Exhibit 1: Administration

2027 Cost of Service

InnPower Corporation
EB-2026-0052

1 GLOSSARY

The following terms are used throughout InnPower's Cost of Service Applications, inclusive of all Exhibits and Appendices.

"ACA"	Asset Condition Assessment
"ADMS"	Advanced Distribution Management System
"AII"	Accelerated Investment Incentive
"Alectra"	Alectra Utilities Corporation
"AM"	Asset Management
"AMI"	Advanced Metering Infrastructure
"ANOVA"	Analysis of Variance
"AODA"	Accessibility for Ontarians with Disabilities Act
"APB"	Activity and Program Based Benchmarking
"APH"	Accounting Procedure Handbook
"APWA"	American Public Works Association
"ARC"	Affiliate Relationship Code
"AVC"	Assurances of Voluntary Compliance
"AWWA"	American Waterworks Association
"BATU"	Barrie Area Transmission Upgrade
"BESS"	Battery Energy Storage System
"BRE"	Business Reply Envelopes
"BOARD"	Ontario Energy Board
"CAPEX"	Capital Expenditures
"CBR"	Capacity Based Recovery
"CCA"	Capital Cost Allowance
"CCO"	Chief Compliance Officer
"CDD"	Cooling Degree Days
"CDM"	Conservation and Demand Management
"CEO"	Chief Executive Officer
"CER"	Customer Engagement Representative

"CFO"	Chief Financial Officer
"CHEC"	Cornerstone Hydro Electric Concepts
"CIS"	Customer Information System
"COO"	Chief Operating Officer
"COP"	Cost of Power
"COS"	Chief of Staff, Cost of Service
"CP"	Coincident Peak
"CSA"	Canadian Standard Association
"CSF"	Cyber Security Framework
"CSG"	Corporate Sustainability Goals
"DAI"	Data Availability Indicator
"DER"	Distributed Energy Resources
"DERMS"	Distributed Energy Resource Management System
"DG"	Distributed Generation
"DGA"	Dissolved Gas Analysis
"DIR"	Disconnect, Inspect and Reconnect
"DRP"	Distribution Rate Protection
"DSC"	Distribution System Code
"DSOs"	Distribution System Operators
"DSP"	Distribution System Plan
"DVA"	Deferral and Variance Account
"EA"	Environmental Assessment
"EDA"	Electricity Distributors Association
"EDI"	Equity, Diversity and Inclusion
"EDDVAR Report"	Electricity Distributors' Deferral and Variance Account Review Initiative
"EOL"	End of Life
"EPA"	Environmental Protection Agency
"ERP"	Enterprise Resource Planning
"ESA"	Electrical Safety Authority
"ESG"	Environmental, Social and Governance
"EUM"	Effective Utility Management

“EV”	Electric Vehicle
“FILING REQUIREMENTS”	Chapter 2 of the OEB’s Filing Requirements for Electricity Distribution Applications”, dated December 16, 2025
“FIT”	Feed-In Tariff
“FLSIR”	Fault-Location, Isolation and Restoration
“FTEs”	Full-Time Equivalent Staff
“GA”	Global Adjustment
“GHG”	Greenhouse Gas
“GIS”	Geographical Information System
“GS”	General Service
“GTA”	Greater Toronto Area
“GTH”	Geothermal Heating
“GUP”	Good Utility Practice
“HDD”	Heating Degree Days
“HEWITT”	Hewitt Developers Group
“HI”	Health Index
“HOEP”	Hourly Energy Price
“HONI”	Hydro One Network Inc.
“HSE”	Health, Safety and Environment
“HWY”	Highway
“IBR”	Innisfil Beach Road
“ICM”	Incremental Capital Module
“IESO”	Independent Electricity System Operator
“IFRS”	International Financial Reporting Standards
“INNISFIL HYDRO”	Innisfil Hydro Distribution System Limited
“INNPOWER”	InnPower Corporation
“IPC”	InnPower Corporation
“IPCC”	Intergovernmentel Panel on Climate Change
“IRM”	Incentive Rate Mechanism
“IRRP”	Integrated Regional Resource Planning
“ISMS”	Information Security Management System
“IT”	Information Technology

“ITP”	InnTerprises Inc.
“IUI”	InnServices Utilities Inc.
“KM”	Kilometer
“KPIs”	Key Performance Indicators
“KV”	Kilovolt
“KWH”	Kilowatt Hours
“LDC”	Local Distribution Company
“LEAP”	Low-Income Energy Assistance Program
“LEED”	Leadership in Energy and Environmental Design
“LIBRARY”	Innisfil ideaLAB & Library
“LIS”	Load Interrupted Switches
“LMS”	Learning Management System
“LP”	Local Planning
“LTFP”	Long-Term Financial Plan
“LV”	Low Voltage
“MCR”	Municipal Comprehensive Review
“MEARIE”	Municipal Electric Advisory Council
“MENDM”	Ministry of Energy, Northern Development and Mines
“METSCO”	METSCO Energy Solutions Inc.
“MIFRS”	Modified International Financial Reporting Standards
“MNP”	Meyers, Norris, Penny
“MP”	Market Participants
“MSC”	Municipal Services Corporation
“MSP”	Master Servicing Plan
“MVA”	Mega Volt Amp
“MW”	Megawatts
“NA”	Needs Assessment
“NAC”	Normalized Average Use per Customer
“NCP”	Non-Coincident Peak
“NERC”	North American Electric Reliability Corporation
“NIST”	National Institute of Standards and Technology
“NRCAN”	Natural Resources Canada

“NPV”	Net Present Value
“OEB”	Ontario Energy Board
“OESP”	Ontario Electricity Support Program
“OM&A”	Operation, Maintenance and Administrative Expenses
“OMS”	Outage Management System
“OPEX”	Operating Expense
“ORTAC”	Ontario Resource and Transmission Assessment Criteria
“OT”	Operational Technology
“PDF”	Peak Demand Factor
“PEG”	Pacific Economics Group
“PILs”	Payments in Lieu of Taxes
“PMS”	Performance Management System
“PP&E”	Property, Plant and Equipment
“PR”	Public Relations
“PV”	Photovoltaic Generation
“Q1”	Quarter One
“Q2”	Quarter Two
“Q3”	Quarter Three
“Q4”	Quarter Four
“QMS”	Quality Management System
“R/C”	Revenue to Cost
“RBDs”	Radial Boom Derricks
“RCVA”	Retail Cost Variance Account
“RIP”	Regional Infrastructure Planning
“ROE”	Return on Equity
“RPP”	Regulated Price Plan
“RRF”	Renewed Regulatory Framework
“RRR”	Reporting and Recordkeeping Requirements
“RRRP”	Rural or Remote Electricity Rate Protection
“RRRW”	Revenue Requirement Work Form
“RSC”	Retail Settlement Code
“RSVA”	Retail Settlement Variance Account

"RSVACN"	Retail Settlement Variance Account – Retail Transmission Connection Charges
"RSVAGA"	Retail Settlement Variance Account – Global Adjustment
"RSVANW"	Retail Settlement Variance Account – Retail Transmission Network Charge
"RSVAPOWER"	Retail Settlement Variance Account – Power
"RSVAWMS"	Retail Settlement Variance Account - Wholesale Market Service
"RTSR"	Retail Transmission Service Rates
"RVH"	Royal Victoria Hospital
"SA"	Scoping Assessment
"SAIDI"	System Average Interruption Duration Index
"SAIFI"	System Average Interruption Frequency Index
"SALEM"	Salem Developers Group
"SAMP"	Strategic Asset Management Plan
"SBUA"	Small Business Utility Alliance
"SCADA"	Supervisory Control and Data Acquisition
"SCORECARD"	Utility Scorecard
"SDG"	Sustainable Development Goals
"SMC"	Smart Meter Charge
"SME"	Smart Meter Entity
"SQR"	Service Quality Requirements
"SSS"	Standard Service Supply
"SSSC"	Standard Supply Service Code
"SSPS"	South Simcoe Police Services
"SWOT"	Strengths, Weaknesses, Opportunities and Threats
"TGB"	Tower Gateway Base Station
"TOTEX"	Total Expenditures
"TOWN"	Town of Innisfil
"TLF"	Total Loss Factor
"TS"	Transformer Station
"TSC"	Transmission System Code
"TUL"	Typical Useful Life
"TWG"	Technical Working Group
"UCAP"	Unforced Capacity

“UCCWG”	Utilities Climate Change Working Group
“ULO”	Ultra-Low Overnight Regulated Price Plan
“UN”	United Nations
“UNM”	Unified Network Model
“USoA”	Uniform System of Accounts
“USF”	Utilities Standard Forum
“USL”	Unmetered Scattered Load
“UTR”	Uniform Transmission Rates
“VECC”	Vulnerable Energy Consumers Coalition
“VP”	Vice President
“WACC”	Weighted Average Cost of Capital
“WC”	Working Capital
“WCA”	Working Capital Allowance
“WIP”	Work in Progress
“WMS”	Wholesale Market Service Charges
“WMS Charges”	Wholesale Market Service Charges
“YEARBOOK”	Electricity Distributor Yearbook

2 LEGAL APPLICATION REQUEST

InnPower Corporation ("**InnPower**") is a corporation incorporated under the *Ontario Business Corporations Act*, and licenced by the Ontario Energy Board ("**OEB**") to own and operate electricity distribution facilities under licence number ED-2002-0520. InnPower hereby applies to the OEB pursuant to section 78 of the *Ontario Energy Board Act, 1998* (the "OEB Act", for the following approvals:

(a) the 2027 Test Year revenue requirement as proposed in Exhibit 6;
(b) the 2027 distribution rates and charges, effective January 1, 2027, as proposed in Exhibit 8;
(c) the Distribution System Plan filed in Exhibit 2;
(d) the load forecast as documented in Exhibit 3;
(e) opening rate base for 2027, including the changes to accounting methodology for capital contribution requirements discussed in Exhibit 2;
(f) inclusion into the 2027 opening rate base the remaining amounts of payments made to Hydro One for the BATU project and related CCRA;
(g) approvals related to deferral and variance accounts, as proposed in Exhibit 9, including:
    a. Disposition of balances in existing deferral and variance accounts;
    b. Continuation of certain existing deferral and variance accounts;
    c. Discontinuance of certain deferral and variance accounts; and
    d. Approval of the new deferral and variance accounts and draft accounting orders.
(h) continuation of distributor-specific and generic OEB Specific Service Charges at proposed in Exhibit 8;
(i) loss factors, as detailed in Exhibit 8;
(j) establish an account to recover any differences between the interim rates and the actual rates effective January 1, 2027 if the requested approvals cannot be issued by the OEB in time to implement final rates effective January 1, 2027.
(k) other items or amounts that may be requested by InnPower in the course of the proceeding, and such other relief or entitlements that the OEB may grant.

This Application is prepared in accordance with the OEB's: Chapter 2 Cost of Service Filing Requirements for Electricity Distribution Cost of Service Rate Applications - 2026 Edition for 2027 Rate Applications issued December 16, 2025 (the "Chapter 2 Filing Requirements"); Chapter 5 Distribution System Plan *Filing Requirements For Electricity Distribution Rate Applications - 2026 Edition for 2027 Rate Applications* issued December 16, 2025 (the "Chapter 5 Filing Requirements"); Report of the Board: *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, dated October 18, 2012; and Handbook for Utility Rate Applications, dated October 13, 2016.

This Application is supported by pre-filed written evidence which may be amended from time to time. For the reasons set out in this Application, InnPower submits that the proposed distribution rates and other charges are just and reasonable.

1. Notice of Hearing Publication

InnPower Corporation recommends that the Notice of Hearing be published in the “Barrie Advance” and “Simcoe.com”, as these newspapers have the highest distribution and online postings available to Innisfil and South Barrie residents.

2. Form of Hearing Requested

This Application is supported by written evidence. The written evidence will be pre-filed and may be amended from time to time, prior to the Board’s final decision on the Application.

InnPower Corporation requests that, pursuant to the Board’s Rules of Practice and Procedure, this proceeding be conducted by way of a written hearing. A written hearing is the most efficient and cost-effective way to adjudicate the application.

3. Application Information & Filing Requirements

Per the OEB’s Chapter 2 Filing Requirements, InnPower is required to provide historical financial information up to its last rebasing application.

Per discussions with the OEB, InnPower has provided Chapter 2 Appendices with historical information from 2023 to the test year of 2027, and Exhibit 2 – Appendix A Distribution System Plan includes historical capital expenditures including variance analysis from 2023 through to 2031.

For reference, if Parties seek information relating to 2022, it can be found in the public record of EB-2023-0033.

3 EARLY REBASING BUSINESS CASE

InnPower submits this application to the Ontario Energy Board ("OEB") seeking approval for early rebasing, with rates to be effective January 1, 2027 in advance of its scheduled rebasing for January 1, 2029 rates. As detailed below, InnPower satisfies the test for early rebasing in section 2.0.4 of the OEB's Chapter 2 Filing Requirements. In particular, InnPower meets the "off-ramp" criteria in section 3.2.10 of Chapter 3, as its achieved return is more than 300 basis points below its approved deemed return on equity of 9.21%.

