reliable use and operation of WPLP's transmission facilities. Since early 2020, WPLP has also coordinated with the IESO to complete various requirements of the IESO's transmission connection process, including authorizations for market and program participation, facility and equipment registrations, and equipment commissioning. WPLP has submitted facility registrations for all substations coming

into service in 2022 and is in the process of completing equipment registration requirements for major equipment within those stations.

Exhibit B, Tab 1, Schedule 3

Project Schedule

PROJECT SCHEDULE

This section describes the current Transmission Project schedule, including the sequencing of in-service dates for all project components and segments. In addition, WPLP identifies and explains the causes of changes in the project schedule relative to the schedule that was presented in the 2022 revenue requirement proceeding, and discusses schedule risks, contingency and risk mitigation.

A. Prior Transmission Project Schedules

WPLP provided regular updates to its forecasted project schedule through semi-annual reports filed pursuant to the OEB's Decision and Order in EB-2016-0262 until July 15, 2019.[1] Commencing October 15, 2019, WPLP has instead provided semi-annual reports pursuant to the OEB's Decision and Order in EB-2018-0190, which did not require information updates regarding the Transmission Project schedule.[2]

In its 2022 revenue requirement application, WPLP presented the then current Transmission Project schedule along with the changes in the schedule relative to that which was presented in the Leave to Construct proceeding. As described in the 2022 revenue requirement proceeding, in late June 2021 WPLP received a series of schedule updates from its EPC Contractor. As a result, WPLP filed updated evidence that included the revised Transmission Project schedule as part of its responses to interrogatories.[3] The revised project schedule indicated that the Line to Pickle Lake as well as three communities (i.e. Pikangikum First Nation, North Caribou Lake First Nation and Kingfisher Lake First Nation) to be served by the Remote Connection Lines remained on-schedule and unchanged from the application as originally filed. The in-service dates for all other

[1] The OEB's Decision and Order in EB-2016-0262 authorized WPLP to establish a deferral account to record project development costs, and required WPLP to file semi-annual reports addressing project progress, costs, schedule and risks.

[2] The OEB's Decision and Order in EB-2018-0190 granted Leave to Construct and required WPLP to file a semi-annual report regarding its CWIP account and three associated sub-accounts, as well as to report on the progress of backup supply arrangements for each community to be connected.

[3] EB-2021-0134, Staff-8, Appendix A attaching Exhibit K.

communities were delayed until 2023 and 2024. WPLP did not provide specific dates as those remained subject to WPLP's then ongoing discussions with the EPC Contractor.

Pursuant to the Settlement Agreement in EB-2021-0134, WPLP agreed to include information relating to the expected connection dates for communities not yet connected to WPLP's transmission system in its semi-annual reports that it continues to be required to file pursuant to the OEB's directions in EB-2018-0190. WPLP's Semi-Annual Report, filed on October 15, 2021, provided the most recent estimates then available regarding the energization dates for each community not yet connected to WPLP's transmission system. Subsequently, in late January 2022, WPLP received a further updated project schedule from its EPC Contractor reflecting all factors known as of December 31, 2021.[4] That schedule represents the most current available project schedule and has therefore been used as the basis for this application.

B. Current Transmission Project Schedule

Table 1, below, presents WPLP's current estimates of the energization dates for each of the remote communities, along with comparisons to the estimated energization dates that were presented in the October 15, 2021 Semi-Annual Report. Descriptions of the reasons for variances follow.

Table 1 – Expected Energization Dates by Community

Community	Estimated Date from October 15, 2021 Semi Annual Report	Current Estimated Date	Difference (Months)
Pikangikum	Apr-22	Jun-22	2
North Caribou Lake	Jun-22	Aug-22	2
Kingfisher Lake	Jun-22	Aug-22	2
Muskrat Dam	May-23	May-23	-
Bearskin Lake	May-23	May-23	-
Wunnumin Lake	May-23	May-24	12

[4] As of March 15, 2022, the EPC Contractor (Valard) and its subcontractors have experienced 450 cases of COVID-19 since January 1, 2022. The impact of these COVID-19 cases has not been reflected in the January 2022 schedule used to prepare this rate application. Any update to this rate application will reflect the impact, if any, to schedule.

Wawakapewin	May-23	Jun-23	1
Kasabonika Lake	Jun-23	May-24	11
KI + Wapekeka	Jun-23	May-24	11
Sachigo Lake	Jun-23	Jul-23	1
Poplar Hill	Apr-24	Apr-24	-
Deer Lake	Apr-24	Apr-24	-
North Spirit Lake	May-24	May-24	-
Sandy Lake	May-24	May-24	-
Keewaywin	May-24	May-24	-

The delays in certain of the community energization dates are primarily driven by: (1) multiple forest fires in the summer of 2021 within the Project Site, and (2) cumulative COVID-19 impacts. The extent of the delays for particular communities are dependent on: (1) construction progress to date, (2) all season road availability, and (3) the geographical location of the community, as more remote communities require winter road access to construct, which causes longer delays which cannot be mitigated economically.

Table 2, below, presents WPLP's current in-service schedule by line segment and station.

Table 2 – In-Service Schedule by Line Segment and Station

Asset Designation	**Description**	**Current Forecast In-Service Date**
Line to Pickle Lake		
Line W54W	230 kV - Dinorwic to Pickle Lake	21-Jun-22
Station A	Wataynikaneyap SS (Dinorwic)	21-Jun-22
Station B	Wataynikaneyap TS (Pickle Lake)	21-Jun-22
Pickle Lake Remote Connection Lines		
Line WBC	115 kV - Pickle Lake to Ebane/Pipestone SS	5-Aug-22
Line WCJ	115 kV - Ebane/Pipestone SS to Kingfisher Lake TS	5-Aug-22
Line WJI	44 kV - Kingfisher Lake TS to Wunnumin Lake TS	28-May-24
Line WJK	115 kV - Kingfisher Lake TS to Wawakapewin TS	14-Jun-23
Line WKL	44 kV – Wawakapewin TS to Kasabonika Lake TS	24-May-24
Line WKM	115 kV – Wawakapewin TS to KI-Wapekeka TS	3-May-24
Line WCD	115 kV - Ebane/Pipestone SS to North Caribou Lake TS	17-Aug-22
Line WDE	115 kV - North Caribou Lake TS to Muskrat Dam TS	15-May-23

Line WEF	115 kV - Muskrat Dam TS to Bearskin Lake TS	31-May-23
Line WEG	115 kV – Muskrat Dam TS to Sachigo Lake TS	11-Jul-23
Line D1	25 kV – North Caribou Lake TS to HORCI 25 kV	17-Aug-22
Line E1	25 kV – Muskrat Dam TS to HORCI 25 kV	15-May-23
Line F1	25 kV – Bearskin Lake TS to HORCI 25 kV	31-May-23
Line G1	25 kV – Sachigo Lake TS to HORCI 25 kV	11-Jul-23
Line I1	25 kV – Wunnumin Lake TS to HORCI 25 kV	28-May-24
Line J1	25 kV – Kingfisher Lake TS to HORCI 25 kV	5-Aug-22
Line K1	25 kV – Wawakapewin TS to HORCI 25 kV	14-Jun-23
Line L1	25 kV – Kasabonika Lake TS to HORCI 25 kV	24-May-24
Line M+/M-	25 kV – KI-Wapekeka TS to HORCI 25 kV	3-May-24
Substation C	Ebane/Pipestone SS	5-Aug-22
Substation D	North Caribou Lake TS	17-Aug-22
Substation E	Muskrat Dam TS	15-May-23
Substation F	Bearskin Lake TS	31-May-23
Substation G	Sachigo Lake TS	11-Jul-23
Substation I	Wunnumin Lake TS	28-May-24
Substation J	Kingfisher Lake TS	5-Aug-22
Substation K	Wawakapewin TS	14-Jun-23
Substation L	Kasabonika Lake TS	24-May-24
Substation M	KI-Wapekeka TS	3-May-24
Red Lake Remote Connection Lines		
Line P1P2	115 kV - Red Lake SS to Existing Pikangikum 44 kV Line	29-Jun-22
Line WQR	115 kV - Pikangikum TS to Poplar Hill SS	15-Apr-24
Line WRS	115 kV - Poplar Hill SS to Poplar Hill TS	15-Apr-24
Line WRT	115 kV - Poplar Hill SS to Deer Lake SS	30-Apr-24
Line WTU	115 kV - Deer Lake SS to Deer Lake TS	30-Apr-24
Line WTZ	115 kV - Deer Lake SS to Sandy Lake SS	31-May-24
Line WZW	115 kV - Sandy Lake SS to Sandy Lake TS	31-May-24
Line WZV	115 kV - Sandy Lake SS to North Spirit Lake TS	15-May-24
Line WVY	115 kV – North Spirit Lake TS to Keewaywin TS	31-May-24
Substation P	Red Lake SS	29-Jun-22
Substation Q	Pikangikum TS	29-Jun-22
Substation R	Poplar Hill SS	15-Apr-24
Substation S	Poplar Hill TS, S1 25kV to HORCI	15-Apr-24
Substation T	Deer Lake SS	30-Apr-24
Substation U	Deer Lake TS, U1 25kV to HORCI	30-Apr-24
Substation V	North Spirit Lake TS, V1 25kV to HORCI	15-May-24
Substation W	Sandy Lake TS, W1 25kV to HORCI	31-May-24
Substation Y	Keewaywin TS, Y1 25kV to HORCI	31-May-24
Substation Z	Sandy Lake SS	31-May-24

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C. Schedule Risks, Contingency and Mitigation

WPLP's project schedule has been materially compressed from what was contemplated at the time of signing the EPC contract. As such, the project schedule now has less inherent float to manage remaining contingency risks.

WPLP's key schedule risks generally fall under the following five categories:

- **Material and Equipment Delivery:** Risks that delivery dates for material and equipment could be delayed arriving to Canada, or being shipped within Canada, due to any combination of further COVID-related closures of factories or shipping facilities, or work stoppages beyond the control of WPLP or its EPC contractor.[5]

- **Access Considerations:** Risks that access within the project footprint will be temporarily unavailable due to uncertainty in weather (which impacts winter road availability, the ability to safely use other roads and access trails, and the ability to safely fly materials to certain areas), forest fires, archaeological finds during construction, COVID outbreaks within the general project footprint or nearby communities, or other factors beyond the control of WPLP or its EPC contractor.

- **Third-Party Factors:** Risks that certain activities in respect of which WPLP and/or its EPC contractor are collaborating or interacting with or otherwise dependent upon third parties (e.g. Hydro One, HORCI, IESO, issuers of various permits, etc.) are delayed due to factors beyond the control of WPLP or its EPC contractor.

[5] This risk has been significantly mitigated. As of the date of filing, the majority of equipment is on the Project Site or in Canada. As it relates to equipment not on site (primarily inventory), the war in Ukraine is having an impact on availability and price.

- **Routing Changes:** Risks that routing changes are required, based on cultural or environmental sensitivities or constraints that are identified during ongoing engagement activities, or through field observations leading up to construction in each area.[6]

- **Construction Execution:** COVID-19 has had a significant impact on construction activity to date. The majority of COVID-19 cases have occurred during the winter period, which has impacted winter construction and given the remote location of the upcoming work and the dependance on winter roads the ability to recover slippages in schedule is limited.

In consideration of the schedule risks described above, WPLP and its EPC contractor have a number of risk management processes and mechanisms in place, as further described in Section B of Exhibit B-1-4.

[6] This risk has been significantly mitigated as most of the final routing has been determined and agreed to by the relevant stakeholders and First Nation communities. There only remain a couple of outstanding routing refinements, primarily around the 25kV and 44kV lines.

Exhibit B, Tab 1, Schedule 4

Project Organization and Execution

PROJECT ORGANIZATION AND EXECUTION

This Schedule sets out WPLP's approach to executing the Transmission Project and the organizational structure it has put in place for this purpose. WPLP's project execution structure reflects its commitment to ongoing engagement and communication with potentially impacted communities, land users and other stakeholders, which is critical to the successful construction of the Transmission Project.[1] Also included in this Schedule are details on the company's role in coordinating and overseeing its contractors, change management processes, cost management, risk and performance management, and its project tracking and reporting practices. In addition, this schedule describes WPLP's plans for transitioning to a structure that will perform and support system operations and maintenance as project segments are placed into service.

A. Transmission Project Organization and Execution

As described in Exhibit B-1-2, WPLP undertook a comprehensive EPC RFP process, which resulted in the execution of an EPC Contract with Valard LP ("Valard" or the "EPC Contractor"). Valard is generally responsible for all engineering, project and construction management, procurement and construction activities related to the Transmission Project, including requirements related to Indigenous participation, health and safety, environmental compliance, and quality control, pursuant to the terms of the EPC Contract.

To provide an appropriate level of project controls, contract administration, risk mitigation, and general oversight during the construction phase, WPLP has developed a project execution structure that continues to leverage the strengths and experience of its partners[2], supplemented by Hatch in its role as WPLP's Owner's Engineer ("OE"), and Mott MacDonald in its role as Independent Engineer ("IE"). The role of each party in the context of WPLP's project execution structure[3] is

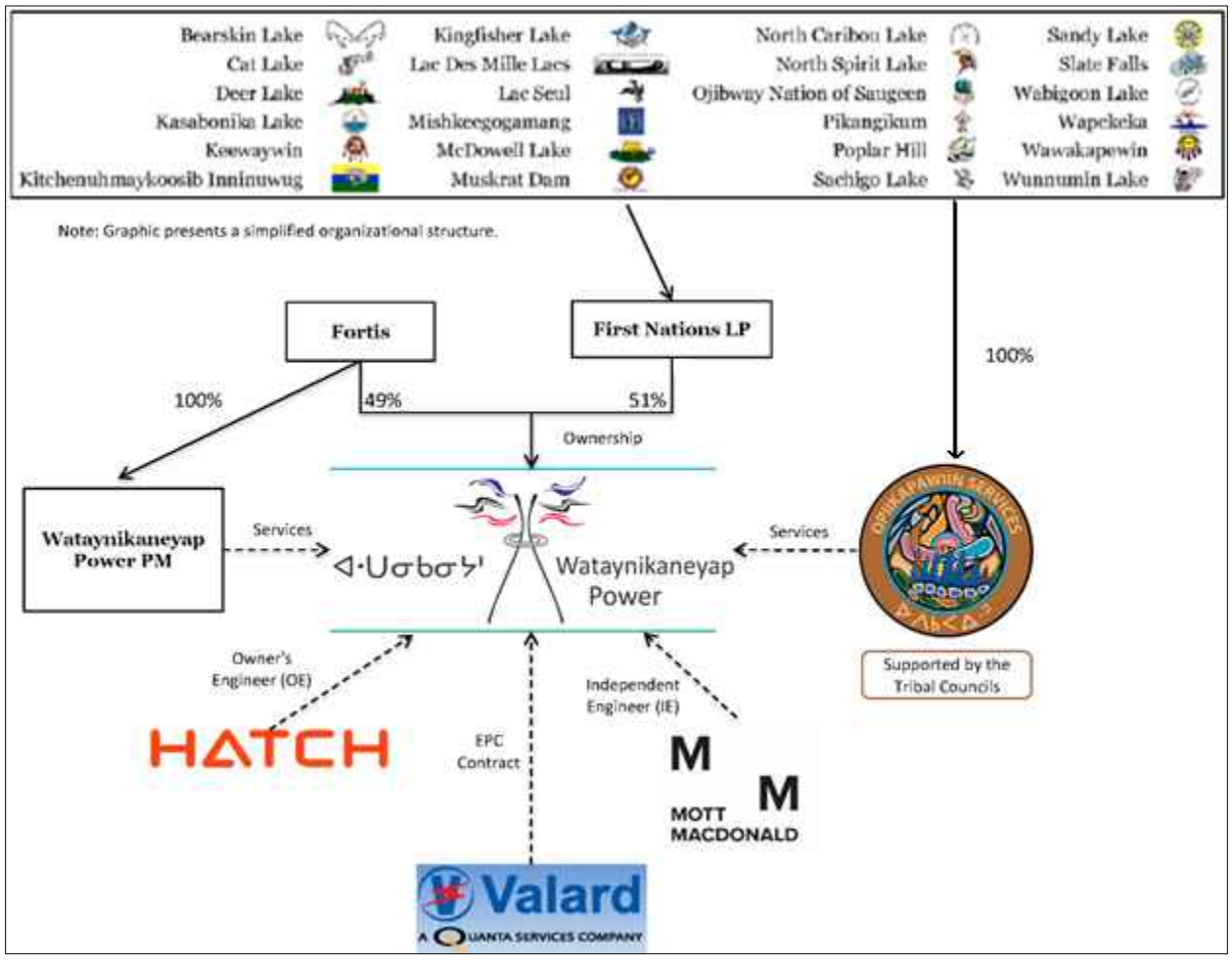
[1] See WPLP's Procurement Policy in Exhibit F-3-1, Appendix 'B' for a description of WPLP's commitment to Indigenous participation and its importance to the Transmission Project.

[2] Including through OSLP and WPPM as service providers, as further explained in Section A of Exhibit B-1-4.

[3] Additional information about WPLP's ownership structure is provided in Exhibit A-4-1.

summarized in Figure 1 below, which is followed by further description of each party's roles and responsibilities related to the Transmission Project.

Figure 1 –Project Execution Structure



1. Opiikapawiin Services LP ("OSLP")

Leveraging the local and traditional knowledge, experience and expertise of the Participating First Nations and Tribal Councils, OSLP is primarily responsible for administering projects and programs for WPLP relating to community engagement, community readiness, education & training, business readiness, communications, capacity building, and certain aspects of stakeholder engagement.

Through a Service Agreement with WPLP, OSLP works with WPLP and Valard to ensure that the Participating First Nations are able to build capacity[4] and obtain 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 related to the EPC contract will mitigate execution risk and benefit all parties, as well as develop potential future employees to operate and maintain the transmission system. Opportunities for Indigenous participation are facilitated through delivery of job-specific training related to various aspects of project construction and logistics, as well as skills-development programs and cultural awareness training. OSLP also maintains a labour pool database and a registry of Indigenous businesses to assist WPLP in filling employment and sub-contracting opportunities for the Transmission Project. OSLP also provides regular monitoring and reporting with respect to Valard's Indigenous Participation Plan commitments in the EPC contract.

With respect to ongoing community engagement and project communications, OSLP coordinates community engagement meetings and logistics, creates monthly newsletters, provides technical support for the project website, and coordinates communications through Community Liaisons to ensure engagement and communication activities are consistent with WPLP's Indigenous Engagement Plan and Indigenous Communications Management Plan.[5]

OSLP also continues to monitor, and to the extent required facilitates, the development and implementation of backup supply arrangements on behalf of WPLP for all communities that will become grid-connected through the Transmission Project and facilitates agreements and arrangements for the transfer of distribution system assets to HORCI for communities currently served by Independent Power Authorities ("IPAs").[6] While the underlying activities relating to backup supply arrangements and transferring distribution system assets from IPAs to HORCI are

[4] Including for example working with local First Nation businesses to obtain the qualifications necessary to provide sub-contracting support to the EPC contractor, and working with individual members of the community to obtain the education, training and qualifications necessary for employment on the project.

[5] See Exhibit B-1-2, Section B.7 for further discussion of these plans.

[6] A copy of the most recent Indigenous Services Canada report on IPA and Backup Power was filed by WPLP as part of its Semi-Annual Report dated April 15, 2022, pursuant to EB-2018-0190.

beyond the scope of this Application, WPLP is 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-2021-0184, and WPLP continues to monitor the status of IPA distribution system transfers through regular reporting completed by OSLP. These activities ensure that the distribution systems currently operated by IPAs will be prepared for connection to WPLP's transmission system in compliance with electrical safety regulations and will be operated by a licensed distributor (HORCI) by the time of connection to the Transmission System. For 13 of the 16 connecting First Nation communities, the backup supply arrangements leverage the generation assets and associated infrastructure currently providing the primary electricity supply within the communities to instead function in an emergency backup capacity during outages on or upstream of WPLP's transmission system. For the other three[7] communities, emergency backup supply will be provided for critical infrastructure locations, as applicable, instead of on a community-wide basis.[8]

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.

2. 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 development and operation, WPPM is responsible for providing services related to project management, engineering, operations, finance, regulatory and various corporate functions (including health and safety, environmental compliance, HR, IT and procurement). Organizationally, WPPM provides these services in three functional areas:

[7] One of these three communities, Wawakapewin First Nation continues to hold discussions with the Backup Power Working Group to determine whether an alternative, to critical asset backup only, is available.

[8] Details and status of backup power solutions for the 16 connecting First Nation 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, 2022.

- WPPM's Chief Operating Officer (COO) oversees all aspects of project and construction management, health and safety, environmental compliance, as well as engineering and operations.

- WPPM's VP Finance & Chief Financial Officer (CFO) oversees all aspects of finance/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, in consideration of WPLP's overall direction to ensure meaningful Indigenous participation in the Transmission Project, and in consideration of WPLP's Indigenous Engagement Plan and Indigenous Communications Management Plan.

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

3. Valard (EPC Contractor)

The terms of the EPC Contract between WPLP and Valard broadly require Valard to undertake all engineering, procurement and construction activities in order to construct the Transmission Project on a turn-key basis. The EPC Contract assigns the majority of the project execution risk to Valard,[9] with the exception of certain pre-determined owner risk events and force majeure events that are typical in consideration of the project and EPC contracting strategy.

The EPC Contract incorporates Indigenous participation commitments, including requirements to report on Indigenous participation and employment results, and to develop remediation and transition plans where results fall short of contractual commitments. OSLP works with Valard,

[9] Valard is the Construction Authority on the Project site with responsibility for all aspects of Health and Safety including the Health and Safety COVID-19 protocols/procedures.

Hatch and WPLP to verify Valard's reporting of Indigenous participation and employment results to the Participating First Nations, and to provide communication, community engagement and liaison support in respect of these activities.

The EPC Contract also places direct responsibility on Valard to prepare and implement project-specific work plans, quality management plans and procedures, including requirements for engaging with communities to confirm work plans, inspections and testing, environmental and permitting requirements, document control, resource competency, equipment certification and quality control, and change management. While the responsibility for project management and quality management of all EPC activities rests with Valard, WPLP has an overall responsibility to monitor and confirm Valard's compliance with the requirements of the EPC Contract. WPLP's efforts in this area, as supported by OSLP, WPPM, and Hatch, are described in Section B of this Schedule.

4. Hatch (Owner's Engineer)

As described in Exhibit B-1-2, WPLP engaged Hatch to provide services in an OE capacity through a competitive procurement process in 2018. As is typical in large infrastructure projects constructed through an EPC process, the OE supplemented WPLP's own engineering and project management resources during the EPC tendering process and continues to provide project management and EPC oversight services during the detailed engineering, procurement and construction phases of the project. Hatch provides a variety of project and process management resources, technical subject matter experts, qualified field inspectors, and document control services to support WPLP's oversight of the EPC Contractor, as well as to support change management, cost management, performance and risk management and reporting processes, as described in Section B below.

5. Mott MacDonald (Independent Engineer)

WPLP negotiated project-specific financing with a consortium of five bank lenders, as well as Ontario, (collectively the "Lenders"), resulting in a Common Terms and Intercreditor Agreement ("CTIA") as described in Exhibit G-2-1. To support the Lenders' due diligence process prior to

financial close, Mott MacDonald, was engaged by WPLP as the IE to undertake a technical review of the Transmission Project. During the construction phase, WPLP has continued its engagement with the IE to support CTIA requirements related to independent review and certification of advances, progress invoices, project completion and milestones, as well as monthly reporting to the Lenders on project status. This independent, third-party review of construction activities, change management, and invoice approval helps ensure that WPLP, and ultimately ratepayers, are receiving value for the services performed and that the objectives of the Project are achieved.

B. Contractor Coordination and Oversight

The EPC Contract assigns most responsibilities and risks to Valard as the EPC Contractor. WPLP's role is to provide coordination and oversight at a level that ensures and confirms compliance with all requirements of the EPC Contract, and otherwise mitigates cost and schedule risk. WPLP also coordinates with the EPC Contractor to obtain and provide certain owner-supplied permits pursuant to the EPC Contract, as well as to review and support any contractor-supplied permits.

1. Contractor Coordination

On behalf of WPLP, OSLP works with the 24 Participating First Nations, as well as any Tribal Councils representing their member communities, to provide ongoing services related to community engagement, project communications, employment and training, and business readiness. Specifically, OSLP delivers targeted training programs and maintains a labour pool database and a registry of Indigenous businesses in the Participating First Nations. These services allow OSLP to coordinate with Valard to maximize Indigenous employment and subcontracting opportunities related to the Transmission Project. As noted above, the mandate to coordinate and work with each Participating First Nation on their local knowledge related to the EPC contract will mitigate execution risk and benefit all parties, as well as develop potential future employees to operate and maintain the transmission system.

The EPC Contract divides permitting responsibility between WPLP and Valard. "Owner Permits" that WPLP is required to obtain generally relate to pre-construction permitting requirements,

permits related to crossing or abutting federally or provincially regulated transportation infrastructure (e.g. railways, airports, highways), and land-related permits (e.g. easements and permits relating to land use, land rights and mining claims). In contrast, Valard's "Contractor Permits" generally relate to obtaining approval or meeting legislative requirements in order to execute the project activities, including taking, treating and discharge of water, removal of aggregate, temporary changes to land use, and the transportation of dangerous goods. While Valard is ultimately responsible for managing the requirements of all permits, once obtained, coordination with WPLP is required for permit applications and amendments. WPPM's land and environmental leads, supported by the OE, regularly interact with Valard to ensure that all permits are monitored and amended as required, and to ensure that any permit applications submitted by Valard are reviewed and approved prior to submission.

In addition to the specific Indigenous participation and permitting coordination efforts described above, WPLP, Hatch and Valard hold a variety of regular meetings to ensure coordination on a range of technical and logistical aspects of the project. WPLP, Hatch and Valard also make use of the Request for Information ("RFI") provisions in the EPC contract to formally communicate and document requests for additional information or clarification related to interpretations of EPC contract provisions to ensure consistent understanding of expectations and deliverables.

2. Contractor Oversight

WPLP's EPC Contract oversight processes and activities are designed to ensure compliance with all aspects of the EPC Contract. Sections 3 through 5 below provide details on procedures related to EPC Contract oversight with respect to change management, cost and performance management, as well as project tracking and reporting.

Direct oversight of construction activity in the field is also provided on behalf of WPLP through daily inspections and monitoring conducted by field inspectors employed by Hatch and periodic inspections completed by WPPM. These efforts are focused on documenting compliance or concerns with respect to health and safety requirements, environmental protection requirements, and QA/QC provisions of the EPC Contract. Each inspector submits concise daily summary

reports, which document compliance with various contractual requirements, identify any areas of concern, and provide summaries of construction progress, including photos of key work activities and constructed assets.

3. Change Management

WPLP has implemented a comprehensive process for managing EPC Contract changes, which is overseen by WPPM and administered by Hatch in its role as OE. This process is consistent with the change provisions in the EPC Contract and ensures that any change request initiated by the EPC Contractor or by WPLP is accompanied by a detailed description of the request and an estimate of cost and schedule impacts resulting from the requested change. The change management process also ensures that any requested changes have contractual merit and are appropriately communicated, documented and reviewed prior to the execution of a formal change order.[10]

As noted above, an RFI process is used to formally communicate requests for clarification or additional information related to interpretation of EPC Contract provisions. This process ensures that all such requests and responses are adequately reviewed by the appropriate subject matter experts and senior leadership for all parties and documented in writing. This process is also used to document and facilitate notifications of emerging issues and to request direction in addressing or responding to issues. In the vast majority of cases, the RFI process provides the required clarification, where all parties agree on solutions that do not require contract change orders.

WPLP and Hatch have implemented additional change management processes related to routing, since routing changes have the potential to significantly impact community engagement, permitting, schedule and cost. Requests to consider routing changes can be initiated either by WPLP or the EPC Contractor, for a variety of reasons as discussed in Exhibit B-1-1. WPLP's change management process related to routing involves reviews of any proposed routing changes

[10] WPLP has implemented a comprehensive risk management system to track all known project risks. WPLP assigns a provisional value to a project risk once any such risk is determined to be the responsibility of WPLP. WPLP does not record reductions in project costs unless a Change Order is executed pursuant to the EPC contract.

to ensure that the proposed changes are based on viability from multiple perspectives, including community approval, technical and constructability, as well as impacts on permitting, cost and schedule.

WPLP's change management processes are integrated with the cost and performance management processes described in Section 4 below and the project tracking and reporting processes described in Section 5 below. This allows for early identification of issues or proposed changes in order to provide clarifications and consider alternative solutions that might mitigate cost and schedule impacts. This process also allows for the EPC contractor to identify and propose alternatives to routing or design to overcome access and constructability challenges, with corresponding reductions in costs, improvements to schedule and/or mitigation of risks.

4. Performance and Cost Management

Conformance to technical specifications included in the EPC contract during the engineering and procurement stages is ensured through detailed design reviews by Hatch subject matter experts and WPPM technical staff, each acting on behalf of WPLP, as well as reviews of test reports, factory acceptance testing, and other approval or certification documents.

WPLP manages the performance of the EPC Contractor through processes and procedures administered by Hatch in its role as the OE, with oversight from WPPM. Many of the related processes and procedures are described in Sections 1 through 3 above.

Hatch also administers a cost management process on behalf of WPLP, which includes reviewing and validating progress invoices and supporting documentation from the EPC Contractor and approving payment certificates. Mott MacDonald, in its role as the IE, also independently reviews and certifies advances and progress invoices. Hatch's cost management procedure for WPLP ensures that payments to the EPC contractor are commensurate with work performed in accordance with the Rules of Credit developed and agreed to by the EPC Contractor, WPLP, Hatch and the IE. The Rules of Credit ensure progress payments to the EPC Contractor tie to the activities in the field and ensure appropriate supporting information is provided to validate work progress. This

procedure is also integrated with the change management process to enable tracking and reporting of costs related to change orders.

5. Project Tracking and Reporting

Valard is required to provide daily, weekly, monthly and annual reports to WPLP under the terms of the EPC Contract. These reports provide insight on project progress, emerging issues, and conformance with various provisions of the EPC Contract, including requirements related to health and safety, environmental protection, Indigenous participation, engineering and procurement progress, permitting, employment, and quality control. These reports support WPLP's general oversight of the EPC Contract, as well as a variety of ongoing project communication and engagement activities.

Hatch also provides daily, weekly, monthly and quarterly reports to WPLP. Hatch's weekly, monthly and quarterly reports summarize content from Valard's reporting requirements, emerging issues and outstanding RFIs, and incorporate additional analysis related to progress vs. plan and key project risks. Daily reports submitted by Hatch's field inspectors provide a snapshot of construction activities each day, document conformance with EPC Contract requirements, and identify any critical health, safety, environmental or quality control issues.

Valard, WPLP and Hatch also provide reporting and information to Mott MacDonald as required to support its monthly IE report to the Lenders.

C. Operations and Maintenance

From the time that WPLP secured all necessary pre-construction approvals and project financing in 2019, it has been focused on implementing a robust structure for project execution to ensure the successful construction of the Transmission Project, as described throughout this Schedule. Almost immediately after working with the OE and EPC Contractor to initiate right of way clearing and initial construction activities in late 2019 and early 2020, COVID-19 was declared a pandemic, and the majority of WPLP's efforts for the balance of 2020 turned to managing the operational, financial and schedule impacts associated with the pandemic. More recently, WPPM has been

focused on developing, refining and implementing an interim O&M and System Control strategy (the "Interim O&M Strategy"), as well as engaging in recruitment and procurement efforts to support and implement the Interim O&M Strategy. The Interim O&M Strategy will allow WPLP to continue to focus on construction activities while developing internal processes, systems, and staffing that will maximize the ability of WPLP resources to operate the transmission system in the future. The primary components and objectives of the Interim O&M Strategy are as follows:

1. Inspection, Maintenance and Emergency Response

WPLP's Interim O&M strategy includes consideration for the scalability of resources from several perspectives. First, as assets come into service at various points during in 2022 and 2023, the number of assets to be operated, inspected and maintained will increase on a monthly basis. Second, WPLP expects that any inspection and maintenance cycles included in its Interim O&M Strategy will be evaluated and adjusted in consideration of actual inspection results, system performance and costs, which may lead to changes in its inspection and maintenance programs.

Third, WPLP's transmission system, like any other transmission system, will be exposed to severe weather events and, due to its remote location and geography, forest fires are also a concern. The frequency, location and intensity of such events cannot be accurately predicted in advance, nor can the extent of any related damage that may occur to WPLP's transmission system. While WPLP's design parameters are intended to allow its system to withstand reasonably foreseeable severe weather events, and the use of lattice steel towers for most line segments will mitigate the risk of fire damage (as compared to wood poles), it is possible that extreme events require emergency response efforts that exceed the capacity of WPLP's internal resources, particularly as an increasing numbers of geographically dispersed line segments and substations are placed in service during 2022 and 2023.

The Interim O&M Strategy therefore contemplates agreements with third-party service providers, and will consider the feasibility of mutual assistance agreements with nearby utilities, in order to be able to quickly and efficiently scale up third-party resources to address increasing requirements

for regular O&M activities and uncertain requirements for emergency response while WPLP and WPPM recruit local operational resources to address longer-term O&M activity levels.

The objectives of the Interim O&M Strategy are to meet immediate requirements for safety, reliability, technical expertise and regulatory compliance, as well as to maximize opportunities for Indigenous Participation and capacity building. In this regard, WPLP with the support of its OE, developed a two-stage competitive procurement process to select one or more service providers with inspection, maintenance and emergency response capabilities. A Request for Expressions of Interest ("EOI") was issued on March 25, 2022, and the Request for Proposals ("RFP") is targeted for issuance in late April 2022. Through this process, WPLP is seeking to identify service providers that can offer the required resources and expertise, with demonstrated commitments to Indigenous Participation and health and safety to provide the inspection, maintenance, and emergency response ("IMER") services needed for the Transmission Project. The IMER services that WPLP seeks to procure include planned inspections of transmission line and substation assets, substation equipment testing and maintenance, and response to power outages and other emergencies. Under the general direction of WPLP, a service provider will be expected to carry out the relevant IMER services over a 3 to 5-year term in a manner that supports the First Nations ownership and control of the transmission system.

Further to the ongoing IMER procurement process, to satisfy the immediate need for 24/7 control room operations, WPLP is in the process of negotiating an agreement for Hydro One Networks Inc. to provide control room services for an interim period until such time that WPLP develops its own control room. The parties are actively discussing the required scope for the control room operation services and intend to formalize the arrangements in the near term.

In addition, to support the reliable operation of transmission assets that will soon be put into service, WPLP has been focused on the procurement of spares and developing its facilities and fleet strategies. These aspects have been impacted by evolving supply chain challenges. Following the receipt of proposals in response to the IMER RFP, WPLP will finalize its facilities

and fleet strategies to account for those services that can be provided by the IMER service provider(s).

2. Focus on Indigenous Participation

Identification of Indigenous businesses in the 24 Participating First Nations with capacity to support construction of the Transmission Project has led to a number of Indigenous subcontractors and joint ventures providing services to the project through subcontracts with Valard. OSLP and Valard on behalf of WPLP have also delivered a variety of training programs to members of the Participating First Nations during the development and construction phases of the Transmission Project, leading to direct and indirect employment opportunities during the construction phase.