Although it is not required to do so under section 2.0.4 of Chapter 2 where the "off-ramp" criteria are satisfied, in this section InnPower nevertheless addresses why and how it cannot adequately manage its resources and financial needs during the remainder of its IRM plan period.

The reasons why InnPower cannot adequately manage <u>during the remainder of the IRM plan period include:</u>

- Elevated levels of debt over the remainder of the IRM plan period which is an impediment to InnPower's ability receive the requisite cash flow to service its customer growth, system reliability and overall capital expenditure plan. Details on the impact of elevated levels of debt are provided in the section below.
- Meet staffing needs related to InnPower's growing customer base, and operational size, has required additional resources to address 1) existing staff burnout, 2) unplanned staff departures, 3) addressing retirements, and 4) increasing the number of operational staff to address business and service needs. These drivers have resulted in management increasing its staffing; primarily to its non-management compliment of FTE. InnPower's management including executive FTE is forecast to remain at 9 FTE between its last rebasing in 2024 and the forecasted 2027 Test Year and its non-management FTE will increase from 64 FTE to 75 FTE. Without these additional FTE InnPower will be challenged to deliver on its service requirements.
- Address a changing government policy and regulatory environment that has InnPower's service territory as a primary area for economic growth in the Province of Ontario; and
- Provide for adequate recovery of capital contributions that have been updated since the last rebasing application. Specifically, the OEB-approved Net Book Value ("NBV") of

Property, Plant and Equipment ("PP&E") underpinning opening 2024 rate base was $68.1 million in EB-2023-0033. Subsequent to InnPower's closing of the 2023 fiscal year and the implementation of the capital contribution adjustment detailed below, the opening PP&E informing 2024 rate base was $79.1 million on an actual basis; resulting in a substantial underfunding of InnPower's capital-related revenue requirement.

This schedule provides the following details underpinning InnPower's application for early rebasing:

- A discussion of how sustained growth necessitates substantial infrastructure investment to support local economic growth;
- Regulatory compliant revisions to capital contribution treatment have materially increased InnPower's unfunded rate base, creating a growing disconnect between actual capital costs and OEB approved funding that now threatens earnings, cash flow, and challenges InnPower to sustain continued system expansion;
- Only $6 million of InnPower's $20 million capital contribution to Hydro One's BATU project was included in ratebase in 2024 – creating a further structural shortfall in revenue requirement;
- OM&A funding approved in InnPower's 2024 Cost of Service application no longer reflects the scale, complexity, and regulatory demands of a rapidly growing utility, resulting in material operational underfunding and its ability to meet ongoing electricity service obligations;
- A summary of incremental cost pressures affecting InnPower which contribute to the need for early rebasing.

Accordingly, InnPower submits that early rebasing of the utility at this time is necessary and in the public interest.

1. InnPower Meets the OEB's Requirements for Early Rebasing

InnPower requires early rebasing of its distribution rates effective January 1st 2027 to maintain its ongoing financial viability by bringing the utility's return on equity back from below 300-basis points relative to its approved return on equity, and deliver the investments necessary to meet very high levels of growth within InnPower's service territory, which are principally driven by municipal, regional, provincial and federal mandates. InnPower last rebased its rates in 2024 under a Price Cap Incentive Rate-Setting ("Price Cap IR") framework and absent this early rebasing request its current rate term would extend through 2028.[1]

Chapter 3 of the OEB Filing Requirements states that distributors meet off ramp conditions when their earnings are more than 300 basis points above or below their approved return on equity.

> A distributor that files a cost of service application earlier than scheduled must justify, in its application, why an early rebasing is required. <u>This requirement only applies if the "off ramp" conditions have not been met.</u> In particular, the distributor must demonstrate why and how it cannot adequately manage its resources and financial needs during the remainder of its IRM plan period.[2]
> For the Price Cap IR and Annual IR index rate-setting options, a regulatory review may be triggered if a distributor's earnings are outside of a dead band of +/- 300 basis points from the OEB-approved ROE.[3]

As shown in Table 1 below, InnPower first started approaching the -300 basis points dead band in 2024 and by its 2025 return on equity was more than 400 basis points lower than its OEB-approved return on equity; demonstrating the utility has met the off-ramp condition for early rebasing.

Table 1: InnPower Achieved vs Approved Return on Equity (%)

	Actual	Actual	Forecast	Forecast	Forecast	
Year	2024	2025	2026	2027	2028	Average

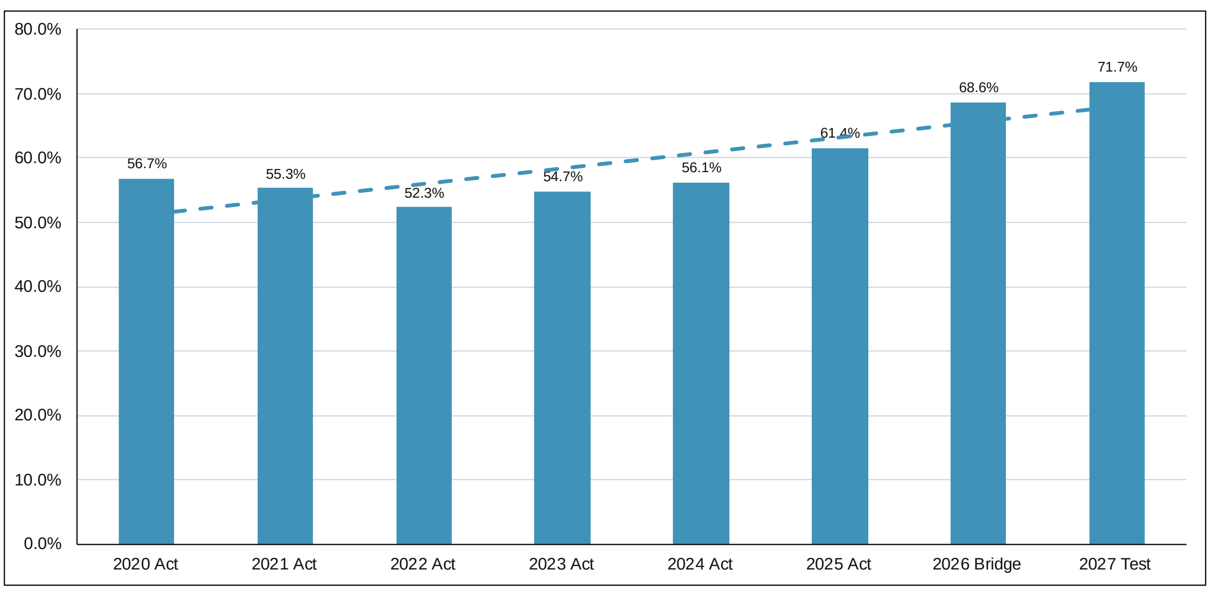
[1] EB-2023-0033.
[2] Ontario Energy Board, "Filing Requirements for Electricity Distribution Cost of Service Rate Applications – 2026 Edition for 2027 Rate Applications, section 2.0.4, page 3.
[3] Ontario Energy Board, "Filing Requirements For Electricity Distribution Rate Applications, Chapter 3 Incentive Rate-Setting Applications", section 3.2.10, page 21.

Approved Return on Equity	9.21%	9.21%	9.21%	9.21%	9.21%	9.21%
Actual and Forecast Return on Equity	6.77%	4.87%	0.94%	-1.18%	-2.13%	1.85%
Variance	-2.44%	-4.34%	-8.27%	-10.39%	-11.34%	-7.36%

Importantly, the drivers of these financial results are not transient or reversible, and will continue to get substantially more pronounced if left unaddressed until the previously planned rebasing year of 2029. As shown above, InnPower is forecasting a 2026 ROE that is more than 800 basis points below OEB-approved, and a shift into negative ROE in 2027 and 2028 absent early rebasing.

The deterioration of InnPower's ROE has had significant impacts on the utility's financial health to date. Since 2024 InnPower's debt to capitalization ratio has risen rapidly; from below the OEB's deemed expectation of 60%, rising to a forecasted 72% debt / 28% equity absent early rebasing in 2027, as shown below.

Figure 1 InnPower Debt to Capitalization 2020 to 2027 Assuming No 2027 Rebasing (%)



Early rebasing will not in and of itself return InnPower to a capital structure of 60% debt / 40% equity in the immediate future, rebasing in 2027 would reverse this trend and hold InnPower's debt-to-capitalization ratio below 70%, at a forecast level of 69%. Absent this relief, InnPower is at risk of failing to meet its debt covenants on a consistent basis; hindering its ability to finance and grow moving forward. InnPower is currently forecasting to miss its debt-to-capitalization covenants for both 2026 and 2027, and forecasts being substantially offside its debt service coverage covenants into the 2027 year absent early rebasing.

As further described in this Schedule, InnPower's deteriorating financial situation risks its capacity to meet its obligations to provide safe and reliable service, while also making the system investments required to enable ongoing population, housing and commercial growth targets. In alignment with the OEB's statutory objectives to facilitate the maintenance of a financially viable electricity sector and support economic growth,[4] InnPower's near-term financial constraints must be alleviated at a critical juncture of growth in the communities served by the utility. InnPower cannot wait until 2029 to rectify the shortfall shown above.

2. InnPower's Operating Environment Creates Unexpected Challenges

Like all electricity distributors in Ontario, InnPower is required by section 28 of the *Electricity Act, 1998,* section 7 of its distribution licence (ED-2002-0520), and section 3 of the OEB Distribution System Code ("DSC") to connect requesting customers to its electricity distribution system.[5] InnPower continues to experience significant customer growth which is a positive challenge for it. This can be seen in the map and table below that shows the current connection projects underway in InnPower's service territory:

Figure 2 InnPower Map of Current Connection Projects

[4] Ontario Energy Board Act, 1998, Section 1(1), Consolidation date December 11, 2025
[5] Electricity Act, 1998, S.O. 1998, c. 15, Sched A, section 28; Ontario Energy Board Distribution System Code, section 3.

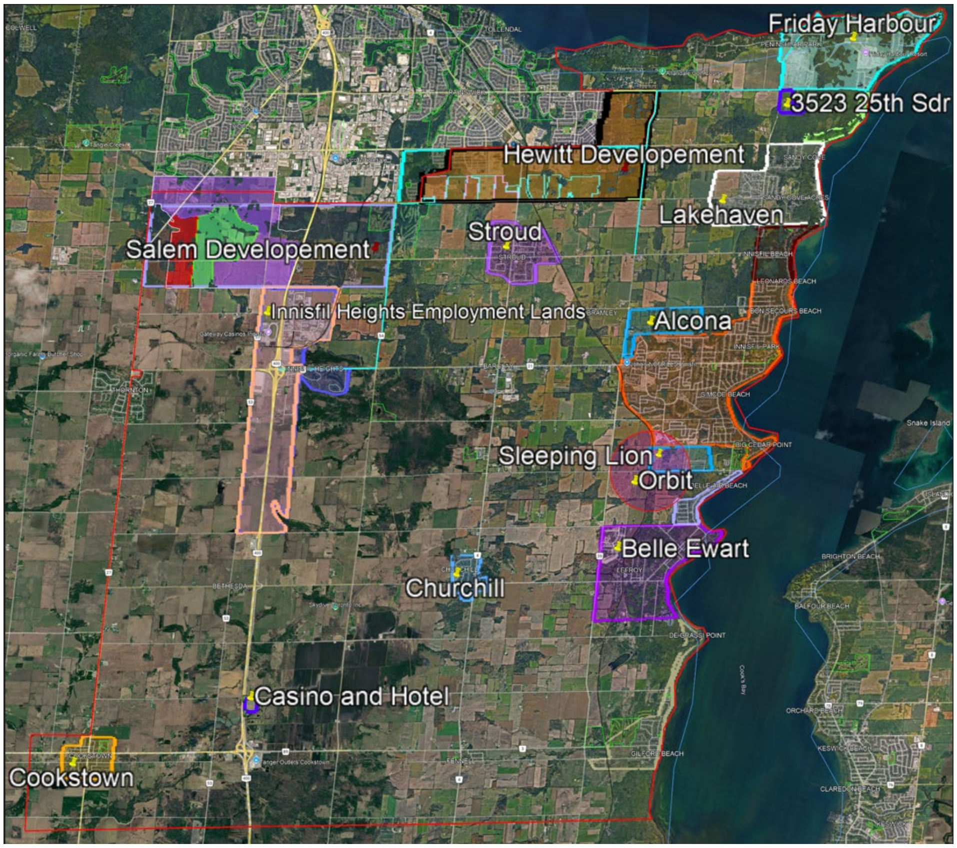

Friday Harbour
3523 25th Sdr
Hewitt Developement
Lakehaven
Salem Developement
Stroud
Innisfil Heights Employment Lands
Alcona
Sleeping Lion
Orbit
Belle Ewart
Churchill
Casino and Hotel
Cookstown

Table 1: List of New Developments from 2026 to 2030

Development	Forecast # Customers	Forecast # Businesses
Salem Developments	**738**	**4**
Hewitt's Developments	**2,235**	**4**
Alcona	**790**	**78**
Belle Ewart	**520**	**22**
Friday Harbour	**186**	**7**
Gateway Casino	**0**	**2**
Lake Haven	**326**	**7**
Cookstown	**64**	**0**
Stroud	**201**	**2**
Sleeping Lion	**155**	**0**
Orbit	**154**	**1**
Churchill	**42**	**1**
3523 25th Sideroad	**105**	**3**
Innisfil Heights	**0**	**7**
Others	**47**	**5**

As part of this obligation, InnPower is required to facilitate system expansion and system enhancement work where necessary to connect requesting customers. In normal course, substantial portions of the gross capital expenditures required to facilitate customer growth is paid by way of capital contribution, and the scale of connection and expansion costs relative to the utility's existing customer base and financial footprint is such that variations in connection and expansion can be managed as part of day-to-day operations.

Unlike most electricity distributors in Ontario, InnPower operates in a circumstance wherein the utility is charged with delivering growth, driven in part by substantial government policy direction, which creates growth-related obligations scaled well above current size. In this environment, InnPower is atypical in its sensitivity to variances in costs, revenues, and external market forces.

Mandates from multiple levels of government, including the Town of Innisfil and South Barrie where InnPower's service territory is located, the Independent Electricity System Operator ("IESO"), and the Government of Ontario, have and will continue to drive substantial population growth, housing development, and economic growth that require corresponding system growth at InnPower. Over the 2021 to 2051 period, the Town of Innisfil is expected to grow by approximately 40,000 residents, 18,000 new households, and more than 20,000 jobs. Similarly, the City of Barrie (including the fast-growing South portion which is served by InnPower) is expected to grow by approximately 145,000 residents, 64,000 new households, and more than 66,000 jobs. Recent reviews of these municipal projections confirmed them as appropriate, suitable for current planning, and guided by smart planning principles.[6]

The Government of Ontario similarly continues to plan for and incent significant housing growth in the immediate future. The Province has created a $1.2 billion Building Faster Fund to support this outcome, having committed to build 1.5 million homes by 2031. The Town of Innisfil has pledged a 10-year target of 6,300 units, and the City of Barrie has pledged 23,000 units in support of this objective. The Government of Canada and Province of Ontario have further implemented measures to stimulate housing demand in the next five years; reducing HST paid on new homes and reducing development charges for a 3 year period. These measures are anticipated to stimulate construction activity over the next 3 to 5 years.[7]

Accelerating more recently, Innisfil is set to be the site of significant industrial and commercial development. The Town of Innisfil has approved extension of urban boundaries to accommodate 1,600 jobs in industrial and advanced manufacturing, with targeted sectors for development including advanced manufacturing, life sciences and technology.[8] All of these developments will increase InnPower's system size, and will rely on InnPower's ability to supply new firms with

[6] Appendix 6 , Petramala Research Inc., Economic Conditions, Growth Outlook and Economics Benefits Assessment: InnPower Service Territory, June, 2026, pages 17-18
[7] Ibid., page 19
[8] Ibid., page 20

adequate electricity in a timely manner in order to operate. The investments made by InnPower ultimately support significant economic benefits for the region, resulting in an estimated $276 million in annual economic activity, 2,226 ongoing jobs, and $134 million in annual wages and salaries at full build-out.[9]

Beyond the need to deliver local assets, services, and capacity, this level of growth drives upstream transmission investment requirements. As described in Exhibit 2, Tab 5, Schedule 7 of EB-2023-0033, the Barrie Area Transmission Upgrade ("BATU") project placed into service in 2023 required the upgrading of two existing 115 kV circuits to 230 kV between Essa Transformer Station ("TS") and Barrie TS, constructing new 230 kV connection points at the Essa TS, and upgrading and expanding the existing Barrie TS with new 230–44 kV facilities. To facilitate this work, InnPower was required to make a capital contribution to Hydro One Networks Inc. ("Hydro One") of $20 million dollars via a series of five $4 million payments.[10] $6 million of the BATU contribution (i.e. 1.5 out of 5 total payments) was included in InnPower's OEB-approved 2024 rate base, with the remaining $13.82 million included in InnPower's 2027 opening rate base in this application (less accumulated depreciation to date).

Looking forward, InnPower will require a new Transformer Station ("TS") by 2031, and is currently in the planning and contracting phase relating to this project as described in Exhibit 2, Appendix 8 Distribution System Plan. Notably, the 2022 South Georgina Bay-Muskoka RIP[11] (page 33) pegs the cost of this transmission line extension at <u>$14 million</u>. InnPower's Distribution System Plan in EB-2023-0033 previously anticipated the TS to cost $23.3 million with an associated investment of $8.2 million relating to a Hydro One transmission line extension ($31.5 million in total), in 2028.[12] However, the combined cost of the TS and transmission line have expanded to an estimated cost of $148 million on a combined basis based on updated Hydro One estimates; a significant portion of which InnPower anticipates being responsible for via capital contribution.

As a consequence of this more than <u>6-times increase in estimated costs by Hydro One</u>, InnPower is taking active steps to attempt to mitigate the cost consequence on the new line and TS on InnPower's local ratepayers (while ensuring fairness to the provincial transmission rate pool) by

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[9] Ibid., page 7
[10] See Exhibit 9 for further details regarding actual expenditures and capital-related revenue requirement
[11] South Georgian Bay-Muskoka – Regional Infrastructure Plan, December 16, 2022 (LINk)
[12] EB-2023-0033, Exhibit 2, Distribution System Plan, page 136, Table 5.4-28

incorporating InnPower Transmission, which as of the date hereof, has applied to the OEB for an electricity transmission licence. As explained at the Transmission Connections Review working group on June 13, 2025 by counsel to InnPower (Appendix 3: BLG_Tx_Con_Rvw_PPT-20250613), by building the new TS through InnPower (Transmission) LP, pursuant to the Transmission System Code, the line connecting the Barrie TS to the new TS will be a "network" facility. InnPower sought guidance from Industry Relations on the rate impact of this approach, and Industry Relations confirmed that "*where a connecting customer is the sole beneficiary of the investment in a network facility, then the connecting customer should be required to pay for the investment.*" This is consistent with Section 6.3.5 of the TSC that enables a transmitter to require a customer to make a capital contribution to network facilities in "exceptional circumstances." The implications of this response are significant. It means that even if the line is categorized in the "network" rate pool – the balance of the customers paying into that rate pool will be protected from any cross-subsidization risk because 100% of the costs of the line will be funded by InnPower.

If Hydro One builds the line and TS, the assets will most likely be classified into the line and transformation connection rate pools and InnPower customers will be required to pay incremental UTRs of:

- $6.37/kW/month - for use of assets in the network rate pool;
- $1.00/kW/month - for use of assets in the line connection rate pool; and
- $3.37/kW/month - for use of assets in the transformation connection rate pool.

Applying the OEB's discounted cash flow model (see Appendix 5 of the TSC) over 25 years to the incremental load InnPower is going to bring onto the system, this will result in InnPower customers paying:

- $48.8 million in incremental network service rates;
- $10.2 million in incremental line connection rates; and
- $25.6 million in incremental transformation connection rates.

In this context, if Hydro One builds the new line and TS, since the assets will be in the line and transformation connection rate pools, InnPower customers will only be entitled to $35.8 million as an offset to the cost of the project. And those offsets would need to be adjusted to account for any amounts already accounted for in respect of the BATU CCRA (only Hydro One could do this).

Under this scenario, because of the OEB's rules prohibiting cross-subsidization between rate pools, even though the load growth in InnPower's service area will pay $48.8 million in incremental network service rates – InnPower customers will not see any benefit from these incremental fees being paid in terms of a reduction in the capital contributions payable to Hydro One.

If, however, InnPower Transmission builds the new TS, which is the proposed solution, then by operation of the TSC the line connecting the new TS will be categorized in the network pool, and based on the Industry Relations response, InnPower will still be responsible for funding 100% of the line.

In this case, InnPower customers will be required to pay incremental UTRs of:

- $6.37/kW/month - for use of assets in the network rate pool; and
- $3.37/kW/month - for use of assets in the transformation connection rate pool.

Applying the OEB's TSC discounted cash flow model over 25 years to the incremental load InnPower is going to bring onto the system, this will result in InnPower customers paying:

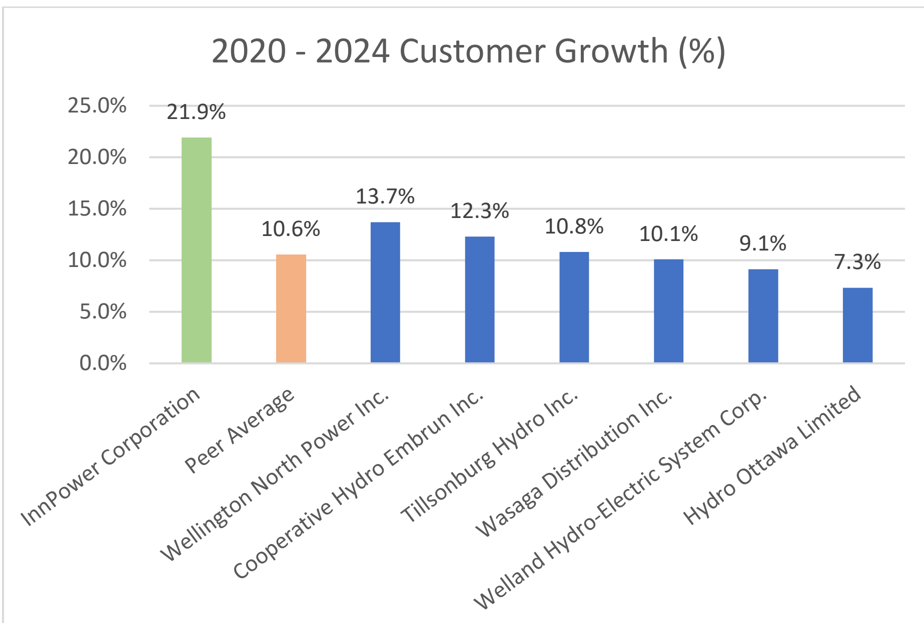
- $48.8 million in incremental network service rates; and
- $25.6 million in incremental transformation connection rates.

In this context, if InnPower Transmission builds the new TS, since the assets will be in the network (the line) and transformation connection (the new TS) rate pools, InnPower customers will under Appendix 5 of the TSC be entitled to the full credit of $74.4 million as an offset to the cost of the project. InnPower's approach ensures that its customers will get the full benefit of the incremental UTRs created through the new load growth as an offset to these costs.

InnPower's 2027 early rebasing application includes required investments in its Distribution System Plan at Exhibit 2 Appendix 8, but does not at this time request rate relief relating to its transmission needs as the precise timing, cost, and structure of the required transmission investment solidifies. As articulated above, InnPower has actively explored alternative structures to manage the cost consequences of these necessary investments for its ratepayers. Under all approaches, InnPower and its staff must manage the planning, engineering, financing, and managerial burdens of a substantial, long-lead transmission built-out of this nature.

The levels of growth and associated investments required at InnPower relative to its existing size is atypical in Ontario. A comparison of InnPower's customer growth to that of the six next highest growth distributors in Ontario demonstrates this in the figure below, which shows InnPower's customer growth over the 2020 to 2024 period as more than double that of the average for these six other utilities.

Figure 3 Highest Customer Growth (%) Distributors in Ontario (2020 – 2024)



For clarity, it is not new information for InnPower leadership, the OEB, or stakeholders that InnPower occupies a position as a rapidly emerging mid-sized utility with customer and system growth more typical of a much larger entity. As noted in InnPower's 2024 Cost of Service, "InnPower is in a state of tremendous growth, underpinned by a small but mighty team of highly skilled and hardworking employees. Over the next five years, InnPower's customers are expected to increase by 29%..."[13] What has become apparent since InnPower's 2024 Cost of Service is the

[13] EB-2023-0033, Exhibit 1, Tab 1, Schedule 5, page 45

sensitivity this circumstance creates to changes in costs, changes in revenues, and shifting external market forces.

InnPower has experienced shifts in costs, revenues, and market forces which could not be reasonably anticipated at the time of its 2024 Cost of Service application, and as such requires a rebasing of rates effective January 1st 2027 to meet its obligations to provide safe and reliable service, to meet its obligation to connect new customers, and to facilitate economic growth in accordance with the OEB's mandate.[14] The following sections detail the drivers of InnPower's need to rebase in 2027, and demonstrate why waiting until 2029 to rebase is untenable.

3. Change to Capital Contribution Methodology has Increased Financial Requirements

As previously noted, InnPower's capital expenditures are substantially weighted towards investments which provide for system expansion and connections to facilitate customer growth. On average over the 2020 to 2024 period, System Access investments represented 48% of total net capital, and gross capital averaged approximately 2.02 times net capital. Stated differently, of InnPower's total gross capital expenditures over the 2020 to 2024 period of $110.5 million, $55.8 million were paid by way of capital contribution. While this reality helps ensure sufficient capital is available for InnPower to grow to mandated levels, it also makes InnPower more financially sensitive to any unexpected variances in the level of contributed capital provided.

In 2024, subsequent to approval of InnPower's 2024 Cost of Service application, the company initiated internal review of its economic evaluation practices. As a result of this review, in compliance with the Distribution System Code, InnPower made certain revisions and restatement of its prior financials in addition to a revision of its capital contribution and net capital expenditure forecasts on a go forward basis. In addition to this internal review and follow up, subsequent to InnPower's 2024 Cost of Service application approval revisions were made to Appendix B of the Distribution System Code extending the revenue horizon applicable to residential customers, which account for the vast majority of InnPower's substantial connection portfolio.