WPLP's commitment to Indigenous participation extends beyond the construction phase of the Transmission Project to all aspects of WPLP's ownership and operation of the transmission system. The Interim O&M Strategy includes a focus on opportunities to extend training programs that have been delayed by COVID-19.[11] This approach is providing opportunities for members of the Participating First Nations to gain relevant experience in operations and maintenance activities to supplement experience gained during the construction phase of the project. Balancing internal and contracted O&M resources during the interim operations period will provide opportunities for job shadowing and longer-term employment for members of the Participating First Nations, as described in Sections 4 and 5 below.

3. Evaluating Emerging Technologies and Work Methods

WPLP is in a position where it will need to be scaling up operations and maintenance activities on its transmission system, but without having pre-existing programs, procedures or work methods related to these activities. While this presents a challenge in the context of developing a comprehensive Interim O&M Strategy supported by appropriate processes and procedures, WPLP recognizes that it also presents a unique opportunity to consider emerging and innovative

[11] Through OSLP, WPLP has been able to get specific funding extended, thereby allowing certain training to continue throughout 2022 and into 2023 to ensure training that was delayed as a result of COVID-19 can be implemented. Over 260 First Nation individuals have been trained since 2017, with over 100 trainees in 2021.

technologies and work methods, and to tailor the overall O&M strategy (both interim and longer-term) to WPLP's circumstances. These opportunities will be considered through the IMER RFP.

As an example, traditional inspection techniques (e.g. drive-by or ground patrols) or typical inspection frequencies may result in safety risks, environmental impacts, or cost impacts that vary significantly for WPLP relative to other Ontario transmitters when considering WPLP's remote location, geography, access logistics and seasonal constraints. This may lead WPLP to consider alternative technologies and work methods, in consultation with First Nation communities, such as aerial patrols with integrated infrared scanning and high-resolution imagery capture, deployment of additional online and remote monitoring equipment, and/or adjustments to the frequency and intensity of inspections.

4. Leveraging Construction Resources

As the Transmission Project comes into service in stages during the 2022 to 2024 period, WPLP will be in a position where the EPC Contractor will still have significant resources mobilized in the general project area to support the construction and commissioning of assets that are not yet in service.

WPLP's Interim O&M Strategy considers opportunities to leverage resources (EPC Contractor, subcontractor, material storage, accommodation space, etc.) that are already mobilized in the project area to support WPLP's O&M requirements. This may include the ongoing use of construction access, direct relationships between WPLP and certain subcontractors currently providing services to the project, and use of labour resources that would otherwise be ramping down efforts on construction. Any agreements resulting from WPLP's continued use of these resources would be expected to include requirements for Indigenous participation, which would provide opportunities for ongoing training and skills development related to O&M requirements for members of the Participating First Nations and long-term opportunities for First Nation businesses.

5. Recruiting Internal Resources

As assets come into service during the construction period, WPLP will balance the use of local operational resources (including direct employment and contracts with local First Nation businesses) and other third-party service providers to perform cyclical inspections, operating activities and maintenance tasks. In the longer term, WPLP will work towards scaling up local operational resources to perform additional O&M tasks, as well as to continue coordinating any other third-party service providers that may be contracted to support certain corrective maintenance activities, large-scale emergency response efforts, or other spikes in overall work activity. The Interim O&M Strategy contemplates recruitment of the local operational staff required to perform these functions over the longer term. It will also identify local candidates that have acquired relevant training and experience through the Indigenous participation components of WPLP's construction and interim O&M activities to cost-effectively support the ongoing operation and maintenance of WPLP's transmission system. Identification of local candidates will be supported by ensuring that a labour pool database remains available to maximize employment opportunities for members of the Participating First Nations.

To this end, WPPM has been actively recruiting additional personnel in the areas of operations, engineering and asset management, who are focused on refining, implementing and supporting the Interim O&M Strategy. Specifically, between July and December 2021, WPLP hired a Transmission Engineer, an Asset Management Specialist and a Senior Electrical Engineer to support its operations. WPLP is currently in the process of recruiting for two additional electrical engineering positions. Over the balance of 2022, WPLP plans to hire for three additional full-time engineering and operations positions with an increasing focus on operations as assets coming into service, as well as for four summer student / co-op positions to support a range of functions associated with the Interim O&M Strategy, including O&M procurement, commissioning, asset management and system/process development.

Exhibit B, Tab 1, Schedule 5

Project Costs

PROJECT COSTS

A. Overview

This schedule provides detailed Transmission Project cost information, as well as information on other infrastructure capital costs and operating costs, and explanations for variances between the OEB approved costs in the 2022 revenue requirement application and current forecasts. The presentation of Transmission Project cost information includes both the costs WPLP has incurred or expects to incur under its EPC contract and those capital costs it has incurred or expects to incur outside of that contract in relation to the Transmission Project. In addition, this schedule describes how overhead costs are assigned to or allocated between capital and OM&A for each of the Line to Pickle Lake and Remote Connection Line portions of the Transmission System over the construction period.

WPLP notes that, as the current application is for a single test year, not all of the costs set out in this schedule will be relevant for purposes of the proposed revenue requirement. Only those capital costs that correspond to the particular stations or line segments of the Transmission System and the particular general plant investments that WPLP has already put into service or that it plans to put into service prior to or during the 2023 test year will be relevant to the calculation of WPLP's proposed 2023 revenue requirement. Also relevant to WPLP's proposed revenue requirement in this Application are its 2023 OM&A costs (which are detailed in Exhibit F), and its overhead costs that are either recorded in CWIP and subsequently capitalized as assets are placed in service or allocated to OM&A as described in **Appendix 'A'**. The exhibits that present the capital and OM&A costs specifically underlying the proposed revenue requirement for 2023 are cross-referenced where appropriate.

WPLP further notes that, except where otherwise indicated, the impacts of the COVID-19 pandemic have not been included in these capital cost forecasts. Instead, WPLP tracks its costs resulting from the COVID-19 pandemic in the COVID Construction Costs Deferral Account, as detailed in Exhibit H-2-2

B. Context for WPLP's Cost Forecasts

In Part C, below, WPLP provides detailed descriptions of its forecast capital costs, including capitalization of overheads. For details on WPLP's proposed rate base and in-service additions, please refer to Exhibit C. For details on WPLP's operating costs during the 2023 test year, please refer to Exhibit F. As context for each of these aspects of the application, particularly for Part C of this schedule, it is helpful to understand (i) the difference in how costs are presented in the current application as compared to the presentation of costs in WPLP's initial rate application, (ii) the various sources or categories of costs that feed into the cost forecasts, (iii) at a high level, the basis upon which the initial rate application was approved, and (iv) WPLP's plans for providing updated information during the course of the current proceeding, as follows.

1. Difference in Presentation of Costs Relative to Initial Rate Application

There is an important difference in the presentation of cost information in the current application as compared to the presentation of cost information in WPLP's 2022 revenue requirement application (EB-2021-0134). As the 2022 revenue requirement application was WPLP's first such application, WPLP was required to provide details of its updated Transmission Project costs and comparisons of those updated Transmission Project costs relative to the cost estimates that had been presented in its Leave to Construct (LTC) application (EB-2018-0190).

WPLP explained in EB-2021-0134 that its forecast of Transmission Project capital costs was not only more current, but also more complete, more rigorous and more accurate than the estimate that it was able to provide during the LTC proceeding. WPLP noted that its ability to produce a better cost forecast for purposes of the initial rate application was a result of the normal project development process, during which further development activities, such as completion of geotechnical surveys and competitive procurement processes (including for the EPC contract), provided increased certainty regarding key project cost drivers, such as ground conditions, equipment costs and construction costs. Through that process, as the various cost components became more certain, the proportion of contingency costs included in the project cost forecast was reduced in the initial rate application as compared to the LTC cost estimate.

In addition, whereas the LTC application only considered Transmission Project costs, the initial revenue requirement application included forecasts of additional capital costs outside of the Transmission Project (i.e. general plant) and OM&A costs, including overheads which are allocated between capital and OM&A. Consequently, the presentation of cost information in EB-2021-0134 was complicated by the need to describe the fundamentally different bases upon which the LTC cost estimate and the 2022 cost forecast were determined, and to explain the resulting variances relative to the estimates that the OEB had previously seen in the LTC proceeding.

In the current application, the presentation of cost information is considerably more straightforward. While there are still some complexities as a result of the Transmission Project continuing to be under construction and WPLP continuing to transition from its organizational focus on development and construction to its longer-term focus on operations, the updated cost information in the current application has been developed on the same basis as, and is generally comparable to, the cost information underlying the 2022 revenue requirement, as presented in EB-2021-0134. It is for this reason that the OEB agreed with WPLP in EB-2018-0190 that any variance analysis provided as construction progresses beyond the initial rate application would consider actual or forecast costs compared to those presented in the initial rate application, rather than compared to the original cost estimates that had been presented in the LTC application.[1]

2. Cost Categories Underlying 2023 Forecast

WPLP's cost forecasts for 2023 are based on the following sources or cost categories:

a) **EPC Contract Costs:** expected engineering, procurement and construction costs based on the agreement with Valard;

b) **Non-EPC Capital Costs:** estimated capital costs of items that are accounted for outside of the EPC contract, but which are nevertheless planned and required by WPLP;

[1] OEB, Decision and Order, EB-2018-0190, April 1, 2019 (Revised April 29, 2019), pp. 12-13.

c) **Overhead Costs:** labour, consulting and administrative costs to December 31, 2024**,** determined by WPLP through a bottom-up forecast, which has been reviewed by Hatch in its capacity as Owner's Engineer (OE) and which identifies costs that are either capitalized or allocated to OM&A using the methodology described in **Appendix 'A'**;

d) **Direct O&M Costs:** operating and maintenance costs, determined by WPLP through a bottom-up forecast, directly related to the regular operation, inspection, maintenance and emergency response requirements associated with operating the transmission assets as they come into service; and

e) **Contingency Costs:** a quantitative risk-based contingency analysis performed by the OE.

The relationship between the cost categories listed above, the Capital cost forecasts presented in Section C of this schedule and the OM&A cost forecasts presented in Exhibit F, are summarized in Table 1, below.

Table 1 – Sources of Cost Forecast Information

Cost Category	Capital Cost Forecast (Section C Below)	OM&A Cost Forecast (Exhibit F)
EPC Contract Costs	100%	-
Non-EPC Capital Costs	100%	-
Overhead Costs	Allocated per Appendix 'A'	Allocated per Appendix 'A'
Direct O&M Costs	-	100%
Contingency Costs	100%	-

3. Basis for Approval of Initial Transmission Rate Application

For context, it is helpful to understand the basis of approval for WPLP's initial transmission rate application (EB-2021-0134). WPLP filed that application on April 28, 2021 based on a project schedule that took into account COVID-19 and other impacts as of September 2020. Based on that schedule, WPLP expected that the Line to Pickle Lake, as well as portions of the Remote Connection Lines connecting 11 communities would go into service in 2022, with 5 additional

communities being connected in 2023. On that basis, WPLP initially requested a $72.4 million revenue requirement for 2022, with recovery of $23.7 million through the UTR Network pool effective April 1, 2022 and $48.7 million through a fixed monthly charge of $6.1 million to HORCI effective May 1, 2022.

On July 30, 2021, through its interrogatory responses, WPLP provided updated evidence on its capital cost forecast, schedule forecast and related aspects of the application. WPLP explained that in June 2021 it received a series of schedule updates from its EPC contractor reflecting construction delays, largely resulting from access issues including a shorter than typical winter road availability period, access restrictions related to COVID-19 protocols and other location-specific access limitations. Under the updated schedule, only the Line to Pickle Lake and Remote Connection Lines connecting 3 communities were expected to go in service in 2022, with the remainder being shifted to 2023 or 2024. Consequently, WPLP's proposed revenue requirement was reduced to $47.7 million, with $24.1 million to be recovered through the UTR Network pool effective April 1, 2022 and $23.5 million through fixed monthly charges of $2.9 million to HORCI effective May 1, 2022.

The parties filed a Settlement Proposal on September 3, 2022, which was approved by the OEB on September 30, 2022. The approved Settlement Proposal further reduced the 2022 revenue requirement to $41.5 million, with recovery of $20.3 million through the UTR Network pool effective April 1, 2022 and $21.3 million through fixed monthly charges of $2.7 million to HORCI, effective May 1, 2022.[2] As part of the approved settlement, the parties agreed that WPLP would remove and defer recovery of $48.1 million in forecasted contingency amounts from its 2022 year-end rate base and establish a variance account to track for future recovery the revenue requirement impacts associated with the amount of contingency allocated to 2022 in-service additions to the extent the contingency is realized and does not exceed the amount removed from rate base. The

[2] The final Revenue Requirement and Change Determinant Order, dated December 2, 2021, reflected an updated total 2022 revenue requirement of $42 million, with recovery of $20.4 million through the UTR network rate pool effective April 1, 2022, and recovery of $21.5 million through fixed monthly charges of $2.7 million to HORCI effective May 1, 2022.

parties also agreed that the disposition of COVID costs from 2020, as recorded in the approved CCCDA, would be over a 4-year period rather than over the proposed 2-year period.

4. Currency of Information and Planned Update

The updated capital cost forecast in the current Application includes audited actual costs to December 31, 2021 as well as WPLP's updated forecasts for 2022-2024 capital costs, as at January 2022.[3] This is aligned with the currency of the project schedule underlying the current Application, which was issued by WPLP's EPC contractor in late January and reflects the schedule as at January 1, 2022. In consideration of the significant amount of construction activity and associated capital spending that is forecasted to take place in 2022 between the filing date of this Application and the expected date of the OEB's decision, WPLP intends to update its capital cost forecasts, as well as the related in-service additions and calculations of rate base presented in Exhibit C, based on the most current schedule available, at an appropriate time during the proceeding.

C. Capital Costs

This section presents WPLP's forecast capital expenditures by year, as well as by expenditure category, including analysis of variances from capital costs approved by the OEB in WPLP's 2022 revenue requirement application to WPLP's updated capital cost forecast as at January 2022.

1. Capital Expenditure Forecast by Year

WPLP's capital expenditures by year, excluding AFUDC and incremental COVID costs, are summarized in Table 2, below.

Table 2 – Capital Expenditures by Year

Year	Capital Expenditures ($000's)		% of Cumulative
	Annual	Cumulative	

[3] WPLP recognizes that inflation rates have been increasing significantly in 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.

Pre-2019 Actual		68,039	4%
2019 Actual	44,812	112,851	6%
2020 Actual	338,064	450,915	25%
2021 Actual	438,819	889,734	50%
2022 Forecast	634,606	1,524,339	86%
2023 Forecast	221,941	1,746,280	99%
2024 Forecast	26,439	1,772,719[4]	100%

The timing of capital expenditures forecasted in Table 2 above is largely based on construction activity by WPLP's EPC contractor, based on the January 2022 updated project schedule that is discussed in detail in Exhibit B-1-3. These expenditures are recorded as CWIP until the related assets become used or useful. WPLP's forecasted in-service additions are presented in Exhibit C-2-1.

2. Capital Expenditure Forecast by Category

WPLP's current forecast of its Transmission Project capital costs (excluding COVID costs) is approximately $1.81 billion inclusive of interest, or approximately $1.82 billion inclusive of other development and infrastructure costs (not forming part of the Transmission Project). WPLP's equivalent forecast as presented in the initial rate application, as amended (EB-2021-0134) was approximately $1.81 billion, or approximately $1.85 billion inclusive of other development and infrastructure costs. These amounts, both for the current forecast and the forecast presented in the initial rate application, are set out in Table 3, below, using cost categories consistent with those presented in EB-2021-0134. The table is followed by detailed descriptions for each individual cost category of the capital expenditure forecast.

Consistent with the structure of Table 3, the descriptions of the individual cost categories are grouped into (i) EPC-related capital costs for the Transmission Project, (ii) non-EPC capital costs for the Transmission Project, and (iii) capital costs for other infrastructure not forming part of the Transmission Project. As indicated in the table, WPLP's total capital cost forecast is approximately

[4] See Appendix to Exhibit C-2-l, Table A-1 for calculation of $1,772 million of project costs.

2% ($28 million) lower than the Transmission Project cost estimate presented in the initial rate application, as amended. This difference is driven by a reduction of Other Infrastructure costs ($27.3 million), which will be incurred outside of the construction period, a reduction in EPC and Non-EPC Capital costs of $12.8 million[5], and additional capitalized interest costs based on January 2022 construction interest rates of $12.1 million.

Table 3 – Capital Cost Forecast and Variance Summary

(Costs in $000's)	Updated Forecast[6]	EB-2021-0134 Forecast	Variance	
			$	%
EPC Costs				
Transmission Line Facilities - Line to Pickle Lake	215,015	213,126	1,889	1%
Transmission Line Facilities - Remote Connection Lines	905,390	889,936	15,454	2%
Station Facilities - Line to Pickle Lake	37,877	36,235	1,642	5%
Station Facilities - Remote Connection Lines	298,094	293,482	4,612	2%
Non-EPC Capital Costs				
EPC Excluded (e.g. Insurance, LIDAR, Stumpage)	13,097	12,530	567	5%
Engineering, Design, Project/Construction Management & Procurement	111,349	118,301	-6,953	-6%
Environmental Assessments, Routing, Permitting, Regulatory & Legal	28,204	30,499	-2,294	-8%
Land Rights	12,931	14,575	-1,644	-11%
Engagement, Stakeholder Consultation, Participation and Training	46,697	49,175	-2,478	-5%
Contingency	94,615	118,211	-23,596	-20%
Costs Included in EB-2018-0190, Pre-AFUDC	***1,763,269***	***1,776,071***	***-12,802***	***-1%***
Capitalized Interest	45,655	33,523	12,132	36%

[5] Includes both recognized and forecasted Non-EPC savings. WPLP continues to look for ways to reduce Non-EPC costs, through cost management processes and a bottom-up budgeting approach.

[6] As at January 2022, excluding incremental COVID costs (see Exhibit H-2-2)

Total Costs Included in EB-2018-0190	***1,808,924***	***1,809,593***	***-669***	***0%***
Other Infrastructure	9,450	36,750	-27,300	-74%
Total Capital Costs	**1,818,374**	**1,846,343**	**-27,969**	**-2%**

(a) Transmission Project Capital Costs (EPC)

WPLP forecasts capital costs relating to the EPC contract totaling approximately $1,456 million, inclusive of all transmission lines and stations for the Line to Pickle Lake and Remote Connection Lines portions of the project. The EPC-related costs in relation to the planned transmission line facilities and station facilities are further described as follows, along with discussion of how the EPC contract costs in the current capital cost forecast compare to the EPC contract costs that were included in the capital cost forecast in the initial rate application, as amended.

(i) Transmission Line Facilities

WPLP's EPC contract cost for the 230 kV transmission line facilities associated with the Line to Pickle Lake is approximately $215 million and the EPC contract cost for the 115 kV, 44 kV and 25 kV transmission lines associated with the Remote Connection Lines portion of the project is approximately $905 million. When compared to the equivalent EPC contract costs presented in the initial rate application as amended, the current amounts are $17.3 million higher. This difference is attributable to executed and expected change orders related to forest fire impacts and route changes[7] for the remainder of construction period.

(ii) Station Facilities

WPLP's forecast costs under the EPC contract cost for the two station facilities associated with the Line to Pickle Lake is approximately $37 million and for the 20 station facilities associated with the Remote Connection Lines portion of the project is approximately $298 million. When compared to the equivalent EPC contract costs presented in the initial rate application, as amended, the current amounts are $6.3 million higher. This difference is attributable to executed and

[7] Additional information on the variance is provided in Exhibit C-2-1.

expected change orders related to forest fire impacts and engineering design changes[8] for the remainder of the construction period.

(b) Transmission Project Capital Costs (non-EPC)

WPLP forecasts capital costs for the Transmission Project outside of the EPC contract totaling approximately $352 million. These non-EPC capital costs for the Transmission Project consist of capital costs that are necessary to develop, construct and put the Transmission Project into service and that were contemplated in the LTC proceeding, but which have not and will not be incurred through the EPC contract with Valard. When compared to the equivalent non-EPC Transmission Project capital costs presented in the initial rate application, as amended, the current amounts are $24.3 million lower. This difference is attributable to a reduction in Non-EPC costs of $12.8 million, $23.6 million lower use of contingency, and increased capitalized interest of $12.1 million due to rising interest rates in 2022.

WPLP undertook a three-step approach to developing its forecast of the non-EPC capital costs for the Transmission Project:

- First, WPLP identified all of the non-EPC costs it has incurred or expects to incur over the project period that are clearly and directly related to the Transmission Project and are therefore clearly capital in nature. These include all costs incurred during the development phase of the Transmission Project, as well as costs for the Owner's Engineer and professional services support during the construction phase of the Transmission Project. The total capital costs identified through this step total approximately $124.6 million.

- Second, WPLP added into the forecast (a) its updated forecast for contingency (excluding EPC expected or executed change orders recognized in section 2(a) above), (b) its updated forecast for capitalized interest, and (c) certain discrete capital costs for aspects previously included as part of the EPC cost estimate but which were not ultimately included within the scope of the EPC services. These include costs, described in greater detail below, for

[8] Additional information on the variance is provided in Exhibit C-2-1.

HONI Interconnection, LiDAR services, stumpage fees and insurance. Office capital costs to December 31, 2024 are also included in this category. The capital costs identified through this step are approximately $94.6 million for contingency and approximately $23.6 million for EPC change orders, $45.7 million for capitalized interest and $13.1 million for aspects previously included in the EPC cost estimate, for a total of approximately $186.4 million.

- Third, WPLP prepared a bottom-up budget forecast for its internal and operating costs, including employee compensation and other labour costs, costs for professional services and other third-party contracts, as well as general administrative or overhead costs. While in an operating utility these types of costs would typically be expensed unless specifically allocated to capital projects, such an approach is not appropriate for WPLP as it transitions from a project development and construction focused utility into an operating utility over a period of several years. Using the methodology described in **Appendix 'A'**, WPLP allocated these amounts between capital and OM&A based on the extent to which the Transmission System will be in service at different points during the construction period. The capital costs identified through this step total approximately $74.6 million.

WPLP has included all of the costs identified through the first and second steps, which are clearly capital in nature, in its forecast of non-EPC capital costs. However, for the costs identified through the third step, being the bottom-up forecast overhead costs, WPLP carried out an analysis of when those costs are expected to be incurred relative to when different segments of the Transmission System are expected to be put into service. WPLP then attributed the amounts from step three to capital or OM&A based on their timing and the corresponding portion of the Transmission System that will be in-service. Through this methodology, which is described in greater detail in **Appendix 'A'** and is consistent with the methodology applied in the initial transmission rate application, WPLP has effectively applied a declining capitalization rate to its overhead costs, commensurate with the extent to which the company is oriented toward Transmission Project execution vs utility operations, as it transitions from being a non-operating utility entirely focused

on putting its system into service to a fully operating utility with a new system that requires minimal capital investment.

(i) EPC Excluded Costs

WPLP's forecast for this cost category includes approximately $13.1 million of costs that were previously accounted for as part of the EPC cost category in the LTC cost estimate. The costs are comprised of insurance costs, stumpage fees, LiDAR services costs and HONI interconnection costs. This category also includes approximately $0.95 million in office capital costs during the construction period.

Insurance costs related to the EPC contract were not budgeted as a distinct line item in the LTC cost estimate but were instead factored into the per-kilometer cost estimates for transmission line facilities and the base substation cost estimates described earlier in this schedule. Costs related to a variety of specific insurance and security requirements for the EPC contractor are included in the EPC-related cost forecasts. However, in order to ensure an appropriate level of overall insurance coverage, WPLP determined that it could leverage the purchasing power of Fortis Inc. to obtain certain project level insurance more cost effectively outside of the EPC contract, without a material impact on allocation of risk. WPLP has therefore included a forecast for its own project-specific insurance costs of $6 million (compared to $18 million forecasted in the EPC cost category) as part of its forecast for EPC Excluded costs.

A portion of estimated stumpage fees related to the clearing of forest resources outside of Sustainable Forest Licence (SFL) areas was removed from the EPC contract since there was no framework for determining these costs at the time of EPC contract negotiations. WPLP received certain exemptions from the *Crown Forest Sustainability Act* on May 9, 2019, and subsequently negotiated lower costs for stumpage fees outside of SFL areas. Approximately $0.7 million in stumpage fees are therefore included in this cost category. For clarity, the EPC contractor retained the responsibility for dealing with SFL holders and paying the required stumpage fees within SFL areas. In addition, approximately $1.3 million for LiDAR surveys was transferred from the EPC cost category to the EPC Excluded cost category. Pre-EPC LiDAR activities were undertaken

directly by WPLP in order to meet timing requirements for certain activities while the EPC tendering process and contract negotiations were still underway. This decision allowed WPLP to provide a certain amount of LiDAR data to all proponents during the EPC tendering process, allowing EPC proponents to de-risk their proposals. WPLP also made the decision to undertake post-construction LiDAR surveys internally so that it could ensure optimal timing and scope in relation to completion of EPC construction activities, WPLP's ongoing data requirements, and narrow windows of favourable conditions for conducting LiDAR surveys in the project area.

While the scope of the EPC contract includes the design, procurement and construction of equipment related to interconnections with both HONI and HORCI, WPLP has included in its non-EPC capital expenditure forecast approximately $3.9 million, separate from the general contingency amount discussed below, to cover undefined costs relating to its interconnections that are not included in the EPC contract scope. This allowance is intended to cover costs associated with any additional LiDAR, geotechnical analysis, soil resistivity analysis and general engineering costs that would be necessary in the event that any further relocations of substations or line taps are required at interconnection points to HONI's transmission system or HORCI's distribution systems in the connecting communities. As such, it is considered by WPLP to be akin to contingency specific to the HONI and HORCI interconnection work that must be completed as part of the Transmission Project.

(ii) Engineering, Design, Project/Construction Management & Procurement

WPLP's updated forecast for capital costs relating to engineering, design, project/construction management and procurement is approximately $111.3 million.

This category of costs includes approximately $60 million in design, engineering and procurement costs related to advancing the conceptual design and engineering during the development phase of the Transmission Project, preparing detailed specifications and design requirements during preparation of the EPC tender package, engineering effort during EPC bid evaluation, and ongoing engineering oversight of the EPC contractor by WPLP's OE. WPLP's progressive design and

engineering efforts demonstrated the viability of the Transmission Project, informed Long Term Energy Plans and IESO Regional Plans, met IESO-prescribed requirements for scope, allowed WPLP to obtain leave to construct the project, and ultimately determined the requirements for the EPC stage of the project. WPLP retained Hatch as its OE through a competitive selection process in 2018, as described in Exhibit B-1-2. This process included comparisons of hourly rates to ensure that any services provided on a time and materials basis would reflect market value. The services provided by Hatch, both during the EPC tendering process and during construction, were critical to reducing EPC cost uncertainty, minimizing change orders during the construction phase of the project, ensuring quality and safety in all EPC activity, and maintaining overall project schedule.

The balance of approximately $51.3 million relates to project and construction management activities that include accounting and finance costs, health and safety costs, project management and executive/board oversight, oversight and support related to community engagement, communications and land access activities, as well as administrative costs related to office space, HR and IT. These costs allowed WPLP to secure overall project funding and financing, meet financial reporting requirements, develop and maintain construction budgets, develop and implement health and safety processes and procedures, provide an appropriate level of oversight to engagement, communication and land access activities critical to the success of the project and to provide corporate financial, HR and IT support to all aspects of the project. Cost increases in this category are a result of the extended construction period due to delays of assets going in-service.

(iii) Environmental Assessments, Routing, Permitting, Regulatory & Legal

WPLP's current forecast for capital costs relating to environmental assessments, routing, permitting, regulatory and legal is approximately $28.2 million.

This category includes approximately $17.6 million in costs directly related to the legislated EA process and meeting all environmental commitments outlined in the Phase 1 EA report and Phase 2 Environmental Study Report (ESR). These costs were incurred to secure necessary approvals

under provincial and federal environmental legislation for the Transmission Project to be constructed.

The balance of approximately $10.6 million relates to costs of permitting and regulatory requirements. This includes applying for and meeting the requirements of legislated permits or exemptions required to construct the Transmission Project. These costs also include the cost of all applications that have been filed or are planned to be filed with the OEB until the end of the construction period, as well as the costs of meeting any reporting requirements during that time.

Additionally, as described in Exhibit A-2-1, WPLP intends file single test year revenue requirement applications for 2024 and 2025. Since the regulatory costs related to these applications will be in respect of single-test year applications, there is no need to amortize the costs over a multi-year incentive rate setting term. WPLP has therefore included the total forecast cost of filing these two applications in its total cost estimates to December 31, 2024 and has allocated these costs between capital and OM&A expenses using the same methodology for other overhead costs as described in **Appendix 'A'**.

WPLP's forecast for this cost category is approximately $2.3 million (8%) lower than the equivalent forecast as provided in the initial rate application, as amended.

(iv) Land Rights

WPLP's updated forecast for capital costs relating to land rights is approximately $12.9 million. This includes all costs related to land options, easements, land sharing protocols, and land rentals required in relation to the construction and ongoing operation of the Transmission Project, as well as all labour costs, legal fees and related expenses for obtaining the required land rights. This category includes costs for both non-Aboriginal land rights and consultations, as well as costs in relation to Aboriginal land rights.

The current forecast is approximately $1.6 million (11%) lower than the equivalent estimate for this category as provided in the initial rate application. This difference is attributable to delays in

incurring certain land costs due to changes in the construction schedule. As described in Exhibit B-1-2, WPLP has made significant progress in securing the various land rights and land permits required for the Transmission Project and it remains on track to secure any outstanding land rights and permits ahead of critical construction milestones.

(v) Engagement, Stakeholder Consultation, Participation and Training

WPLP's updated forecast for capital costs relating to Indigenous and Métis engagement, stakeholder consultation, Indigenous participation and training is approximately $46.7 million. These are costs related to Indigenous and Métis engagement during the EA process, WPLP's comprehensive Indigenous Engagement Plan and Indigenous Communications Management Plan (which are summarized in Exhibit B-1-2), meaningful Indigenous economic participation in all aspects of the Transmission Project, consultations with stakeholders (such as municipalities and potentially affected landowners), and overall project communications activities. These activities will ensure that the Transmission Project is designed, permitted, constructed and operated in a manner that respects the Treaty, Aboriginal and Inherent rights of the Anishinabe and Anishinninuwug, and that appropriately considers input from various stakeholders.

The updated forecast is approximately $2.5 million (5%) lower than the equivalent estimate for this category as provided in the initial rate application, as amended. This difference is attributable to realized savings in 2021 and expected future construction savings.

(vi) Contingency and EPC Change Orders

WPLP performs a contingency analysis on a semi-annual basis taking into consideration construction progress to date, the updated construction risk profile and known risks associated with remaining construction. As part of this process, WPLP's Owner's Engineer performs a Quantitative Risk Analysis (QRA), determines any changes to the probability and financial impacts of previously identified risks, and considers any risks that can be eliminated as various construction activities are completed. Differences in the contingency percentage for each category of costs reflect differences in the ranges of cost uncertainty attributable to different risk events

(e.g. risks associated with EPC activities generally have a much wider range of probability of occurrence and cost impacts than risks associated with non-EPC activities). Based on the latest QRA, no change to contingency requirements has been made for the remaining construction period at this time. As noted below, $23.6 million of the contingency requirement has been allocated to EPC change orders, leaving a remaining contingency allowance of $94.6 million.

As at December 31, 2021, WPLP had executed or was in the process of executing EPC change orders in the amount of $23.6 million, leaving a contingency allowance of $94.6 million. These change orders are reflected in EPC Costs in Table 3 above, which has reduced the contingency allowance by the same amount. Details of the split between EPC contingency allowance, non-EPC contingency allowance, and EPC contract change orders are provided below in Table 5.

Table 5 – Contingency Allowances and EPC Change Order Costs ($000's)

Cost Category	Pre-Contingency Cost Forecast	Contingency (P50)	Contingency %
EPC Costs	1,456,375	92,296	6.3%
EPC Excluded + Other Infrastructure[9]	22,547	445	2.0%
Non-EPC Capital	199,181	1,875	0.9%
Contingency Allowance Subtotal	**1,678,104**	**94,615**	**5.6%**
EPC Change Order Costs		**23,596**	
Total Contingency + Change Order		**118,211**	

The contingency allowance is approximately 5.6% of WPLP's total estimated capital costs before contingency and AFUDC. This compares to the contingency amount in the initial transmission rate application, which was approximately 6.9% of the equivalent estimate. This difference is attributable to change orders incurred in relation to forest fires and route changes. As identified risks to the Project materialize into change orders, or the likelihood and/or magnitude of impacts decrease through the QRA process, contingency is reduced.

[9] See Section (c) below for discussion of Other Infrastructure costs that were excluded from the LTC cost estimate.

Excluding COVID-19 related change order costs, which are addressed in Exhibit H, Tab 2, Schedule 2, the total value of change order costs included in the current cost estimate is approximately $23.6 million, which represents less than 1.6% of the EPC contract value. For change orders relating to risks identified in WPLP's QRA, the contingency allowance is typically reduced in consideration of any change orders, to reflect utilization of the contingency allowance.[10] Exhibits B-1-1 and B-1-2 provide further discussion of the nature and timing and costs of these EPC contract change orders and Exhibit B-1-4 provides details of WPLP's change management process.

(vii) Capitalized Interest

WPLP's updated forecast for capitalized interest costs is approximately $45.7 million. These costs represent WPLP's estimated total borrowing costs related to the development and construction phases of the Transmission Project. The equivalent forecast for this cost category as provided in the initial rate application, as amended, was $33.5 million. This difference is attributable to rising construction interest costs at the end of 2021 and beginning of 2022. Details of the project-specific financing obtained by WPLP for the construction phase of the Transmission Project are provided in Exhibit G-2-1.

WPLP notes that it has not included amounts related to capitalized interest in the in-service additions outlined in Exhibit C as it intends to include the total amount of capitalized interest in its 2024 rate base, coincident with the anticipated federal funding that will act as a contribution to offset this amount.

The increase in interest costs is driven primarily by the change in schedule, which results in assets going in-service at a later date, thereby causing more interest to be capitalized. In addition, the market is seeing a quick rise in interest rates experienced over the first two years of COVID-19.

[10] For example, if the QRA identified a risk of cost increase related to a specific routing change, and that routing change was confirmed through a change order, then the change order component of the EPC cost forecast would increase by the amount of the change order and the contingency allowance would decrease to reflect reduction of risk.

(c) Other Infrastructure Capital Costs

WPLP's capital expenditure forecast, to the end of 2024, includes approximately $9.45 million for investments in general plant assets that are required to own and operate the Transmission System. These are investments that do not relate directly to the construction of electricity transmission lines or interconnection facilities, but which are otherwise required and include facilities and assets such as service centres, fleet, and business systems. The following table provides a summary of these costs, followed by detailed descriptions for each of the listed cost categories.

Table 6 – Other Infrastructure Capital Expenditure Forecast ($000's)

Category	2022	2023	2024	Total Forecast
Facilities (Office and Work Centres)		5,000		5,000
Fleet	224	201	525	950
Business Systems		500	3,000	3,500
Total	**224**	**5,701**	**3,525**	**9,450**

Approximately $5.9 million (or 63%) of WPLP's forecasted costs for Other Infrastructure are relevant to the determination of WPLP's 2023 revenue requirement in this application, and the nature of these costs are discussed in Sections (i), (ii) and (iii) below.

The remaining approximately $3.5 million of WPLP's forecasted costs for Other Infrastructure are preliminary forecasts for 2024 spending, based on identified needs for business systems infrastructure and additional fleet requirements. The sections below include a discussion of the individual investments included in each cost category, and the assumptions underpinning these investments. WPLP has refined its plans for Other Infrastructure requirements and associated cost estimates over the past year. Exhibit B-1-4 provides additional discussion of WPLP's Interim O&M Strategy as assets begin coming into service in 2022, and continuing throughout 2023.

(i) Facilities

WPLP previously forecasted Facilities investments of $27 million, comprised of $11 million for construction of its main operating centre, $1 million for a backup operating centre, and $15 million

for construction of three service centres at a cost of approximately $5 million each. WPLP is currently forecasting that one service centre would be constructed and put into service in 2023 and that the remaining facility investments would be constructed and put into service outside of the Project construction period.

(A) Operating Centres

The $11 million budget for WPLP's main operating centre includes office space for operational staff, including provision for control room space and associated software/systems, any required IT infrastructure, security systems and backup operating centre. The smaller backup operating centre would be a stand-alone facility (or space within another facility distinct from the main operating centre) that would be used as a back-up control room only, in the event of an emergency where the main control room could not be used. WPLP intends to procure interim control room services from a third-party provider. WPLP expects that the costs and the term of its third-party control room service agreement, which is being negotiated in Q2 2022, will influence the scope and timing of its longer-term strategy for control room operations, which could affect 2024 costs.

(B) Service Centres

Once the Transmission Project is entirely in service, WPLP's transmission system will occupy a geographic footprint spanning approximately 480 km between its southernmost and northernmost points,[11] and approximately 415 km between its westernmost and easternmost points.[12] Based on the foregoing, WPLP has determined that the development and construction of three service centres, geographically dispersed across the Transmission System's service area, would allow for reasonable mobilization of crews, materials and equipment for planned maintenance and emergency response. WPLP's preliminary plan is to have one service centre located in the Red

[11] This represents the geodesic distance between Dinorwic (which is the southernmost point where WPLP's Line to Pickle Lake connects to HONI's transmission system) and Bearskin Lake First Nation (which is the northernmost point of WPLP's North of Pickle Lake Remote Connection Lines).

[12] This represents the geodesic distance between Poplar Hill First Nation (which is the westernmost point of WPLP's North of Red Lake Remote Connection Lines) and Kasabonika Lake First Nation (which is the easternmost point of WPLP's North of Pickle Lake Remote Connection Lines).

Lake area, one service centre in the general vicinity of the Line to Pickle Lake assets, and one service centre in a location to be determined north of Pickle Lake. The final number of service centres, as well as the final location of and design of each service centre, are expected to be determined in 2022, following additional assessment of long-term access considerations, operating strategy, and development of detailed cost estimates. In 2023, WPLP expects to have one service centre operational to service the Line to Pickle Lake as well as the Remote Connection Line segments energized in 2022 and 2023.

(ii) Fleet

WPLP forecasts Fleet investments of $950k over the 2022-2024 period. These investments are for assets that will include 4-wheel drive pickup trucks, snow machines, off-road vehicles and trailers, which are required for routine inspections and maintenance as well as emergency access to WPLP's transmission system. The current estimates are based on purchasing these assets due to the high number of kilometres and extensive off-road use that are likely to be required. Forecasted fleet purchases in the 2023 test year are currently comprised of four pick-up trucks, four snowmobiles and four off-road vehicles to support WPLP's oversight of commissioning activities and the commencement of operations activities. WPLP's 2024 forecasted fleet purchases are based on preliminary estimates of the required number of pickup trucks, snow machines, off-road vehicles and trailers required for operations, maintenance and emergency response, and will be refined in 2022 as WPLP implements and refines its Interim O&M Strategy.

WPLP currently expects that fleet requirements for major construction and repairs, such as large off-road tracked vehicles and helicopters, would be sourced on an as-needed basis (i.e. rental or through contractors retained to perform certain work), with consideration of retainers to ensure adequate availability when needed.

(iii) Business Systems

WPLP forecasts Business System investments of $3.5 million, of which $0.5 million is expected to be put into service in 2023 with the completion of WPLP's Asset Management system. These

investments consist of purchases of ERP and Asset Management systems and related software, which are required for WPLP's accounting and financial management/reporting requirements, inventory management, work management and the implementation of a comprehensive asset management program. WPLP is currently forecasting to purchase the required software and licensing directly but will evaluate alternatives for hosted solutions before committing to any purchases.

(iv) Initial Inventory, Tools & Equipment

WPLP previously forecasted investments in Initial Inventory, Tools and Equipment of $4.5 million over the 2022-2024 period. These investments will now be purchased through working capital based on WPLP's assessment of its operating inventory requirements. Based on its review of assets and required inventory, none of the inventory items would be classified as major spare parts or stand-by equipment and therefore do not qualify as property, plant and equipment and are not included as part of total capital costs in the Project. As WPLP, is not seeking an allowance for working capital in 2023, further inventory details will be provided as part of first multi-year rate application.

Appendix 'A'

Overhead Cost Allocation Methodology

WPLP's forecast of its general overhead costs is presented in Table A-1 below. Overhead costs are comprised of costs such as internal labour (including departmental costs and overheads), services provided by third-party consultants and professionals of a general nature, costs related to continued Indigenous engagement and participation in the project, general administrative costs, and stakeholder engagement costs. Prior to Pikangikum becoming grid-connected on December 20, 2018, WPLP did not have any assets in service and all overhead costs were recorded as capital development costs. Between January 2019 and December 2024, WPLP expects to incur total overhead costs as presented in Table A-1, and WPLP has capitalized these costs on a declining basis, with the balance allocated to OM&A, using the methodology set out below.

Table A-1 – Overhead Costs During the Construction Period

Category	Forecast Overhead Costs 2019-2024 ($000's)
Labour and Departmental Costs	51,822
Environmental Services	5,332
Other Consultants (Allocate)	7,326
Indigenous Engagement & Communications	18,180
Stakeholder Engagement	537
Indigenous Participation and Training	19,771
Administrative Costs	8,838
Total	**111,806**

Allocation Methodology

For purposes of cost recovery, the overhead costs summarized in Table A-1 must be capitalized or allocated to OM&A. To accomplish this, WPLP has calculated the costs identified in Table A-1 on a quarterly basis from Q1 2019 to Q4 2024, and the resulting costs for each quarter are multiplied by allocation factors that are determined based on the relative percentage of assets in-

service in each month.[13] Using this methodology, the capitalization of overhead costs declines over time from complete capitalization during project development, a predominantly capital allocation until mid-2022 (during which period only the Pikangikum assets are in service and WPLP is primarily focused on construction), to a blended allocation from 2022 to 2024 during which period WPLP will be balancing construction and operation of in-service assets, and ultimately to a 100% OM&A allocation in 2025 when all assets are expected to be in service (subject to any minor ongoing capital costs incurred in the immediate years thereafter).

Tables A-2 and A-3 below illustrate the calculation of these quarterly allocation factors.

Table A-2 – Total Line and Station Capital Costs

Item	Costs ($000's)
EPC Contract Costs	1,432,779
EPC Contingency + Change Order	115,892
Pikangikum Costs	61,000
Total Line and Station Costs	**1,609,671**

[13] In the context of this methodology "total line and station capital costs" reflect total costs associated with the 2018 construction of the Pikangikum system, plus the total forecasted EPC costs (i.e. contract + contingency + change orders) related to the construction of WPLP's transmission system. "Assets in service" reflects the portion of these costs related to assets that are forecasted to be in service at the end of each month, based on the most recent project schedule. The "asset in service" amounts in this Appendix are therefore different that the "in service addition" amounts that are described in detail in Exhibit C.

Table A-3 – Calculation of Cost Allocation Factors

Qtr	Month	Cumulative Assets in Service[14]		Cost Allocation[15]	
		Amount ($000's)	% of Total	% OM&A	% Capitalization
Q1 2019	Jan-19	61,000	3.8%	3.8%[16]	96.2%
	Feb-19	61,000	3.8%		
	Mar-19	61,000	3.8%		
No change from Q1 2019 to Q1 2022					
Q2 2022	Apr-22	61,000	3.8%	9.9%	90.1%
	May-22	61,000	3.8%		
	Jun-22	357,222	22.2%		
Q3 2022	Jul-22	357,222	22.2%	36.1%	63.9%
	Aug-22	693,687	43.1%		
	Sep-22	693,687	43.1%		
Q4 2022	Oct-22	693,687	43.1%	43.1%	56.9%
	Nov-22	693,687	43.1%		
	Dec-22	693,687	43.1%		
Q1 2023	Jan-23	693,687	43.1%	43.1%	56.9%
	Feb-23	693,687	43.1%		
	Mar-23	693,687	43.1%		
Q2 2023	Apr-23	693,687	43.1%	51.0%	49.0%
	May-23	844,503	52.5%		
	Jun-23	925,211	57.5%		
Q3 2023	Jul-23	1,000,828	62.2%	62.2%	37.8%
	Aug-23	1,000,828	62.2%		
	Sep-23	1,000,828	62.2%		
Q4 2023	Oct-23	1,000,828	62.2%	62.2%	37.8%
	Nov-23	1,000,828	62.2%		
	Dec-23	1,000,828	62.2%		

[14] In forecasting the in-service asset value by month, the EPC contingency allowance and change order costs were prorated based on the pre-contingency forecast of in-service additions.

[15] The percentage allocations are based on the cost estimates presented in this application, and may vary marginally as the contingency allowance is either utilized or reduced.

[16] The allocation to OM&A from Q1 2019 to Q1 2022 is based on the value of Pikangikum assets, notwithstanding that the capital cost of these assets was funded by the Government of Canada and is therefore not added to WPLP's rate base. The overhead costs allocated to OM&A during this period are being recorded in WPLP's Distribution System Deferral Account. Once other transmission assets come into service, WPLP would stop recording overhead costs allocated to OM&A in the Distribution System Deferral Account and would begin recording these costs in transmission OM&A accounts.

Q1 2024	Jan-24	1,000,828	62.2%	62.2%	37.8%
	Feb-24	1,000,828	62.2%		
	Mar-24	1,000,828	62.2%		
Q2 2024	Apr-24	1,212,356	75.3%	91.8%	8.2%
	May-24	1,609,671	100.0%		
	Jun-24	1,609,671	100.0%		
100% allocated to OM&A for Q3/Q4 2024					

1

Table A-4 below summarizes the overall result of applying the allocation and capitalization factors from Table A-3 to the overhead costs in Table A-1. Exhibit C-6-1 provides a description of WPLP's capitalization policy, as it applies to capital costs incurred after construction of the Transmission Project is complete.

Table A-4 – Allocation of Forecasted Overhead Costs

Category	**Item**	**Forecasted Overhead Costs 2019-2024 ($000's)**		
		Capital	**OM&A**	**Total**
Overhead	Labour and Departmental Costs	32,618	19,204	51,822
	Environmental Services	4,557	775	5,332
	Other Consultants (Allocate)	5,705	1,622	7,326
	Indigenous Engagement & Communications	11,392	6,788	18,180
	Stakeholder Engagement	419	119	537
	Indigenous Participation and Training	13,834	5,937	19,771
	Administrative Costs	6,102	2,736	8,838
	Total	**74,626**	**37,181**	**111,806**

Exhibit B, Tab 2, Schedule 1

Asset Categorization

ASSET CATEGORIZATION

The purpose of this schedule is to categorize the Transmission System assets into the various transmission rate pools and to identify which assets are part of the bulk electricity system, as defined by 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).

The relevant asset categories for WPLP, each of which is described below, are Network, Line Connection, Transformation Connection, and Common.

A. 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.[1] The Line to Pickle Lake will include:

a) a 230 kV switching station located adjacent to the existing Hydro One circuit D26A approximately 9 km southeast of Dinorwic (the "Wataynikaneyap SS");

b) an approximately 303 km single circuit, overhead, 230 kV transmission line running from the Wataynikaneyap SS generally in a northeasterly direction to the Wataynikaneyap TS (described below) (the "Line to Pickle Lake"); and

c) 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 (the "Wataynikaneyap TS").

[1] EB-2018-0190, Decision and Order, p.23

Additionally, Exhibit D-1-2 in EB-2018-0190 describes the network assets that HONI intends to construct at each of Dinorwic, Pickle Lake and Red Lake for the purpose of interconnecting WPLP's transmission system to HONI's existing transmission facilities. Since the assets in question are Network assets, WPLP would include these costs along with the costs related to the Line to Pickle Lake assets identified above for recovery through the UTR network charge.[2]

In the final SIA Report for CAA ID 2016-567, the IESO identified that all of WPLP's Line to Pickle Lake assets will fall within the NERC definition of the Bulk Electric System ("BES"). None of WPLP's other assets meet the BES definition.

B. Line Connection and Transformation Connection Assets

All assets comprising the Remote Connection Lines are categorized as either line connection or transformation connection assets. 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;[3]

b) The OEB approved a cost recovery and rate framework that will result in the revenue requirement associated with the Remote Connection Lines (based on direct and indirect capital expenditures and OM&A expenses) being recovered via a fixed monthly charge applicable to Hydro One Remote Communities Inc. ("HORCI"), instead of being recovered through UTRs;[4] and

[2] EB-2018-0190, Response to Supplemental IR C-Staff-66.

[3] EB-2018-0190, Decision and Order, p.23

[4] EB-2018-0190, Decision and Order, pp. 24-28

c) Notwithstanding that the fixed monthly charge described in (b) above would not distinguish between line connection and transformation connection assets, WPLP will maintain the distinction between these categories to align with the UTR rate pools.[5]

WPLP's line connection assets will include approximately 1441[6] 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 stations that do not contain transformers. Specifically, WPLP's transformation connection assets will include 15 transformer stations from which transmission service will be provided to distribution systems owned and operated by HORCI, which in turn will serve customers in 16 remote First Nation communities. [7]

C. Common Assets

WPLP's common assets will include general plant assets such as fleet, facilities, tools and equipment, IT hardware and software, and business systems. For rate setting purposes, the rate base amounts related to these assets will be 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 2023 Test Year.

[5] 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.

[6] As described on page 10 of Exhibit B Tab 1, Schedule 1, there has been a number of minor routing changes that have increased the overall line length by approximately 8 km (less than 1%). The total length has been adjusted by 11 km since the previous application (EB-2021-0134), 8 km related to the routing change and 3 km related to an addition error in EB-2021-0134.

[7] 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.

APPENDIX ‘A’

Summary of WPLP Substations

Designation	Name	Location[1]	Voltage	Functionality[2]	Asset Categorization
Line to Pickle Lake (Bulk Electricity System):					
A	Wataynikaneyap SS	SE of Dinorwic	230 kV	Switching; Reactive Power Compensation	Network
B	Wataynikaneyap 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

[1] Locations are within 5 km of reference point unless otherwise noted. Exhibit C-2-1 (In-Service Additions) contains more specific location descriptions for assets with 2023 in-service dates.

[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

[3] Interim operation at 44 kV from Dec 2018 until converted to 115 kV operation in 2022. There is currently no intent to operate assets in this station at 44 kV beyond 2022.

[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	Wataynikaneyap SS	Wataynikaneyap TS	230	303.3	Network
North of Pickle Lake Remote Connection Lines (non-Bulk Electricity System):					
WBC	Pickle Lake TS	Ebane/Pipestone SS	115	147.8	Line Connection
WCD	Ebane/Pipestone SS	North Caribou Lake TS	115	132.6	Line Connection
D1	North Caribou Lake TS	HORCI 25 kV Demarcation	25	1.6	Line Connection
WDE	North Caribou Lake TS	Muskrat Dam TS	115	99.5	Line Connection
E1	Muskrat Dam TS	HORCI 25 kV Demarcation	25	14.9	Line Connection
WEF	Muskrat Dam TS	Bearskin Lake TS	115	63.7	Line Connection
F1	Bearskin Lake TS	HORCI 25 kV Demarcation	25	0.1	Line Connection
WEG	Muskrat Dam TS	Sachigo Lake TS	115	83.9	Line Connection
G1	Sachigo Lake TS	HORCI 25 kV Demarcation	25	3.6	Line Connection
WCJ	Ebane/Pipestone SS	Kingfisher Lake TS	115	98.1	Line Connection
J1	Kingfisher Lake TS	HORCI 25 kV Demarcation	25	4.3	Line Connection
WJI	Kingfisher Lake TS	Wunnumin Lake TS	44	54.6	Line Connection
I1	Wunnumin Lake TS	HORCI 25 kV Demarcation	25	1.2	Line Connection
WJK	Kingfisher Lake TS	Wawakapewin TS	115	84.7	Line Connection
K1	Wawakapewin TS	HORCI 25 kV Demarcation	25	4.6	Line Connection
WKL	Wawakapewin TS	Kasabonika Lake TS	44	39.0	Line Connection
L1	Kasabonika Lake TS	HORCI 25 kV Demarcation	25	2.3	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	0.4	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
P1	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	1.3	Line Connection
WRT	Poplar Hill SS	Deer Lake SS	115	67.9	Line Connection
WTU	Deer Lake SS	Deer Lake TS	115	20.5	Line Connection
U1	Deer Lake TS	HORCI 25 kV Demarcation	25	0.1	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	0.4	Line Connection
WZV	Sandy Lake SS	North Spirit Lake TS	115	31.4	Line Connection
V1	North Spirit Lake TS	HORCI 25 kV Demarcation	25	1.6	Line Connection
WVY	North Spirit Lake TS	Keewaywin TS	115	79.1	Line Connection
Y1	Keewaywin TS	HORCI 25 kV Demarcation	25	3.6	Line Connection

[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 is being constructed between the Red Lake TS and the existing 44 kV Pikangikum Line, after which the entire WPQ line segment will operate at 115 kV. The remaining 3.4 km (98.9 km constructed less 95.5 km being converted to 115 kV) of the 44 kV distribution line constructed in 2018 will be decommissioned once the 115 kV line is in service.

Exhibit B, Tab 3, Schedule 1

Regional Considerations

REGIONAL CONSIDERATIONS

Section 2.4.2 of the Filing Requirements specifies that, where applicable, a transmitter shall file as part of their TSP information on the regional planning processes in which they are a participant and information demonstrating that regional considerations have been appropriately considered and addressed in the development of the transmitter's plans. While the manner in which WPLP has participated in regional planning processes and the way in which regional considerations have been considered in WPLP's plans are not typical, 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. The historical context for this is discussed below.

A. Alignment with Long-Term Energy Plans

In 2010, the Province issued its first LTEP. In the 2010 LTEP 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 the Northwest Ontario First Nation Transmission Planning Committee ("Draft Remote

[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)

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 will be 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.

The second cycle of regional planning for the Northwest started in March 2020 and is currently ongoing. The Needs Assessment is the first step in this process and was carried out by a study team led by Hydro One. The Needs Assessment report was finalized on July 17, 2020 (the "2020 Needs Assessment Report"). The 2020 Needs Assessment Report acknowledged the development of

[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

[4] WPLP's transmission system will also allow 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

WPLP's Transmission System and concluded that, among other things, the Transmission System provides relief to the E1C circuit and Red Lake sub-system capacity needs but, nevertheless, this area continues to have the potential for high mining-related load growth, which warrants further study in the current regional planning cycle.

The information in the 2020 Needs Assessment Report was an input to the next phase of the process, which was concluded on January 13, 2021 with the IESO publishing its Scoping Assessment Outcome Report ("Scoping Report"). The Scoping Report continues to acknowledge the development of WPLP's Transmission System and recommends a single IRRP for the Northwest region with a focus on updating previous studies to assess the capability of the existing system and potential options if future needs materialize.

Since the issuance of the Scoping Report, the IESO has been focused on engagement efforts related to the IRRP and is currently finalizing demand forecast scenarios. The IESO has scheduled a webinar in late April 2022 to present an overview on system needs in the Northwest and seek input on options that may be considered to address those needs. WPLP is actively monitoring the IESO's current engagement activities and intends to participate in the development of the Northwest IRRP as required. It is expected that the IRRP report will be issued in mid-2022.

C. Coordinated Planning with Third Parties

Each of the regional planning initiatives described above (the RCCP, IRRP and RIP) 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.[7]

- In preparing the North of Dryden IRRP, the OPA/IESO identified 44 First Nation communities and four Métis communities to be consulted and held a number of

[7] RCCP; pp. 91-92

consultation sessions. Further, the OPA/IESO engaged with a number of First Nations organizations, municipalities, industry associations, and proponents (including WPLP).

- In preparing the Northwest Ontario RIP, Hydro One Transmission included input from a working group that included the IESO, Hydro One Distribution and five LDC's. The RIP also considers the results from the prior RCCP and IRRP reports mentioned above.

Exhibit C, Tab 1, Schedule 1

Rate Base Overview

RATE BASE OVERVIEW

This Exhibit provides WPLP's forecasted rate base for the 2023 test year, and a description of each component of the forecasted rate base. Given that this is only the second revenue requirement application filed by WPLP and is in respect of the second year in which WPLP will have transmission assets in service, this Exhibit provides information only pertaining to the 2023 Test Year, the 2022 Bridge Year and the associated variance analysis between those years. As no transmission assets were in service in the historical period, WPLP does not have historical actual data and therefore provides no variance analysis in relation to the historical period.

A. Rate Base Forecast

WPLP's proposed rate base for the 2023 test year is based on a forecast of net fixed assets[1], calculated using the 12-month average of gross assets and accumulated depreciation, consistent with WPLP's approach in its initial rate application (OEB approved).

Given that portions of the Remote Connection Lines will be coming into service at different points during the 2023 test year, and consistent with the approach taken for 2022 rates, it is more appropriate to calculate the proposed rate base by applying a 12-month average of forecast monthly in-service additions. This will result in the same value as the traditional "half-year rule" for those assets that will be in-service for the entirety of the 2023 rate year (i.e. the Line to Pickle Lake and certain segments of Remote Connection Lines).

WPLP's proposed rate base methodology apportions WPLP's revenue requirement more accurately between the distinct customer groups that will benefit from each group of assets, while also better reflecting the timing of assets coming into service. As described in Exhibit C-3-1, the Network pool will be receiving the full benefit from the Line to Pickle Lake throughout 2023, whereas HORCI will benefit based on the portions of the Remote Connection Lines that are

[1] Net fixed assets are calculated as gross plant in service minus accumulated depreciation and minus any contributed capital. WPLP is not requesting an allowance for working capital in 2023 but intends to do so in its first multi-year rate application.

expected to be in service throughout 2023 and the additional portions of the Remote Connection Lines that are expected to come into service at different points throughout 2023.

WPLP's approved and budgeted rate base for the 2022 bridge year, are summarized in Table 1, below. Forecasted rate base for the 2023 test year is provided in Table 2.

Table 1 – 2022 Rate Base

Item	2022 Approved ($000's)			2022 Budget ($000's)			Variance 12-Month Avg
	Opening	Closing	12-Month Avg	Opening	Closing	12-Month Avg	
Gross Fixed Assets	0	679,135	420,879	0	679,733	308,050	-112,829
Less Accumulated Depreciation	0	-7,887	-2,328	0	-5,618	-1,204	1,124
Net Fixed Assets	**0**	**671,248**	**418,552**	**0**	**674,114**	**306,846**	**-111,706**
Working Capital Allowance	-	-	-	-	-	-	-
Total Rate Base	**0**	**671,248**	**418,552**	**0**	**674,114**	**306,846**	**-111,706**

Table 2 – 2023 Rate Base

Item	2023 Forecast ($000's)		
	Opening	Closing	12-Month Avg
Gross Fixed Assets	679,733	1,021,065	870,584
Less Accumulated Depreciation	-5,618	-22,885	-13,418
Net Fixed Assets	**674,114**	**998,181**	**857,166**
Working Capital Allowance	-	-	-
Total Rate Base	**674,114**	**998,181**	**857,166**

Details of WPLP's 2022 in-service additions by asset category and type of assets are provided in Exhibit C-2-1. WPLP's proposal to calculate gross fixed asset and accumulated depreciation values using an average of twelve monthly values is further articulated in Exhibit C-3-1.

B. Variance Analysis

WPLP's 12-month average rate base forecast for 2022 is $112 million lower than the 2022 OEB-approved value from the initial rate application. The variance is primarily driven by the delayed in-service date of Line to Pickle Lake from April 2022 to June 2022, and the delayed in-service date of certain segments of the Remote Connection Lines from June 2022 to August 2022. The delay in the in-service dates significantly reduces the 12-month average rate base forecast, as assets are in-service for a shorter period. Additional detail on the 2022 variance is provided in Exhibit C-2-1.

Exhibit C, Tab 2, Schedule 1

In-Service Additions

IN-SERVICE ADDITIONS

In total, the Transmission Project is comprised of 22 stations (6 switching stations and 16 transformer stations) and 35 distinct line segments – running from one station to another, or from a station to a HORCI-owned[1] and operated distribution system serving a remote community – that will be operated at four different voltages (230 kV, 115 kV, 44 kV and 25 kV) over a total distance of approximately 1,744 km[2]. As described in Exhibit B, Tab 1, Schedule 3, during 2022 WPLP plans to put into service the Line to Pickle Lake component of the Transmission Project, as well as those portions of the Pickle Lake Remote Connection Lines that are needed to provide service to HORCI at North Caribou Lake First Nation and Kingfisher Lake First Nation, and those portions of the Red Lake Remote Connection Lines that are needed to provide service to HORCI at Pikangikum First Nation.[3] In 2023, WPLP plans to put into service those portions of the Pickle Lake Remote Connection Lines that are needed to provide service to HORCI at Muskrat Dam First Nation, Bearskin Lake First Nation, Wawakapewin First Nation and Sachigo Lake First Nation. Together, the elements that will be put into service in 2023 represent approximately 19% of the total forecast cost for the Transmission Project.

The remaining nine communities (Wunnumin Lake First Nation, Kasabonika Lake First Nation, Kitchenuhmaykoosib Inninuwug, Wapekeka First Nation, Poplar Hill First Nation, Deer Lake First Nation, North Spirit Lake First Nation, Sandy Lake First Nation and Keewaywin First Nation) are forecasted to be connected to WPLP's transmission system in 2024.

The specific line segments and substations that comprise the 2023 test year in-service additions are summarized in Table 1 and described below. Details of the allocation of capital costs to each fixed asset (i.e. each line segment and substation) are provided in **Appendix 'A'**. A map

[1] HORCI continues to work with the IPA communities. An update on progress has been provided in the Semi-Annual Report dated April 15, 2022, filed pursuant to EB-2018-0190.

[2] As described on page 10 of Exhibit B-1-1, there have been a number of minor route changes that have increased the overall line length by approximately 8 km (less than 1%). As such, the total length indicated here has been adjusted by 8 km as compared to the previous application under EB-2021-0134.

[3] The current supply to Pikangikum First Nation will transition from a 44 kV distribution supply to a 115 kV transmission supply in 2022.

highlighting the portions of the Transmission System that are forecasted to be in service by the end of 2023 is provided in **Appendix 'B'**.

Table 1 – 2023 Transmission System In-Service Additions by Asset

Asset Designation	Description	2023 In-Service Additions ($000's)
Line WJK	115 kV - Kingfisher Lake TS to Wawakapewin TS	57,879
Line WK1 (25kV)	25 kV - Wawakapewin TS to HORCI Wawakapewin	1,974
Line DE	115 kV - North Caribou Lake TS to Muskrat Dam TS	73,486
Line E1 (25kV)	25 kV - Muskrat Dam TS to HORCI Muskrat Ram	6,368
Line EF	115 kV - Muskrat Dam TS to Bearskin Lake TS	41,790
Line F1 (25kV)	25 kV - Bearskin Lake TS to HORCI Bearskin Lake	370
Line EG	115 kV - Muskrat Dam TS to Sachigo Lake TS	58,650
Line G1 (25kV)	25 kV - Sachigo Lake TS to HORCI Sachigo Lake	2,249
Subtotal RCL Lines		***242,766***
Station E	Muskrat Dam TS	28,068
Station F	Bearskin Lake TS	19,676
Station G	Sachigo Lake TS	19,389
Station K	Wawakapewin TS	25,734
Subtotal RCL Stations		***92,866***
Total Transmission System In-Service Additions		**335,632**

The portions of the Pickle Lake Remote Connection Lines that are needed to provide service to HORCI at Muskrat Dam First Nation, Bearskin Lake First Nation, Wawakapewin First Nation and Sachigo Lake First Nation are comprised of:

- Four transformer stations, each with a fenced yard, a control building and a variety of transformation, switching, protection and reactive power compensation equipment, depending on the functionality of the station. The location and functionality of each station is summarized in Table 2.

- Eight overhead line segments, operating at 115 kV or 25 kV, the length, location and functionality of which are summarized in Table 3.

Table 2 – Pickle Lake Remote Connection Lines: 2023 Station In-Service

Station Name	Location	Functionality
Muskrat Dam TS	Approximately 12.5 km northeast of the Muskrat Dam Airport	115 kV to 25 kV transformation to supply Muskrat Dam First Nation; switching and protection for incoming/outgoing 115 kV lines; reactive power compensation to prevent system over-voltage
Bearskin Lake TS	Approximately 4 km southeast of the Bearskin Lake Airport	115 kV to 25 kV transformation to supply Bearskin Lake First Nation; switching and protection for incoming 115 kV lines; reactive power compensation to prevent system over-voltage
Wawakapewin TS	Approximately 1 km south of the Wawakapewin First Nation reserve boundary (approximately 4 km south of the community)	115 kV to 25 kV transformation to supply Wawakapewin First Nation; 115 kV to 44 kV transformation to supply the 44 kV transmission line to Kasabonika Lake TS; switching and protection for incoming/outgoing 115 kV lines; reactive power compensation to prevent system over-voltage
Sachigo Lake TS	Approximately 1 km northwest of the Sachigo Lake Airport	115 kV to 25 kV transformation to supply Bearskin Lake First Nation; switching and protection for incoming 115 kV lines; reactive power compensation to prevent system over-voltage

Table 3 – Pickle Lake Remote Connection Lines: 2023 Line Segment In-Service Additions

Identifier	Origin	Endpoint	Voltage (kV)	Length (km)
WJK	Kingfisher Lake TS	Wawakapewin TS	115	84.7
K1	Wawakapewin TS	HORCI 25 kV Demarcation	25	4.6
WDE	North Caribou Lake TS	Muskrat Dam TS	115	99.5
E1	Muskrat Dam TS	HORCI 25 kV Demarcation	25	14.9
WEF	Muskrat Dam TS	Bearskin Lake TS	115	63.7
F1	Bearskin Lake TS	HORCI 25 kV Demarcation	25	0.1
WEG	Muskrat Dam TS	Sachigo Lake TS	115	83.9
G1	Sachigo Lake TS	HORCI 25 kV Demarcation	25	3.6

The remaining four communities (Wunnumin Lake First Nation, Kasabonika Lake First Nation, Kitchenuhmaykoosib Inninuwug, Wapekeka First Nation) within the Pickle Lake Remote

Connection Lines are expected to come into service in 2024 and, as such, are not part of the in-service additions to rate base in this Application.

With the exception of transmission facilities required to connect Pikangikum First Nation, which are going into service as transmission facilities in 2022, all other portions of the Red Lake Remote Connection Lines that are needed to provide service to HORCI at Poplar Hill First Nation, Deer Lake First Nation, North Spirit Lake First Nation, Sandy Lake First Nation and Keewaywin First Nation are expected to come into service in 2024 and, as such, are not part of the in-service additions to rate base in this Application.[4]

Further to the Transmission System in-service additions described up to this point, general plant in-service additions for 2023 will consist of fleet, asset management software and a service centre, as further discussed in Exhibit B-1-5. Table 4 summarizes WPLP's total in-service additions for 2023.

Table 4 – Total 2023 In-Service Additions

Asset Category	**In-Service Additions ($000's)**
Remote Connection Lines – Lines	242,766
Remote Connection Lines – Stations	92,866
General Plant	5,701[5]
Total 2023 In-Service Additions	**341,333**

The in-service additions identified in Table 4 are reasonable as they reflect the EPC contract costs attributable to each of the line segments and stations coming into service, as well as an appropriate allocation of WPLP's non-EPC capital costs, as detailed in **Appendix 'A'**. WPLP's EPC contract procurement process and ongoing oversight, as well as its approach to planning, managing and forecasting non-EPC capital costs, are described in detail in Exhibit B, Tab 1, Schedules 2, 4 and

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

[5] See Table 6 in Exhibit B-1-5 for further detail on General Plant in-service additions.

5, and have been considered by the OEB in the leave to construct proceeding and the initial rates application.

A. VARIANCE ANALYSIS

As noted in Exhibit A-5-2, the parties to the Settlement Agreement in the initial revenue requirement application (EB-2021-0134) agreed that, in future transmission applications for years in which additional transmission line segments and stations will be placed into service, WPLP will include information on variances for such line segments and stations being placed into service, relative to both the values presented in a respective application and the values that were presented in the Leave to Construct proceeding (EB-2018-0190). The following provides information on variances relative to those presented in the Leave to Construct proceeding.

The WPLP Leave to Construct application in EB-2018-0190 did not include any general plant, as general plant investments were not subject to the requirement for Leave to Construct and therefore were not considered at that time. As a result, no variance analysis is provided for general plant compared to the amount being placed in-service in the 2023 test year. Based on the unit costing WPLP used to complete the Leave to Construct application in EB-2018-0190, total costs for lines ($174.2 million) and substations ($43.1 million) included in the Leave to Construct for the 2023 in-service assets was $217.3 million, for a variance of $124 million (including general plant). The drivers of this variance between the costs presented in the Leave to Cost application and the costs of the in-service asset additions related to the Remote Connection Lines in 2023 are provided in EB-2021-0134 in Exhibit B-1-5. The drivers outlined in EB-2021-0134 are the same drivers for the specific substations and line segments that are going in-service in this application. In addition to the variances described in EB-2021-0134, the 2023 in-service additions sought in this application have increased by the following Change Orders, which are set out in Table 5 below.

Table 5 – 2023 In-Service Asset Reconciliation ($000)

	Transmission Lines	**Substations**	**Total**
Leave to Construct – Asset Value	174,170	43,056	217,226
Change based on EPC Contract Execution	28,006	36,387	64,392
Non-EPC Cost Allocation	32,047	12,592	44,639
Change Orders			
Changes to Routing	7,482	-	7,482
Change to Design Requirements	56	215	271
2021 Forest Fire Impacts	1,005	279	1,284
Additional Scope	-	337	337
	242,766	**92,866**	**335,632**
General Plant Additions	**-**	**-**	5,701
Total 2023 In-Service Additions	**242,766**	**92,866**	**341,333**

There are two main drivers for the variance between the values in the Leave to Construct application and the forecasted in-service additions for the Remote Connection Lines: (1) executed EPC contract (described in Exhibit B-1-5 in EB-2021-0134) and (2) executed and pending EPC change orders (described below).

As of December 31, 2021, WPLP has executed/pending change orders, the majority of which relate to design changes, routing changes, and 2021 forest fire impacts.[6] These change orders represent additional forecasted costs of approximately $9.4 million. Regarding the change orders noted in Table 5 above, four change orders exceed application materiality. The first relates to routing changes on the Muskrat Dam to Sachigo Lake 115kV line segment resulting in a project cost reduction of $1 million. The second relates to route changes to the Sachigo Lake 25kV line segment, resulting in increased costs of $0.7 million. The third relates to route changes to the North Caribou Lake to Muskrat Dam line segment for additional costs of $8 million.[7] The fourth relates to forest fires (MNRF Emergency Area Order 2021-13) that occurred during the 2021 summer

[6] The cost impacts of the 2021 forest fires are not yet known as Wataynikaneyap and Valard continue to negotiate the proposed Change Orders.

[7] Route change continues to be under negotiation with the EPC contractor.

construction season, which shut down all construction on the Line to Pickle Lake for an approximate six-week period.