The net effect of the revisions is a material decrease in capital contributions that were estimated in the 2024 Cost of Service application (in some instances, retrospectively back to 2021), and a corresponding increase in net capital expenditures and in-service additions moving forward.

[14] Ontario Energy Board Act, 1998, S.O. 1998, Section 1(1)

Retrospectively, the revisions above had a substantial impact on 2024 opening rate base and net income relative to InnPower's expectation at the time of the OEB's approval of its 2024 Cost of Service application. Specifically, the OEB-approved Net Book Value ("NBV") of Property, Plant and Equipment ("PP&E") underpinning opening 2024 rate base was $68.1 million[15] in EB-2023-0033. Subsequent to InnPower's closing of the 2023 fiscal year and the implementation of the capital contribution adjustment noted, the opening PP&E informing 2024 rate base was $79.1 million on an actual basis; resulting in a substantial underfunding of InnPower's capital-related revenue requirement.

Importantly, InnPower is not seeking any approval for retroactive ratemaking. InnPower has and will bear the consequence of its understated rate base from 2024-2026. However, InnPower is seeking OEB approval to fix this issue in 2027 and going forward, to meet the growth needs of its service territory.

Prospectively and as shown in Table 3 below, where previously the OEB had approved in-service additions of $10.0 million in 2024, InnPower's actual in-service additions in 2024 were $17.2 million; resulting in a closing 2024 PP&E NBV of $93.3 million on an actual basis relative to the 2024 OEB-approved closing PP&E NBV of $75.3 million. Continuing into 2025 on an actual basis, where InnPower anticipated net in-service additions of $9.2 million, actuals proved to be $17.5 million, while in 2026 forecast net in-service additions were $9.3 million, and are now forecast to be $16.4 million.

Table 2: InnPower OEB-Approved & Prior Forecast In-Service Additions vs. Actuals and Current Forecast

In-Service Addition Variances	2024	2025	2026	2027	Total
EB-2023-0033 OEB Approved / Forecasts	$10.1	$9.2	$9.3	$9.3	**$37.8**
Actuals / Current Forecast	$17.2	$17.5	$16.4	$23.4	**$74.5**
Variance	**$7.1**	**$8.3**	**$7.1**	**$14.0**	**$36.6**

As shown above, InnPower's expected in-service additions through 2027 are $36.6 million higher than anticipated and requested in EB-2023-0033; approximately double expectations. Based on

[15] EB-2023-0033, Decision & Order, Attachment: Settlement Proposal, page 89, row Total PP&E for Rate Base Purposes, column Net Book Value

the commonly established conservative rule of capital-related revenue requirement being approximately 10% of rate base additions, this variance alone would drive a shortfall in capital-related revenue requirement of $3.7 million. Importantly, the interest expense associated with this gap in rate base represents a material cost impacting InnPower's cashflow and debt-to-equity ratio.

In conclusion, the revisions implemented to ensure compliance with the current Distribution System Code and resulting capital contributions drive an unreasonable gap between InnPower's actual cost to serve, and the funding currently provided in distribution rates. To date and through 2026, the consequence of this revision has been significant negative impacts for InnPower's earnings and financial health. While in retrospect InnPower's 2024 OEB-approved rate base should have been substantially larger than was approved for inclusion in distribution rates, thus far ratepayers have continued to receive safe and reliable service, and connections have continued to be made in a timely manner. Moving forward however, failing to address this and other drivers of substantial underfunding risks jeopardizing these outcomes, and risks failing to meet the obligations of the utility and the OEB's mandate with respect to the electricity sector.

InnPower cannot wait until 2029 to rectify the issue of unfunded capital via rebasing, and must re-align its rates with rate base in the requested 2027 test year. While managing the substantial growth in its service territory is challenging, InnPower has risen to this challenge over many years. However, the financial strain created by substantial amounts of unfunded capital stand to erode the utility's financing power at a critical juncture, with the most likely consequence being delays in construction and connection of assets for customers which InnPower is obligated to serve.

4. InnPower's Operational Funding must be Scaled to its Operations

In its 2024 Cost of Service application, InnPower brought forward an application requesting approval of $8.3 million in OM&A expenditures for inclusion in rates; at that time noting the prioritization of addressing aging infrastructure, ensuring the safety and reliability of the system, addressing customer expectations, responding to customer growth, and succession planning.[16] In that proceeding, InnPower agreed via settlement to total OM&A funding in distribution rates of $7.6 million, representing a reduction of $750k.[17] The OEB ultimately approved the settlement

[16] EB-2023-0033, Exhibit 4, Tab 1, Schedule 1, page 17
[17] EB-2023-0033, Decision and Order, Appendix: Settlement Proposal, page 7

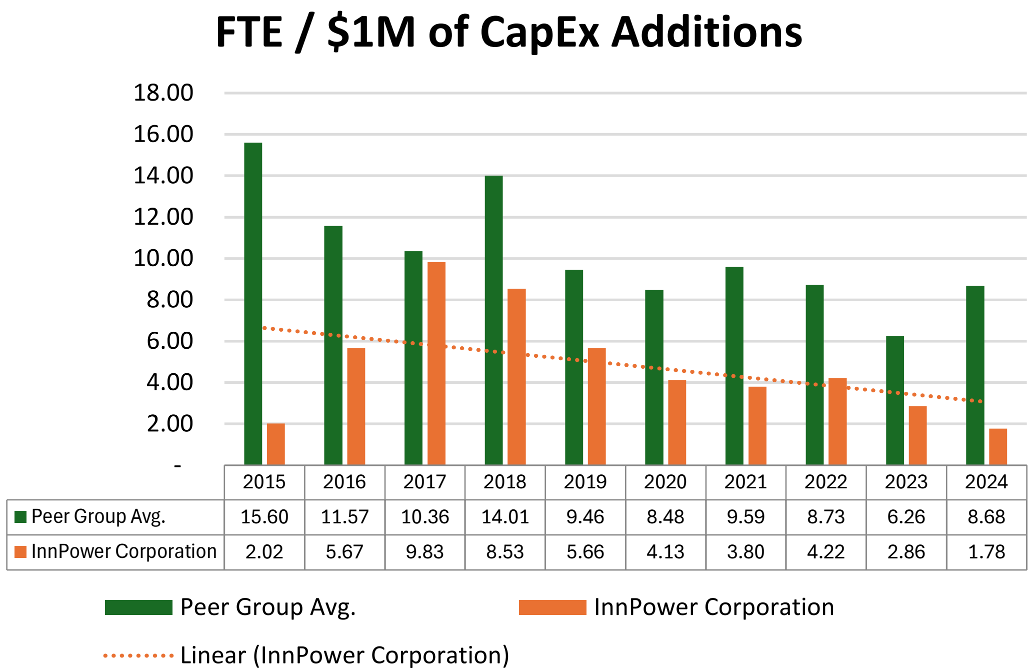
proposal, and InnPower's rates were established on this basis. InnPower worked diligently to manage within the funding provided by the 2024 Cost of Service approval; including OM&A funding. The utility initially sought to manage its OM&A costs by deferring the hiring of required staff, in addition to significantly reducing important but discretionary spending on items such as training and industry engagement. Prior to the results of the above-noted economic evaluation review, it became apparent that InnPower could not manage under reduced staffing levels, as overtime costs began to increase and staff burnout increased to levels unacceptable to InnPower.

Despite these efforts, on an actual basis, the realities of a dynamic growth environment and new incremental requirements are such that InnPower is not able to fund its operational requirements within the envelope currently provided in distribution rates; particularly when managing other cost and revenue challenges, as articulated in the sections above and below. OM&A underfunding materially contributes to InnPower's cashflow and deteriorating financial health, and requires relief in order to deliver on the utility's obligations in the present and future.

The high-growth environment of InnPower's service territory places a strain on utility staff. While the net capital expenditures of InnPower are significant year-to-year, these financial commitments are substantially smaller than the gross capital expenditures and resulting distribution system which must ultimately be managed by InnPower's small but effective team. Figure 3 below shows the number of Full Time Equivalents ("FTEs") at InnPower relative to Gross Capital Expenditures over the 2015 to 2024 period, alongside the same metric for the peer group of Ontario's fastest growing distributors referenced above.[18] This data demonstrates both a significant increase in the responsibility and strain placed on individual staff responsible for managing an expanding investment and asset portfolio relative to past year, as well as the low staffing levels at InnPower relative to its peers when assessed against capital additions.

Figure 4 FTE / $1M Capital Additions amongst Highest Growth Distributors (2020 – 2024)

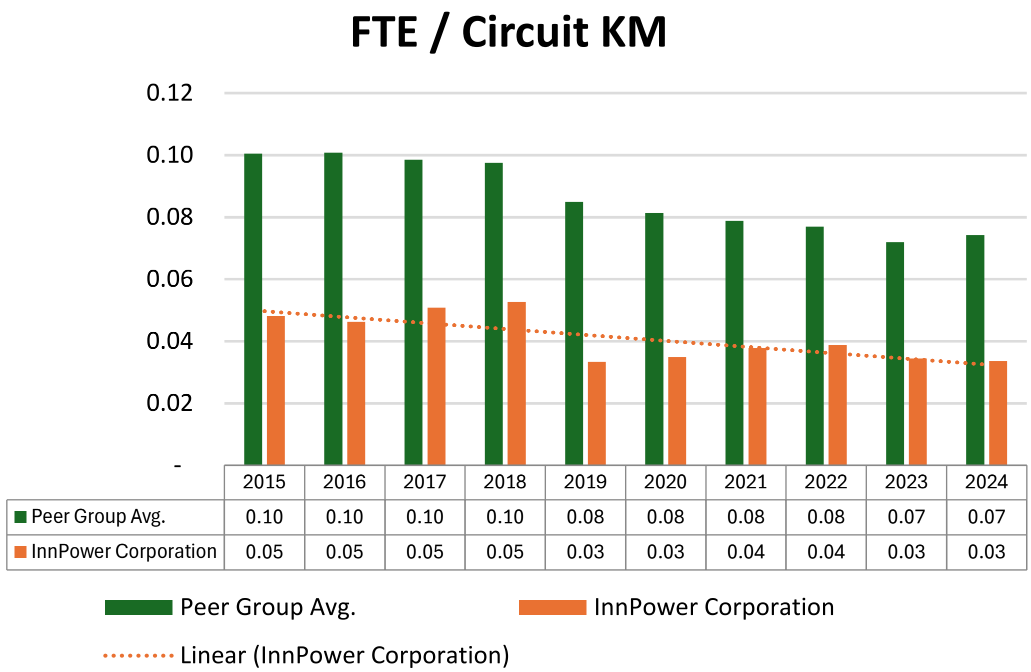
[18] Wellington North Power, Cooperative Hydro Embrun, Tillsonburg Hydro, Wasaga Distribution, Welland Hydro, Hydro Ottawa



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Peer Group Avg.	15.60	11.57	10.36	14.01	9.46	8.48	9.59	8.73	6.26	8.68
InnPower Corporation	2.02	5.67	9.83	8.53	5.66	4.13	3.80	4.22	2.86	1.78

Average annual gross capital expenditures over the 2024 to 2028 period have nearly tripled to $38.3 million based on a blend of actual (2024, 2025) and forecast (2026, 2027, 2028) data, relative to an average of $14 million annually in the preceding 5 years (i.e. 2019 – 2023). The dynamics of InnPower's growth have similar effects on the size of the system InnPower's team must manage relative to FTE count, as demonstrated by comparing FTE per Circuit-Km in the figure below:

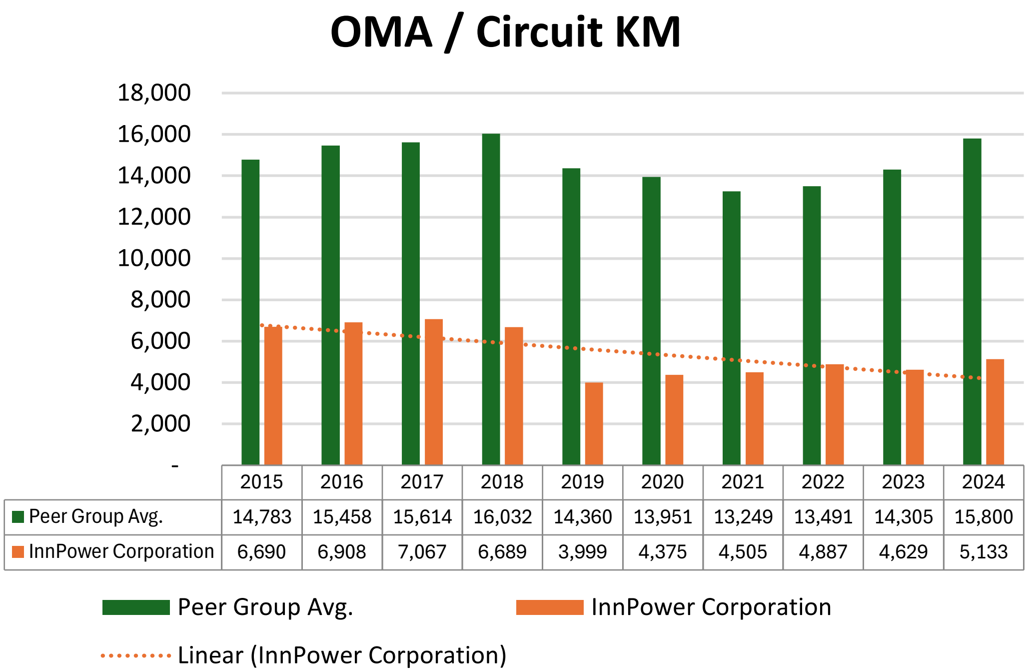
Figure 5 FTE / Circuit-KM amongst Highest Growth Distributors (2020 – 2024)



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Peer Group Avg.	0.10	0.10	0.10	0.10	0.08	0.08	0.08	0.08	0.07	0.07
InnPower Corporation	0.05	0.05	0.05	0.05	0.03	0.03	0.04	0.04	0.03	0.03

InnPower's lean staffing levels ultimately translate into efficient OM&A expenditures relative to its system size, as demonstrated when comparing InnPower to the Peer Group based on OM&A per Circuit-Km below:

Figure 6 OM&A / Circuit-KM amongst Highest Growth Distributors (2020 – 2024)



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Peer Group Avg.	14,783	15,458	15,614	16,032	14,360	13,951	13,249	13,491	14,305	15,800
InnPower Corporation	6,690	6,908	7,067	6,689	3,999	4,375	4,505	4,887	4,629	5,133

Despite this significant increase in capital management burden, and the subsequent burden of managing a larger system with more customers, InnPower's request in this application is limited to an increase of 11 FTE's relative to the OEB-Approved FTEs in EB-2023-0033, and only 6 FTEs relative to the 2026 Bridge Year. InnPower's restrained staffing increases has had a significant impact on its current employees, with increased overtime hours, increased sick leave, and a survey-based feedback to leadership indicating current workload per employee is hindering staff members ability to deliver strong performance.