Since the 2022 bridge year reflects the first year in which WPLP has transmission system assets going into service, there are no historical year additions to report or to compare to. Variance analysis between approved and forecasted 2022 in-service additions for the Line to Pickle Lake and Remote Connection Lines are summarized in Table 6 and Table 8 respectively.

Table 6 – 2022 Line to Pickle Lake In-Service Addition Variance ($000)[8]

OEB Account and Description	Line to Pickle Lake (UTR Network Rate)		Variance
	OEB Approved	Forecast	
1715 - Station Equipment (Station and Transformers)	34,238	35,534	1,297
1715A - Station Equipment (Switches and Breakers)	6,299	6,235	-64
1715B - Station Equipment (Protection and Control)	1,491	1,476	-15
1720 - Towers and Fixtures	112,476	112,980	504
1725 - Poles and Fixtures	0	0	0
1730 - OH Conductor and Devices	134,720	133,611	-1,109
Total	**289,223**	**289,837**	**613**

There are three main drivers for the variance between OEB approved and forecasted in-service additions for Line to Pickle Lake: (1) executed or pending EPC change orders, (2) additional overhead costs due to in-service date delays, and (3) Project savings relating to 2021 and 2022 and expected future Project savings.

[8] In the WPLP Leave to Construct proceeding WPLP forecasted the Line to Pickle Lake costs before interest and contingency to be $295.5 million for a reduction in cost of $5.67 million compared to the same in-service costs forecasted for the 2022 year. The drivers between the Leave to Cost and the OEB approved costs are provided for in EB-2021-0134 in Exhibit B-1-5 with the variance between the OEB approved costs are provided for in EB-2021-0134 and this rate application are provided below.

As of December 31, 2021, WPLP has executed/pending change orders, the majority relating to design changes, routing changes, and 2021 forest fire impacts[9]. These change orders represent additional forecasted costs of approximately $3.5 million. In addition, there are additional overhead costs based on the allocation methodology provided in Exhibit B-1-5 - Appendix A, which results in additional costs of $0.6 million. The total increase in costs of $4.1 million is partially offset by savings in Non-EPC capital costs realized in 2021 and forecasted savings for the 2022 construction period. Total Non-EPC cost savings are forecasted to be $3.5 million. Further details on change order costs are provided in Table 7 below.

Table 7 – Line to Pickle Lake Change Orders

Transmission Line Change Orders	**($000)**
Changes to Routing	620
Changes to Design Requirements	14
2021 Forest Fire Impacts	1,005
Additional Scope	250
Substation Change Orders	
Changes to Design Requirements	156
Additional Scope	928
2021 Forest Fire impacts	558
	3,531

Regarding the change orders noted in Table 7 above, two change orders exceed application materiality. The first change order relates to changes in power line carrier equipment specifications and providing additional control building equipment to ensure compatibility with Hydro One's existing power line carrier system, and to ensure reliable performance, for additional project costs of $0.5 million. The second change order relates to forest fires (MNRF Emergency Area Order 2021-13) that occurred during the 2021 summer construction season that shut down the entire construction on the Line to Pickle Lake for an approximate six-week period.

[9] The cost impacts of the 2021 forest fires are not yet known as Wataynikaneyap and Valard continue to negotiate proposed Change Orders.

Similar to the Line to Pickle Lake, there are three main drivers for the variance between OEB approved and forecasted in-service additions for the Remote Connection Lines: (1) executed or pending EPC change orders, (2) additional overhead costs due to in-service date delays, and (3) Project savings relating to 2021 and 2022.

Table 8 – 2022 Remote Connection Lines In-Service Addition Variance ($000)

OEB Account and Description	Remote Connection Lines (H1RCI Rate)		Variance
	OEB Approved	Forecast	
1715 - Station Equipment (Station and Transformers)	64,439	65,515	1,075
1715A - Station Equipment (Switches and Breakers)	6,716	6,648	-68
1715B - Station Equipment (Protection and Control)	2,911	2,881	-29
1720 - Towers and Fixtures	145,754	144,859	-895
1725 - Poles and Fixtures	1,744	1,738	-5
1730 - OH Conductor and Devices	168,125	168,034	-91
Total	**389,688**	**389,676**	**-12**

As of December 31, 2021, WPLP has executed/pending Change Orders, the majority relating to design changes, routing changes, and 2021 forest fire impacts[10]. These Change Orders represent additional forecasted costs of approximately $3.9 million. There are also $0.8 million of additional overhead costs based on the allocation methodology provided in Exhibit B-1-5 - Appendix A. The increase in costs of $4.7 million is offset by $4.7 million of savings in Non-EPC capital costs realized in 2021 and 2022 construction period. Further details on change order costs are provided in Table 9, below.

[10] The cost impacts of the 2021 forest fires are not yet known as Wataynikaneyap and Valard continue to negotiate proposed Change Orders.

Table 9 – Remote Connection Lines Change Orders

Transmission Line Change Orders	**($000)**
Changes to Routing	(359)
Changes to Design Requirements	(1,858)
2021 Forest Fire Impacts	3,810
Additional Scope	600
Substation Change Orders	
Changes to Design Requirements	197
Additional Scope	426
2021 Forest Fire impacts	1,103
	3,919

Regarding the change orders noted in Table 9 above, four individual change orders exceed application materiality. The first relates to a design change to tower structures in line segment BC (Pickle Lake to Pipestone) resulting in a $1 million reduction in Project costs. The second relates to design change to tower structures in line segment P1P2 (Red Lake to Pikangikum) resulting in a $0.9 million reduction in Project costs. The third relates to compensation of $0.6 million for lost resources in a gravel pit. The fourth change order relates to forest fires (MNRF Emergency Area Order 2021-13) that occurred during the 2021 summer construction season that shut down the entire construction on the Line to Pickle Lake for an approximate six-week period.

Variance analysis between overall capital cost estimates presented in EB-2021-0134 and WPLP's current capital cost estimates (excluding impacts of the COVID-19 pandemic, which are addressed in Exhibit H-2-2) are provided in Exhibit B-1-5. Fixed asset continuity and depreciation schedules are provided in Exhibit C-3-1.

APPENDIX ‘A’

Capital Cost Allocation to Fixed Asset Accounts

Appendix 'A'

Capital Cost Allocation to Fixed Asset Accounts

The capital costs outlined in Exhibit B-1-5 include several categories of costs:

- **EPC Contract Costs:** EPC costs that include costs directly attributable to individual line segments and substations (based on the breakdown provided in the EPC bid) as well as general EPC costs that were pro-rated to individual line segments and substations.

- **Non-EPC Capital Costs:** Estimated costs of (i) certain discrete capital costs that were excluded from the EPC contract scope and costs related to general plant investments, (collectively "EPC Excluded Costs") and (ii) other non-EPC capital costs that WPLP has incurred or expects to incur over the project period that are clearly and directly related to the Transmission Project and are therefore clearly capital in nature ("Non-EPC Attributed to Capital").

- **Overhead Costs:** The portion of WPLP's overhead costs that are forecasted to be capitalized, based on the methodology described in Appendix 'A' of Exhibit B-1-5.

Pursuant to the settlement agreement in EB-2021-0134, WPLP agreed to remove and defer the forecasted contingency amounts from its in-service 2022 year-end rate base. WPLP also agreed to establish a new deferral account to track the revenue requirement impacts associated with the amount of contingency allocated to 2022 in-service additions, to the extent that such contingency is realized and does not exceed the amount removed from rate base. In the current Application, WPLP is proposing to continue to use this approach and, as a result, has not included any of the $66.8 million of contingency costs associated with the in-service additions.

This Appendix 'A' describes how the capital costs in the categories listed above are assigned to WPLP's various fixed asset accounts for the purpose of determining its 2023 in-service additions.

Table A-1 below provides a breakdown of the forecasted capital cost (before AFUDC), according to whether or not the costs are directly attributable to fixed assets.

Table A-1 – Summary of Total Direct and Allocated Capital Costs

Cost Category	Allocation of Capital Costs ($000's)			
	Direct to Fixed Assets	**Allocate Proportional to EPC Costs**	**Excluded from In-Service additions**	**Total**
EPC Costs	1,419,979	12,800	0	1,432,779
EPC Excluded Costs	9,450	13,097	0	22,547
Non-EPC Attributed to Capital	0	124,556	0	124,556
Capitalized Overhead Costs	0	74,626	0	74,626
Change Orders (Executed and in negotiations)	23,596	0	0	23,596
Contingency	0	0	94,615	94,615
Total	**1,453,025**	**225,078**	**94,615**	**1,772,719**[11]

WPLP expects to transfer approximately $1,420 million of base EPC contract costs from CWIP to specific fixed asset accounts, based on breakdowns provided in the EPC bid schedules. EPC excluded costs of approximately $9.45 million relating to fleet, facilities and business systems, plus $23.6 million for Change Orders on those items, are also directly attributable to specific fixed asset accounts.

The remaining approximately $225 million of WPLP's forecasted capital project costs relate to general costs that are not directly attributable to specific fixed asset accounts. These costs include items such as contract security, insurance, project development[12] and construction management costs, and capitalized overhead costs. In order to clear these costs from CWIP to rate base at an appropriate pace as WPLP's assets come into service, WPLP proposes to pro-rate these costs in proportion to the base EPC contract costs of $1,420 million, as each station or line segment comes

[11] With reference to Table 3 in Exhibit B-1-5, this total is equal to the total project costs ($1,818,374) less capitalized interest of $45,655,

[12] These costs were initially recorded in WPLP's Development Cost Deferral Account, and subsequently transferred into the CWIP account, pursuant to the OEB's decision in EB-2018-0190.

into service. Table A-2 below illustrates the proportional allocation for assets that are scheduled to go into service in 2023.

Table A-2 – Proportional Allocation for 2023 In-Service Additions ($000's)

Asset Designation	EPC Base Amount	% of EPC Costs	Proportional Allocation of General Capital Costs	Change Orders	Additions to Fixed Asset Accounts
	A	B = A / 1,419,979	C = B * 225,078	D	E = A + C + D
Line WJK	50,176	3.53%	7,953	-251	57,879
Line WK1 (25kV)	1,704	0.12%	270	0	1,974
Line DE	55,646	3.92%	8,820	9,019	73,486
Line E1 (25kV)	5,497	0.39%	871	0	6,368
Line EF	36,037	2.54%	5,712	41	41,790
Line F1 (25kV)	320	0.02%	51	0	370
Line EG	51,483	3.63%	8,161	-994	58,650
Line G1 (25kV)	1,312	0.09%	208	729	2,249
Station E	24,118	1.70%	3,823	126	28,068
Station F	16,667	1.17%	2,642	368	19,676
Station G	16,538	1.16%	2,621	230	19,389
Station K	22,120	1.56%	3,506	107	25,734
Total	**281,618**	**19.83%**	**44,639**	**9,374**	**335,632**

Appendix 'B'

WPLP 2023 In Service Forecast Map

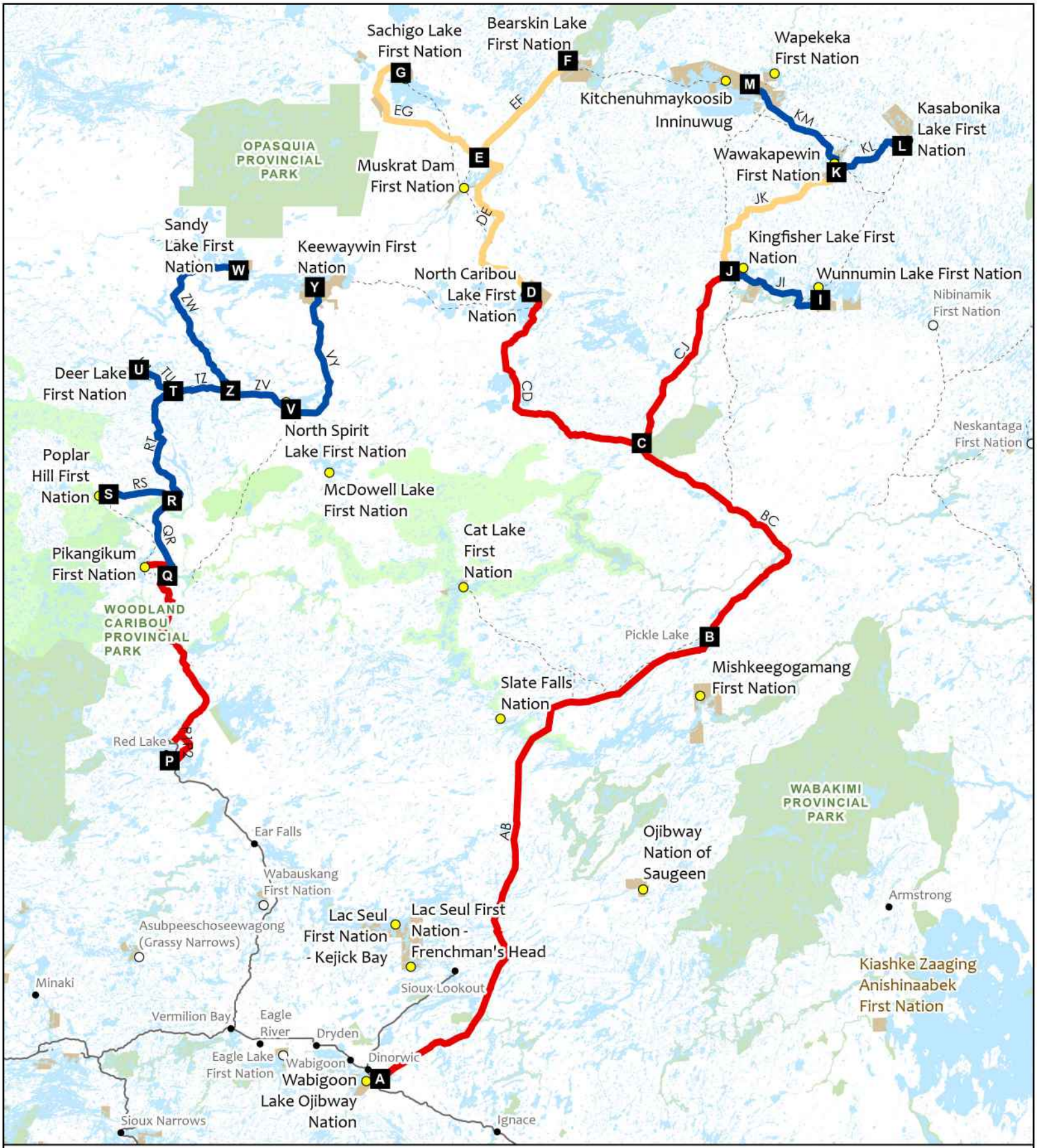

Sachigo Lake First Nation
Bearskin Lake First Nation
Wapekeka First Nation
Kitchenuhmaykoosib Inninuwug
Kasabonika Lake First Nation
Wawakapewin First Nation
Muskrat Dam First Nation
OPASQUIA PROVINCIAL PARK
Sandy Lake First Nation
Keewaywin First Nation
Kingfisher Lake First Nation
Wunnumin Lake First Nation
North Caribou Lake First Nation
Nibinamik First Nation
Deer Lake First Nation
North Spirit Lake First Nation
Neskantaga First Nation
Poplar Hill First Nation
McDowell Lake First Nation
Cat Lake First Nation
Pikangikum First Nation
WOODLAND CARIBOU PROVINCIAL PARK
Pickle Lake
Mishkeegogamang First Nation
Slate Falls Nation
Red Lake
WABAKIMI PROVINCIAL PARK
Ear Falls
Ojibway Nation of Saugeen
Wabauskang First Nation
Armstrong
Asubpeeschoseewagong (Grassy Narrows)
Lac Seul First Nation - Kejick Bay
Lac Seul First Nation - Frenchman's Head
Sioux Lookout
Minaki
Kiashke Zaaging Anishinaabek First Nation
Vermilion Bay
Eagle River
Dryden
Eagle Lake First Nation
Wabigoon
Dinorwic
Wabigoon Lake Ojibway Nation
Sioux Narrows
Ignace
EG
EF
DE
KM
KL
JK
JI
ZW
VY
TU
TZ
ZV
RT
RS
QR
PQ
CD
CJ
BC
AB
Wataynikaneyap Power
Wataynikaneyap Power Community
First Nation Community
Town
Substation
Existing Arterial Road/Highway
Existing Winter Road
In Service Date
2022
2023
2024
First Nation Reserve
Provincial Park
Dedicated Protected Area - Far North
Waterbody
WATAYNIKANEYAP POWER
In Service Forecast by Year
0 10 20 40 60 80 100 km
REFERENCE:
Transmission Routes - Provided by Wataynikaneyap Power
First Nation Reserve Communities, Waterbodies, Provincial Parks, Existing Roads - Land Information Ontario (https://geohub.lio.gov.on.ca/datasets)
Coordinate System - NAD 1983 CSRS UTM Zone 15N
N
KBM RESOURCES GROUP

Exhibit C, Tab 3, Schedule 1

Gross Assets – Property, Plant & Equipment

and Accumulated Depreciation

GROSS ASSETS – PROPERTY, PLANT & EQUIPMENT AND ACCUMULATED DEPRECIATION

As discussed in EB-2021-0134, during 2022 WPLP plans to put into service the entirety of the Line to Pickle Lake including its 2 associated substations, and for the Remote Connection Lines, WPLP plans to put into service 5 of the 20 substations and 7 of the 34 line segments[1], as well as to convert the Pikangikum Distribution System to form part of the Transmission System. Table 1 provides the approved, forecasted and resulting variance for the 2022 in-service asset additions.[2] Table 2 provides the approved, forecasted and resulting variance for the 2022 depreciation[3]. The forecasted balances from Tables 1 and 2 are used to determine WPLP's resulting opening balances for 2023 gross assets and accumulated depreciation, which are set out in Tables 6 and 7, below.

[1] These counts include line segments and substations associated with the Pikangikum Distribution System that are already in service and will transition to a transmission supply in 2022.

[2] Forecasted balances reflect forecasted capital spend and in-services dates, variance analysis is provided in Exhibit C-2-1.

[3] 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 - 2022 Year-End Gross Assets by OEB Account ($000's)

	Initial Rate Application			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**
1715 - Station Equipment (Station and Transformers)	34,238	64,439	98,677	35,534	65,515	101,049	2,372
1715A - Station Equipment (Switches and Breakers)	6,299	6,716	13,015	6,235	6,648	12,883	-131
1715B - Station Equipment (Protection and Control)	1,491	2,911	4,402	1,476	2,881	4,358	-44
1720 - Towers and Fixtures	112,476	145,754	258,230	112,980	144,859	257,839	-391
1725 - Poles and Fixtures	0	1,744	1,744	0	1,738	1,738	-5
1730 - OH Conductor and Devices	134,720	168,125	302,845	133,611	168,034	301,645	-1,200
Sub-Total Transmission System Plant	**289,223**	**389,688**	**678,911**	**289,837**	**389,676**	**679,513**	**601**
1930 - Transportation Equipment[4]	109	115	224	112	108	220	-4
Total	**289,332**	**389,803**	**679,135**	**289,949**	**389,784**	**679,733**	**598**

[4] See Exhibit I-2-1 for details on allocation between LTPL and RCL.

Table 2 – 2022 Year-End Accumulated Depreciation by OEB Account ($000's)

	Initial Rate Application			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**
1715 - Station Equipment (Station and Transformers)	457	678	1,134	355	472	827	307
1715A - Station Equipment (Switches and Breakers)	105	91	196	78	62	140	56
1715B - Station Equipment (Protection and Control)	50	76	126	37	51	88	38
1720 - Towers and Fixtures	1,250	1,239	2,488	942	828	1,770	719
1725 - Poles and Fixtures	0	19	19	0	13	13	6
1730 - OH Conductor and Devices	1,996	1,897	3,893	1,485	1,274	2,758	1,135
Sub-Total Transmission System Plant	**3,857**	**4,000**	**7,857**	**2,896**	**2,700**	**5,596**	**2,260**
1930 - Transportation Equipment[5]	15	15	30	11	11	22	8
Total	**3,871**	**4,015**	**7,887**	**2,907**	**2,711**	**5,618**	**2,268**

[5] See Exhibit I-2-1 for details on allocation between LTPL and RCL.

Table 3, below, summarizes WPLP's forecasted year-end gross assets for the 2023 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 – 2023 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
1715 - Station Equipment (Station and Transformers)	35,534	147,206	182,741
1715A - Station Equipment (Switches and Breakers)	6,235	14,084	20,319
1715B - Station Equipment (Protection and Control)	1,476	6,619	8,095
1720 - Towers and Fixtures	112,980	269,027	382,007
1725 - Poles and Fixtures	0	7,612	7,612
1730 - OH Conductor and Devices	133,611	280,759	414,370
Sub-Total Transmission System Plant	**289,837**	**725,307**	**1,015,144**
1908 - Buildings and Fixtures	1,660	3,340	5,000
1915 - Office Furniture and Equipment	50	101	151
1930 - Transportation Equipment[6]	90	180	270
1611 - Computer Software	166	334	500
Total	**291,803**	**729,263**	**1,021,065**

Table 4 summarizes WPLP's accumulated depreciation by OEB Account and by rate pool for the 2023 test year. Exhibit F-4-1 provides further detail on the calculation of depreciation expense.

Table 4 – 2023 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
1715 - Station Equipment (Station and Transformers)	1,066	2,639	3,705
1715A - Station Equipment (Switches and Breakers)	234	329	562

[6] See Exhibit I-2-1 for details on allocation between LTPL and RCL.

1715B - Station Equipment (Protection and Control)	111	293	403
1720 - Towers and Fixtures	2,825	4,329	7,154
1725 - Poles and Fixtures	0	123	123
1730 - OH Conductor and Devices	4,454	6,298	10,752
Sub-Total Transmission System Plant	**8,689**	**14,010**	**22,699**
1908 - Buildings and Fixtures	6	11	17
1915 - Office Furniture and Equipment	1	1	2
1930 - Transportation Equipment[7]	25	50	75
1611 - Computer Software	30	61	92
Total	**8,750**	**14,134**	**22,885**

A. Treatment of Pikangikum Distribution System Assets

As detailed in Exhibit H-1-1, WPLP's Pikangikum Distribution System was placed in service in December 2018, and WPLP's costs related to that system after the in-service date are being recorded in the Pikangikum Distribution System Deferral Account until such time as the assets form part of WPLP's transmission system in 2022. Since these assets are currently distribution assets, they are not included in the opening values presented in WPLP's fixed asset continuity schedules. Further, because the initial capital costs for constructing these assets were funded by Indigenous and Northern Affairs Canada ("INAC", now Indigenous Services Canada), the capital contribution offsets the fixed asset value, effectively resulting in zero rate base. Since there is no rate base or revenue requirement impact related to the initial capital costs for these assets, WPLP intends to exclude these assets from its fixed asset continuity schedule in its 2021 and 2022 applications for approval of its 2022 and 2023 test year revenue requirements consistent with the initial rate application filing in EB-2021-0134. This approach avoids adding further complexity to the calculation of WPLP's rate base and depreciation expense using a 12-month average approach during the 2022 and 2023 construction period. WPLP intends to add these assets to its fixed asset continuity schedule in its 2023 application for approval of its 2024 test year revenue requirement. In that application, WPLP intends to revert to the half-year rule approach to

[7] See Exhibit I-2-1 for details on allocation between LTPL and RCL.

calculating rate base and depreciation expense, and WPLP will also address both the initial capital contribution from INAC/ISC towards the construction of the Pikangikum system, and any capital contribution resulting from the federal funding framework discussed in I-4-1.

B. Average Values for Rate Base Determination

In EB-2021-0134, considering the differences in timing, and the differences in cost recovery[8], WPLP proposed (and the OEB accepted) the use of 12-month averages of gross assets and accumulated depreciation for the determination of net fixed assets included in rate base. In WPLP's view, this method remains appropriate and is therefore proposed for the 2023 test year because it continues to apportion WPLP's revenue requirement more accurately between the parties that distinctly benefit from each group of assets as the Remote Connection Lines continue to come into service[9]. Table 5 summarizes WPLP's 2023 average net fixed assets using this approach.

Table 5 – Summary of 2023 Average Net Fixed Assets

Item	**2023 12-Month Average ($000's)**			
	LTPL	**RCL**	**GP**	**Total**
Gross Fixed Assets	289,837	578,932	1,815	870,584
Less Accumulated Depreciation	-5,793	-7,534	-92	-13,418
Net Fixed Assets	**284,044**	**571,398**	**1,723**	**857,166**

Monthly totals of WPLP's gross asset and accumulated depreciation balances supporting the 12-month average calculation are provided in Tables 6 and 7. Fixed asset continuity schedules reflecting all in-service additions for the 2023 test year are included as Appendix 'A' to this schedule.

[8] Cost recovery for the Line to Pickle Lake will be through the UTR Network rate, whereas cost recovery for the Remote Connection Lines will be directly from HORCI. See Exhibit I.

[9] The Network pool receives the full benefit from the Line to Pickle Lake coming into service in June 2022, whereas HORCI benefits to varying degrees as additional portions of the Remote Connection Lines come into service.

Table 6 – 2023 Gross Asset Balances by Month ($000's)

		Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Oct	Nov	Dec	Avg
LTPL	Opening	289,837	289,837	289,837	289,837	289,837	289,837	289,837	289,837	289,837	289,837	289,837	289,837	
	Additions	0	0	0	0	0	0	0	0	0	0	0	0	
	Closing	289,837	289,837	289,837	289,837	289,837	289,837	289,837	289,837	289,837	289,837	289,837	289,837	
	Average	289,837	289,837	289,837	289,837	289,837	289,837	289,837	289,837	289,837	289,837	289,837	289,837	289,837
RCL	Opening	389,676	389,676	389,676	389,676	389,676	559,433	645,020	725,307	725,307	725,307	725,307	725,307	
	Additions	0	0	0	0	169,757	85,587	80,288	0	0	0	0	0	
	Closing	389,676	389,676	389,676	389,676	559,433	645,020	725,307	725,307	725,307	725,307	725,307	725,307	
	Average	389,676	389,676	389,676	389,676	474,554	602,226	685,164	725,307	725,307	725,307	725,307	725,307	578,932
GP	Opening	220	770	770	770	770	770	810	810	810	810	5,810	5,810	
	Additions	550	0	0	0	0	40	0	0	0	5,000	0	111	
	Closing	770	770	770	770	770	810	810	810	810	5,810	5,810	5,921	
	Average	495	770	770	770	770	790	810	810	810	3,310	5,810	5,866	1,815

Table 7 – 2023 Accumulated Depreciation by Month ($000's)

		Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Oct	Nov	Dec	Avg
LTPL	Opening	2,896	3,379	3,862	4,344	4,827	5,310	5,793	6,275	6,758	7,241	7,723	8,206	
	Additions	483	483	483	483	483	483	483	483	483	483	483	483	
	Closing	3,379	3,862	4,344	4,827	5,310	5,793	6,275	6,758	7,241	7,723	8,206	8,689	
	Average	3,138	3,620	4,103	4,586	5,068	5,551	6,034	6,517	6,999	7,482	7,965	8,447	5,793
RCL	Opening	2,700	3,351	4,001	4,652	5,303	5,953	6,885	7,961	9,171	10,381	11,591	12,801	
	Additions	651	651	651	651	651	932	1,075	1,210	1,210	1,210	1,210	1,210	
	Closing	3,351	4,001	4,652	5,303	5,953	6,885	7,961	9,171	10,381	11,591	12,801	14,010	
	Average	3,025	3,676	4,327	4,977	5,628	6,419	7,423	8,566	9,776	10,986	12,196	13,406	7,534
GP	Opening	22	26	39	51	64	77	90	103	116	129	143	164	
	Additions	4	13	13	13	13	13	13	13	13	13	22	22	
	Closing	26	39	51	64	77	90	103	116	129	143	164	186	
	Average	24	32	45	58	71	83	96	110	123	136	153	175	92

APPENDIX ‘A’

Fixed Asset and Depreciation Continuity

Fixed Asset Continuity Schedule - All Assets

Accounting Standard ASPE
Year 2022

			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	-	-	-	-	-	-	-	-	-	-
	1612	Land Rights (Intangible)	-	-	-	-	-	-	-	-	-	-
		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)	-	101,048,929	-	101,048,929	50	-	827,131	-	827,131	100,221,798
47	1715A	Station Equipment (Switches and Breakers)	-	12,883,434	-	12,883,434	40	-	140,128	-	140,128	12,743,306
47	1715B	Station Equipment (Protection and Control)	-	4,357,508	-	4,357,508	20	-	87,947	-	87,947	4,269,562
47	1720	Towers and Fixtures	-	257,839,357	-	257,839,357	60	-	1,769,858	-	1,769,858	256,069,499
47	1725	Poles and Fixtures	-	1,738,229	-	1,738,229	45	-	12,876	-	12,876	1,725,353
47	1730	OH Cond and Devices	-	301,645,045	-	301,645,045	45	-	2,758,357	-	2,758,357	298,886,689
	1735	UG Conduit	-	-	-	-	-	-	-	-	-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-	-	-	-
	1745	Roads and Trails	-	-	-	-	-	-	-	-	-	-
		General Plant										
	1905	Land (General Plant)	-	-	-	-	-	-	-	-	-	-
10.1	1908	Buildings and Fixtures	-	-	-	-	50	-	-	-	-	-
8	1915	Office Furn & Equipment	-	-	-	-	10	-	-	-	-	-
	1920	Comp Hardware	-	-	-	-	-	-	-	-	-	-
10.1	1930	Transportation Equipment	-	220,000	-	220,000	5	-	22,000	-	22,000	198,000
	1935	Stores Equip	-	-	-	-	-	-	-	-	-	-
	1940	Tools, Shop & Garage Equip	-	-	-	-	-	-	-	-	-	-
	1945	Measurement & Testing Equipment	-	-	-	-	-	-	-	-	-	-
	1950	Power Operated Equipment	-	-	-	-	-	-	-	-	-	-
	1955	Communication Equipment	-	-	-	-	-	-	-	-	-	-
	1960	Misc. Equipment	-	-	-	-	-	-	-	-	-	-
	1980	System Supervisory Equipment	-	-	-	-	-	-	-	-	-	-
	1995	Contributions & Grants	-	-	-	-	-	-	-	-	-	-
	2440	Deferred Revenue	-	-	-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-	-	-
		Sub-Total	**-**	**679,732,503**	**-**	**679,732,503**		**-**	**5,618,296**	**-**	**5,618,296**	**674,114,207**
	2055	**Add: Construction Work in Progress**	915,254,096	646,678,633	(679,732,503)	882,200,226		-	-	-	-	
		Less Other Non Rate-Regulated Utility Assets (input as negative)			-	-		-	-	-	-	
		Total PP&E	915,254,096	1,326,411,136	(679,732,503)	1,561,932,729		-	5,618,296	-	5,618,296	674,114,207
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										
		Total Additions to Accumulated Depreciation							5,618,296			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation* (input as negative)

Transportation	
Stores Equipment	
Net Depreciation	**5,618,296**

Fixed Asset Continuity Schedule - Line to Pickle Lake

Accounting Standard ASPE
Year 2022

			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)	-	35,534,358	-	35,534,358	50		355,344		355,344	35,179,014
47	1715A	Station Equipment (Switches and Breakers)	-	6,234,973	-	6,234,973	40		77,937		77,937	6,157,036
47	1715B	Station Equipment (Protection and Control)	-	1,476,085	-	1,476,085	20		36,902		36,902	1,439,183
47	1720	Towers and Fixtures	-	112,980,331	-	112,980,331	60		941,503		941,503	112,038,828
47	1725	Poles and Fixtures	-	-	-	-			-		-	-
47	1730	OH Cond and Devices	-	133,610,986	-	133,610,986	45		1,484,567		1,484,567	132,126,419
	1735	UG Conduit	-	-	-	-			-		-	-
	1740	UG Cond and Devices	-	-	-	-			-		-	-
	1745	Roads and Trails	-	-	-	-			-		-	-
		Sub-Total	**-**	**289,836,733**	**-**	**289,836,733**		**-**	**2,896,252**	**-**	**2,896,252**	**286,940,481**
	2055	**Add: Construction Work in Progress**				-					-	
		Less Other Non Rate-Regulated Utility Assets (input as negative)				-					-	
		Total PP&E	-	289,836,733	-	289,836,733		-	2,896,252	-	2,896,252	286,940,481
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										
		Total Additions to Accumulated Depreciation							2,896,252			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation* (input as negative)

Transportation	
Stores Equipment	
Net Depreciation	**2,896,252**

Fixed Asset Continuity Schedule - Remote Connection Lines

Accounting Standard ASPE
Year 2022

			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)	-	65,514,571	-	65,514,571	50		471,787		471,787	65,042,784
47	1715A	Station Equipment (Switches and Breakers)	-	6,648,460	-	6,648,460	40		62,191		62,191	6,586,270
47	1715B	Station Equipment (Protection and Control)	-	2,881,423	-	2,881,423	20		51,044		51,044	2,830,378
47	1720	Towers and Fixtures	-	144,859,026	-	144,859,026	60		828,355		828,355	144,030,671
47	1725	Poles and Fixtures	-	1,738,229	-	1,738,229	45		12,876		12,876	1,725,353
47	1730	OH Cond and Devices	-	168,034,060	-	168,034,060	45		1,273,790		1,273,790	166,760,269
	1735	UG Conduit	-	-	-	-			-		-	-
	1740	UG Cond and Devices	-	-	-	-			-		-	-
	1745	Roads and Trails	-	-	-	-			-		-	-
		Sub-Total	**-**	**389,675,770**	**-**	**389,675,770**		**-**	**2,700,044**	**-**	**2,700,044**	**386,975,726**
	2055	**Add: Construction Work in Progress**				-					-	
		Less Other Non Rate-Regulated Utility Assets (input as negative)				-					-	
		Total PP&E	-	389,675,770	-	389,675,770		-	2,700,044	-	2,700,044	386,975,726
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										
		Total Additions to Accumulated Depreciation							2,700,044			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation* (input as negative)

Transportation	
Stores Equipment	
Net Depreciation	**2,700,044**

Fixed Asset Continuity Schedule - All Assets

Accounting Standard ASPE
Year 2023

			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	-	500,000	-	500,000	5	-	91,667		91,667	408,333
	1612	Land Rights (Intangible)	-	-	-	-	-	-	-		-	-
		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)	101,048,929	81,691,884	-	182,740,813	50	827,131	2,877,753		3,704,884	179,035,928
47	1715A	Station Equipment (Switches and Breakers)	12,883,434	7,435,985	-	20,319,419	40	140,128	422,241		562,369	19,757,050
47	1715B	Station Equipment (Protection and Control)	4,357,508	3,737,772	-	8,095,280	20	87,947	315,415		403,361	7,691,919
47	1720	Towers and Fixtures	257,839,357	124,167,559	-	382,006,916	60	1,769,858	5,383,967		7,153,825	374,853,091
47	1725	Poles and Fixtures	1,738,229	5,873,407	-	7,611,636	45	12,876	110,043		122,919	7,488,717
47	1730	OH Cond and Devices	301,645,045	112,724,931	-	414,369,977	45	2,758,357	7,993,522		10,751,879	403,618,097
	1735	UG Conduit	-	-	-	-	-	-	-		-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-		-	-
	1745	Roads and Trails	-	-	-	-	-	-	-		-	-
		General Plant										
	1905	Land (General Plant)	-	-	-	-	-	-	-		-	-
10.1	1908	Buildings and Fixtures	-	5,000,000	-	5,000,000	50	-	16,667		16,667	4,983,333
8	1915	Office Furn & Equipment	-	151,420	-	151,420	10	-	2,000		2,000	149,420
	1920	Comp Hardware	-	-	-	-	-	-	-		-	-
10.1	1930	Transportation Equipment	220,000	50,000	-	270,000	5	22,000	53,167		75,167	194,833
	1935	Stores Equip	-	-	-	-	-	-	-		-	-
	1940	Tools, Shop & Garage Equip	-	-	-	-	-	-	-		-	-
	1945	Measurement & Testing Equipment	-	-	-	-	-		-		-	-
	1950	Power Operated Equipment	-	-	-	-	-		-		-	-
	1955	Communication Equipment	-	-	-	-	-		-		-	-
	1960	Misc. Equipment	-	-	-	-	-		-		-	-
	1980	System Supervisory Equipment	-	-	-	-	-		-		-	-
	1995	Contributions & Grants	-	-	-	-	-		-		-	-
	2440	Deferred Revenue	-	-	-	-	-		-		-	-
			-	-	-	-	-		-		-	-
		Sub-Total	**679,732,503**	**341,332,957**	**-**	**1,021,065,460**		**5,618,296**	**17,266,442**	**-**	**22,884,737**	**998,180,722**
	2055	**Add: Construction Work in Progress**	882,200,226	221,941,048	(341,332,957)	762,808,317					-	
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-	-	-	-					-	
		Total PP&E	1,561,932,729	563,274,005	(341,332,957)	1,783,873,777		5,618,296	17,266,442	-	22,884,737	998,180,722
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										
		Total Additions to Accumulated Depreciation							17,266,442			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation* (input as negative)