The high-growth reality for InnPower is also coming at a time of significant new regulatory requirements and policies, such as implementation of the Capacity Allocation Model, Vulnerability Assessment and System Hardening, Benefit Cost Analyses, new and enhanced cybersecurity requirements, and others.

InnPower has taken measures to mitigate the impact of its OM&A through cost-sharing arrangements and restrained staffing, however growth in InnPower's workforce to match its increasing size has become unavoidable. Putting in place the workforce required to serve InnPower's customers and maintain the distribution system is the single largest driver of the OM&A increase of $2.7 million requested in this application relative to 2024 Actuals. Leading into the 2027 Test Year, InnPower requires the following incremental six FTE positions to be filled in order to continue to meet its obligations and facilitate growth within its service territory:

- Supervisor of System Planning;
- Apprentice Linesperson;
- Key Accounts Representative;
- Customer Service Representative (“CSR);
- Director of Finance; and,
- Financial Planning & Analysis Analyst.

While additional OM&A cost pressures have arisen since InnPower’s last Cost of Service, as further discussed in Exhibit 4, the most pressing operational need for the utility is to put in place a team which is appropriately sized and skilled to manage the increasing scale and complexity of InnPower’s distribution business. InnPower has continued to hire the staff required despite such staff not being funded in rates, and despite the other substantial financial pressures facing the utility described in this evidence. Like capital, InnPower cannot continue to self-fund necessary staff at a time of significant growth-related financial needs, and significant financial strain. Rebasing in 2027 is required to rectify this situation, and ensure InnPower’s customers are served by a team that is sufficient in size to serve them.

5. InnPower is Affected by External Market Forces

Since 2016, InnPower has operated under the principle that “growth will pay for growth” in the management of the utility.[19] While this principle has not been, and should not be, interpreted as a mathematical expectation or reality, InnPower generally considers it appropriate that growth in expenditures should directionally align with growth in revenues driven by increased customer count and load. It is not always the case that growth costs and revenues align in timing, and where they do not, the gap in revenues can be significant for a utility in InnPower’s circumstance.

Growth in InnPower’s service territory has historically been heavily weighted toward greenfield residential expansion, as new residential developments are constructed in previous farmland or

[19] EB-2023-0033, Exhibit 1, Tab 1, Schedule 5, pages 38-39

greenspaces. The consequence of such significant growth of this nature is the need to extend supporting upstream distribution infrastructure and capacity to areas which do not have pre-existing capacity of the required magnitude, which in turn requires the construction of assets well in advance of the full connection of revenue-generating customers. While these upstream distribution investments are typically funded in whole or in part by capital contribution, this does not alleviate the need for InnPower to have a team capable of managing an expansive portfolio of gross capital expenditures (as discussed above).

In accordance with the DSC, connecting residential customers are afforded a revenue allowance in the calculation of their capital contribution which is equal to the discounted value of 40 years of distribution revenue; recognizing that while new customers will grow costs, they will also grow revenues. One dynamic experienced by InnPower is the lag between the energization of assets designed to service entire residential developments, and the final connection of individual residential units. This dynamic creates a circumstance where the majority of the capital cost required to serve new customers has been incurred by the utility and capitalized, while the revenues from customers taking service from these assets may be delayed. This challenge can be further compounded through the customer connection horizon, which was recently extended to 15 years. While customer deposits representative of expected customer revenues are held by the utility over this period, they cannot be drawn on by the utility to fund operations until the end of the connection horizon.

Ontario's new home construction market has slowed since InnPower's 2024 Cost of Service in response to elevated borrowing costs and reduced population growth.[20] Accompanying this short-term trend shift, InnPower has noted a material increase in the lag between substantial capitalization of expansion assets and the final connection of residential customers; both in duration and number of residential units. Over the course of 2024 and 2025, InnPower placed into service $10.9 million in assets required to service 2,298 residential units across 15 subdivision projects. Of the total 2,298 units for which these assets were built, only 927 have been connected to the distribution system as of May 2026; leaving 1,371 residential units unconnected despite the capital investments required to serve them being substantially completed. Based on InnPower's 2026 OEB-approved distribution rates, 1,371 residential customers equates to $67,097 in monthly

[20] Exhibit 1 Appendix 6, Petramala Research Inc., Economic Conditions, Growth Outlook and Economics Benefits Assessment: InnPower Service Territory, June, 2026, page 13

distribution revenue, or $805,161 on an annual basis. This revenue lag is a material contributor to InnPower's current cashflow constraints and financial health, highlighting InnPower's sensitivity to external market forces; in this case, the residential new construction market in Ontario.

For clarity, despite the immediate term slowing of Ontario's new construction home market, InnPower's mid-to-long term expectations for growth remain elevated.[21] This places InnPower in the position where it must continue to expand its capacity and system to accommodate population and economic growth, but must also have the financial wherewithal to manage near-term fluctuations in housing market trends. The combination of these dynamics have contributed to the erosion of InnPower's financial health, and stand as one of the key drivers in the utility's need for early rebasing.

While InnPower continues to believe that growth should notionally pay for growth, this dynamic has proven insufficient to fund the levels of growth experienced by InnPower, at a time of substantial change in the new housing industry. InnPower cannot wait until 2029 to re-align its capital and operational costs with distribution rates, and requires early rebasing in 2027.

6. Incremental Cost Pressures Augment the Need for Early Rebasing

As described above, the core drivers of InnPower's need to rebase early are changes in net capital requirements driven by necessary revisions to its capital contribution methodology, increased OM&A costs primarily driven by the need to staff to InnPower's increasing scale, and the impact of a changing new construction housing market in Ontario; all overlaid on InnPower's operating environment as a rapidly emerging mid-sized utility, with an growth profile. Beyond these drivers, InnPower is also affected by a series of other cost drivers common to many utilities in Ontario. While these incremental drivers would not of themselves drive InnPower to seek early rebasing, they solidify InnPower's difficulties managing within the funding currently provided by its distribution and rates, and contribute to the utility's cost structure and requested relief of the OEB.

Incremental cost pressures addressed in this application include:

[21] Ibid., page 7

- Continued growth in system renewal expenditures to manage the aging portions of the InnPower system (Exhibit 2, Section 5.4.1.2.3 System Renewal);
- Growth in Externally-Initiated Plant and Relocations (Exhibit 2, Section 5.4.1.3.1 System Access);
- Increasing cybersecurity costs to respond to increased regulatory requirements and enhanced cybersecurity threats (Exhibit 4, Section 2.4.3 OM&A Variance Analysis, Exhibit 5, Section 5.4.1.2.6 General Plant);
- Updated collective bargaining, concluding the first labour negotiation since the return of inflationary pressures in 2022 (Exhibit 4, Section 2.4.3.1 Union Compensation);
- Increased insurance costs (Exhibit 4, Section 2.4.3 OM&A Variance Analysis);
- Increased OEB Cost Assessment requirements (Exhibit 4, Section 2.4.3.5 Regulatory Costs); and,
- Increased regulatory and administrative burden relating to initiatives and consultations such as the Capacity Allocation Model, Vulnerability and System Hardening, Benefit-Cost Analysis and Non-Wires requirements, the Next Generation Rate Framework and PULSE Panel consultation, and others.

4 APPLICATION SUMMARY AND BUSINESS PLAN

As described above, InnPower is requesting early rebasing effective January 1, 2027 to ensure the utility remains financially viable and capable of delivering on its obligations and commitments to customers; including the delivery of customer growth which is proportionally greater than growth delivered by any other distributor in Ontario. Delivery of these outcomes has implications for InnPower's rate base (past, present and future), regulated return, operational expenditures, and billing determinants.

InnPower's application has been formed as an outcome of its business planning process that includes development of Appendix 7 to this Exhibit, the InnPower 2027 to 2031 Business Plan.

The following sub-sections summarize the core components of InnPower's application to the OEB.

1. Revenue Requirement

InnPower's forecast Service Revenue Requirement for the 2027 Test Year is $26.8 million, offset by $4.3 million in Other Revenue, resulting in a Base Revenue Requirement of $22.7 million, as shown in Table 3 below.

Table 3: Revenue Requirement Summary

Particulars	2024 OEB-Approved	2027 Test Year	Variance	Variance
OM&A Expenses	7,577,618	11,848,631	4,271,013	56%
Depreciation Expense	5,096,877	6,809,558	1,712,681	34%
Property Taxes	129,180	114,484	(14,696)	-11%
Total Distribution Expenses	12,803,675	18,772,672	5,968,997	47%
Regulated Return On Capital	4,478,052	8,020,764	3,542,712	79%
Grossed up PILs	169,442	0	(169,442)	-100%
Service Revenue Requirement	17,451,169	26,793,437	9,342,267	54%
Less: Revenue Offsets	(3,567,620)	(4,129,578)	(561,958)	16%
Base Revenue Requirement	13,883,549	22,663,859	8,780,309	63%

InnPower's 2027 Test Year Service Revenue Requirement represents a 54% increase relative to 2024 OEB-approved, driven primarily by a substantial increase in rate base, and necessary OM&A expenditures to support a rapidly growing utility. A full description of InnPower's 2027 Test Year Revenue Requirement is provided in Exhibit 6, Tab 1 of this application, with substantiating evidence for rate base and depreciation provided in Exhibit 2, evidence supporting OM&A

requirements in Exhibit 4, evidence supporting cost of capital and return in Exhibit 5, and evidence supporting PILs and Other Revenue provided in Exhibit 6, tabs 2 and 3 respectively.

A completed version of the OEB's Revenue Requirement Workform is provided as a live excel model to this application as IPC_2027COS_RRWF_20260724, as well as a completed version of the OEB's PILs Workform as IPC_2027COS_PILs_20260724, and a version of the OEB's Chapter 2 Appendices as IPC_2027COS_Chapter_2_Appendices_20260724, inclusive of Appendix 2-H regarding Other Revenue.

2. Load and Customer Forecast

Table 5 below provides a summary of InnPower's 2027 Test Year forecast load and customer/connection count, relative to 2024 OEB-approved, 2024 Actuals, 2025 Actuals, and the 2026 Bridge Year forecast. As fully described in Exhibit 3 of this application, InnPower has used the same multi-variate regression and other methodologies relied upon in its 2024 Cost of Service in the preparation of its 2027 load and customer/connection count forecast.

1 **Table 4: 2024 OEB-Approved vs. 2027 Customer and Load Forecast**

	2024 OEB-Approved	2027 Test Weather Normal	Variance	Variance (%)
Predicted kWh Purchases	320,664,140	368,832,356	48,168,216	15%
% Difference				
Total Billed	302,070,456	350,182,246	48,111,790	16%
By Class				
Residential				
Customers	20,736	24,725	3,989	19%
kWh	196,515,750	231,433,978	34,918,228	18%
General Service < 50 kW				
Customers	1,314	1,373	59	5%
kWh	43,471,713	49,324,890	5,853,177	13%
General Service > 50 kW				
Customers	87	90	3	4%
kWh	59,688,867	66,825,175	7,136,308	12%
kW	156,832	179,308	22,477	14%
Embedded Distributor				
Customers	1	1	-	0%
kWh	935,589	976,590	41,001	4%
kW	2,361	2,575	214	9%
Unmetered Scatter Load				
Connections	75	68	(7)	-10%
kWh	466,609	417,038	(49,572)	-11%
Sentinel Lighting				
Connections	149	140	(9)	-6%
kWh	96,591	91,147	(5,445)	-6%
kW	267	295	28	10%
Street Lighting				
Connections	4,460	5,450	990	22%
kWh	895,336	1,113,428	218,092	24%
kW	2,674	3,382	708	26%
Total				
Customer/Connections	26,822	31,847	5,025	19%
kWh	302,070,456	350,182,246	48,111,790	16%
kW from applicable classes	162,134	185,561	23,426	14%

The Load Forecast Model relied upon to prepare the above described billing determinant forecast for 2027 has been provided as a live excel file to this application as IPC_2027COS_Load_Forecast_20260724.

3. Rate Base and Distribution System Plan

Table 6 below compares InnPower's 2024 OEB-approved rate base to its forecast 2027 Test Year rate base, including the impacts of InnPower's planned 2027 in-service additions of $23.4 million; an increase of approximately 132% relative to 2024 OEB-approved in-service additions of $10.1 million.

Table 5: Rate Base Summary – 2024 OEB-Approved vs 2027 Test Year ($000's)

	Forecast Period / Planned			
	2027 vs 2024			
	Approved 2024	Test 2027	Var $	Var %
Average Gross Assets	94,346	163,888	69,541	74%
Average Accumulated Depreciation	(22,631)	(35,672)	(13,041)	58%
Average Net Book Value	71,715	128,215	56,500	79%
Working Capital Allowance	3,209	4,496	1,287	40%
TOTAL	74,924	132,712	57,787	77%

As described in Tab 3 above regarding InnPower's early rebasing request, a substantial portion of the variance as between 2024 OEB-approved relates to changes to the calculation of capital contributions from customers to ensure compliance with the Distribution System Code, in addition to substantial additions to rate base to facilitate customer growth and other system needs. Exhibit 2 Rate Base and InnPower's Distribution System Plan provide a detailed description of InnPower's rate base and capital investments, including the drivers of its expansion from 2024 through to the forecast period of 2027 through 2031.

A completed version of the OEB's Chapter 2 Appendices has been filed with this application as IPC_2027COS_Chapter_2_Appendices_20260724, inclusive of Appendices 2-AA and 2-AB relating to capital expenditures, 2-BA providing a Fixed Asset Continuity Schedule, 2-BB and 2-

C regarding asset service life and depreciation expense, and 2-D regarding capitalized overheads.

4. Operations, Maintenance and Administration Expense

Table 6 below provides a comparison of InnPower's required 2027 OM&A expenditures relative to 2024 OEB-approved. InnPower is requesting approval of OM&A expenditures, including funds

Table 6: OM&A Expenditures – 2024 OEB-Approved vs 2027 Test Year

Program	2024 OEB Approved	2027 Test Year	Variance ($)	Variance (%)
Distribution Operations	1,797,038	2,477,777	680,739	38%
Distribution Maintenance	1,015,178	1,532,350	517,173	51%
Billing and Collecting	1,086,995	2,045,156	958,161	88%
Community Relations	103,618	130,668	27,050	26%
Administrative and General	3,574,789	5,662,679	2,087,890	58%
TOTAL	7,577,618	11,848,631	4,271,013	56%

While InnPower's requested 2027 Test Year OM&A expenditures represent a 56% increase relative to 2024 OEB-Approved, the 2027 forecast represents only a 29% increase relative to 2024 Actuals, at a Compound Annual Growth Rate ("CAGR") of 8.8%. Over this same time period, the OEB's Inflation Factors applicable to electricity distributors 2025 through 2027 imply compounded inflationary increases of 10.7%, while InnPower's customer/connection count has increased by 19% relative to 2024 OEB-approved as shown above. As noted above in Section 3 regarding this early rebasing request, InnPower's growing OM&A requirements are most notably a reflection of the operational requirements of the utility as a relatively small, but growing, distributor. Exhibit 4 provides a detailed explanation of the cost drivers of InnPower's OM&A requirements.

A completed version of the OEB's Chapter 2 Appendices has been filed with this application as IPC_2027COS_Chapter_2_Appendices_20260724, inclusive of Appendices 2-JA through 2-N regarding OM&A expenditures and associated analyses.

5. Cost of Capital

In compliance with the OEB's EB-2024-0063 Decision and Order (the "2025 Cost of Capital Report") InnPower is proposing a deemed capital structure of 40% equity, 56% long-term debt, and 4% short-term debt. Consistent with the 2025 Cost of Capital Report, the utility has adopted the OEB's most recent Return on Equity rate for the purpose of establishing return on equity, as well as the OEB's most recent short-term debt rate. The long-term debt rate relied upon is the weighted average interest rate applicable to InnPower's existing and forecast long-term debt. InnPower proposes to update the final Return on Equity and short-term debt rates relied upon to establish 2027 rates to align with the OEB's 2027 Cost of Capital Parameters once they are released.

Table 8 below summarizes InnPower's 2027 Test Year cost of capital. Exhibit 5 provides a full description of InnPower's cost of capital parameters, and the sources upon which they rely.

Table 7: 2027 Test Year Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt (Deemed)	56.00%	$74,318,499	4.09%	$3,040,363
2	Short-term Debt	4.00%	$5,308,464	2.72%	$144,390
3	**Total Debt**	60.0%	$79,626,964	4.00%	$3,184,753
	Equity				
4	Common Equity	40.00%	$53,084,642	9.11%	$4,836,011
5	Preferred Shares		$ -		$ -
6	**Total Equity**	40.0%	$53,084,642	9.11%	$4,836,011
7	**Total**	100.0%	$132,711,606	6.04%	$8,020,764

A completed version of the OEB's Chapter 2 Appendices has been filed with this application as IPC_2027COS_Chapter_2_Appendices_20260724, inclusive of Appendices 2-OA and 2-OB relating to capital structure and debt instruments, respectively.

6. Cost Allocation and Rate Design

With respect to Cost Allocation, InnPower has in this application fulfilled its commitment in the OEB-Approved 2024 settlement agreement to update its load profiles for the purpose of establishing the demand allocators relied upon in cost allocation. As articulated in Exhibit 7 of this application, InnPower has used the Historical Average Method outlined in section 2.7.1.1 of the OEB's Chapter 2 Filing Requirements.

To complete cost allocation for this application, InnPower completed an updated version of the OEB's 2027 Cost Allocation Model, inclusive of the updated load profiles and demand allocators noted above. Table 8 below compares the revenue-to-cost ratios approved in EB-2023-0033 against updated values calculated in this application via the OEB's Cost Allocation Model, as well as InnPower's proposed revenue-to-cost ratios.

Table 8: 2027 Revenue-to-Cost Ratios

Customer Class Name	Previously Approved Ratios	Status Quo Ratios	Proposed Ratios	Policy Range
	2024	(7C + 7E) / (7A)	(7D + 7E) / (7A)	
	%	%	%	%
Residential	103.2%	103.6%	103.6%	85 - 115
GS < 50	88.2%	87.9%	87.9%	80 - 120
GS > 50 kW	81.3%	82.0%	82.0%	80 - 120
Unmetered Scattered Load	120.0%	108.6%	103.6%	80 - 120
Sentinel	120.0%	102.4%	102.4%	80 - 120
Street Light	120.0%	88.7%	88.7%	80 - 120
Embedded Distributor	114.7%	71.2%	80.0%	80 - 120

The impact of updated cost allocation relative to 2024 is limited, with 7 of InnPower's 8 rate classes remaining inside the OEB's prescribed revenue-to-cost policy ranges. Only the Embedded Distributor was out of range. The revenue-to-cost ratio of this rate class was adjusted upwards to the bottom end of the OEB's policy range, with resulting excess revenues allocated to reduce the revenue-to-cost ratios of the Residential and Unmetered Scattered Load rate classes.

With respect to rate design and the determination of fixed vs. variable charges, InnPower has assessed its current fixed charges for each rate class, against what fixed charges would need to be in order to maintain the current split between fixed and variable revenues per rate class, and against the fixed charge ceiling identified in the completed Cost Allocation Model referenced above (with the exception of Residential, for which all distribution revenues are recovered via fixed charge). Where maintaining the current fixed variable revenue split results in fixed charges below the fixed charge ceiling, fixed charges are designed to maintain the current fixed/variable revenue split. Where maintaining the fixed/variable revenue split results in charges above the fixed charge ceiling, InnPower has proposed the lower of the existing fixed charge or the fixed charge ceiling, as applicable. Exhibit 8 provides details regarding the resulting fixed and variable charges.

InnPower is not proposing any new rate classes, any change to the definition of rate classes, or the elimination of any rate classes.

InnPower has filed with this application a completed version of the OEB's Cost Allocation Model as IPC_2027COS_Cost_Allocation_Model_20260724, as well as a supporting Load Profile Model has been filed with filenam IPC_2027COS_Load_Profiles_20260724 demonstrating the derivation of proposed demand allocators for use in cost allocation. InnPower has also provided filed with this application as IPC_2027COS_RTSR_20260724 a completed version of the OEB's Retail Transmission Service Rates workform, inclusive of Low Voltage rate calculations. Finally, InnPower has provided a completed version of the OEB's Revenue Requirement Workform as IPC_2027COS_RRWF_20260724, inclusive of tabs regarding cost allocation and rate design.

7. Deferral and Variance Accounts

InnPower is proposing to dispose of debit of $1,472,720 related to Group 1 and Group 2 deferral and variance accounts ("DVAs") as identified in Table 9 below. The debit includes carrying charges up to and including December 31, 2026. Group 1 and Group 2 DVA balances are proposed to be disposed of over a one-year period. InnPower Corporation has followed the OEB's guidance as provided by the OEB's Electricity Distributor's Disposition of Variance Accounts Reporting Requirements Report. InnPower Corporation applies the accrual method in calculating carrying charges, which is in accordance with the OEB's directive. The forecasted interest on December 31, 2025, principal balances of the DVA is calculated using the OEBs prescribed rates. Table 9 below is a summary of the principal, carrying charges and disposition amounts for all active Group 1 and Group 2 accounts, including the reason for not claiming disposition. Additional details are provided in subsequent sections of Exhibit 9.

Table 9: Summary of Group 1 and Group 2 Account Balances

Account Description	USoA	Principal	Interest to Dec 31, 2025	Total	Balance per 2.1.7	Variance to 2.1.7	Projected Interest	Total Claim	Reason for $0 Claim
Group 1 Accounts									
LV Variance Account	1550	(173,857)	3,902	(169,955)	(169,955)	0	(4,433)	(174,388)	
Smart Metering Entity Charge Variance Account	1551	(48,021)	(2,063)	(50,084)	(50,084)	0	(1,225)	(51,309)	
RSVA - Wholesale Market Service Charge	1580	(602,320)	2,064	(600,256)	(600,257)	0	(15,359)	(615,616)	
Variance WMS – Sub-account CBR Class B	1580	304,023	4,474	308,496	308,496	0	7,753	316,249	
RSVA - Retail Transmission Network Charge	1584	(50,980)	11,789	(39,191)	(39,191)	0	(1,300)	(40,491)	
RSVA - Retail Transmission Connection Charge	1586	14,134	9,287	23,421	23,421	0	360	23,781.42	
RSVA - Power (excluding Global Adjustment)	1588	1,892,115	48,022	1,940,137	1,940,137	0	48,249	1,988,386	
RSVA - Global Adjustment	1589	(318,652)	10,798	(307,854)	(307,854)	0	(8,126)	(315,980)	
DVA Regulatory Balances (2021)	1595	(138,483)	3,344	(135,140)	(135,140)	0	0	0	Disposed in previous IRM
DVA Regulatory Balances (2022)	1595	(161,920)	31,070	(130,850)	(130,850)	0	0	0	Disposed in previous IRM
DVA Regulatory Balances (2023)	1595	(236,132)	161,941	(74,191)	(74,191)	(0)	(6,021)	(80,213)	
DVA Regulatory Balances (2024)	1595	(73,947)	128,576	54,629	54,629	(0)	(1,886)	0	Rate rider expiry period not met
DVA Regulatory Balances (2025)	1595	(725,613)	580,029	(145,584)	(145,584)	0	(18,503)	0	Rate rider expiry period not met
Group 1 total (including Account 1589)		(319,654)	993,232	673,578	673,577	1	(491)	1,050,421	
Group 1 total (excluding Account 1589)		(1,002)	982,434	981,432	981,431	1	7,635	1,366,400	
Group 2 Accounts									
OEB Assessment Costs	1508	39,407	786	40,193	40,193	0	1,005	0	Balance not material
BATU Incremental Revenue	1508	100,554	0	100,554	100,554	0	2,564	103,118	
Green Button Implementation	1508	50,942	5,198	56,139	56,139	0	1,299	0	Balance not material
Broadband Expansion	1508	1,998	291	2,289	2,289	(0)	51	0	Balance not material
Ultra Low Overnight (ULO) Implementation	1508	4,777	528	5,304	5,304	0	122	0	Balance not material
Incremental LEAP Funding	1508	62,942	1,133	64,075	64,075	0	1,605	0	Balance not material
Pension & OPEB	1522	0	1,201	1,201	1,201	0	0	1,201	
Extraordinary Event Costs: Z-Factor	1572	484,779	7,183	491,962	491,962	0	0	0	Disposed in previous IRM
Group 2 Total		745,398	16,320	761,719	761,717	2	6,646	104,319	
Group 1 & Group 2 Total		744,397	998,754	1,743,151	1,743,148	2	14,281	1,470,720	
Account Description	USoA	Principal	Interest to Dec 31, 2025	Total	Balance per 2.1.7	Variance to 2.1.7	Projected Interest	Total Claim	

8. Bill Impacts

Table 9 below provides a summary of the change in total bill for each of InnPower's rate classes from current OEB-approved to the total bill proposed in this application absent any rate mitigation.