Transportation	
Stores Equipment	
Net Depreciation	**17,266,442**

Fixed Asset Continuity Schedule - Line to Pickle Lake

Accounting Standard ASPE
Year 2023

CCA Class	OEB	Description	Cost				Useful Life	Accumulated Depreciation				Net Book Value
			Opening Balance	Additions	Disposals	Closing Balance		Opening Balance	Additions	Disposals	Closing Balance	
		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)	35,534,358	-	-	35,534,358	50	355,344	710,687		1,066,031	34,468,327
47	1715A	Station Equipment (Switches and Breakers)	6,234,973	-	-	6,234,973	40	77,937	155,874		233,811	6,001,162
47	1715B	Station Equipment (Protection and Control)	1,476,085	-	-	1,476,085	20	36,902	73,804		110,706	1,365,379
47	1720	Towers and Fixtures	112,980,331	-	-	112,980,331	60	941,503	1,883,006		2,824,508	110,155,823
47	1725	Poles and Fixtures	-	-	-	-		-	-		-	-
47	1730	OH Cond and Devices	133,610,986	-	-	133,610,986	45	1,484,567	2,969,133		4,453,700	129,157,286
	1735	UG Conduit	-	-	-	-		-	-		-	-
	1740	UG Cond and Devices	-	-	-	-		-	-		-	-
	1745	Roads and Trails	-	-	-	-		-	-		-	-
		Sub-Total	**289,836,733**	**-**	**-**	**289,836,733**		**2,896,252**	**5,792,504**	**-**	**8,688,756**	**281,147,977**
	2055	**Add: Construction Work in Progress**	-	-	-	-					-	
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-	-	-	-					-	
		Total PP&E	289,836,733	-	-	289,836,733		2,896,252	5,792,504	-	8,688,756	281,147,977
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										
		Total Additions to Accumulated Depreciation							5,792,504			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation* (input as negative)

Transportation	
Stores Equipment	
Net Depreciation	**5,792,504**

Fixed Asset Continuity Schedule - Remote Connection Lines

Accounting Standard ASPE
Year 2023

CCA Class	OEB	Description	Cost				Useful Life	Accumulated Depreciation				Net Book Value
			Opening Balance	Additions	Disposals	Closing Balance		Opening Balance	Additions	Disposals	Closing Balance	
		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)	65,514,571	81,691,884	-	147,206,455	50	471,787	2,167,066		2,638,854	144,567,601
47	1715A	Station Equipment (Switches and Breakers)	6,648,460	7,435,985	-	14,084,446	40	62,191	266,367		328,557	13,755,888
47	1715B	Station Equipment (Protection and Control)	2,881,423	3,737,772	-	6,619,194	20	51,044	241,610		292,655	6,326,540
47	1720	Towers and Fixtures	144,859,026	124,167,559	-	269,026,585	60	828,355	3,500,961		4,329,316	264,697,269
47	1725	Poles and Fixtures	1,738,229	5,873,407	-	7,611,636	45	12,876	110,043		122,919	7,488,717
47	1730	OH Cond and Devices	168,034,060	112,724,931	-	280,758,991	45	1,273,790	5,024,389		6,298,180	274,460,811
	1735	UG Conduit	-	-	-	-		-	-		-	-
	1740	UG Cond and Devices	-	-	-	-		-	-		-	-
	1745	Roads and Trails	-	-	-	-		-	-		-	-
		Sub-Total	**389,675,770**	**335,631,537**	**-**	**725,307,307**		**2,700,044**	**11,310,437**	**-**	**14,010,481**	**711,296,826**
	2055	**Add: Construction Work in Progress**	-	-	-	-					-	
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-	-	-	-					-	
		Total PP&E	389,675,770	335,631,537	-	725,307,307		2,700,044	11,310,437	-	14,010,481	711,296,826
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets)										
		Total Additions to Accumulated Depreciation							11,310,437			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation* (input as negative)

Transportation	
Stores Equipment	
Net Depreciation	**11,310,437**

Exhibit C, Tab 4, Schedule 1

Allowance for Working Capital

ALLOWANCE FOR WORKING CAPITAL

WPLP does not have historical revenues on which to base an analysis of revenue lag, nor does it have negotiated settlement agreements with IESO or HORCI. WPLP has therefore not prepared a lead/lag study for 2023 and has not requested an allowance for working capital in its 2023 test year rate base. WPLP will consider filing a lead/lag study as part of its first multi-year revenue requirement application, for a period beginning with a 2026 test year, by which time 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 2.5.2 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.

In its decision and order in EB-2018-0190, the OEB found "that the Line to Pickle Lake is a network facility for which exceptional circumstances under section 6.3.5 of the TSC do not exist at this time."[1] As a result of this finding, section 6.3.5 of the TSC provides that WPLP will not require any customer to make a capital contribution toward the cost of the Line to Pickle Lake.

With respect to the Remote Connection Lines, the OEB approved WPLP's proposed cost recovery and rate framework, specifically "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."[2]

The OEB also approved WPLP's request for temporary exemptions from various TSC provisions related to cost recovery and cost responsibility, until such time as all facilities are placed in service or December 31, 2023.[3] Specifically, WPLP's transmission licence was amended to include exemptions from all sections of the TSC relating to customer capital contributions and cost responsibility in respect of connection facilities, subject to a number of conditions. These conditions include, among other things, a requirement for WPLP to file Customer Connection Procedures ("CCPs") with the OEB by December 31, 2022, and a requirement for WPLP to seek further direction from the OEB in the event that it receives one or more connection requests in advance of the OEB's approval of its CCPs.

[1] EB-2018-0190, Decision and Order dated April 1, 2019, p. 23.
[2] EB-2018-0190, Decision and Order dated April 1, 2019, pp. 27-28.
[3] EB-2018-0190, Decision and Order dated April 1, 2019, p. 23.

WPLP is in the process of preparing its CCPs and anticipates filing them through a standalone application to the OEB later this 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. 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.

- Overhead costs (including labour costs and related departmental costs) incurred during the development and construction period (i.e. to December 31, 2024) will be capitalized on a

declining basis, in consideration of the portion of WPLP's transmission system assets in service.[1]

B. Capitalization of Overhead and Burden Rates

Overhead costs (including labour costs and related departmental costs) incurred during the development and construction period (i.e. to December 31, 2024) will be capitalized on a declining basis, in consideration of the portion of WPLP's transmission system assets in service. As a result of this methodology, burden rates are not relevant to the determination of WPLP's 2023 revenue requirement.

[1] See Appendix 'A' of Exhibit B-1-5 for a description of these overhead costs and detail of the capitalization/allocation methodology.

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 addresses the OEB's scorecard expectations relative to WPLP's circumstances of constructing a new transmission system. Reliability expectations in the context of WPLP's transmission system are addressed in Tab 2 of this Exhibit.

A. WPLP's Circumstances

The initial segments of WPLP's transmission system will be placed into service in 2022, with additional segments being put into service at different points during the 2023 test year and remaining segments expected to go into service in 2024. After primarily focusing on construction activities during the 2020-2024 period, WPLP's Transmission System is expected to be in service in its entirety by the end of 2024. Since the portion of WPLP's Transmission System in service will vary significantly from month to month over this period, as additional segments are completed, the tracking of typical transmission scorecard measures would be impractical and provide little value in comparing WPLP to other transmitters. WPLP will begin tracking information for typical scorecard measures related to safety, reliability and costs during the construction period so that this information can be used in setting future performance expectations, with consideration for any adjustments required to reflect the transition from construction to operation. WPLP therefore intends to file an initial draft scorecard in 2025 when applying for a multi-year revenue requirement for the period beginning with the 2026 test year. That scorecard will propose measures that will be tracked starting in 2025, which will be the first full year that WPLP's entire transmission system is in service.

In the interim, until WPLP is in a position to file a draft scorecard, the OEB will have the benefit of other information on project status and performance. Specifically, as a condition of approval in EB-2018-0190, WPLP is required provide the OEB with semi-annual updates 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 has expanded the scope of its 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 provide the OEB with information relevant to WPLP's physical progress and cost performance in the construction of its transmission system.[1]

Furthermore, in accordance with the approved Settlement Agreement from EB-2021-0134, the parties agreed that WPLP would begin tracking 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 will be placed into service in 2022, WPLP will 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;

[1] The Semi-Annual Report dated April 15, 2022 in EB-2018-0190 contains the most recent update on physical progress and cost performance in the construction of its transmission system

- 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".

WPLP proposes to 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, in approximately April 2024 consistent with the timing of (but not pursuant to) the OEB's RRR reporting requirements.

The remainder of this schedule sets out how WPLP's activities to date and various aspect of the semi-annual reporting 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 will have a direct impact on the quality of distribution service that HORCI is able to provide to customers in the connecting communities. WPLP intends to coordinate with HORCI to ensure that its customer-focused performance metrics are presented in a way that complements any similar metrics reported by HORCI, and provides appropriate context related to the quality of service experienced by end-use customers in the connecting communities. WPLP and HORCI have already established formal operational and communications protocols in relation to WPLP's distribution line, which connects the HORCI distribution system that serves Pikangikum. WPLP expects to expand on these protocols based on experience with and feedback from HORCI as transmission assets are placed in service to serve additional communities and the line to Pikangikum is integrated into the Transmission System. Consideration of customer delivery point performance standards will be integrated with plans for backup power, as further discussed in Exhibit B-1-2. Progress on backup power plans for each community is a core requirement of

WPLP's semi-annual reports until such time as a solution is implemented for each community to be connected to WPLP's Transmission System.

2. RRF Outcome #2 – Operational Effectiveness

Since the vast majority of WPLP's 2020-2024 costs will be focused on the initial construction of its Transmission System, the initial scorecard that WPLP plans to file in 2025 in support of its multi-year 2026 revenue requirement application will be an appropriate starting point for implementing metrics related to the ongoing operation of and reinvestment in the system.

Further, as indicated in Exhibit B-1-1, WPLP expects to file an initial TSP in 2025 in support of its application for rates for 2026 and subsequent years. WPLP expects that the TSP will include a number of performance measures and targets related to operational effectiveness that will be consistent with the scorecard it would then propose.

Finally, worker health and safety, public safety and the protection of the natural environment ("Health, Safety and Environment" or "HSE") are of the utmost importance to WPLP. WPLP has established HSE policies and is in the process of developing and implementing comprehensive procedures and management systems that support those policies. WPLP will incorporate HSE-related metrics into its future scorecard.

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

[2] Including the design to allow the future connection of a 17th community, McDowell Lake First Nation.

businesses in the region.[3] The project is directly aligned with policy objectives of the provincial and federal governments, as further detailed in Exhibit B-3-1.

4. RRF Outcome #4 – Financial Performance

In addition to the CWIP reporting discussed above, WPLP will file all required financial information under the OEB's Electricity Reporting and Record Keeping Requirements.[4] Furthermore, the current application includes, and the single test year applications that WPLP intends to file for the 2024 and 2025 test years will include, information on WPLP's actual costs as compared to its cost forecasts and information sufficient to calculate a number of financial ratios (e.g. liquidity, leverage), and deemed vs. actual ROE. WPLP's future scorecard metrics will include similar financial ratios as reported by LDC's and other transmitters.

[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] Under its Transmission Licence, WPLP is exempt from Sections 3.1.1 through 3.1.4, inclusive, of the Electricity Reporting and Record Keeping Requirements. This exemption applies in respect of the 2019 to 2023 reporting periods. WPLP is required to commence reporting under Sections 3.1.1 through 3.1.4 of the Electricity Reporting and Record Keeping Requirements in 2025 in respect of the 2024 reporting period.

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 various specified measures. However, because WPLP's Transmission System is only starting to go into service in 2022, the requirements for providing historical reliability performance are generally not applicable. WPLP does have reliability performance information in respect of the distribution line serving Pikangikum, which is summarized below. However, as that line has only been in service for a relatively short period and is operating temporarily as a distribution line, the corresponding reliability performance data is of limited value.

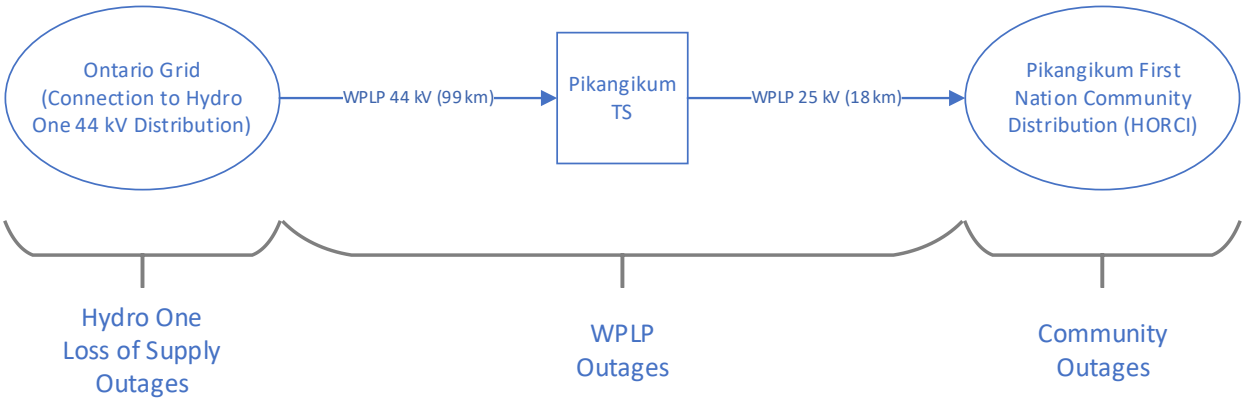
As noted in Exhibit D-1-1, the parties to the Settlement Agreement in EB-2021-0134 agreed that in respect of the Line to Pickle Lake and the portions of the Remote Connection Lines that will be placed into service in 2022, WPLP will monitor performance based on certain agreed-upon reliability metrics without establishing performance targets and that WPLP will report to the OEB on such performance in approximately April 2023, based on data as at year end 2022. As further noted in Exhibit D-1-1, WPLP proposes to continue monitoring its performance on the same basis and reporting to the OEB on such performance in approximately April 2024, based on data as at year end 2023.

A. Pikangikum System Reliability Performance

WPLP developed and implemented an innovative solution to address the critical need for grid connection of the Pikangikum First Nation on an accelerated schedule, while largely avoiding the duplication of electricity infrastructure, by constructing an approximately 117 km line to a transmission standard but operating it on an interim basis at a distribution voltage while connected to HONI's distribution system. WPLP plans to convert the line to operate at a transmission voltage at such time that it can be connected to HONI's transmission system and integrated into WPLP's Transmission System, which is forecasted to occur in Q2 2022. WPLP's distribution line to Pikangikum was completed and went into service on December 20, 2018. As such, approximately three years of reliability performance data for the line is available.

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 gird, via WPLP's Pikangikum Distribution System. 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 Pikangikum Distribution System



Performance of the Pikangikum system in 2019 and 2020 was described in WPLP's initial revenue requirement application (EB-2021-0134), as follows.

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 have since been 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.

With respect to 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 and resulted in annual system reliability performance (excluding loss of supply) of: (1) SAIFI of 2, (2) SAIDI of 0.345, and (3) overall availability of 99.996%.

Exhibit E, Tab 1, Schedule 1

Load and Revenue Forecasts

LOAD AND REVENUE FORECASTS

A. Operating Revenue

WPLP's forecasted 2023 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 2023 revenue requirement, as calculated and allocated in Exhibit I.

Table 1 – 2023 Revenue Requirement Forecast

	LTPL	RCL	Total
Revenue Requirement for Rates	34,739,785	58,191,280	92,931,065

WPLP's 2023 status-quo transmission revenue, based on applying 2022 approved rates to the 2023 load forecast presented in Section B below, is provided in Table 2. The differences in the amounts shown in Table 2 vs Table 1 represent WPLP's revenue deficiencies for the 2023 test year with respect to the Line to Pickle Lake and the Remote Connection Lines, and on an overall basis.

Table 2 – 2023 Status-Quo Revenue Forecast

	LTPL[1]	RCL	Total
Revenue Requirement for Rates	27,310,263	32,271,348	59,581,611

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

[1] WPLP's requested revenue requirement for the LTPL in 2022 (per EB-2021-0134) was $20,477,862 for the operating period April to December 2022. However, the amounts reflected in Table 2 are annualized and agree to the OEB-issued UTR update in EB-2022-0084.

through monthly fixed charges applicable to HORCI). WPLP's load forecast therefore needs to consider the incremental network charge determinants related to incremental load being served by its Line to Pickle Lake, but does not need to consider line connection or transformation connection charge determinants. The load supplied by WPLP's Line to Pickle Lake in 2023 will fall into two categories:

1. Some or all of the load currently supplied by HONI's transmission system in the Pickle Lake area, which will be supplied by WPLP's Line to Pickle Lake via a 115 kV interconnection between WPLP's Wataynikaneyap TS and HONI's new Pickle Lake SS; and,

2. Load on the existing distribution systems in the six First Nation communities that will be connected to the North of Pickle Lake Remote Connection Lines for all or part of 2023, which will be supplied directly by WPLP's Transmission System.

For the 2023 test year, the majority of the load supplied by WPLP's Transmission System will fall into the first category. Since these delivery points are all currently supplied by HONI, 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.

The incremental 2023 load supplied by WPLP's Line to Pickle Lake is therefore limited to the second category above, specifically the load associated with the six communities that are expected to be connected to WPLP's Pickle Lake Remote Connection Lines in 2022 or 2023. Load in the Pikangikum First Nation is already being supplied from Hydro One's transmission system in the Red Lake area (via the Hydro One distribution system and WPLP's distribution system), and would therefore already be captured in the historical data used to inform Hydro One's load forecasts. WPLP is therefore excluding this load from its load forecast.

In 2024, an additional four communities will be connected to WPLP's Pickle Lake Remote Connection Lines. Additionally, the load on the existing distribution systems in the five First Nation communities that are expected to be connected to the Red Lake Remote Connection Lines in 2024 will be able to be supplied by WPLP from Hydro One's transmission system in the Red Lake area as a direct result of sufficient capacity being made available on that portion of Hydro One's transmission system when WPLP's Line to Pickle Lake comes into service. Load forecasts for these nine communities will be addressed in WPLP's 2024 revenue requirement application.

In lieu of developing a load forecast based on weather-normalized historical data (which WPLP does not have at this point in time), WPLP took the following approaches to forecast charge determinants:

1. For North Caribou Lake First Nation and Kingfisher Lake First Nation (which are being connected in 2022) and for Bearskin Lake First Nation and Sachigo Lake First Nation (which are two of the communities being connected in 2023), WPLP had monthly load data available from HORCI for 2021. For these four communities, this data was used, normalized to remove anomalies such as cold starts, and escalated by 4% annually. For the other two communities (Muskrat Dam First Nation and Wawakapewin First Nation), WPLP used the peak load estimating process described in Approach 2, below.

2. WPLP used the monthly demand data from HORCI to forecast the monthly demand for the two communities, Muskrat Dam First Nation and Wawakapewin First Nation, currently not serviced by HORCI. Using annual peak demand forecast details from WPLP's SIA Application, which were informed by prior OPA and IESO data, WPLP first identified annual peak demand forecasts for these two communities. This data included a 4% annual growth rate, consistent with the expected level of growth identified in HORCI's 2018 backup power report.

   Within the historical demand data provided by HORCI, WPLP determined that Bearskin Lake First Nation and Kingfisher Lake First Nation were the two communities where annual peak demand was closest to Muskrat Dam First Nation and Wawakapewin First

Nation, respectively. WPLP then determined the ratio of monthly demand to annual peak demand for each of Bearskin Lake First Nation and Kingfisher Lake First Nation and multiplied the annual demand for Muskrat Dam First Nation and Wawakapewin First Nation by these ratios as a proxy for estimating the monthly demand for each month in 2023 that the load is expected to be in-service. The resulting demand forecast is provided in Table 3, and the total 2023 forecasted charge determinants of 34.8 MW 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 for the grid-connected communities. For the 2023 test year, WPLP notes that the change in the 2023 Network UTR charge determinants resulting from the above method is approximately 0.008%.

Table 3 – WPLP Peak Demand (MW) for UTR Charge Determinants

Community	2023 Annual Peak Forecast (MW)	Forecast Demand by Month (MW)												
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Pikangikum First Nation[2]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
North Caribou First Nation	1.3	1.2	1.3	1.1	1.1	1.0	0.8	0.9	0.8	0.9	1.0	1.2	1.2	12.5
Kingfisher Lake First Nation	0.8	0.7	0.8	0.8	0.6	0.6	0.5	0.5	0.5	0.5	0.6	0.7	0.8	7.6
Muskrat Dam First Nation	0.9	0.0	0.0	0.0	0.0	0.6	0.5	0.5	0.5	0.5	0.6	0.7	0.8	4.5
Bearskin Lake First Nation	0.9	0.0	0.0	0.0	0.0	0.6	0.5	0.5	0.5	0.5	0.6	0.7	0.8	4.7
Wawakapewin First Nation	0.2	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.9
Sachigo Lake First Nation	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	0.6	0.6	0.8	0.9	1.0	4.5
Total	5.2	1.9	2.1	1.9	1.7	2.8	2.4	3.1	3.1	3.0	3.7	4.3	4.8	34.8

[2] As noted above, Pikangikum First Nation load is already connected to Hydro One's distribution system and would therefore be captured in historical data used to inform Hydro One's load forecasts.

Exhibit E, Tab 2, Schedule 1

Accuracy of Load Forecast and Variance Analysis

ACCURACY OF LOAD FORECAST AND VARIANCE ANALYSIS

As WPLP does not have any assets in service as of the filing of this application for the 2023 test year, the historical load comparisons and related variance analysis called for in Section 2.7.2 of the Filing Requirements are not applicable. WPLP's 2023 test year load forecast and explanation of the methodology used to arrive at that forecast are provided in Exhibit E-1-1.

Exhibit E, Tab 3, Schedule 1

Other Revenue

OTHER REVENUE

WPLP is not forecasting any Other Revenues for the 2023 test year, and expects that its 2023 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 2023 test year include operations, maintenance and administration (OM&A); depreciation and amortization; and income taxes. A summary of WPLP's operating costs for the 2023 test year is presented in Table 1 below.

Table 1 – Summary of Operating Costs

Operating Cost Category	2023 Test Year ($000's)
OM&A Expenses	21,869
Depreciation and Amortization	17,266
Income Taxes	398
Total Operating Costs	**39,534**

WPLP confirms that no charitable or political donations are included in its 2023 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 also provides forecasted costs for the 2023 test year, forecasted costs for the 2022 bridge year and associated variance analysis. Given that this is the second revenue requirement application filed by WPLP, it does not yet have information relating to historical actuals. As such, the OEB's Filing Requirements with respect to providing historical year information and variance analysis are not applicable in WPLP's circumstances.

Pursuant to the Settlement Agreement in EB-2021-0134, WPLP agreed to prepare and file benchmarking studies in its 2023 transmission rate application 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; and
ii. WPLP's compensation costs relative to Hydro One compensation costs.

With respect to the benchmarking on OM&A spending, WPLP retained Clearspring Energy Advisors, LLC ("Clearspring") to design and perform a benchmarking study to compare WPLP's OM&A spending levels on a per line kilometer basis and on a per station basis against comparable Ontario and Canadian transmitters (the "Clearspring Study"). At the time of filing this application, WPLP is in the process of selecting third-party service providers to undertake certain Operating and Maintenance activities and to provide SCADA support services. While WPLP's OM&A forecast has been reasonably forecast based on the best information available at the time of filing, the outcomes of these processes have the potential to impact part of WPLP's forecast OM&A costs.[1] As such, WPLP has requested that Clearspring delay completion of the Clearspring Study so that the final analysis can reflect the impacts of the above-noted procurement processes. WPLP anticipates that it will be in a position to file the Clearspring Study and any corresponding updates to the pre-filed evidence relating to OM&A benchmarking prior to the OEB's issuance of its first Procedural Order.[2]

With respect to the compensation benchmarking, WPLP issued an RFP to several compensation benchmarking experts. However, due to concerns about conflicts, each of those experts declined to participate. Underlying these concerns is that the Settlement Agreement in EB-2021-0134 contemplates that the benchmarking be performed specifically in relation to Hydro One's compensation costs. After consulting with OEB staff, WPLP instead engaged Korn Ferry, a firm which has previously advised WPLP on compensation matters, to undertake a benchmarking study to assess WPLP's compensation levels and costs relative to its peers in the utility sector.

Korn Ferry benchmarked WPLP's base salary and total cash compensation levels, as well as WPLP's total compensation costs on a base salary and total cash basis, against those of a peer group comprised of 46 companies in the utilities industry, primarily from Ontario. Korn Ferry's analysis indicates that WPLP's compensation levels and compensation costs are aligned with

[1] A segment representing approximately 20-25% of the OM&A forecast may require an update depending on the outcomes of these processes relative to WPLP's forecast for that segment.

[2] WPLP has previously communicated this intention to OEB staff, who concurred with the approach as it would avoid impacting the hearing schedule.

market median. More particularly, in terms of total base salary costs, WPLP is approximately 2.7% lower than the market median and, in terms of total cash compensation costs, WPLP is approximately 1.7% higher than market median. In dollars, relative to market median, this means that WPLP's total base salary compensation costs for all employees are approximately $40K lower than the peer group, and that WPLP's total cash compensation costs for all employees are approximately $60K higher than the peer group. Compensation levels are also aligned with market median, with overall compensation levels for WPLP being 95% and 98% of market median on a base salary and total cash basis, respectively. The Korn Ferry report is discussed in greater detail in Exhibit F-3-1 and a copy of Korn Ferry's report, setting out the methodology and results of the study, is provided in Exhibit F-3-1, Appendix 'A'.

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

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 2023 test year. The 2023 test year is the second year in which WPLP has transmission assets coming into service and, therefore, it is the second year in which WPLP is seeking to recover OM&A expenses through its transmission revenue requirement. Accordingly, WPLP has no historical rate years and provides variance analysis only in respect of the changes in OM&A expenses from the 2022 bridge year to the 2023 test year.

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, 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. 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

Category	2022 Bridge Year ($000's)	2023 Test Year	Variance
Operations	1,401	5,491	4,090
Maintenance	1,908	3,533	1,625
Administration & General	6,133	12,846	6,713
Total OM&A	**9,441**	**21,869**	**12,428**

The increase in total OM&A from the 2022 bridge year to the 2023 test year is driven by: (1) the 2022 in-service assets being in service for 12 months, (2) the addition of the 2023 in-service assets, and (3) a larger allocation of overhead costs to operations vs capital given that more assets will be in-service in 2023.[1] Other than the increase in in-service assets, there are no material variances in specific costs.

C. OM&A Cost Drivers

1. Summary of Cost Drivers

Table 2 below presents the cost drivers for each component of WPLP's 2023 OM&A expenses along with the associated variances.

Table 2 – 2023 OM&A Cost Drivers

	Category of Expense	2022 OM&A	2023 OM&A Cost Driver ($000's)				Variance
			Operations	Maintenance	Administration	Total	
Direct Operating	Direct O&M Labour	0	159	159	0	**317**	**317**
	Controlling Authority (3rd Party)	306	780	0	0	**780**	**474**
	Substation and Line Routine Maintenance	532	3,549	0	0	**3,549**	**3,017**
	Emergency Response	1,558	206	2,774	0	**2,980**	**1,422**
	Forestry	10	0	506	0	**506**	**496**
	Other (Material, Fleet, Insurance)	596	429	94	463	**987**	**391**
	Sub-Total	*3,002*	*5,122*	*3,533*	*463*	***9,118***	***6,116***

[1] The allocation of Overhead costs between capital and operations is outlined in Appendix 'A' of Exhibit B-1-5.

Overhead Costs Allocated to OM&A	Labour and Departmental Costs	3,218	369	0	6,063	**6,432**	**3,214**
	Environmental Services	146	0	0	251	**251**	**105**
	Other Consultants	358	0	0	631	**631**	**273**
	Indigenous Engagement & Communications	1,300	0	0	2,313	**2,313**	**1,013**
	Stakeholder Engagement	29	0	0	54	**54**	**25**
	Indigenous Participation and Training	921	0	0	2,178	**2,178**	**1,257**
	Administrative Costs	467	0	0	892	**892**	**425**
	Sub-Total	*6,439*	*369*	*0*	*12,382*	***12,751***	***6,312***
Total		**9,441**	**5,491**	**3,533**	**12,846**	**21,869**	**12,428**

At the time of filing this application, WPLP is in the process of selecting third-party service providers to undertake certain Operating and Maintenance activities and to provide SCADA support services. While WPLP's OM&A forecast has been reasonably forecast based on the best information available at the time of filing, as noted in Exhibit F-1-1 the outcomes of these processes have the potential to impact part of WPLP's forecast OM&A costs. As further noted in Exhibit F-1-1, WPLP plans to update the pre-filed evidence relating to OM&A prior to the OEB's issuance of its first Procedural Order. WPLP's update will include the OM&A benchmarking report, along with updates to Table 2 and any cost drivers at that time.

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 2022 bridge year to the 2023 test year.

(a) Direct Operating Costs

WPLP's interim operating and maintenance strategy for the 2022-2024 period, during which time assets are being placed in service in stages but the overall project is still being constructed, is detailed in Section C of Exhibit B-1-4. Overall, Direct Operating costs are forecast to increase based on (i) the assets that will go into service for part of 2022 will be in service for the entirety of 2023, and (ii) an additional 4 substations and approximately 350 km of transmission lines will be put into service in 2023. Based on its interim operating and maintenance strategy, and using a

bottom-up forecasting approach, WPLP has forecast direct operating costs for the 2023 Test Year as follows:

- Approximately $0.78 million related to third-party control room operation, which is based on a unit cost estimate for a third-party to provide control room services for an average WPLP substation, multiplied by the forecasted number of substations in service in each quarter. As noted in Exhibit A-3-1, WPLP intends to update its schedule and cost forecasts at an appropriate stage in this proceeding to reflect the outcome of selecting third-party service providers to undertake certain O&M and SCADA support services.

- Approximately $3 million for outage and emergency response, plus $3.5 million related to routine line and substation inspection and maintenance activities and $0.5 million for forestry costs, for assets forecasted to be in service at times throughout 2023. These costs are based on WPLP's interim per km and per substation costs for operating and maintaining its Pikangikum distribution system since 2019, adjusted to reflect the total kilometres of line and total number of substations in service in each quarter, and adjusted for increased access/travel costs for locations that are generally more remote than the Pikangikum system. As further discussed in Exhibit B-1-4, WPLP is currently in the process of selecting one or more service providers that can offer the required resources and expertise, with demonstrated commitments to Indigenous Participation and health and safety to provide the inspection, maintenance, and emergency response ("IMER") services needed for the Transmission Project. The IMER services that WPLP seeks to procure include planned inspections of transmission line and substation assets, substation equipment testing and maintenance, and response to power outages and other emergencies. WPLP has also reached an agreement in principle with Hydro One Networks Inc. to provide control room services for an interim period until such time that WPLP develops its own control room.

- Approximately $1 million for other costs that include fleet and insurance costs for operations staff (gas, insurance premiums, general maintenance and repairs) as well as a

provision for materials issued from inventory during the performance of outage and emergency response.

Given that WPLP is in the process of entering into third party service agreements, as noted above and as further discussed in Exhibit B-1-4, for certain inspection, maintenance and emergency response activities, as well as SCADA and control room services, WPLP expects to update its OM&A cost forecasts along with cost driver explanations and file an update to this evidence prior to the OEB's issuance of its first Procedural Order, as further discussed in Exhibit F-1-1..

(b) Overhead Cost Allocated to OM&A

As set out in Table 2, above, WPLP's overhead costs include costs such as internal labour and departmental costs,[2] services provided by environmental 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.

As the construction phase of WPLP's Transmission Project progresses and assets come into service during the 2022-2024 period, a progressively larger portion of these overhead costs transitions from being directly attributable to capital development and construction activity to being attributable to the ongoing operation and maintenance of in-service assets. Accordingly, WPLP developed a methodology to allocate these costs between capital and OM&A, which is described in detail in Appendix 'A' of Exhibit B-1-5. Applying the allocation methodology to WPLP's 2023 forecasted overhead costs results in the following 2023 forecast for OM&A costs:

- Approximately $6 million for labour costs[3], including related overheads, for WPLP's internal staff, whose focus will shift from construction of the Transmission Project to ongoing operations and maintenance of the transmission system as more assets come into service.

[2] 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).

[3] Further detail on labour costs provided in Exhibit F-3-1.

- Approximately $0.3 million for environmental and other consultants that provide services and expertise in a wide variety of areas (e.g. environmental services, legal/regulatory, finance/audit, engineering, etc.).

- Approximately $2.4 million for Indigenous engagement and communications and stakeholder engagement, and $2.2 million for Indigenous participation and training. These activities relate to WPLP's comprehensive Indigenous Engagement Program and Indigenous Communications Management Plan (which are summarized in Exhibit B-1-2), meaningful economic participation by Indigenous businesses in all aspects of the Transmission Project, consultations with stakeholders (such as municipalities and potentially affected landowners), and overall project communications activities. As assets come into service, continued efforts in these areas will ensure that WPLP's transmission system is operated in a manner that respects the Guiding Principles, Treaty, Aboriginal and Inherent rights of the Anishinabe and Anishinninuwug, and that considers input from other stakeholders.

- Approximately $0.9 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.

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 2023 Test Year, which reflects the categorization suggested 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	2023 Test Year ($000's)
Employee compensation	3,480
Shared services and corporate cost allocation	3,028
Purchase of non-affiliate services	15,362
One-time costs	0
OEB costs	0
Charitable and political donations	0
Total	**21,869**

The total OM&A expense in Table 1 above is equal to and reflects the same amounts as are included in the total 2023 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 B-1-4, 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 successful completion of WPLP's Transmission Project and 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 and regulatory costs for amortization over a multi-year period is provided in Sections D and 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

[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, 2023 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, construction oversight, project management, 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.

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 Korn Ferry 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.[2]

Salary increases for all WPPM employees are based on market information provided by Korn Ferry. 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.

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.

[2] As noted above, this discussion applies to WPPM and this discussion of WPPM Executive compensation excludes the CEO of WPLP.