Table 10: 2027 Total Bill Impacts

Rate Class	Current OEB-Approved Total Bill	Proposed Total Bill	Change ($)	Change (%)
Residential	$154.09	$155.58	$1.49	1.0%
GS <50kW	$365.80	$385.14	$19.34	5.3%
GS 50 to 4,999kW	$11,699.31	$11,523.85	($175.46)	(1.5%)
Embedded Distributor	$15,472.92	$15,271.32	($201.60)	(1.3%)
Unmetered Scattered Load	$89.01	$94.31	$5.30	6.0%
Sentinel Lighting	$68.42	$84.78	$16.36	23.9%
Street Lighting	$35,336.30	$41,180.17	$5,843.87	16.5%

InnPower is subject to implementation of Distribution Rate Protection ("DRP") under O. Reg. 198/17. Table 10 above and Table 11 below reflect the implementation of DRP and provides a breakdown of the total bill impact as between the various Sub-Totals outlined in the OEB's Tariff Schedule and Bill Impact model:

Table 11: 2027 Total Bill Impact Sub-Totals

Rate Class	Units	RPP / Non-RPP	Sub-Total						Total	
			A		B		C		Total Bill	
			$	%	$	%	$	%	$	%
Residential	kwh	RPP	$0.23	0.5%	$0.61	1.1%	$1.67	2.3%	$1.49	1.0%
GS <50kW	kwh	RPP	$16.95	24.1%	$19.23	18.7%	$21.61	15.2%	$19.34	5.3%
GS 50 to 4,999kW	kw	Non-RPP	$335.61	30.6%	($248.58)	(13.9%)	($155.04)	(4.7%)	($175.46)	(1.5%)
Embedded Distributor	kw	Non-RPP	$578.34	49.6%	($275.78)	(13.2%)	($178.06)	(4.9%)	($201.60)	(1.3%)
Unmetered Scattered Load	kwh	RPP	$5.27	23.2%	$5.39	17.7%	$5.92	15.1%	$5.30	6.0%
Sentinel Lighting	kw	Non-RPP	$17.50	30.0%	$17.86	29.2%	$18.28	26.9%	$16.36	23.9%
Street Lighting	kw	Non-RPP	$5,889.16	30.0%	$5,095.44	25.0%	$5,171.90	23.9%	$5,843.87	16.5%

As shown above, the majority of InnPower's rate classes will experience total bill impacts of less than 10% as a result of this application, with two rate classes (GS 50 to 4,999kW and Embedded

Distributor) experiencing a total bill decrease. InnPower's Sentinel and Street Lighting experiencing total bill impacts in excess of 10. Per the OEB's Chapter 2 Filing Requirements, InnPower is proposing rate mitigation for these two rate classes to limit their 2027 Total Bill Impacts to 10.0%. InnPower proposes the use of credit rate riders for the Sentinel and Streetlighting classes in 2027, and a reduced credit rate rider for Sentinel Lighting in 2028, to smooth the impacts of this application for customers. Implementation of this approach, as fully described in Exhibit 8, will result in Total Bill Impacts for Sentinel and Streetlighting of 10.0% in 2027, followed by Total Bill Impacts of less than 10% in 2028 under current assumptions. Corresponding to the credit rate riders noted, InnPower has proposed a new Group 2 Deferral Account, Account 1508 – Foregone Revenue (Rate Mitigation) to capture foregone revenues resulting from the rate mitigation credit rate riders for recovery in a future proceeding.

InnPower has filed with this application two completed version of the OEB's Tariff Schedule and Bill Impact model as IPC_2027COS_Tariff_Bill_Impacts_No_Rate_Mitigation_20260724 and IPC_2027COS_Tariff_Bill_Impacts_ Rate_Mitigation_20260724, as well as copies of its current and proposed Tariff Schedule as Appendices 1 and 2 to Exhibit 8.

9. Conditions of Service

A copy of the Conditions of Service can be found on InnPower's website linked here:
https://innpower.ca/customer-care/pages/conditions-of-service

InnPower has updated its Customer Service policies and approach to be consistent with new and current OEB customer service policies.

The following section describes the changes to the Conditions of Service made by InnPower and the respective section:

Table of Contents

- Section 2- Distribution Activities 2.3.1(b) – Added Severe Weather Event-Power Outage and Restoration

- Section 3- Customer Class Specific -3.5.6- Removed Micro Embedded Generation
- Section 5 Appendices- Section H – Added Distributor Specific Requirements for Electric Vehicle Supply Equipment (EVSE) Connections
- Section 5 Appendices-Section I- Added reference to the OEB Distributed Energy Resources Connection Procedures (DERCP)

<u>Conditions of Services Document Changes</u>

<u>Section 2-Distribution Activities (General)</u>

- Section 2.1.2- Offer to connect- Removed Paragraph 2- no longer relevant
- Section 2.1.2 Offer to connect- Replaced reference to CHEC Generation Guide with the Distributed Energy Resources Connection Procedures (DERCP)
- Section 2.3.1 Guarantee of Supply (2.3.1 (b) Severe Weather Event- Power outage Restoration and Communication- added Distributor responsibilities in the event of a severe weather event
- Section 2.3.3- Power Quality- Added reference to the OEB Power Quality Guide
- Section 2.3.8.11- Meter Sockets- Added OESC Regulation with regard to mounting meters
- Section 2.3.8.14-Net Metering for Distributed Resources- Replaced and updated this whole section – existing document was no longer relevant
- Section 2.4.4- Billing and Payment- added Section 2.4.4.6- Arrears Management Program

<u>Section 3- Customer Class Specific</u>

- Section 3.5 Distributed Energy Resources (DER) Facilities
- Section 3.5.1 General- Reworded section- DER definition, reference to 6.2.2 of Distribution System Code Connection agreement.
- Section 3.5.1 updates also included the addition of the flexible hosting capacity arrangements.
- Section 3.5.5 Post Connection Changes- last paragraph references the OEB's Distributed Energy resources Connection Proceduresv(DERCP)
- Section 3.5.6 micro Embedded Generation- This section was removed

<u>Section 4 Glossary of Terms</u>

Additions:

- Customers Critical
- Electric Vehicle Supply Equipment (EVSE)
- Severe Weather
- Severe Weather Event

Section 5 Appendices

- Section H- Added – Distributor Specific Requirements for Electric Vehicle Supply Equipment (EVSE) Connections
- Section I- Added- reference to-OEB Distributed Energy Resources Connection Procedures (DERCP)

5 ALIGNMENT WITH THE RENEWED REGULATORY FRAMEWORK

In 2012, the OEB adopted its current performance-based approach to regulation, through the release of its report entitled Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach This approach, which the OEB has since applied to all rate-regulated utilities under its jurisdiction and has captioned as the "Renewed Regulatory Framework" ("RRF"), is intended to serve several key purposes: act as a more consumer centered approach to utility regulation; better align the interests of customers and utilities; facilitate the achievement of specific performance outcomes by utilities; places a greater focus on delivering value for money.

As highlighted below, InnPower's corporate vision, mission, and core values, as well as its strategic goals, are well aligned with the RRF.

Figure 7 Vision, Mission and Core Values

InnPower's core values are well aligned with the OEB's RRF performance outcome objectives as shown in Table 11 below.

Table 12: OEB Performance Outcomes and InnPower Values

OEB Performance Outcome	InnPower Values
Customer Focus	Community Leadership and Presence
Operational Effectiveness	Innovation and Sustainability
Public Policy Responsiveness	Fostering a Collaborative, Supportive & Respective Culture
Financial Performance	Fiscal Prudence

6 DISTRIBUTION SYSTEM OVERVIEW AND SYSTEM MAP

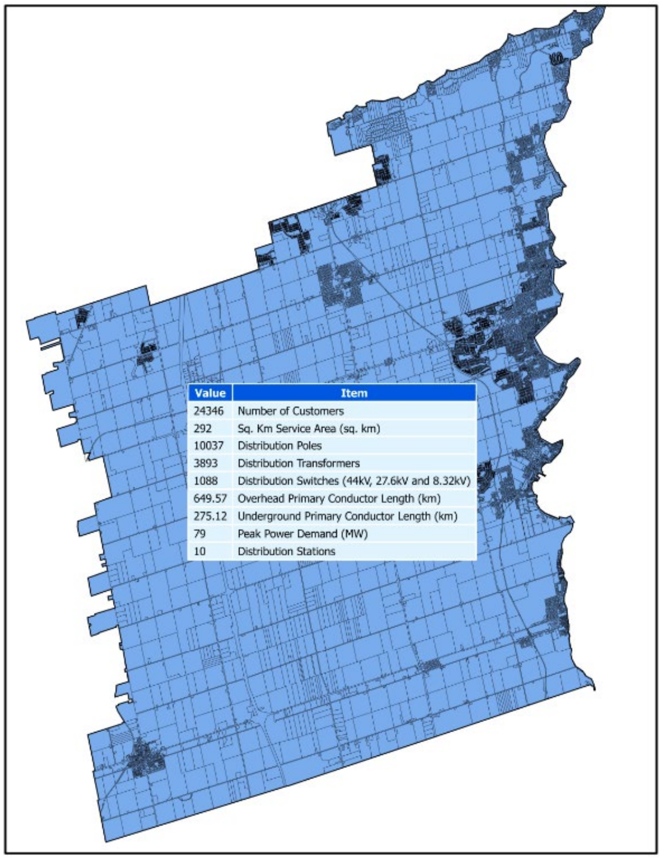
The Hydro Electric Commission of the Corporation of the Town of Innisfil was created in January 1991 as provided for in *Bill 177* (1990). It served only the former Village of Cookstown until 1993 when the Town of Innisfil incorporated and purchased the balance of distribution assets to service the Town from Ontario Hydro. Innisfil Hydro Distribution Systems Limited (Innisfil Hydro) was incorporated as a for-profit local distribution company (LDC) holding an electricity distribution license # ED-2002-0520 in the year 2000 as required by the *Electricity Act* (1998) serving the Town of Innisfil.

In 2009, the Province of Ontario passed *Bill 196, The Barrie-Innisfil Boundary Adjustment Act*, which annexed two thousand, three hundred (2,300) hectares from the Town of Innisfil. Innisfil Hydro continued to service this land as part of its licensed service territory of 292 square kilometers within the Town of Innisfil and the south portion of the City of Barrie. As such, InnPower's service territory encompasses the lands of South Barrie and all of the Town of Innisfil, which includes the communities of Stroud, Alcona, Lefroy, Churchill, Cookstown, Gilford, Sandy Cove, and Big Bay Point. InnPower's service territory is depicted below.

In January 2015, Innisfil Hydro changed its name to InnPower Corporation (InnPower) and relocated its Head Office and Operations Centre to a LEED certified Operations Centre in the Innisfil Town Campus at 7251 Yonge St., Innisfil, Ontario, where, as a municipal hub, operational synergies benefit both taxpayers and utility customers alike. InnPower currently serves twenty - four thousand, five hundred (24,500) customers (residential, GS<50 & GS>50) served by a dedicated and knowledgeable team of sixty-four (64) employees.
InnPower continues to be one hundred percent (100%) owned by the Town of Innisfil and maintains a close relationship with its other affiliate organizations including InnServices Utilities Inc. (InnServices), InnTerprises Inc. (InnTerprises).

InnPower is a member of the Cornerstone Hydro Electric Concepts Association (CHEC), a collaborative organization that provides shared resources, expertise, and services across its sixteen (16) member LDCs, collectively representing more than 275,000 electricity customers. Through this partnership, member utilities benefit from knowledge sharing and operational collaboration across the sector. InnPower also participates in GridSmartCity, an industry collaboration focused on advancing innovation, data analytics, and smart grid technologies within the electricity distribution sector. In addition, InnPower has access to a common set of design, construction, and material standards through its membership in the Utilities Standards Forum (USF). The company is also an active member of the Electricity Distributors Association (EDA), the Utility Advisory Council at the Electrical Safety Authority (ESA), and the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE) Group. Table 1-24 below highlights key aspects of InnPower's assets.