(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, capital project completion, customer service, quality of construction, safety and environment and regulatory compliance, and are expected to shift as WPLP's focus transitions from construction to ongoing operation. 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 benefit ratepayers. In particular, the cost control measure sets targets for reducing operating costs. The capital project measure sets targets for meeting budgeted capital project costs and completing construction of the project with respect to scope and schedule. 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, capital project completion, 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, capital project completion 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. WPPM has since grown to 28 employees including a number of non-management positions which has balanced the management to non-management ratio to 11:17. The company is projected to grow to 34 (13:21) employees by the end of 2022 and to 39 by the end of 2023. The largest driver of FTE growth is related to Operations Management and Engineering positions, which are required to ensure effective implementation and oversight of WPLP's Interim O&M Strategy as discussed in Exhibit B-1-4.[3]

WPPM's FTEs now include an increased number of operational positions, which utilize the Korn Ferry methodology to determine appropriate rates for compensation. Given the nature of the organization and the focus on the construction of the transmission line, some positions had to be uniquely designed to meet the qualifications of the candidates. 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 as a result 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, 2023 is provided in Table 2, below.

[3] As described in Exhibit B-1-4, additional positions in 2022 include Forestry Manager, P&C Engineer, Junior Engineer, Technologist, IT Analyst and Indigenous Relations advisor. Additional positions in 2023 include, Substation Manager, Transmission Line Manager, Regulatory Accountant, Administrative positions and Co-ops.

Table 2: Employee Compensation Breakdown

	2020 Actual	2021 Actual	2022 Forecast	2023 Forecast
Number of Employees (FTEs including Part-Time)				
Management (including executive)	8	12	13	15
Non-Management (all non-union)	9	14	21	24
Total	**17**	**26**	**34**	**39**
Total Salary and Wages including overtime and incentive pay				
Management (including executive)	$1,992,257	$2,335,708	$2,708,337	$3,584,199
Non-Management (all non-union)	$687,504	$912,428	$1,872,778	$2,207,174
Total	**$2,679,761**	**$3,248,136**	**$4,581,115**	**$5,791,373**
Total Benefits (Current + Accrued)				
Management (including executive)	$223,906	$317,038	$311,561	$346,003
Non-Management (all non-union)	$68,633	$127,338	$176,024	$169,867
Total	**$292,539**	**$444,376**	**$487,585**	**$515,870**
Total Compensation (Salary, Wages, & Benefits)				
Management (including executive)	$2,216,163	$2,652,746	$3,019,898	$3,930,202
Non-Management (all non-union)	$756,136	$1,039,766	$2,048,802	$2,377,041
Total	**$2,972,300**	**$3,692,512**	**$5,068,700**	**$6,307,243**
Total Allocated to Capital	$2,876,746	$3,549,118	$3,937,818	$2,857,515
Total Allocated to Distribution Deferral Account (Pikangikum)	$95,554	$143,394	$24,260	-
Total Allocated to OM&A	-	-	$1,106,622	$3,479,727

6. Variance Analysis

Employee compensation costs are increasing primarily due to actual and forecasted WPPM employee hiring to support WPLP's transition from constructing the Transmission Project to long-term operation of its transmission system.[4] A description of WPLP's approach to the organization and execution of the construction period, and the transition to ongoing operation and maintenance,

[4] See footnote 3.

is provided in Exhibit B-1-4. Some salaries appear higher than industry norm as they are short-term construction contracts that require specific skills set for the duration of the construction period. In order to attract and retain these employees, WPPM has 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 assets come into service in 2022 and 2023. WPLP's methodology supporting the declining labour capitalization rate is provided in Appendix 'A' of Exhibit B-1-5.

7. Compensation Benchmarking

As discussed in Exhibit F-1-1, WPLP issued an RFP to several compensation benchmarking experts. However, due to concerns about conflicts, each of those experts declined to participate. Underlying these concerns is that the Settlement Agreement in EB-2021-0134 contemplates that the benchmarking be performed specifically in relation to Hydro One's compensation costs. After consulting with OEB staff, WPLP instead engaged Korn Ferry, a firm which has previously advised WPLP on compensation matters, to undertake a benchmarking study and perform related analysis to assess WPLP's compensation costs relative to its peers in the utility sector.

Korn Ferry gained an understanding of WPLP's organizational structure, reporting relationships, job descriptions and roles, and performed analysis using its well-established job evaluation methodology, which enabled positions to be mapped to particular job levels to facilitate benchmarking on a like to like basis with the comparator companies in the utilities peer group. Korn Ferry utilized its proprietary compensation database to benchmark WPLP's compensation levels and compensation costs against those of 46 comparator utilities comprising the peer group. In summary, Korn Ferry determined that:

i. In terms of its total base salary costs, WPLP is approximately 2.7% lower than the market median and, in terms of its total cash compensation costs, WPLP's is approximately 1.7% higher than market median. In dollars, this means that WPLP's total base salary

compensation costs for all employees are approximately $40K lower than market median, and that WPLP's total cash compensation costs for all employees are approximately $60K higher than market median.

ii. In terms of employee compensation levels, the ratios of base salary and total cash compensation for WPLP employees, on an overall basis, relative to market median base salary and total cash compensation for the utilities sector, are 0.95 and 0.98, respectively. These comparative ratio values, being close to and marginally lower than 1, indicate near (slightly lower than) market median compensation levels for WPLP employees.

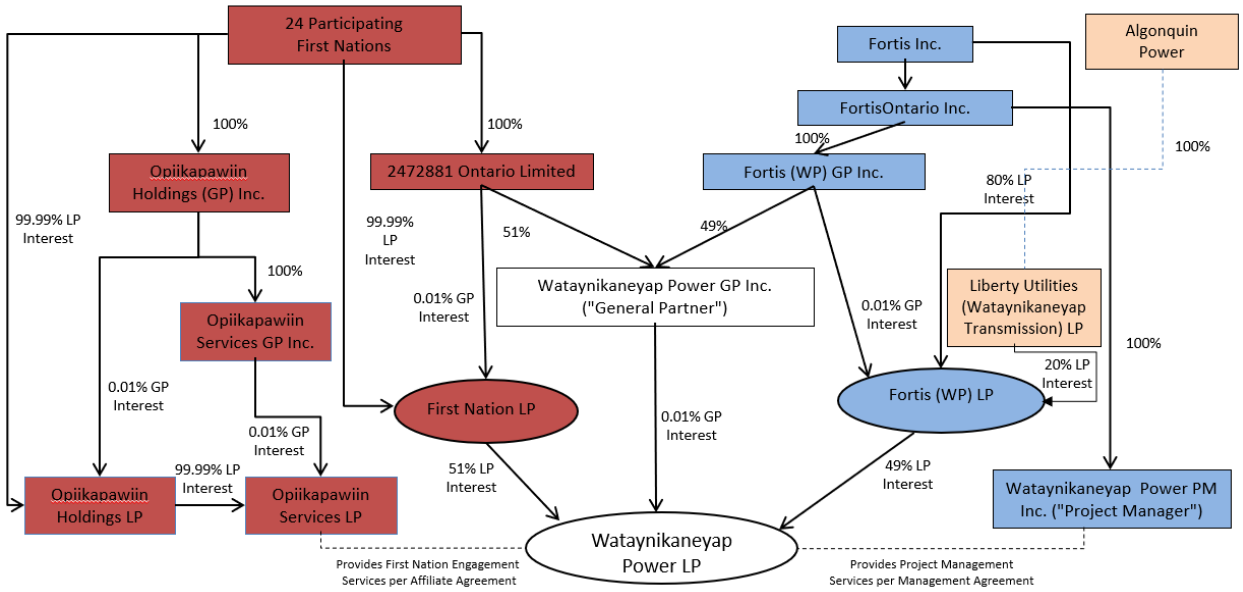
iii. Considering employee compensation levels in a different way, average base salary and total cash compensation levels for WPLP employees are slightly higher than market median for Senior Manager and above positions, and slightly lower than market median for all other positions.

A copy of the Korn Ferry compensation benchmarking report is provided in Exhibit F-3-1, Appendix 'A'.

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 manages the construction of the Transmission Project and will manage the operation of its transmission system, primarily through services received by 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:

- **Affiliate Contract (OSLP):** Opiikapawiin Services LP ("OSLP"), a service company indirectly owned by the 24 Participating First Nations, is responsible for 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 B-1-4.

- **Management Agreement (WPPM):** Wataynikaneyap Power PM Inc. ("WPPM"), a wholly-owned subsidiary of FortisOntario Inc., is responsible for providing project management, 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.

- **Services Contract (FortisOntario):** FortisOntario Inc. provides similar but distinct complementary services as provided by WPPM under the Management Agreement, 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;

- 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; and

- Subsidiaries of Renewable Energy Systems Canada Inc. ("RES Canada"), which previously had a material interest in WPLP (via Fortis-RES LP) and whose subsidiaries provided services to WPLP via Fortis-RES PM Inc.[5]

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

Name of Company		**Service Offered**	**Cost for the Service ($)**			
From	**To**		**2020**	**2021**	**2022**	**2023**
			Actual	**Actual**	**Forecast**	**Forecast**
Fortis Subsidiaries	WPLP	Multiple per Services Contract	1,860,578	1,705,252	2,108,144	2,148,799
OSLP and FNLP	WPLP	Multiple per Affiliate Contract	2,682,315	2,822,838	3,161,715	3,395,292
RES Subsidiaries	WPLP	Multiple per Services Contract	-	-	-	-
Total:			**4,542,893**	**4,528,090**	**5,269,859**	**5,544,091**

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 coming into service in 2022 and 2023.

[5] See EB-2017-0009 for details of WPLP's corporate structure prior to the OEB granting leave to acquire Fortis-RES GP Inc.

Table 4 – Allocation of Affiliate and Related Party Costs

Cost Category	Annual Cost Allocation ($)			
	2020	2021	2022	2023
	Actual	Actual	Forecast	Forecast
Capital	4,423,161	4,434,098	4,069,228	2,516,023
Distribution Deferral Acct (Pikangikum)	119,731	93,992	27,467	-
OM&A	-	-	1,173,164	3,028,068
Total	**4,542,893**	**4,528,090**	**5,269,859**	**5,544,091**

WPLP's methodology for allocating overhead costs, including the affiliate and related party costs presented above, is detailed in Appendix 'A' of Exhibit B-1-5. Support for the resulting capital, deferral account and OM&A costs is provided in the following Exhibits:

- Capital cost forecasts and variance analysis is provided in Exhibit B-1-5.
- Deferral Account costs are described in Exhibit H-2-1.
- OM&A costs, by cost driver, are described in Exhibit F-2-1.

C. Purchase of Non-Affiliate Services

This section describes WPLP's 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. Supporting local opportunities and capacity to provide services will provide long-term benefits to WPLP, and the customers in the First Nation 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 'B' to this schedule.

As described in Section B above, WPPM provides services to WPLP under a Management Agreement, which include project and construction management, 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 'C' 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 non-EPC[6] 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

Cost Category	2020 Actual	2021 Actual	2022 Forecast	2023 Forecast
Aboriginal Engagement, Indigenous Participation, Communication	2,625,177	2,393,026	5,174,432	5,538,757
Admin, Office, Fleet and Support	420,263	378,735	449,409	994,349

[6] The costs presented in this Schedule exclude the following capital costs from Exhibit B-1-5: (a) EPC contract costs (see Exhibit B-1-2 for details of competitive tendering and selection process); (b) "EPC Excluded" capital costs (which relate to the EPC contracting effort, but are excluded from the EPC contractor's responsibility); (c) "Other Infrastructure" costs (most of which are forecasted for 2023); and (d) contingency allowance.

O&M Service Providers	275,363	805,437	3,037,716	8,277,588
Overheads and Easement/Access Fees	1,020,513	920,430	4,591,364	4,405,253
Consulting, Professional and Advisory	11,461,485	13,347,675	15,977,051	12,691,126
Total	**15,802,801**	**17,845,302**	**29,229,972**	**31,907,074**

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 coming into service in 2022 and 2023.

Table 6 – Allocation of Third-Party Costs

Cost Category	2020 Actual	2021 Actual	2022 Forecast	2023 Forecast
Capital	15,318,440	16,899,726	23,335,937	16,545,460
Distribution Deferral Acct (Pikangikum)	484,360	945,576	144,303	-
OM&A	-	-	5,749,732	15,361,614
Total	**15,802,801**	**17,845,302**	**29,229,972**	**31,907,074**

WPLP's methodology for allocating overhead costs, including the affiliate and related party costs presented above, is detailed in Appendix 'A' of Exhibit B-1-5. Support for the resulting capital, deferral account and OM&A costs is provided in the following Exhibits:

- Capital cost forecasts and variance analysis is provided in Exhibit B-1-5.
- Deferral Account costs are described in Exhibit H-2-1.
- 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 2023 and anticipates filing two additional single-year cost of service revenue requirement applications for each of the 2024 and 2025 test years, as

noted in Exhibit A-2-1. 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, as well as the single-year cost of service revenue requirement application that WPLP anticipates filing for the 2024 test year, are part of its total forecasted Transmission Project costs to December 31, 2023, which are described in Exhibit B-1-5. Consistent with the treatment of one-time costs discussed above, there is no need in the current application to amortize those regulatory costs over any incentive rate setting period.

WPLP has not included costs for OEB assessments in the current application, since the allocation of OEB costs between electricity transmitters is based on a 3-year average of transmission revenue, and WPLP therefore anticipates that its allocation would be $0 for the 2023 test year.

F. Charitable and Political Donations

WPLP confirms that no charitable or political donations have been included in the calculation of its revenue requirement.

APPENDIX 'A'

Korn Ferry Report for Wataynikaneyap Power LP

2022 Compensation Review



KORN FERRY®

Korn Ferry Report for Wataynikaneyap Power LP

2022 Compensation Review

April, 2022

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Section 1: Introduction and Methodology

Overarching Summary of Findings

Korn Ferry's benchmarking analysis determined that the overall compensation level and related cash compensation costs at Wataynikaneyap Power LP Inc. (Watay Power) are aligned with the median of the Utilities sector. Detailed market benchmarking calculations, results and observations have been provided in Section 2 of this report.

Project Context

Watay Power made its inaugural rate application with the Ontario Energy Board (OEB) in 2021. Pursuant to the OEB's decision in that proceeding, Watay Power is committed to filing a benchmarking study or similar information concerning its compensation costs as part of its next rate application, which is to be filed in 2022.

To this effect, Watay Power engaged Korn Ferry (KF) with conducting a thorough market compensation analysis for the various roles/ levels at the organization. Korn Ferry has completed previous assignments with Watay Power and has a general understanding of the operations, organization structure, functions/ job families, and talent strategy and considerations. Based on the understanding of the scope and requirements, Korn Ferry has conducted an objective compensation benchmarking exercise and the results have been provided in this report.

Market of Comparison

In view of Watay Power's operations and talent context, the Utilities sector was considered to be the most appropriate market of comparison. Please refer to the Appendix for the detailed list of organizations that form the market of comparison.

Methodology and Project Steps

The various steps involved in conducting the compensation benchmarking analyses were as follows:

- Korn Ferry team collected Watay Power's relevant organizational information such as organization charts, job descriptions and compensation data
- Meetings were conducted with Watay Power's HR team to further clarify the organization structure, reporting relationships, scope and nature of the various roles. The meetings were also used to close any follow up queries around job content as well as compensation data provided
- Based on the job descriptions and role understanding, the jobs were evaluated using the KF Hay job evaluation methodology (snapshot of the methodology is provided in the Appendix). The evaluations were reviewed within the Korn Ferry team to ensure quality and accuracy
- Discussions were held with Watay Power's HR team to review the evaluation scores. Based on the completion of job evaluations, all Watay Power positions in scope were mapped to a KF Hay job level. This was a critical prerequisite for compensation benchmarking to ensure a like to like comparative analysis with the market
- Compensation benchmarking analysis was then conducted with the Utilities sector organizations. The market percentiles were statistically analyzed to ensure data accuracy and validity

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Data Sources and Compensation Notes

For the purpose of compensation benchmarking, Korn Ferry utilized it's proprietary compensation database KF Pay that has compensation data for organizations across industry sectors in Canada.

Each compensation data point in the database is mapped to a KF Hay level. With Watay Power's jobs evaluated and mapped to the same KF Hay level framework, an accurate and like to like compensation benchmarking was ensured. The compensation analysis focused on Base Salary and Total Cash (base salary + short-term incentive) also referred to as Total Salary and Wages including overtime and incentive pay.

The following table depicts the details of Watay Power's employee inclusions/ exclusions from a benchmarking analysis standpoint:

Parameter	Details/ Count	Comments/ Notes
Number of roles/ positions included	24	NA
Total headcount included	25	Administrative Assistant was the only multi-incumbent role
Headcount excluded	6	Vacant roles (P&C Engineer; Junior Electrical Engineer; Electrical Engineering Technologist; IT Systems Administrator; Forestry Manager; Manager, Project Relations)
	3	1 Administrative Assistant and 1 Executive Assistant owing to being in temporary/ outside of 'home' roles. 1 part-time contract First Nations Senior Advisor

Additional notes on compensation data:

- The market data is effective as of 2021 which was aged to reflect 2022 levels. The aging factor used was 2.2%, which is the average planned base salary increase for 2022. This was based on Korn Ferry's annual compensation planning survey conducted in August, 2021
- For certain positions, the actual payouts under the Short-term Incentive (STI) plan will begin in 2023 (for Financial Year 2022). For benchmarking purposes, the target payout was used
- For 1 Part-Time employee in scope, compensation has been extrapolated to reflect full-time equivalence for accurate benchmarking with the market

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Section 2: Compensation Analyses Results

Comparative Ratio Analysis

Comparative Ratio or Compa ratio is the most often utilized industry-wide metric to determine the competitiveness of pay in an organization. It reflects the ratio of the salary in an organization to the median (P50 or 50th percentile) of the market of comparison (in this case, the Utilities sector). Compa ratio close to 1 indicates compensation levels near the market median. Compa ratio significantly greater or lesser than 1 indicates compensation levels higher and lower than the market median, respectively.

Based on the compensation benchmarking analysis, the table below reflects the average compa ratio for the various levels/ positions at Watay Power:

Watay Levels/ Titles*	KF Hay Levels	Typical Profile	Watay Headcount	Avg. Compa Ratio (Base Salary)	Avg. Compa Ratio (Total Cash)
Senior Manager and above	19 to 23	Senior Managers/ Manager of Managers/ Executives	6	1.05	1.11
Manager/ Senior Engineer/ Engineer/ Lead	16 to 18	Experienced Professionals/ Subject Matter Experts/ Managers	10	0.94	0.95
Advisor/ Accountant/ Coordinator	13 to 15	Entry Level Professionals/ Individual Contributors/ Senior Staff	6	0.90	0.90
Administrative Assistant/ Clerk	9 to 12	Operational Staff	3	0.91	0.93

**As majority of the roles at Watay Power are single employee roles, relevant levels have been grouped to protect individual data confidentiality. Average compa ratio has been shown owing to the same reason.*

While the above table depicts the break-down of compa ratio by levels, **the employee-wise average compa ratio for Watay Power on Base Salary and Total Cash was seen to be 0.95 and 0.98, respectively**.

The compa ratio values being extremely close to 1 (albeit marginally lower) indicate near market median compensation levels for Watay Power overall on both Base Salary and Total Cash.

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Watay Power vs. Utilities Sector Compensation Differential

Based on the compensation benchmarking analysis, the table below reflects the average base salary and total cash compensation for both Watay and the market of comparison. This has been depicted for the various levels/ positions at Watay Power. The last 2 columns in the table show the catch-up/ differential for Watay vis-à-vis the market:

Watay Levels/ Titles*	Avg. Base* Salary (Watay)	Avg. Base Salary (Market)	Avg. Total Cash* (Watay)	Avg. Total Cash (Market)	Catch-up (Base Salary)**	Catch-up (Total Cash)**
Senior Manager and above						
Manager/ Senior Engineer/ Engineer/ Lead						
Advisor/ Accountant/ Coordinator						
Administrative Assistant/ Clerk						

**As majority of the roles at Watay Power are single employee roles, relevant levels and data has been grouped to protect individual data confidentiality. Average salary has been shown owing to the same reason.*
***Catch-up is calculated as (Watay – Market)/ Market. A (-) catch-up indicates that Watay's compensation levels are higher than market average. A (+) catch-up indicates that Watay's compensation levels are lower than the market average.*

For Senior Manager and above, Watay's average compensation seen to be higher than the Utilities market. For all other levels, Watay's average compensation seen to lag the market average – on both base salary and total cash compensation.

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Compensation Cost Analysis

While compa ratio helps in determining the competitiveness of pay in an organization vis-à-vis the market of comparison, it does not provide an indication of the trend on compensation cost. An organization with a < 1 average compa ratio overall may still have a higher than market median compensation cost depending on the distribution and deviation of compa ratio across levels/ roles.

The following table helps ascertain the trend on compensation cost for Watay Power vis-à-vis the market of comparison:

Watay Levels/ Titles*	Base Salary Cost (Watay)	Median Base Salary Cost (Market)**	Total Cash Cost (Watay)	Median Total Cash Cost (Market)**
Senior Manager and above	[redacted]			
Manager/ Senior Engineer/ Engineer/ Lead				
Advisor/ Accountant/ Coordinator				
Administrative Assistant/ Clerk				
Total				

**As majority of the roles at Watay Power are single employee roles, relevant levels have been grouped to protect individual data confidentiality.*

***Reflects the compensation cost if all employees at Watay were to be paid at the median (50th percentile) of the market of comparison.*

In terms of base salary cost, Watay Power is seen to be approximately 2.7% behind the market median. On a total cash compensation basis, the spend seen to exceed the market median by 1.7%.

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Section 3: Appendix

List of Comparator Organizations

Data from the following list of organizations was used for benchmarking purposes:



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KF Hay Job Evaluation Methodology Snapshot

THE KORN FERRY HAY GUIDE CHART-PROFILE METHOD[SM]

The Korn Ferry Hay job evaluation method is a form of factor comparison that has been used by thousands of organizations to evaluate clerical, trade and technical, management and professional, and executive level jobs. At present, it is used in profit and non-profit organizations in over forty countries around the world. A substantial number of clients have relied on our approach for many years, applying the methodology through many reorganizations; during periods of growth and also when they must rationalize their structures. They have also used it to evaluate totally new product and service organizations and as a means to maintain consistency in periods of great change or legal challenge to the previously established order.

The Korn Ferry Hay method works because it is a dynamic process that organizations adapt and apply in ways that meet their needs. It is based on the notion that jobs can be measured on the basis of their relative contribution to the overall objectives of the organization. By considering core aspects of content and context that are common to all jobs, it provides a clear, understandable and systematic basis for defining and comparing the requirements for all kinds of jobs at all levels. However, the Korn Ferry Hay method can readily be adapted to reflect special determinants that affect only some jobs in some organizations.

It is this combination of discipline and flexibility that has made it possible for the fundamental principles of the Korn Ferry Hay method to remain intact over the years, even as there have been many refinements in language and application. For example: in Canada core factors of Know-How, Problem Solving and Accountability have been expanded to include, once again, a fourth factor – Working Conditions – in response to equal pay legislation. The following explanation covers all four factors and their twelve dimensions.

The Four Factors Used by Korn Ferry

Know-How

This factor is used to measure the total of every kind of ***knowledge and skill, however acquired***, needed for acceptable job performance. Three dimensions are considered:

- practical procedures and knowledge, specialized techniques, and learned skills;
- planning, coordinating, directing or controlling the activities and resources associated with an organizational unit or function; and
- active, practising, person-to-person skills in the area of human relationships.

Problem Solving

This factor measures the ***thinking required*** in the job by considering two dimensions:

- the environment in which the thinking takes place; and
- the challenge presented by the thinking to be done.

Accountability

This factor measures the relative degree to which the job when performed competently, can affect the end results of the organization or a unit within the organization. The opportunity to contribute to an organization is reflected through three dimensions:

- the nature and degree of the decision-making or influence of the job;
- the unit or function most clearly affected by the job; and
- the nature of that effect.

Working Conditions

This factor measures ***the context*** in which the job is performed by considering four dimensions:

- ***Physical Effort –*** Levels of physical activity that vary in intensity, duration and frequency that contribute to physical stress and fatigue.
- ***Physical Environment*** – Progressive degrees of exposure of varying intensities to unavoidable physical and environmental factors which increase the risk of accident, ill health or discomfort.
- ***Sensory Attention*** – Levels of sensory attention (e.g., seeing, hearing, smelling, tasting, touching) during the work process that vary in intensity, frequency and duration.
- ***Mental Stress*** – Progressive degrees of exposure of varying intensities of factors inherent in the work process which increase the risk of such things as tension or anxiety.

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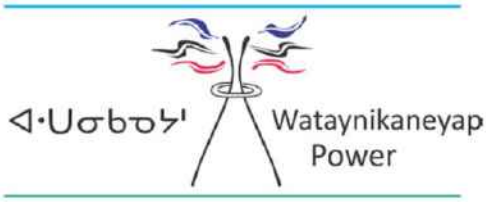
About Korn Ferry

Korn Ferry is a global organizational consulting firm. We help clients synchronize strategy and talent to drive superior performance. We work with organizations to design their structures, roles, and responsibilities. We help them hire the right people to bring their strategy to life. And we advise them on how to reward, develop, and motivate their people.



APPENDIX ‘B’

WPPM Procurement Policy



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."*

APPENDIX ‘C’

WPPM Procurement Policy

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]

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.

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 use vendor proposed 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. At the procurement manager's discretion, 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.

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.

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]

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
Senior Engineer	K. Kilfoil
Sr. Manager Health Safety & Environment	N. Hammond
Manager Project Environmental Assessments	N. Sooley
Manager Project Control	J. Fretz-Joseph
Manager Communications	M. Kita
Manager Project Relations & Project Engineer	
Manager Construction	M. Applin

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. 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
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%
1915 – Office Furniture	10	10.00%
1920 – Computer Hardware	5	20.00%
1930 - Transportation Equipment[1]	5-10	10.00-20.00%
1611 – Computer Software	5	20.00%

WPLP's 2023 depreciation expense is summarized in Table 2, with detailed calculations provided in **Appendix 'A'** of this Schedule. WPLP's proposed depreciation expense for the 2023 test year is based on a forecast of net fixed assets, calculated using (a) the average of the forecast opening and closing balances for net fixed assets in respect of those portions of the transmission system that are expected to be in service by the end of 2022, and (b) the 12-month average of forecast monthly in-service additions in respect of those portions of the transmission system that are expected to go into service during the 2023 test year. This approach is consistent with WPLP's approach to calculate rate base, as detailed in Exhibit C-3-1.

[1] All in-service fleet is based on 5-year useful life (20% depreciation rate).

Table 2 – 2023 Depreciation Expense (Costs in $000's)

OEB Account and Description	Line to Pickle Lake (UTR Network Rate)	Remote Connection Lines (HORCI Rate)	Total
1715 - Station Equipment (Station and Transformers)	711	2,167	2,878
1715A - Station Equipment (Switches and Breakers)	156	266	422
1715B - Station Equipment (Protection and Control)	74	242	315
1720 - Towers and Fixtures	1,883	3,501	5,384
1725 - Poles and Fixtures	0	110	110
1730 - OH Conductor and Devices	2,969	5,024	7,994
Sub-Total Transmission System Plant	**5,793**	**11,310**	**17,103**
1908 - Buildings and Fixtures	6	11	17
1915 - Office Furniture and Equipment	1	1	2
1930 - Transportation Equipment	18	36	53
1611 - Computer Software	30	61	92
Total	**5,847**	**11,420**	**17,266**

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.[2], 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,[3] 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.

[2] EB-2010-0178, Asset Depreciation Study for the Ontario Energy Board, July 8, 2010.

[3] 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.

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[4] includes assets such as ground wires (which for WPLP include 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.[5]

[4] OEB Accounting Procedures Handbook; Issued December 2011; p.56

[5] 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[6]	FNEI Useful Life Range[7]	GLPT Useful Life Range[8]	Kinectrics	
OEB Account and Description	**Useful Life (Yrs)**	**Depreciation Rate**				**Category/Component**	**Useful Life Range**
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[9]	
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
1915 - Office Furniture and Equipment	10	10.00%	N/A	4-10	10	Office Equipment	5-15
1930 - Transportation Equipment	5-10	10.00-20.00%	N/A	5-7	5	Vehicles (Various)	5-20
1611 – Computer Software	5	20.00%	N/A	4	5-15	Computer Software	2-5

[6] EB-2014-0204, Exhibit 4, Tab 10, Schedule 2, p.1.

[7] EB-2016-0231, IRR 6-Staff-30(e).

[8] EB-2014-0238, Exhibit 4, Tab 3, Schedule 1, p.2.

[9] The Kinectrics Depreciation Study did not include lattice steel structures.

APPENDIX ‘A’

Depreciation Expense Detail

Calculation of Depreciation Expense - All Assets

Accounting Standard ASPE
Year 2023

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 = Avg Monthly Opening	*F*	*G = 1/F*	*H = E * G*
	1606	Organization	-	-	-	-	-	-	-	-
	1610	Miscellaneous Intangible Plant	-	-	-	-	-	-	-	-
	1611	Computer Software	-	-	-	500,000	458,333	5	20.00%	91,667
	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)	-	-	-	-	-	-	-	-
	1708	Buildings and Fixtures (Transmission Plant)	-	-	-	-	-	-	-	-
	1710	Leasehold Improvements	-	-	-	-	-	-	-	-
47	1715	Station Equipment (Station and Transformers)	101,048,929	-	101,048,929	81,691,884	143,887,669	50	2.00%	2,877,753
47	1715A	Station Equipment (Switches and Breakers)	12,883,434	-	12,883,434	7,435,985	16,889,645	40	2.50%	422,241
47	1715B	Station Equipment (Protection and Control)	4,357,508	-	4,357,508	3,737,772	6,308,294	20	5.00%	315,415
47	1720	Towers and Fixtures	257,839,357	-	257,839,357	124,167,559	323,037,999	60	1.67%	5,383,967
47	1725	Poles and Fixtures	1,738,229	-	1,738,229	5,873,407	4,951,951	45	2.22%	110,043
47	1730	OH Cond and Devices	301,645,045	-	301,645,045	112,724,931	359,708,509	45	2.22%	7,993,522
	1735	UG Conduit	-	-	-	-	-	-	-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-	-
	1745	Roads and Trails	-	-	-	-	-	-	-	-
		General Plant	*A*	*B*	*C = A - B*	*D*	E = Avg Monthly Opening	*F*	*G = 1/F*	*H = E * G*
	1905	Land (General Plant)	-	-	-	-	-	-	-	-
10.1	1908	Buildings and Fixtures	-	-	-	5,000,000	833,333	50	2.00%	16,667
8	1915	Office Furn & Equipment	-	-	-	151,420	20,000	10	10.00%	2,000
	1920	Comp Hardware	-	-	-	-	-	-	-	-
10.1	1930	Transportation Equipment	220,000	-	220,000	50,000	265,833.33	5	20.00%	53,167
	1935	Stores Equip	-	-	-	-	-	-	-	-
	1940	Tools, Shop & Garage Equip	-	-	-	-	-	-	-	-
	1945	Measurement & Testing Equipment	-	-	-	-	-	-	-	-
	1950	Power Operated Equipment	-	-	-	-	-	-	-	-
	1955	Communication Equipment	-	-	-	-	-	-	-	-
	1960	Misc. Equipment	-	-	-	-	-	-	-	-
	1980	System Supervisory Equipment	-	-	-	-	-	-	-	-
	1995	Contributions & Grants	-	-	-	-	-	-	-	-
	2440	Deferred Revenue	-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-
		Total	**679,732,503**	**-**	**679,732,503**	**341,332,957**	**856,361,567**			**17,266,442**

Calculation of Depreciation Expense - Line to Pickle Lake

Accounting Standard ASPE
Year 2023

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)	35,534,358	-	35,534,358	-	35,534,358	50	2.00%	710,687
47	1715A	Station Equipment (Switches and Breakers)	6,234,973	-	6,234,973	-	6,234,973	40	2.50%	155,874
47	1715B	Station Equipment (Protection and Control)	1,476,085	-	1,476,085	-	1,476,085	20	5.00%	73,804
47	1720	Towers and Fixtures	112,980,331	-	112,980,331	-	112,980,331	60	1.67%	1,883,006
47	1725	Poles and Fixtures	-	-	-	-	-	-	-	-
47	1730	OH Cond and Devices	133,610,986	-	133,610,986	-	133,610,986	45	2.22%	2,969,133
	1735	UG Conduit	-	-	-	-	-	-	-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-	-
	1745	Roads and Trails	-	-	-	-	-	-	-	-
		Total	**289,836,733**	**-**	**289,836,733**	**-**	**289,836,733**			**5,792,504**

Calculation of Depreciation Expense - Remote Connection Lines

Accounting Standard ASPE
Year 2023

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 = Avg Monthly Opening	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)	65,514,571	-	65,514,571	81,691,884	108,353,311	50	2.00%	2,167,066
47	1715A	Station Equipment (Switches and Breakers)	6,648,460	-	6,648,460	7,435,985	10,654,672	40	2.50%	266,367
47	1715B	Station Equipment (Protection and Control)	2,881,423	-	2,881,423	3,737,772	4,832,209	20	5.00%	241,610
47	1720	Towers and Fixtures	144,859,026	-	144,859,026	124,167,559	210,057,668	60	1.67%	3,500,961
47	1725	Poles and Fixtures	1,738,229	-	1,738,229	5,873,407	4,951,951	45	2.22%	110,043
47	1730	OH Cond and Devices	168,034,060	-	168,034,060	112,724,931	226,097,523	45	2.22%	5,024,389
	1735	UG Conduit	-	-	-	-	-	-	-	-
	1740	UG Cond and Devices	-	-	-	-	-	-	-	-
	1745	Roads and Trails	-	-	-	-	-	-	-	-
		Total	**389,675,770**	**-**	**389,675,770**	**335,631,537**	**564,947,334**			**11,310,437**

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 2023 test year. It also provides context with respect to the tax implications of WPLP's corporate structure with respect to various legislation.

Attachment 1 to this Schedule contains detailed calculations of WPLP's income tax expenses for the 2023 test year, which have also been filed in Excel format. A copy of WPLP's most recent tax return is included as an attachment to Exhibit A-7-1.

WPLP has calculated a total income tax expense of $398,095 for the 2023 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 whose forecasted allowable capital cost allowance ("CCA") deduction exceeds its forecasted taxable income for 2023.

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 2023 income tax expense. However, as detailed in Attachment 1, WPLP's forecasted allowable CCA deduction of approximately $113 million and forecasted deductible financing fees of approximately $3M significantly exceed its regulatory net income (before tax) of approximately $30 million, resulting in zero taxable income and a loss carryforward.

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 Attachment 1, with WPLP's 2023 forecasted OCMT payable summarized in Table 1 below.

Table 1 – WPLP's 2023 Ontario Corporate Minimum Tax ($000's)

Item	Description	Allocation / Rate	Amount
A	WPLP Regulatory Net Income (before Tax and adjustments)		30,090
B	% of LP Interests Held by Taxable Entities	49%	
C = A x B	Regulatory Net Income subject to Taxation		14,744
D	Ontario Minimum Corporate Tax Rate	2.7%	
E = C x D	***Ontario Minimum Corporate Tax***		***398***
F	Ontario Corporate Income Tax Payable		0
G = E-F	**Ontario Corporate Minimum Tax Payable**		**398**

As detailed in Attachment 1, 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 Attachment 1. WPLP confirms that the depreciation amount included in Attachment 1 is equal to the depreciation expense included in its 2023 test year revenue requirement, as calculated in Exhibit F-10-1.

WPLP's CCA calculation for the 2023 test year is provided in Attachment 2 to this Schedule, and includes the effect of Accelerated CCA.

F. Taxable Income and Income Tax Expense

WPLP's confirms that its forecasted 2023 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 Attachment 1. For each partner (i.e. First Nation LP and Fortis (WP) LP), Attachment 1 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 Attachment 1.

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 Attachment 1 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's has included an immaterial property tax expense (less than $1,000) in its 2023 test year OM&A cost forecasts in relation to WPLP's land interests for the Wataynikaneyap TS.

ATTACHMENT 1

WPLP 2023 Income Tax Calculation

WPLP
Calculation of Utility Income Taxes
2023 Test Year
($000's)

SUMMARY OF TAX EXPENSE

	2023
First Nation LP	0
Fortis (WP) LP	398
Total	**398**

WPLP

Line No.	Particulars		2023	
	Determination of Taxable Income			
1	Regulatory Net Income (before tax)		30,090	(1)
2	Book to Tax Adjustments:			
3	Depreciation and amortization		17,266	
4	Capital Cost Allowance		-113,205	
5	Other		-3,121	
6	Total Adjustments	$	-99,059	
7	Regulatory Taxable Income/(Loss) before Loss Carry Forward	$	-68,969	
	Allocation of Taxable Income			
8	First Nation LP (51%)		-35,174	
9	Fortis (WP) LP (49%)		-33,795	
10	Total	$	-68,969	
	Tax Rates			
11	Federal Tax		15.00	%
12	Provincial Tax		11.50	%
13	Total Tax Rate		26.5	%

(1) The regulated income of $29,692,214 provided in G-2-1 Table 1 has been grossed up for tax purposes.

WPLP
Calculation of Utility Income Taxes
2023 Test Year
($000's)

First Nation LP

Line No.	Particulars		2023	
	Determination of Taxable Income			
1	Allocation of Taxable Income from WPLP		-35,174	
4	Tax Rate		0.00	%
5	**Income Tax Expense**	**$**	**0**	
	Determination of Corporate Minimum Tax			
	Allocation of Accounting Income from WPLP		15,346	
	Corporate Minimum Tax Rate		0.00	%
	Corporate Minimum Tax Payable (Utilized)	**$**	**0**	
	Total Taxes Expense for First Nation LP	**$**	**0**	

WPLP
Calculation of Utility Income Taxes
2023 Test Year
($000's)

Fortis (WP) LP

Line No.	Particulars		2023	
	Determination of Taxable Income			
1	Allocation of Taxable Income from WPLP		-33,795	
2	Loss Carryforward		33,795	
3	Taxable Income after Loss Carryforward		0	
4	Tax Rate		26.50	%
5	**Income Tax Expense**	**$**	**0**	
	Loss Continuity Schedule			
6	Opening Losses Carryforward		-37,388	
7	Losses (Incurred)/Utilized during the year		-33,795	
8	Closing Losses Carryforward		-71,183	
	Determination of Corporate Minimum Tax			
9	Allocation of Accounting Income from WPLP		14,744	
10	Corporate Minimum Tax Rate		2.70	%
11	Corporate Minimum Tax Potentially Applicable		398	
12	Ontario Income Tax		0	
13	**Corporate Minimum Tax Payable (Utilized)**	**$**	**398**	
14	Opening CMT Credit Carryforward		143	
15	CMT Credit Incurred/(Utilized)		398	
16	Closing CMT Credit Carryforward		541	
17	**Total Taxes Expense for Fortis (WP) LP**	**$**	**398**	

ATTACHMENT 2

WPLP 2023 CCA Calculation

WPLP
Calculationn of Utility Income Taxes
2023 Test Year
($000's)

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Accelerated CCA Initiative	Closing UCC
1	-	5,000	5,000	(2,500)	2,500	0.04	100	200	4,700
8	-	151	151	(76)	76	0.20	15	30	106
10.1	121	50	171	(25)	146	0.30	44	33	94
12	-	500	500	(250)	250	1.00	250	500	(250)
47	597,971	335,632	933,603	(167,816)	765,787	0.08	61,263	50,769	821,570
UCC	598,092	341,333	939,425	(170,666)	768,758		61,672	51,533	826,220
						TOTAL CCA	**113,205**		

Exhibit G, Tab 1, Schedule 1

Capital Structure

CAPITAL STRUCTURE

WPLP proposes a deemed capital structure for rate-making purposes of 4% short-term debt, 56% long-term debt, and 40% common equity. WPLP's partners (First Nation LP and Fortis (WP) LP) are expected to make significant equity contributions beginning in June 2022 in consideration of assets coming into service and the overall financing and funding framework for the project. [1]

WPLP's proposed capital structure is consistent with the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities*, dated December 11, 2009 (the "Cost of Capital Report"). Table 1 illustrates the application of this capital structure to WPLP's 2023 rate base.

Table 1 – Capital Structure

	Capitalization Ratio	
	(%)	**($)**
Long-term Debt	56%	$480,012,692
Short-term Debt	4%	$34,286,621
Total Debt	*60%*	*$514,299,313*
Common Equity	*40%*	*$342,866,208*
Total	**100%**	**$857,165,521**

Cost of capital parameters are discussed in Exhibit G-2-1.

[1] Through the Federal Funding Framework, WPLP has agreed to contribute equity based on the forecasted total cost of the project, subject to restrictions that could limit WPLP's maximum equity contribution. Such limits do not limit WPLP's ability to contribute 40% of rate base during the 2023 Test Year. To the extent that WPLP's equity contribution is limited to less than 40% of rate base in a future year, this will be addressed in WPLP's revenue requirement application for the relevant Test Year.

Exhibit G, Tab 2, Schedule 1

Cost of Capital

COST OF CAPITAL

A. Overview

This schedule supports the cost rate applied to each component of WPLP's 2023 cost of capital. WPLP's total cost of capital for the 2023 test year is summarized in Table 1 below.

Table 1 – Capital Structure and Cost of Capital

	Capitalization Ratio		Cost Rate	Return
	(%)	**($)**	**(%)**	**($)**
Long-term Debt	56%	$480,012,692	1.51%	$7,232,632
Short-term Debt	4%	$34,286,621	1.17%	$401,153
Total Debt	60%	$514,299,313	1.48%	$7,633,785
Common Equity	40%	$342,866,208	8.66%	$29,692,214
Total	**100%**	**$857,165,521**	**4.35%**	**$37,325,999**

B. Cost of Equity

WPLP's proposed revenue requirement reflects its use of the OEB's rate of return on equity ("ROE") of 8.66% for 2022 rate applications, as established by the OEB's Cost of Capital Parameter update letter of October 28, 2021, as a placeholder. WPLP will update this rate at a later stage of the proceeding to reflect the OEB's ROE for 2023 applications once the OEB publishes its cost of capital parameters for 2023.

C. Cost of Short-Term Debt

WPLP has used the OEB's deemed short-term debt rate of 1.17% for 2022 rate applications, as established by the OEB's Cost of Capital Parameter update letter of October 28, 2021, as a placeholder. WPLP will update this rate at a later stage of the proceeding to reflect the OEB's deemed short-term debt rate for 2023 applications once the OEB publishes its cost of capital parameters for 2023.

D. Cost of Long-Term Debt

As this is WPLP's second transmission revenue requirement application and it continues to be focused on constructing the Transmission System while transitioning 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. However, it has secured financing that would cover a combination of 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 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. Therefore, 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.

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[1], 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") 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.

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 *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, dated December 11, 2009 (EB-2009-0084), and its subsequent *Review of the Existing Methodology of the Cost of Capital for Ontario's Regulated Utilities*, dated January 14, 2016. Debt issuance costs are amortized over the term of the Ontario Facility and the Senior Bank Facility. The total of 2023 amortization of debt issuance costs and forecasted administrative fees described above are included in the determination of total 2023 interest and fees. The effective 2023 cost of debt rate for each debt facility is then calculated by dividing the forecasted 2023 total interest and fees by the forecasted 2023 12-month average principal balance. Based on this methodology, WPLP's long-term debt rate is calculated to be 1.51% for 2023, as illustrated in Table 2.

[1] 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 2023 Test Year.

Table 2 – Debt Facilities and Cost of Long-Term Debt

Description	Lender	2023 Principal ($) (12-month Average)[2]	2023 Interest & Fees ($)	Rate (%)[3]
Ontario Facility	Province of Ontario	876,215,903	6,823,378	0.78%
Senior Bank Facility	Senior Bank Lenders	442,859,664	13,051,904	2.95%
Total		**1,319,075,567**	**19,875,283**	**1.51%**

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 actual construction progress and associated payment requirements related to WPLP's EPC contract; and (b) the actual Ontario T-Bill and CDOR rates in 2023, 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 to record the difference between its forecasted and actual costs of debt during the construction phase of the project, as further detailed in Exhibit H-1-1.

[2] Principal balance reflects repayment of debt expected when assets go in-service in accordance with WPLP's CTIA.

[3] 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.

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 during the 2023 test year. WPLP is not seeking to establish any new accounts in this application. 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 to the treatment of incremental COVID-related amounts incurred in the construction of the Transmission Project.

A. Existing Accounts and their Continuation

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 are related to the in-servicing of portions of WPLP's transmission system over time.

1. CWIP Account 2055 (Transmission Development Costs)

On March 23, 2017, the OEB in its Decision and Order in EB-2016-0262 approved WPLP's request to establish a deferral account to capture and record development costs associated with the Transmission Project up to the effective date of the initial transmission rate order for WPLP. Specifically, the OEB authorized the account with an effective date of November 23, 2010 (recognizing the critical role of prior development activities for the project) and required WPLP to establish three sub-accounts (1508.001 through 1508.003), as follows:

- Sub-account 1508.001 was established for WPLP to record its actual development costs incurred for the Wataynikaneyap Transmission Project from November 23, 2010, excluding any start-up and formation costs and costs for electricity distribution-related activities. As set out in the relevant accounting order, development costs include 13 categories of costs, including for engineering, design and procurement, permitting, environmental assessments, Aboriginal engagement and communication, project management and regulatory activities.

- Sub-account 1508.002 was established for WPLP to record "all funding amounts received for development activities" related to the Wataynikaneyap Transmission Project from November 23, 2010. In a post-decision letter dated May 12, 2017, OEB staff clarified the scope of this sub-account and its purpose, which was "intended to facilitate informed decision-making by the OEB when considering disposition of the account". In WPLP's initial transmission revenue requirement proceeding (EB-2021-0134), the parties to the OEB-approved Settlement Agreement agreed, and the OEB in approving the Settlement Agreement confirmed, that this subaccount should be discontinued and that the amounts tracked in the subaccount should not be applied as offsets to any development or construction costs.

- Sub-account 1508.003 was established for WPLP to record "carrying charges on net development costs". Given the discontinuation of Sub-account 1508.002, this sub-account continues to be used to record carrying charges but without netting off any amounts.

Balances recorded in the Transmission Development Costs Deferral Account, including each of the three sub-accounts, were reported to the OEB semi-annually, from July 2017 until July 2019, pursuant to the OEB's requirements in EB-2016-0262.

In the LTC proceeding (EB-2018-0190), WPLP requested that the OEB approve an accounting order establishing a Construction Work in Progress (CWIP) Deferral Account into which WPLP would transfer costs from its Transmission Development Costs Deferral Account and record capital costs incurred from the date of the OEB's LTC Decision until such time as the OEB approves the inclusion of those amounts in WPLP's rate base. Instead of approving the proposed account, the OEB directed WPLP to use CWIP Account 2055, which is a standard account in the OEB's Uniform System of Accounts, to record construction costs for future disposition. The OEB also approved WPLP's request to transfer the balance of the Transmission Development Costs Deferral Account to CWIP Account 2055. As such, WPLP continued to separately track capital costs, funding received and carrying charges within CWIP Account 2055. Following the decision in EB-2021-0134, WPLP has stopped tracking the funding amounts received but has continued to

track capital costs and carrying charges in CWIP Account 2055. Moreover, pursuant to the LTC Decision and consistent with the initial rates Decision from EB-2021-0134, WPLP has continued to provide semi-annual reports to the OEB in relation to its CWIP account since October 15, 2019, thereby continuing the reporting previously carried out pursuant to EB-2016-0262.

As identified in Exhibit C-2-1, WPLP is allocating all of its indirect capital costs (including development costs) to fixed asset accounts as assets come into service, in proportion to the direct capital costs associated with each asset. As the in-servicing of certain segments of the Transmission System will continue into 2024, CWIP Account 2055 remains relevant. As such, WPLP proposes to continue to use this account in 2023.

2. 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),[1] and that the account 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 is being operated at a distribution voltage.

[1] Currently Indigenous Services Canada (ISC)

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, and is currently being 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. In June, 2022, the system is expected to be converted to transmission, commence being supplied by the Hydro One Networks Inc.'s (HONI) 115 kV transmission system, and thereafter will form part of WPLP's Transmission System. WPLP proposes to continue using this account until the Pikangikum Distribution System has been converted to transmission and the final balance has been disposed of in a future transmission revenue requirement application to the OEB. As WPLP expects to incur costs in respect of the Pikangikum Distribution System during 2022, up to the date it is converted to transmission, the final balance is not expected to be disposed of until WPLP's 2024 transmission rate application. As such, WPLP proposes to continue to use this account in 2023.

3. 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. There are separate sub-accounts to record principle 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 the Transmission Project is still under construction, and transmission assets will be coming into service throughout the 2023 test year, WPLP proposes to continue using the ISDVA to record differences between its approved revenue requirement based on the forecasted in-service dates in 2023 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.

For clarity, when calculating its revenue requirement based on the actual in-service dates for each asset for purposes of determining the amounts to record in this account for 2023, WPLP plans to use the same cost of capital rates as those which are ultimately approved in this Application, and would record any difference between its approved revenue requirement and its recalculated revenue requirement in the ISDVA.

4. 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[2] 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 relies on 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,[3] it is expected based on the current project schedule that Interest Cost Differentials will continue to be recorded up to and during the 2025 rate year, with WPLP's 2026 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. There are separate sub-accounts to record principle and interest amounts related to the Line to Pickle Lake and the Remote Connections Lines.

[2] Prior to the in-service date, interest will be calculated on WPLP's CWIP account balance, in accordance with the OEB's Decision and Order in EB-2018-0190 and will be recorded as a carrying cost within the CWIP account.

[3] The process of transitioning to long-term financing is expected to take approximately 6-9 months once all project components are in-service.

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 2023, as the Transmission Project is still under construction and interest rate differences may continue to arise.

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 principle 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). WPLP has continued to record COVID costs in the account for 2021 and 2022, the proposed disposition of which is discussed in Exhibit H-2-1.[4]

[4] Consistent with the OEB Decision and Order in EB-2021-0134 and WPLP's consultation with its auditor, all COVID-19 costs are recorded in the deferral account.

The continuance of the CCCDA is in the best interests of Ontario ratepayers, as demonstrated by the analysis presented by WPLP in Exhibit H-2-2. The expensing, rather than capitalizing, of COVID costs will result in additional funds remaining in the trust to offset the total RRRP funding that the IESO would otherwise be required to collect from Ontario ratepayers.

Given that COVID-19 and construction of the Transmission Project are both expected to continue into 2023, WPLP proposes to continue using the CCCDA to record all construction costs that are directly attributable to the COVID-19 pandemic during the 2023 test year and for the duration of the construction period, if necessary. WPLP's proposed treatment of the amounts recorded in the CCCDA, from January 1, 2021 onward, is described in Exhibit H-2-2.

6. 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 is 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 principle and interest amounts related to the Line to Pickle Lake and the Remote Connections Lines. As the actual amount of contingency realized in 2022 is not yet available, and WPLP has additional forecasted contingency amounts associated with its planned 2023 in-service asset additions used to calculate year-end rate base, WPLP proposes to continue this account in 2023. WPLP proposes to continue to use the DCDA to track the revenue requirement impacts associated with the Deferred Contingency Amount, which WPLP will seek to recover, to the extent the forecasted contingency is actually realized, limited to the

revenue requirement impact attributable to contingency costs for 2022 and 2023 to a maximum of $66,840,377.

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, 2021. Continuity schedules for WPLP's existing regulatory accounts from their inception up to and including their audited balances as at December 31, 2021 have been filed in Excel format with the application as "H-1-1_WPLP Deferral and CWIP Continuity 2023.xlsx".

Table 1: Existing Regulatory Account Balances (December 31, 2021)

Account	Principal	Carrying Charges (Net)	Total
2055 – CWIP: Transmission Development Costs	$889,734,204	$25,519,892	$915,254,096
1508 – Pikangikum Distribution System Deferral Account	$3,194,911	$49,017	$3,243,928
1508 – In-Service Date Variance Account	-	-	-
1508 – Construction Period Interest Costs Variance Account	-	-	-
1508 – COVID Construction Costs Deferral Account	$59,331,651	$164,984	$59,496,635
1508 – Deferred Contingency Deferral Account	-	-	-

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[5] to the monthly opening principal balances in each account. In accordance with the LTC Decision,[6] WPLP applied its effective borrowing cost to determine carrying charges for CWIP Account 2055, since its cost of debt has been lower than the OEB's published CWIP interest rates.

[5] See: https://www.oeb.ca/industry/rules-codes-and-requirements/prescribed-interest-rates

[6] EB-2018-0190, Decision and Order, April 1, 2019 (Revised April 29, 2019), p. 28

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 six existing regulatory accounts, which are described in Exhibit H-1-1 and are as follows:

- CWIP Account 2055 (Transmission Development Costs);
- Pikangikum Distribution System Deferral Account;
- In-Service Date Variance Account ("ISDVA");
- Construction Period Interest Costs Variance Account ("CPICVA");
- COVID Construction Costs Deferral Account ("CCCDA"); and
- Deferred Contingency Deferral Account ("DCDA").

Of WPLP's six existing deferral accounts, WPLP is only seeking partial disposition of three of the deferral accounts in the 2023 test year. Table 1, below, provides a summary of the proposed amounts for disposition for the Pikangikum Distribution System Deferral Account and the CCCDA. WPLP is seeking to dispose of the incremental costs incurred in 2021 that form part of the Audited 2021 balances in the 2023 test year. The third account for which disposition is sought, CWIP Account 2055, is disposed of through rate base (as further described in Section A below) and is therefore not listed in the summary table below.

Table 1 – Deferral Account Disposition Continuity

	Audited 2020 Balance[1]	2021 Incremental Costs	Audited 2021 Balance[2]	Disposition to LTPL[3]	Disposition to RCL[3]
Pikangikum Distribution System Deferral Account	$2,046,966	$1,196,963	$3,243,928	-	$1,196,963
COVID Construction Costs Deferral Account	$17,399,652	$42,096,982	$59,496,634	$9,268,939	$5,605,220
	$19,446,618	$43,293,945	$62,740,562	$9,268,939	$6,802,183

A. CWIP Account 2055

As described in Exhibit H-1-1, WPLP was directed by the OEB in the LTC Decision to record its transmission system construction costs in CWIP Account 2055. In addition, in the LTC Decision the OEB directed WPLP to transfer the balances from its Transmission Development Costs Deferral Account to CWIP Account 2055. The transferred development costs are recorded in sub-accounts related to capital costs and carrying charges. WPLP proposes to recover these amounts as follows:

- The balances in the CWIP Account 2055 sub-accounts for development capital costs and associated carrying charges[4], previously included in the Transmission Development Costs Deferral Account, are proposed to be recovered through the allocation of all indirect capital costs (which include these development costs) to fixed asset accounts as assets come into service, in proportion to the direct capital costs associated with each asset, as described in

[1] Exhibit A-7-1- Attachment 2. COVID-19 costs were recorded in CWIP account 2055 in the 2020 audited financial statements and reclassed to a deferral account in 2021 upon OEB approval of deferral account in EB-2021-0134.

[2] Audited balances include deferral account carrying charges.

[3] Disposition amount is 25% of 2021 incremental COVID-19 costs plus 25% of deferral account balance as at December 31, 2020 approved in EB-2021-0134.

[4] In accordance with the approved Settlement Agreement in EB-2021-0134, the third-party funding sub-account has been discontinued.

Exhibit C-2-1.[5] The reasonableness of WPLP's transmission development costs is supported by evidence provided throughout this application, particularly in Exhibit B.

- The balances in the CWIP Account 2055 consisting of construction costs for the transmission project are proposed to be recovered through the assignment of these direct capital costs to fixed asset accounts as assets come into service, in proportion to the direct capital costs associated with each asset, as described in Exhibit C-2-1. The reasonableness of WPLP's transmission construction costs is supported by evidence provided throughout this application, particularly in Exhibit B.

B. Pikangikum Distribution System Deferral Account

For 2023, WPLP proposes to dispose of the incremental portion of the audited December 31, 2021 balance in this account, and to continue using this account and recording carrying costs until the Pikangikum Distribution System is converted to transmission and the final balance is disposed of in a future transmission revenue requirement application.

Specifically, WPLP proposes to dispose of $1,196,963, being the incremental portion of the audited December 31, 2021 inclusive of carrying charges, by adding this amount to the portion of its 2023 base revenue requirement that is allocated to the Remote Connection Lines.

On the day that the Pikangikum Distribution System is converted to transmission, WPLP will stop recording costs in the account, other than carrying costs. WPLP therefore proposes in the current application to dispose of the audited balance from 2021, and in its 2023 application for the 2024 rate year, WPLP expects that it will be able to seek final disposition of the audited account balance as of December 31, 2022, following which the account will no longer be needed.

[5] WPLP's development costs are part of the Non-EPC Capital Costs described in Exhibits B-1-5 and C-1-2. For clarity, the Non-EPC Capital Costs that are allocated proportionally to fixed assets as they come into service include both historical actual development costs described in this bullet, plus the historical and forecasted capital construction costs described in the next bullet.

In each of the above cases, adding the amount being disposed 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 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.

C. In-Service Date Variance Account (ISDVA)

As of December 31, 2021, there is no balance in the ISDVA as no segments of the Line to Pickle Lake or the Remote Connection Lines were put into service during 2021. As such, WPLP is not seeking disposition of any amounts from this account in this application. As assets come into service in 2022, WPLP will record the differences between its approved revenue requirement based on the forecasted in-service dates for the relevant lines/stations and its revenue requirement if calculated based on the actual in-service dates for those lines/stations. WPLP will seek disposition of the balance in the ISDVA in subsequent applications.

D. Construction Period Interest Costs Variance Account ("CPICVA")

As of December 31, 2021, there is no balance in the CPICVA as no segments of the Line to Pickle Lake or the Remote Connection Lines were put into service during 2021. As such, WPLP is not seeking disposition of any amounts from this account in this application. As assets come into service in 2022, WPLP will record the revenue requirement impact attributable to the difference between the effective interest rate for long-term debt approved in the 2022 rate application and WPLP's actual effective interest rate on long-term debt during the construction period. WPLP will seek disposition of the balance in the CPICVA in subsequent applications.

E. COVID Construction Costs Deferral Account ("CCCDA")

Pursuant to the approved Settlement Agreement in EB-2021-0134, the parties agreed that WPLP would recover its audited 2020 year-end balance in this account as an expense through disposition

of the audited 2020 year-end balance over a four-year period (i.e. 25% in each of 2022, 2023, 2024 and 2025). Accordingly, in 2023 WPLP seeks recovery of $4,349,913, which represents 25% of the total audited 2020 year-end balance, plus applicable carrying costs.

In addition, WPLP has recorded COVID construction costs of $42,096,982 incurred during 2021. Consistent with the approach approved in EB-2021-0134, WPLP seeks recovery of its incremental audited 2021 COVID construction costs in the CCCDA over a four-year period (i.e. 25% in each of 2023, 2024, 2025 and 2026). Accordingly, in 2023 WPLP seeks recovery of $10,524,246, which represents 25% of its total audited 2021 additions to the CCCDA, plus applicable carrying costs.

Based on the foregoing, WPLP proposes to dispose of a total balance from the CCCDA of $14,874,159, of which $9,268,939 is in respect of the Line to Pickle Lake and $5,605,220 is in respect of the Remote Connection Lines, by adding such amounts to the applicable revenue requirements for each of these groups of assets. As discussed in Exhibit H-2-2, recovery of these COVID construction costs in this manner, rather than through further rate base additions, is in the best interests of Ontario ratepayers.

F. Deferred Contingency Deferral Account ("DCDA")

As of December 31, 2021, there is no balance in the DCDA as no segments of the Line to Pickle Lake or the Remote Connection Lines were put into service during 2021. As such, WPLP is not seeking disposition of any amounts from this account in this application. WPLP will continue to use the DCDA to track the revenue requirement impacts associated with the Deferred Contingency Amount, which WPLP will seek to recover, to the extent the forecasted contingency is actually realized, limited to the revenue requirement impact attributable to contingency costs for 2022 and 2023 to a maximum of $66,840,377. Subject to OEB review in a future transmission rate application.

Exhibit H, Tab 2, Schedule 2

Incremental COVID Construction Costs

INCREMENTAL COVID CONSTRUCTION COSTS

This schedule provides a detailed description of WPLP's incremental construction costs directly resulting from the COVID-19 pandemic, as well as WPLP's proposed rate treatment for those amounts.

A. BACKGROUND

On March 11, 2020, the World Health Organization declared the outbreak of the COVID-19 virus to be a pandemic. In the days that followed, a provincial state of emergency was declared in Ontario under the *Emergency Management and Civil Protection Act*, which resulted in widespread closures and restrictions on businesses and other facilities and activities. Regional state of emergency declarations were also declared in multiple parts of Ontario, imposing additional closures and restrictions. For WPLP, the onset of the pandemic introduced a wide range of impacts, both in relation to the construction of the Transmission System under its EPC contract with Valard and in relation to WPLP's non-EPC activities in support of the Transmission Project.

On the day the COVID-19 outbreak was declared to be a pandemic, Valard issued an Event Notice under the EPC contract on the basis that the pandemic qualified as a Force Majeure Event which was likely to impact the Transmission Project, thereby allowing for cost compensation and schedule relief to the contractor. Upon the pandemic being declared, ongoing work activities continued on site (right of way clearing and access roads) as those activities were physically distanced from the remote First Nation communities. Subsequent planned work activities, most notably foundations and assembly works, would have required mobilization of different crews. The mobilization of those new crews had to be postponed until development and implementation of Valard's COVID-19 health and safety measures (also known as the COVID Management Plan or CMP), which came into effect in May 2020. Given the locations of Valard's work camps and their proximity to vulnerable remote First Nation communities, it was essential that Valard develop and adopt appropriate COVID-19 health and safety measures in consultation with First Nation leadership before allowing new construction crews on site.

In EB-2021-0134, at Exhibit H-2-2, WPLP outlined the initial work with Valard in response to the March 11 Event Notice and WPLP's proposed regulatory treatment for the incremental COVID-19 construction costs incurred in 2020.

Over the past year, Valard has worked with both WPLP and the First Nation communities to continuously monitor and amend the CMP,[1] as well as to implement First Nation community-specific CMPs to minimize the impact of COVID-19 on the project, the public, employees and First Nation communities. The proactive management of COVID-19 has allowed construction on the project to continue.

As part of WPLP's initial rate filing, the OEB approved the expensing of WPLP's COVID-19 costs incurred up to December 31, 2020 through a deferral account, referred to as the COVID-19 Construction Costs Deferral Account (CCCDA), the balance of which would be recovered over a four-year period. WPLP proposes to continue with the same OEB-approved treatment for the remainder of the construction period.

B. SUMMARY OF IMPACTS

The impacts of the pandemic on the Transmission Project fall into two broad categories – impacts under the EPC contract and non-EPC impacts, as follows.

1. EPC Contract Impacts

Valard's initial assessment of the impacts of the pandemic was provided to WPLP in June 2020, and was updated in subsequent months to reflect additional analysis and quantification of COVID-19 impacts. Based on this assessment, Valard determined that due to factors such as schedule delays, availability of workforce, complying with COVID-19 health and safety measures, travel restrictions, work camp isolation and shift length requirements to combat the effects of the pandemic and maintain worker and public safety, key milestone dates under the contract were no longer feasible and that it would not be able to meet various obligations under the EPC contract.

[1] The CMP has been updated 3 times since originally implemented to adapt to the changes in COVID-19 and to continuously ensure the health and safety of employees, the public and surrounding First Nation communities.

Valard identified three main categories of impacts affecting its ability to execute the project at the cost and in accordance with the schedule agreed to in the EPC contract: (a) compliance with COVID-19 health and safety measures and the corresponding impact on productivity; (b) flight and travel restrictions; and (c) construction activities, specifically work camps, substations and lines. These three factors continue to be the main categories impacting Valard's ability to execute the project. While the main categories of impacts have remained constant, the specific impacts within each category have evolved. As a result, both the project schedule[2] and the project cost impacts have continued to change.

(a) Productivity and COVID-19 Health and Safety Measures

The initial COVID-19 health and safety measures, as described in Exhibit H-2-2 from EB-2021-0134, remain in effect. In addition, Valard has implemented additional health and safety measures as follows: (1) mandatory exit testing for Participating First Nation employees, (2) COVID-19 rapid testing, (3) hotel or accommodation for quarantine measures, and (4) mandatory vaccination of all personnel on the project. The new health and safety measures are required to address the continuously changing COVID-19 environment and for the safety of the public, employees and First Nation communities.

WPLP incurs direct costs as a result of the COVID-19 health and safety measures. In addition, the COVID-19 health and safety measures result in general reductions to worker productivity. Valard and WPLP negotiated a 10% loss in overall productivity of construction works between March 11, 2020 and August 2020, followed by a 6% productivity reduction from August 2020 to March 2021 to reflect the efficiency that has been learned and implemented during the March to August timeframe, after which point the COVID-19 related impact on productivity was subject to review. WPLP and Valard have not been able to agree on a loss productivity factor for the period after March 31, 2021 and, as such, this aspect continues to be a subject of negotiation. WPLP and

[2] Schedule impact is described in more detail in Exhibit B-1-3.

Valard have agreed to continue to use the 6% loss productivity factor in the interim, with a symmetrical true-up or true-down based on the final agreed upon productivity factor.

Given the impact of COVID-19 on the Project, the COVID-19 health and safety measures continue to remain in place. As a result, WPLP continues to incur: (1) direct costs for implementing the COVID-19 health and safety measures, and (2) costs related to loss of productivity. WPLP continues to monitor the changes to provincial and federal COVID-19 requirements, along with the circumstances in the surrounding First Nation communities, and is continuing to work with Valard to determine when it is appropriate for the project CMP and/or First Nation community-specific CMPs to be modified or eliminated.

(b) Flight and Travel Restrictions

COVID-19 has significantly impacted the cost and availability of commercial flights. Given that Valard uses a workforce located throughout Canada in order to provide the necessary volume of appropriately qualified workers required to construct WPLP's Transmission System, the pandemic has resulted in a significant increase to the cost of mobilizing its crews. WPLP and Valard held two separate RFPs, without success, in an effort to secure a third-party consultant to determine the Base Rate of a flight so that the parties could accurately assess the impact of COVID-19 on flight and travel costs, as described in EB-2021-0134. The parties have just recently agreed to a third-party, and are in the process of executing an engagement letter with that third party to determine the Base Rate. WPLP expects the third-party to be engaged by the beginning of May 2022, and to be in a position to issue their report by August 2022.

Given the limited availability of commercial flights in the project area, Valard has primarily relied on chartered flights to transport workers to and from the project site. Valard has been able to use chartered flights to service both the WPLP project and the East West Tie project (in which it is also involved) to help mitigate the costs of travel. As of January 1, 2022, Valard is utilizing more commercial flights given the increase in availability. Moreover, as the East West Tie project goes into service, the opportunity to mitigate charter costs will no longer be available.

As COVID-19 continues to impact flight costs, WPLP is continuing to work with Valard to determine when the COVID-19 impact on the commercial air transportation industry, and flight costs, has ended.

(c) Construction Activities

The COVID-19 impacts to construction activities were outlined in Exhibit H-2-2 in EB-2021-0134. Those impacts are continuing to impact construction activities relating to the Transmission Project. Adding to the construction challenges, nine First Nation Community lockdowns were implemented in an effort by those First Nations to manage COVID-19 in their respective communities. These community lockdowns restricted Valard's access to portions of the Project Site. In addition to the First Nation Community lockdowns, the number of construction personnel directly impacted by COVID-19 has had consequences for project construction and caused a schedule delay, as discussed in Exhibit B-1-3.

While WPLP and Valard executed Change Orders to address construction risk from both a schedule and cost perspective, the Change Orders included specific exclusions due to the impacts of various activities not known at the time the Change Orders were executed. In addition, the Change Orders did not cover anything that was not known or could not reasonably have been known at the time of executing the Change Orders. While Valard has sought schedule relief for delays as a result of COVID-19 as at December 31, 2021, Valard has not provided any cost estimate for the COVID-19 schedule delays. Any schedule or cost relief sought by Valard as it relates to impacts on construction will be pursuant to the EPC contract and subject to negotiations between WPLP and Valard. As COVID-19 evolves, the potential impacts to schedule and costs continue to evolve.[3]

COVID-19 continues to impact construction activities, as such, WPLP is continuing to work with Valard to determine when the COVID-19 impact on construction activities has ended.

[3] For example, due to the impacts of COVID-19 variants, WPLP has experienced 450 cases of COVID-19 among its personnel, including its contractor's personnel, during the period from January 1 to March 15, 2022.

WPLP is forecasting incremental EPC contract project costs attributable to COVID-19 of $90.3 million. The variance from the $71.4 million indicated in the initial rate application is driven by the continued use of the improved health and safety measures up to June 2022, the impact on productivity up to June 2022 at the 6% productivity loss factor, increased flight and travel costs for the Project duration, and additional measures to mitigate COVID-19 construction impacts.[4]

2. Non-EPC Impacts

WPLP is incurring incremental costs outside of its EPC contract that are directly attributable to the COVID-19 pandemic. These costs generally relate to additional efforts required by WPLP's Owner's Engineer[5], the Independent Engineer[6], as well as WPLP's professional services providers related to reviewing, analysis and assessing the EPC Contractor Change Requests and the various scenarios discussed in Part C.

WPLP expects that these costs represent an immaterial part of its overall incremental COVID costs. WPLP confirms that such costs do not form part of the non-EPC costs presented elsewhere in the application, and proposes to record and recover these costs in the same manner as its EPC COVID-19 cost impacts, as set out in Part C, below.

WPLP is forecasting non-EPC incremental project costs attributable to COVID-19 of $0.6 million, which is consistent with the forecasted cost in the initial rate application.

C. PROPOSED RATE TREATMENT

The incremental costs incurred by WPLP as a result of the pandemic, both under the EPC contract and otherwise, are part of the development and construction costs for the Transmission Project. WPLP has acted reasonably and with an appropriately high degree of diligence to manage the impacts of the pandemic on the Transmission Project, including in particular with respect to the

[4] Forecasted costs are as of December 31, 2021, and therefore do not include any compensation Valard may seek in relation to COVID-19 as a result of impacts to schedule or incremental costs as a result of COVID-19 (including variants) impacts in 2022.

[5] See Exhibit B-1-2 and Exhibit B-1-4 regarding the role of the Owner's Engineer.

[6] See Exhibit B-1-4 regarding the role of the Independent Engineer.

impacts under its EPC contract. As a result of that diligence, and by selecting the package of EPC contract amendments reflected by Scenario 4 as discussed in EB-2021-0134[7], WPLP has been able to minimize the EPC cost and ratepayer impacts of the pandemic while managing the impact to the pre-pandemic schedule for connecting remote First Nation communities to the provincial transmission system. It is therefore appropriate for WPLP to be permitted to continue to recover its incremental development and construction costs directly resulting from the COVID-19 pandemic, in the same manner as approved in EB-2021-0134, for the remainder of the construction period.

Similar to the basis for OEB approval in the initial rate application (EB-2021-0134), WPLP proposes to recover its incremental costs arising from the pandemic as an expense through the remaining construction period, with incremental costs incurred in each year being recovered over a four-year period. There are three fundamental reasons why the expensing of COVID-19 costs, in the circumstances of WPLP's project, is a better approach relative to capitalizing the COVID-19 costs:

i. Ratepayers are better off, or held neutral, when the COVID-19 costs are expensed;

ii. The incentive under the Federal Funding Framework, which incentivizes WPLP to seek capital cost reductions in exchange for higher project equity levels, is preserved; and

iii. WPLP's credit funding surplus under its credit arrangements for the Project is maintained, thereby enabling it to fund unforeseen events.

These aspects must be considered in the unique context of the Project. As a project that has been designated as a priority project under the *Ontario Energy Board Act*, it is important to give weight to those aspects that facilitate the completion of the Project in the most efficient and cost-effective manner possible. In addition, the completion of this Project will have a fundamentally beneficial

[7] Under Scenario 4, Line to Pickle Lake energization was delayed by 12 months, and the community energization dates were delayed by a total of 14 months, affecting 2 of 16 communities, with one community delayed 9 months, another community delayed 5 months, and all other community energization dates being maintained. See EB-2021-0134, Exhibit H-2-2, Section C.

impact on the communities that will be served by it. Against this backdrop, the Project faces many challenges, including difficult terrain and geography, forest fire risks[8], remote work sites and variable weather that can limit access and construction periods. The funding and credit arrangements that WPLP has established are structured to aid WPLP in meeting these challenges and successfully completing this Project. Whereas WPLP's proposal to expense rather than capitalize its COVID costs is consistent with this structure, the capitalization of these costs would instead extinguish these advantages.

In EB-2021-0134, WPLP described the Federal Funding Framework relating to its project. The Federal Funding Framework for the project was finalized on July 3, 2019, based on definitive documents signed by WPLP, Canada and Ontario. At a high level, the Federal Funding Framework specifies that Canada will provide $1.55 billion in funding in relation to the project, which will serve to reduce the resulting ratepayer impact in two ways:

a) a portion of the funding will be applied as a Contribution in Aid of Construction ("CIAC"), thereby reducing WPLP's rate base in respect of the Remote Connection Lines; and

b) the remainder of the funding will be provided to an independent Trust which will use the funding to help offset the rate impacts of the Remote Connection Lines on RRRP for Ontario ratepayers.

The portion of funding to be provided to WPLP as a CIAC will be determined by WPLP's total project capital costs. The negotiated Federal Funding Framework establishes a sliding scale such that, as WPLP's costs increase, the CIAC amount increases at a rate that reduces WPLP's deemed equity position in the project. This provides a strong incentive to control and reduce capital costs during construction. Federally funded CIAC treatment for the Remote Connection Lines results in a reduction to the fixed monthly charges that WPLP recovers 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

[8] In the summer of 2021, the Project Site was shut down as a result of an MNRF Emergency Area Order (EAO 2021-13) impacting construction for approximately 6 weeks.

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.

To illustrate the relative ratepayer impacts, depending on whether COVID-19 costs are expensed or capitalized, WPLP has prepared the tables below to explain and quantify the impacts on Owner's Equity, Ratepayers and Trust Fund balance. As the receipt of funding under the Federal Funding Framework remains subject to Parliamentary appropriation, WPLP has provided the requested analysis under two scenarios: 1) without federal funding, and 2) with federal funding. The scenarios are compared to the base model used prior to COVID-19 impacts, which is consistent with analysis completed in the approved Settlement Proposal from the initial rate application.[9]

Table 1 calculates rate base before the CIAC and the total capital costs used to determine Owner Equity under the Federal Funding Framework (all figures in $M):

Table 1: Calculation of Capital Cost

Calculation of Capital Costs	Capitalized	Expensed (4 year amort)	Expensed (4 year amort) $20M Savings
AFUDC incurred	$1.43	$1.43	$1.43
Cost of funds during construction	$44.10	$44.10	$44.08
Development costs incurred	$70.90	$70.90	$70.90
Construction costs incurred	$1,775.37	$1,701.82	$1,681.82
Total rate base carried into operations	$1,891.79	$1,818.26	$1,798.24
Pikangikum	$62.82	$62.82	$62.82
Rate Base before CIAC	**$1,954.61**	**$1,881.08**	**$1,861.06**
CWIP carried into final regulatory implementation	($45.53)	($45.54)	($45.52)
Capital Cost used to determine Owner Equity under federal funding framework	**$1,909.09**	**$1,835.54**	**$1,815.54**

Table 2 provides the owner equity, rate payer impact and impact on the independent Trust under the assumption there is no federal funding (i.e. Canada does not appropriate funds). WPLP believes

[9] EB-2021-0134, Decision and Order, September 30, 2021, Schedule 'A' (Settlement Proposal), pp. 50-54 (of 59).

this analysis needs to be considered as the risk of appropriation is still outstanding (all figures in $M).

Table 2: Ratepayer Impact – No Federal Funding

No Federal Funding Framework	Capitalized	Expensed (4 year amort)	Expensed (4 year amort) $20M Savings
Owners Equity at end of Construction	**$781.85**	**$752.43**	**$744.42**
Rate Payer Impact			
Revenue Requirement Impact During Construction			
Cashflows from Operations (Result of delay of in-service dates)	($67.05)	($65.64)	($70.43)
COVID-19 Proceeds	$10.24	$33.13	$33.13
Total	($56.81)	($32.50)	($37.29)
Revenue Requirement Impact			
Incremental Rate Base	$61.45	($11.47)	($31.90)
Incremental Return	$53.47	($9.97)	($27.76)
Collection of remaining deferral account plus carrying charges	$7.41	$59.34	$59.34
Total	$122.32	$37.90	($0.32)
Total Rate Payer Impact*	**$65.52**	**$5.40**	**($37.61)**
Trust Impact	**N/A**	**N/A**	**N/A**

**Before diesel costs as it has the same impact on both scenarios*

Table 3 provides the owner equity, ratepayer impact and impact on the independent Trust under the assumption there is federal funding (i.e. WPLP receives a CIAC under the Federal Funding Framework) (all figures in $M).

Table 3: Ratepayer Impact – With Federal Funding

Federal Funding Framework	Capitalized	Expensed (4 year amort)	Expensed (4 year amort) $20M Savings
Owners Equity at end of Construction	**$400.00**	**$434.46**	**$454.46**
Rate Payer Impact			
Revenue Requirement Impact During Construction			
Cashflows from Operations (Result of delay of in-service dates)	($67.05)	($65.64)	($70.43)
COVID-19 Proceeds	$10.24	$33.13	$33.13
Total	($56.81)	($32.50)	($37.29)
Revenue Requirement Impact			
Loss (Increase) of Trust funds as a result of increased contribution to WPLP	$70.43	($88.64)	($159.08)
Earnings on Incremental Trust Balance	$0.00	($76.39) (A)	($110.22) (B)
Incremental Rate Base	$0.00	$86.15	$136.15
Incremental Return	$0.00	$74.95	$118.45
Collection of remaining deferral account plus carrying charges	$7.41	$59.34	$59.34
Total	$77.84	$55.42	$44.65
Total Rate Payer Impact*	**$21.03**	**$22.91**	**$7.36**
Calculation of Trust Impact (Balance)			
OEB construction costs	$1,909.09	$1,835.54	$1,815.54
Interest accounts	$45.53	$45.54	$45.52
Rate Base before Capital Contribution	$1,954.61	$1,881.08	$1,861.06
Rate base after CIAC (per Schedule1.1 (d) = Owner Equity / 40%)	($1,000.00)	($1,086.15)	($1,136.15)
Interim depreciation	($44.86)	($44.24)	($44.66)
Capital contribution	$909.75	$750.68	$680.24
Federal Funding	$1,550.00	$1,550.00	$1,550.00
Funds Remaining in Trust	**$640.25**	**$799.32**	**$869.76**

**Before diesel costs as it has the same impact on both scenarios*

Calculation of Incremental Trust Earnings		
	Inputs (A)	**Inputs (B)**
Incremental Trust Balance	$159.07	$229.51
Interest Rate	4%	4%
Period (years)	10	10
Earnings on Incremental Trust Balance	**$76.39**	**$110.22**

1. Ratepayer Impact

As Table 2 indicates, the ratepayer impact is less when the COVID-19 costs are expensed and amortized over 4-year period rather than capitalized, under the scenario where Federal Funding is not provided. Table 3 indicates that ratepayers are slightly worse off with COVID-19 costs expensed. However, with project savings resulting from minimizing the use of contingency, as described below, ratepayers are better off as they will realize cost savings which would not be available under the capitalized model. Further details on project cost impacts with Federal Funding

Framework sliding scale funding incentives are provided below. The expensing of COVID-19 costs instead of capitalizing them would also result in additional funds remaining in the Trust to offset the total RRRP funding that the IESO would otherwise need to collect from Ontario ratepayers each month. A 4-year amortization period has been proposed in recognition of the financial hardships that COVID-19 has had on many individuals and businesses in Ontario and because it is in line with the approved settlement in EB-2021-0134. Recovery over a 4-year period reduces the short-term impact on ratepayers during this critical recovery period when ratepayers are experiencing unique financial pressures.

2. Funding Incentive

Pursuant to the Federal Funding Framework, WPLP is subject to a sliding scale such that, as WPLP's costs increase, the CIAC amount increases at a rate that reduces WPLP's deemed equity position in the project. This provides a strong incentive for WPLP to control and reduce costs during construction.[10]

As Table 3 indicates, based on the current forecasted construction cost, the Owner's equity at the end of construction would be $434.46 million. Based on the Federal Funding Framework, the Owner's equity cannot rise above $400 million when costs are above $1.87 billion. Where COVID-19 costs are expensed, WPLP will have an opportunity to achieve cost savings by minimizing the use of contingency. This is consistent with the incentive built into the Federal Funding Framework.

The incentive would be impaired if the COVID-19 costs are capitalized. As indicated in Table 3, where the COVID-19 costs are capitalized, the Project's capital cost is approximately $1.91 billion. Contingency is a project cost that is established to account for foreseeable risks that have not yet materialized. While WPLP will work to mitigate the impact of those risks, it cannot ignore the potential impact of those risks and the use of contingency. As a result, its ability to achieve cost savings over the remainder of construction will have its limitations. This, together with the

[10] Exhibit I-4-1, p.5-6

increased level of capital costs above $1.87B, when COVID-19 costs are capitalized, will make it almost impossible for WPLP to reduce costs below $1.87B. This will have the effect of nullifying a key incentive in the Federal Funding Framework.

An example of the application of the incentive is set out in Table 3, above. The example considers the possible circumstances of WPLP achieving $20[11] million of savings in capital costs, such as from an underspend of contingency. This would represent a reduction to Capital Cost from $1.835 billion to $1.815 billion with a corresponding increase in equity to $454 million. Importantly, there would be two key additional benefits. First, when the COVID-19 costs are expensed, the ratepayer impact declines from $22.91 million to $7.36 million with a 4-year amortization period. Second, because capital costs have decreased, the level of the CIAC correspondingly declines. The decline in CIAC means that more funds remain in the independent Trust. As that amount will accrue interest or a return over time, there will be an incremental amount in the independent Trust to offset the costs of the Remote Connection Lines for ratepayers over time. Although WPLP is not privy to the investment parameters of the independent Trust, Table 3 sets out an example to show how the incremental increase in the independent Trust amount extends the time over which the independent Trust is available to offset RRRP funding.

As result, expensing the COVID-19 costs provides benefits to ratepayers, or holds ratepayers neutral, while maintaining the incentive to manage the capital costs of the Project and the available funds for the independent Trust amount, both of which are key to the Federal Funding Framework.

3. Credit Surplus

WPLP completed a negotiated Common Terms and Inter-Creditor Agreement ("CTIA") with the Province of Ontario and a group of Senior Bank 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"). WPLP is not forecasting

[11] WPLP through its OE performs a contingency analysis semi annually. The December 31, 2021 contingency analysis identified the possibility that contingency could be reduced by approximately $20 million. As a result, WPLP utilized $20 million in the calculation as a reasonable assumption.

to require the entire available financing amount. However, as prudent project management, WPLP has secured financing that would cover a combination of worst-case scenarios resulting in cost increases, interest rate increases and/or construction delays. This amount reflects WPLP's credit surplus.

WPLP proposes to expense COVID-19 costs by recording them in a deferral account and recovering those amounts over a four-year period. As indicated in Table 3, this would allow WPLP to collect COVID-19 Proceeds of approximately $33 million. This would allow WPLP to fund a portion of the overall forecasted COVID-19 costs from rate revenues and not require the COVID-19 costs to be funded through the available credit surplus.

Under a capitalization approach, WPLP would recover no COVID-19 Proceeds in rates (except for a limited amount through depreciation). The result is that WPLP would be required to fund a significant portion of the COVID-19 costs out of its credit surplus, which would otherwise be available to cover cost increases, interest rate increases and construction delays.

Maintaining a credit surplus is particularly important for the Project given its unique circumstances. As noted above, the Project faces a number of geographical and environmental challenges that are not readily predictable. For example, since the Project depends on the availability of winter roads, a shortened winter season may limit transportation causing delays and increased costs. Likewise, the summer months present forest fire risks. Preserving the credit surplus to meet these challenges (if needed) is an appropriate way to manage risk in completing this priority project. In addition, maintaining the surplus avoids material additional costs to obtain and negotiate incremental credit arrangements.

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, requested and 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 2023 revenue requirement.

The components of WPLP's 2023 revenue requirement, with references to supporting schedules in this Application, are summarized in Table 1, below.

Table 1 – Summary of 2023 Revenue Requirement

	Total	**Reference**
Gross Fixed Assets (avg)	870,583,773	C-3-1
Accumulated Depreciation (avg)	-13,418,252	C-3-1
Net Fixed Assets (avg)	857,165,521	C-1-1
Working Capital Allowance	0	C-4-1
Rate Base	857,165,521	C-1-1
Regulated Rate of Return	4.35%	G-2-1
Regulated Return on Rate Base	37,325,999	G-2-1
OM&A Expenses	21,869,409	F-2-1
Property Taxes	0	F-11-1
Depreciation Expense	17,266,442	F-10-1
Income Taxes	398,095	F-11-1
Service Revenue Requirement	**76,859,944**	
Other Revenue Offset	0	E-3-1
Base Revenue Requirement	**76,859,944**	
Disposition of Pikangikum Distribution System Deferral Account	1,196,963	H-2-1
Disposition of COVID Deferral Account (CCCDA)	14,874,159	H-2-2
Revenue Requirement for Rates	**92,931,065**	

A. Cost Allocation

WPLP's 2023 Revenue Requirement for Rates of approximately $92.9 million is allocated between the Line to Pickle Lake and the Remote Connection Lines as shown in Table 2.

Table 2 – Allocation of 2023 Revenue Requirement

	LTPL	**RCL**	**Total**
Revenue Requirement for Rates	**34,739,785**	**58,191,280**	**92,931,065**

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 change in the UTR Network rate of $0.04/kW, 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 $0.04 per month, or 0.03% for a typical residential customer, as detailed in Exhibit I-4-1. WPLP anticipates that the OEB will determine actual 2023 UTR rates in a generic proceeding, based on the approved 2023 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 $4,849,273 applicable to HORCI, effective from January 1, 2023, 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 $0.15 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 2023 revenue requirement is $0.20 per month, or 0.15%.

Details of bill impacts for typical general service customers and transmission-connected customers arising from WPLP's 2023 revenue requirement are provided in Exhibit I-4-1.

[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 as first implemented in the initial rate proceeding in EB-2021-0134, 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

[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-2-1.

B. Rate Base

The rate base information from Exhibit C, summarized in Table 1 below, includes all direct capital costs as well as an allocation of overhead costs, as detailed in Appendix A of Exhibit B-1-5.

Table 1 – Rate Base by Category

Category	Item	2023 Forecast ($000's)		
		Opening	**Closing**	**12-Month Average**
LTPL	Gross Fixed Assets	289,837	289,837	289,837
	Less Accumulated Depreciation	-2,896	-8,689	-5,793
	Net Fixed Assets	**286,940**	**281,148**	**284,044**
	Working Capital Allowance	0	0	0
	Rate Base			**284,044**
	% of Transmission System Rate Base			***33.2%***
RCL	Gross Fixed Assets	389,676	725,307	578,932
	Less Accumulated Depreciation	-2,700	-14,010	-7,534
	Net Fixed Assets	**386,976**	**711,297**	**571,398**
	Working Capital Allowance	0	0	0
	Rate Base			**571,398**
	% of Transmission System Rate Base			***66.8%***
Sub-Total Transmission System		**673,916**	**992,445**	**855,443**
GP	Gross Fixed Assets	220	5,921	1,815
	Less Accumulated Depreciation	-22	-186	-92
	Net Fixed Assets	**198**	**5,736**	**1,723**
	Working Capital Allowance	0	0	0
	Rate Base			**1,723**
Total Rate Base				**857,166**

For the purpose of determining WPLP's 2023 revenue requirement and setting rates, rate base attributable to General Plant ("GP") assets (i.e. fleet purchases, operating centre and business system in 2023) is allocated 33.2% to the LTPL and 66.8% to the RCL based on the respective proportions of 2023 transmission system rate base for each category, as shown in Table 2.

Table 2 – Rate Base by Category with General Plant Allocations

Category	2023 Rate Base		
	Transmission System Assets	**Allocation of GP Assets**	**Total**
LTPL	284,044	572	284,616
RCL	571,398	1,151	572,549
Total	**855,443**	**1,723**	**857,166**

C. OM&A Expenses and Income Taxes

WPLP's 2023 OM&A includes expenses that are directly related to fixed assets, as well as an allocation of overheads, as detailed in Appendix A of Exhibit B-1-5. WPLP's 2023 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 2023 test year are allocated 33.2% to the Line to Pickle Lake and 66.8% to the Remote Connection Lines, as illustrated in Table 3.

Table 3 – Allocation of 2023 OM&A and Income Tax Expense

	LTPL	RCL	Total
Direct OM&A Expenses	2,226,555	4,971,726	7,198,280
Indirect OM&A Expenses			14,671,128
Income Tax Expense			398,095
Allocation Factor from Table 1	*33.2%*	*66.8%*	*100%*
Allocation of Indirect OM&A	4,871,454	9,799,674	14,671,128
Allocation of Income Tax Expense	132,185	265,910	398,095
Total 2023 OM&A	**7,098,009**	**14,771,400**	**21,869,409**
Total 2023 Allocated Income Tax	**132,185**	**265,910**	**398,095**

D. Depreciation Expense

In Exhibit F-10-1, 2023 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 fleet are allocated between the Line to Pickle Lake and the Remote Connection Lines on the same 33.2%/66.8% basis described above. Table 4 below shows the depreciation expense for each rate category for the 2023 test year.

Table 4 – 2023 Depreciation Expense by Rate Category

	LTPL	RCL	Total
Depreciation Expense	5,846,793	11,419,648	17,266,442

E. Partial Disposition of Deferral Account Balances

WPLP proposes to dispose of the incremental audited December 31, 2021 balance of $1,196,963 in the Pikangikum Distribution System Deferral Account by adding this amount to the portion of its 2023 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.

WPLP also proposes to dispose of $42,096,982 in incremental COVID-related construction costs incurred in 2021 over a 4-year period commencing in 2023, as described in H-2-2. As a result, WPLP has added 25% of this amount, being $10,524,246, to its 2023 base revenue requirement. This is distinct from the addition to WPLP's 2023 base revenue requirement of a further 25% of its incremental COVID-related construction costs incurred in 2020, being $4,349,913, as approved by the OEB in the initial rate proceeding (EB-2021-0134). As described in H-2-2, WPLP records these costs separately for the Line to Pickle Lake and the Remote Connection Lines. Therefore, the costs included in Table 5 are based on direct tracking for each asset pool and no further cost allocation is required.

Table 5 – Partial Disposition of Deferral Account Balances

	LTPL	**RCL**	**Total**
Disposition of Pikangikum Distribution System Deferral Account	-	$1,196,963	$1,196,963
Disposition of COVID Construction Costs Deferral Account (CCCDA)	$9,268,939	$5,605,220	$14,874,159
Total	**$9,268,939**	**$6,802,183**	**$16,071,122**

F. Allocation of Revenue Requirement

WPLP's 2023 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 2023 Revenue Requirement

	LTPL	**RCL**	**Total**	**Reference**
Gross Fixed Assets (avg)	290,439,412	580,144,361	870,583,773	C-3-1
Accumulated Depreciation (avg)	-5,823,087	-7,595,166	-13,418,252	C-3-1
Net Fixed Assets (avg)	284,616,325	572,549,196	857,165,521	C-1-1
Working Capital Allowance	0	0	0	C-4-1
Rate Base	284,616,325	572,549,196	857,165,521	C-1-1
Regulated Rate of Return	4.35%	4.35%	4.35%	G-2-1
Regulated Return on Rate Base	12,393,859	24,932,140	37,325,999	G-2-1
OM&A Expenses	7,098,009	14,771,400	21,869,409	F-2-1
Property Taxes	0	0	0	F-11-1
Depreciation Expense	5,846,793	11,419,648	17,266,442	F-10-1
Income Taxes	132,185	265,910	398,095	F-11-1
Service Revenue Requirement	**25,470,846**	**51,389,098**	**76,859,944**	
Other Revenue Offset	0	0	0	E-3-1
Base Revenue Requirement	**25,470,846**	**51,389,098**	**76,859,944**	
Disposition of Pikangikum Distribution System Deferral Account	0	1,196,963	1,196,963	H-2-1
Disposition of COVID Construction Costs Deferral Account (CCCDA)	9,268,939	5,605,220	14,874,159	H-2-2
Revenue Requirement for Rates	**34,739,785**	**58,191,280**	**92,931,065**	

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. The current Ontario Transmission Rate Schedules were made effective on a final basis starting April 1, 2022 pursuant to the Board's Decision and Order in EB-2022-0084.

As described in Exhibit I-2-1, the portion of WPLP's revenue requirement associated with the Line to Pickle Lake, which is $34,739,785 for the 2023 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 place in-service in 2023, WPLP is forecasting an increase in Network charge determinants to 34.8 MW, as detailed in Exhibit E-1-1.

The addition of the above revenue requirement and charge determinants results in an increase of $0.04/kW, or 0.56**%**, to the Network UTR rate.

B. Current Uniform Transmission Rates

Table 1 below illustrates the calculation of the current Final UTRs effective April 1, 2022, which includes WPLP's approved 2022 UTR revenue requirement.[1] These values serve as the starting point for comparison in the tables that follow.

[1] Footnote 12 of the OEB's Decision and Rate Order in its 2022 UTR Update (EB-2022-0084) states that WPLP's approved 2022 transmission revenue requirement from EB-2021-0134, of $20,477,862, effective April 1, 2022, was annualized to $27,303,816 ($20,477,862/ (9 months/12 months)) to be included in the calculation of the UTRs.

Table 1 – Current UTR Calculations

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$4,877,864	$842,035	$2,268,193	$7,988,092
CNPI	$2,837,776	$489,867	$1,319,558	$4,647,201
WPLP	$27,303,816	$0	$0	$27,303,816
NextBridge	$53,100,835	$0	$0	$53,100,835
H1N SSM	$25,907,166	$4,472,189	$12,046,762	$42,426,118
H1N	$1,150,125,339	$198,538,821	$534,805,167	$1,883,469,327
B2MLP	$33,652,083	$0	$0	$33,652,083
NRLP	$8,281,339	$0	$0	$8,281,339
All Transmitters	$1,306,086,218	$204,342,912	$550,439,681	$2,060,868,811

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	14,468	0.000	0.000	
NextBridge	0.000	0.000	0.000	
H1N SSM	3,498.236	2,734.624	635.252	
H1N	234,736.371	228,350.406	194,599.235	
B2MLP	0.000	0.000	0.000	
NRLP	0.000	0.000	0.000	
All Transmitters	239,002.379	231,883.148	195,856.785	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**5.46**	**0.88**	**2.81**	
	↓	↓	↓	
FNEI	0.00373	0.00412	0.00412	
CNPI	0.00217	0.00240	0.00240	
WPLP	0.02091	0.00000	0.00000	
NextBridge	0.04066	0.00000	0.00000	
H1N SSM	0.01984	0.02189	0.02189	
H1N	0.88058	0.97159	0.97159	
B2MLP	0.02577	0.00000	0.00000	
NRLP	0.00634	0.00000	0.00000	
Total of Allocation Factors	1.00000	1.00000	1.00000	

C. Calculation of 2023 Test Year UTRs

Table 2 below shows the calculation of 2023 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-2022-0084. WPLP expects that the OEB will determine the actual 2023 UTRs once 2023 revenue requirements are approved for all other Ontario licensed transmitters.

WPLP has also provided an analysis of the changes in 2023 UTRs resulting from the current Application in Table 3 below.

Table 2 – Calculation of 2023 UTRs

Transmitter	Revenue Requirement ($)			
	Network	**Line Connection**	**Transformation Connection**	**Total**
FNEI	$4,877,864	$842,035	$2,268,193	$7,988,092
CNPI	$2,837,776	$489,867	$1,319,558	$4,647,201
WPLP	$34,739,785	$0	$0	$34,739,785
NextBridge	$53,100,835	$0	$0	$53,100,835
H1N SSM	$25,907,166	$4,472,189	$12,046,762	$42,426,118
H1N	$1,150,125,339	$198,538,821	$534,805,167	$1,883,469,327
B2MLP	$33,652,083	$0	$0	$33,652,083
NRLP	$8,281,339	$0	$0	$8,281,339
All Transmitters	$1,313,522,187	$204,342,912	$550,439,681	$2,068,304,780
Transmitter	**Total Annual Charge Determinants (MW)**			
	Network	**Line Connection**	**Transformation Connection**	
FNEI	230.410	248.860	73.040	
CNPI	522.894	549.258	549.258	
WPLP	34.767	0.000	0.000	
NextBridge	0.000	0.000	0.000	
H1N SSM	3,498.236	2,734.624	635.252	
H1N	234,736.371	228,350.406	194,599.235	
B2MLP	0.000	0.000	0.000	
NRLP	0.000	0.000	0.000	
All Transmitters	239,022.678	231,883.148	195,856.785	
Transmitter	**Uniform Rates and Revenue Allocators**			
	Network	**Line Connection**	**Transformation Connection**	
Uniform Transmission Rates ($/kW-Month)	**5.50**	**0.88**	**2.81**	
	↓	↓	↓	
FNEI	0.00371	0.00412	0.00412	
CNPI	0.00216	0.00240	0.00240	
WPLP	0.02645	0.00000	0.00000	
NextBridge	0.04043	0.00000	0.00000	
H1N SSM	0.01972	0.02189	0.02189	
H1N	0.87561	0.97159	0.97159	
B2MLP	0.02562	0.00000	0.00000	
NRLP	0.00630	0.00000	0.00000	
Total of Allocation Factors	1.00000	1.00000	1.00000	

Table 3 – Changes in 2023 UTRs Resulting from this Application

Transmitter	**Change in Revenue Requirement ($)**			
	Network	**Line Connection**	**Transformation Connection**	**Total**
FNEI	-	-	-	-
CNPI	-	-	-	-
WPLP	$7,435,969	$0	$0	$7,435,969
NextBridge	-	-	-	-
H1N SSM	-	-	-	-
H1N	-	-	-	-
B2MLP	-	-	-	-
NRLP	-	-	-	-
All Transmitters	$7,435,969	$0	$0	$7,435,969
Transmitter	**Change in Total Annual Charge Determinants (MW)**			
	Network	**Line Connection**	**Transformation Connection**	
FNEI	-	-	-	
CNPI	-	-	-	
WPLP	20.299	-	-	
NextBridge	-	-	-	
H1N SSM	-	-	-	
H1N	-	-	-	
B2MLP	-	-	-	
NRLP	-	-	-	
All Transmitters	20.299	-	-	
Transmitter	**Change in Uniform Rates and Revenue Allocators**			
	Network	**Line Connection**	**Transformation Connection**	
Uniform Transmission Rates ($/kW-Month)	**0.04**	**0.00**	**0.00**	
	↓	↓	↓	
FNEI	-0.00002	-	-	
CNPI	-0.00001	-	-	
WPLP	0.00554	-	-	
NextBridge	-0.00023			
H1N SSM	-0.00012	-	-	
H1N	-0.00497	-	-	
B2MLP	-0.00015	-	-	
NRLP	-0.00004	-	-	
Total of Allocation Factors	0.00000	-	-	

D. Revenue Reconciliation

Table 4 below compares WPLP's forecasted 2023 revenue, based on the rates and charge determinants in Table 2, with the 2023 revenue requirement calculated in Exhibit I-2-1.

Table 4 – 2023 Revenue Reconciliation

2023 Network Charge Determinants (kW)	239,022,678
2023 Network UTR Rate ($/kW)	$5.50
2023 WPLP Network Allocation Factor	0.02645
2023 Revenue Forecast	$34,742,662
2023 WPLP LTPL Revenue Requirement	$34,739,785
Difference due to Rounding	$2,877
	0.008%

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 in the OEB's Final Rate Order in EB-2021-0134 (December 2, 2021), 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, 2023.

WPLP's 2023 revenue requirement attributable to the Remote Connection Lines is $58,191,280. This amount includes an allocated base revenue requirement of $51,389,098, as detailed in Exhibit I-2-1, and interim disposition of deferral accounts of $6,802,183, 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 2023 results in a fixed monthly charge of $4,849,273 that would apply for each month from January 2023 to December 2023.

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 2023.

The bill impacts discussed in this schedule do not include any offsetting reductions to the portion of HORCI's existing revenue requirement related to the purchase of diesel fuel or the impact of any future changes in the revenue that HORCI receives from rates. Additionally, the RRRP rate impacts do not include the impact of any amounts provided under the Federal Funding Framework, which WPLP anticipates receiving in 2024, as discussed in Part C 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 2023 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.

A. Bill Impacts for Distribution-Connected Customers

The total bill impact of this application for a typical residential customer is an increase of approximately $0.20 per month, or 0.15%, and the total bill impact of this application for a typical General Service customer is an increase of approximately $0.51 per month, or 0.12%, as summarized in Table 1.

Table 1 – Summary of Total 2023 Bill Impact

Item	Description	Amount[1]	
		Residential	General Service
A	Typical monthly bill	$134.69 [2]	$424.67 [3]
B	Increase related to Network RTSR	$0.04	$0.09
C	Increase related to RRRP rate	$0.15	$0.42
D = B + C	Total bill increase	$0.20	$0.51
E = D / A	Bill impact (%)	0.15%	0.12%

B. Bill Impact Resulting from Line to Pickle Lake

As calculated in Exhibit I-3-1, the portion of WPLP's 2023 revenue requirement associated with the Line to Pickle and allocated to the UTR Network rate pool results in an increase in the UTR Network rate of $0.04/kW, or 0.56%. The resulting bill impact of this application for a typical residential customer is an increase of 0.03%, and the resulting bill impact of this application for a typical General Service customer is an increase of 0.02%, 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)	$134.69	$424.67
B	Portion of bill related to Network RTSR	$7.63[4]	$16.30
C	Increase in Network UTR	0.56%	0.56%
D = B x C	Bill increase	$0.04	$0.09
E = D / A	Bill impact (%)	0.03%	0.02%

[1] All amounts are inclusive of 13% HST and the Ontario Electricity Rebate.

[2] 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 March 15, 2022.

[3] 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 March 15, 2022.

[4] HONI R1 Network RTSR Rate of $0.0103/kWh * 750 kWh * 1.076 loss factor = $8.31 ($7.63 after 13% HST and 17% 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 2023 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 2022.

Table 3 – RRRP Rate Calculation

	2022	**2023**	**Change**
First Nations (O. Reg. 442/01, schedule 1)	$1,600,000	$1,600,000	$0
Algoma Power	$15,647,625	$15,647,625	$0
Hydro One Remote Communities Inc.	$35,223,000	$35,223,000	$0
Hydro One Remote Communities Inc. - WPLP	$21,514,230	$58,191,280	$36,677,050
Total RRRP Funding Required[5]	***$73,984,855***	***$110,661,905***	***$36,677,050***
Ontario TWh	132.2	132.2	0
RRRP Rate (Calculated)	$0.000560	$0.000837	$0.000277
RRRP Rate (Rounded to 4 Decimals)	$0.0006	$0.0008	$0.0002

[5] 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 2023 RRRP funding requirements for parties other than WPLP have been held constant from 2022 to 2023 for the purpose of bill impact analysis. WPLP expects that the OEB will consider the RRRP variance account balance and changes to 2023 RRRP funding for other parties when it determines the 2023 RRRP rate in due course.

The calculation in Table 3 shows that the calculated RRRP rate rounded to 4 decimal places would increase 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)	$134.69	$424.67
B	RRRP rate increase ($/kWh)	$0.0002	$0.0002
C = kWh * 1.076	Uplifted consumption (kWh)	807	2,192
D = B x C	Bill increase due to RRRP	$0.16	$0.44
E = D * (1+ 0.13 - 0.212)	Bill increase adjusted for HST and OER	$0.15	$0.42
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 2023 revenue requirement, as detailed in Table 5, below. WPLP relied on the IESO's December 2021 Year-to-Date weighted average wholesale market electricity charges[6] 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 ($/MWh)	118.17
B	Total Wholesale Transmission Charges ($/MWh)	12.75
C = B / A	Transmission % of Total Bill	10.79%
D	% Increase in Transmission Revenue Requirement	0.36%
E = C * D	% Bill Increase from Line to Pickle Lake	0.04%
F	Total RRRP Charges ($/MWh)	0.50

[6] https://www.ieso.ca/en/Power-Data/Monthly-Market-Report – Generated for December 2021

G = F / A	RRRP % of Total Bill	0.42%
H	% Increase in RRRP Rate	33%
I = G * H	% Bill Increase from Remote Connection Lines	0.14%
J = E + I	**Total % Bill Increase**	**0.18%**

E. Federal Funding Framework

In EB-2018-0190, WPLP described a contemplated Federal Funding Framework relating to its project, resulting from a March 12, 2018 Memorandum of Understanding between WPLP, Canada and Ontario.[7] 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.[8] At a high level, Canada will provide $1.55 billion in funding in relation to the project, which will serve to reduce the resulting ratepayer impact in two ways:

a) a portion of the funding will 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 would 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 would be provided to WPLP as a CIAC will be determined by WPLP's total project costs. As WPLP's costs increase, the CIAC amount increases at a rate that reduces 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 would therefore result 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

[7] EB-2018-0190, Exhibit J-1-2.

[8] EB-2018-0190, WPLP Reply Submission, February 15, 2019, pp. 27-29.

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 definitive documents regarding the Federal Funding Framework for the project. While funding remains conditional on appropriation by Parliament of the required funds, the definitive documents solidify the mechanics by which the funding would be provided.

WPLP anticipates that the distribution of funds will occur in 2024, following the later of: (a) the OEB's Decision and Order in respect of WPLP's 2023 application for approval of a 2024 test year revenue requirement; or (b) completion of construction and receipt of funds by the independent Trustee.

Accordingly, the bill impacts presented in this Application do not consider any potential reductions resulting from federal funding. WPLP expects that its application for a 2024 test year revenue requirement (filed in 2023) will incorporate the impact of federal funding on a forecast basis.