Figure 8 InnPower's Assets

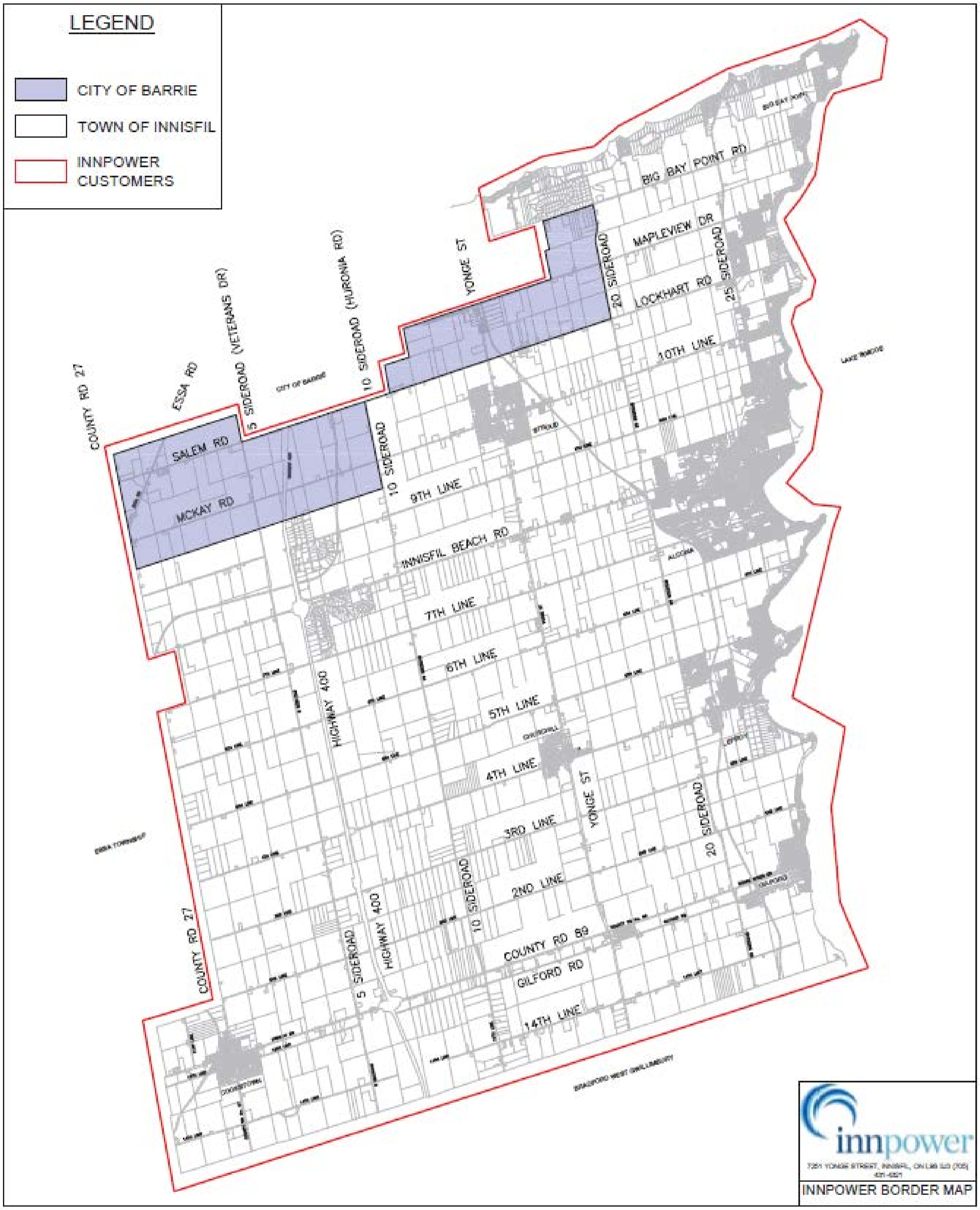


Value	Item
24346	Number of Customers
292	Sq. Km Service Area (sq. km)
10037	Distribution Poles
3893	Distribution Transformers
1088	Distribution Switches (44kV, 27.6kV and 8.32kV)
649.57	Overhead Primary Conductor Length (km)
275.12	Underground Primary Conductor Length (km)
79	Peak Power Demand (MW)
10	Distribution Stations

InnPower currently provides electricity distribution services to customers in the Town of Innisfil and City of Barrie (South Barrie). It operates voltages of forty-four thousand (44,000), twenty-seven thousand, six hundred (27,600) and eight thousand, three hundred (8,300) volts and provides customer voltages at six hundred (600), three hundred and forty-seven (347), two hundred and forty (240), two hundred and eight (208) and one hundred and twenty (120) volts.

InnPower's Distribution System Map is shown in Figure 7 below:

Figure 9 InnPower's Distribution System Map


LEGEND
CITY OF BARRIE
TOWN OF INNISFIL
INNPOWER CUSTOMERS
COUNTY RD 27
ESSA RD
5 SIDEROAD (VETERANS DR)
10 SIDEROAD (HURONIA RD)
YONGE ST
20 SIDEROAD
25 SIDEROAD
BIG BAY POINT RD
MAPLEVIEW DR
LOCKHART RD
10TH LINE
SALEM RD
MCKAY RD
10 SIDEROAD
9TH LINE
INNISFIL BEACH RD
7TH LINE
6TH LINE
5TH LINE
4TH LINE
3RD LINE
2ND LINE
HIGHWAY 400
COUNTY RD 89
GILFORD RD
14TH LINE
5 SIDEROAD
INNPOWER BORDER MAP

7 TRANSMISSION ASSETS

There are currently no transmission assets within InnPower's rate base. InnPower's load is primarily delivered through transmission connection points.

Moving forward, InnPower is planning for incremental transmission assets to serve its growing load and customer base. InnPower is actively exploring available approaches and structures to facilitating transmission assets in order to manage the cost of such investments for its ratepayers. Please see Exhibit 2, Appendix 1 for further information.

8 PERFORMANCE MANAGEMENT SUMMARY

This exhibit will highlight InnPower's performance management framework consistent with the direction in the OEB's RRF and the OEBs Rate Handbook. It will also demonstrate how this performance framework, which focuses on the achievement of performance outcomes and delivering value for money for customers, has been embedded into this rate application and all that InnPower does.

Included in this exhibit are the following items:

- InnPower's 2024 OEB Scorecard (Appendix 1)
- InnPower's Productivity and Continuous Improvement Initiatives (Exhibit 1-1-12),
- A discussion of InnPower's initiatives to facilitate innovation (Exhibit 1-1-13), and
- A discussion of InnPower's effort to reduce costs and increase efficiencies by considering collaborative work with other utilities and distributor consolidation (Exhibit 1-1-14).

1. Activity & Program Based Benchmarking (APB)

The APB framework is designed to enhance the OEB's oversight of electricity distributors in Ontario by providing a more granular and targeted approach to performance assessment. APB examines specific operational activities enabling a deeper understanding of utility cost structures, operational efficiency, and value delivered to customers. In accordance with section 2.1.6 of the Chapter 2 filing Requirements, Table 1 provides a summary of the APB's ten programs relative to its cohort peer group and Ontario industry, showing the cumulative average performance for the period 2020-2024.

InnPower respectfully notes volatility in unit cost results from year to year across Ontario distributors in the source data, with some reporting missing unit costs. The volatility of these unit costs suggests that some of the programs are not pragmatically quantified and that variability in spending is driving large differences in unit costs between years.

With exception to 5 programs (Metering O&M, Vegetation Management O&M, Stations CAPEX, Poles, and Towers CAPEX, and Meters CAPEX), InnPower remains below its peer group averages in 10 metrics. These results are particularly noteworthy given InnPower's unique operational challenges, including lower customer density, mix of urban and rural service territory, a set of service territories that are not continuous in nature, and simultaneous pressures of system growth and infrastructure maintenance.

Table 1: Summary Table of APB Metrics (Cumulative 2020-2024)

Unit Cost Calculations (2020-2024)	2020	2021	2022	2023	2024	5-Year Average			2-Year Average			Performance with	
						InnPower	Peer Group	Industry	InnPower	Peer Group	Industry	Peer Group	Industry
Billing O&M	20.8	20.3	21.9	24.3	25.0	22.4	30.3	37.4	24.7	31.5	39.5	Below Average	Below Average
Metering O&M	14.3	21.0	25.1	24.8	24.5	21.9	19.0	19.4	24.6	19.4	20.0	Above Average	Above Average
Vegetation Management O&M	27.7	38.0	30.6	40.3	37.1	34.7	27.7	41.6	38.7	29.5	46.0	Above Average	Below Average
Lines O&M	600.8	782.4	726.0	653.9	668.1	686.2	2,344.0	1,819.4	661.0	2,291.2	1,864.1	Below Average	Below Average
Stations O&M	482.7	1,479.8	1,145.6	1,317.0	1,655.4	1,216.1	2,015.8	1,786.7	1,486.2	2,124.4	1,933.4	Below Average	Below Average
Poles, Towers O&M	4.2	9.9	3.5	3.6	3.6	5.0	9.6	11.7	3.6	9.3	11.9	Below Average	Below Average
Stations CAPEX	33,373.6	28,469.8	5,505.6	34,270.7	21,297.8	24,583.5	5,267.2	5,642.8	27,784.2	3,028.1	5,554.9	Above Average	Above Average
Poles, Towers CAPEX	11,995.5	14,106.3	14,739.1	15,648.6	22,948.2	15,887.6	12,595.9	11,272.7	19,298.4	14,209.8	12,615.1	Above Average	Above Average
Line Transformers CAPEX	6,358.2	5,649.1	12,369.4	12,047.8	16,852.4	10,655.4	12,977.1	14,316.7	14,450.1	16,994.6	18,293.3	Below Average	Below Average
Meters CAPEX	13.6	13.6	11.1	37.8	7.6	16.8	11.0	12.8	22.7	13.0	14.7	Above Average	Above Average

Concerning the 5 APB metrics that were above the peer-group averages, the drivers for these above-average results are outlined below:

- **Metering O&M**

The Metering O&M unit cost is the sum of InnPower's USofA 5065 - Meter Expenses, USoA 5175 - Maintenance of Meters, and USofA 5310 - Meter Reading Expenses, divided by total number of customers. Overall, InnPower's billing O&M have increased by 71 percent over time. The higher average was primarily due to inflationary pressures on contracted meter reading services, as well as the continued maintenance costs associated with aging meters prior to their replacement.

Table 2: InnPower vs. Industry and Peer Group Metering O&M (2020-2024)

Metering O&M	2020	2021	2022	2023	2024	InnPower Average	Peer Group Average	Ontario Industry Average
Cost ($1,000) – USoA [5315]	276.21	413.33	515.58	552.84	576.67	466.92		
Scale (1,000 Customers)	19.28	19.70	20.51	22.34	23.51	21.07		
Unit Cost($/Customer)	14.33	20.98	25.13	24.75	24.53	21.94	19.02	19.41
Year-over year change		46%	20%	-2%	-1%			
Cumulative change (2020-2024)					71%			

- **Vegetation Management O&M**

The Vegetation Management O&M unit cost is the sum of InnPower's USofA 5135 - Overhead Distribution Lines and Feeders Right of Way, divided by pole counts. Vegetation management O&M includes costs incurred for tree trimming and for maintaining the right of way during line construction. Overall, InnPower's vegetation management O&M have increased by 34 percent over time. The higher average was primarily due to InnPower's predominantly vast rural service territory, which necessitates extensive vegetation management to protect system infrastructure. Even with its poorer performance in this metric compared to its peer group, it is substantively better than the Ontario industry average over the same time period.

- **Table 3: InnPower vs. Industry and Peer Group Vegetation Management O&M (2020-2024)**

Vegetation Management O&M	2020	2021	2022	2023	2024	InnPower Average	Peer Group Average	Ontario Industry Average
Cost ($1,000) – USoA [5315]	305.57	428.04	347.89	465.67	434.24	396.28		
Scale (1,000 Customers)	11.05	11.28	11.35	11.56	11.71	11.39		
Unit Cost($/Customer)	27.66	37.96	30.65	40.27	37.08	34.72	27.70	41.65
Year-over year change		37%	-19%	31%	-8%			
Cumulative change (2020-2024)					34%			

- **Stations CAPEX**

The Stations Capital Expenditures (CAPEX) unit cost is the sum of InnPower's USofA 1820 - Distribution Station Equipment Normally Primary Below 50 kV divided by MVA. Station additions include the installation cost of transforming and switching equipment used for stepping down to distribution voltages. The higher average reflects substantive investments related to both improving station's asset condition and improve InnPower's system capacity. While these investments do not materially increase the overall system capacity, they were required to maintain system reliability and long-term asset health.

Table 4: InnPower vs. Industry and Peer Group Stations CAPEX (2020-2024)

Stations CAPEX	2020	2021	2022	2023	2024	InnPower Average	Peer Group Average	Ontario Industry Average
Cost ($1,000) – USoA [5315]	2,836.76	2,419.93	467.97	2,913.01	2,300.16	2,187.57		
Scale (1,000 Customers)	85.00	85.00	85.00	85.00	108.00	89.60		
Unit Cost($/Customer)	33,373.62	28,469.78	5,505.58	34,270.65	21,297.76	24,583.48	5,267.24	5,642.77
Year-over year change		-15%	-81%	522%	-38%			
Cumulative change (2020-2024)					-36%			

- **Poles and Towers CAPEX**

The Poles, Towers, and Fixtures CAPEX unit cost is the sum of USofA 1830 - Poles, Towers, and Fixtures divided by pole installations in the same year. The Poles, Towers, and Fixtures additions include the installation cost of poles, towers, and appurtenant fixtures used to support overhead distribution conductors and wires. Poles, Towers, and Fixtures CAPEX unit cost increased due to large development work and road authority jobs that require new and reallocated poles.

Table 5: InnPower vs. Industry and Peer Group Poles and Towers CAPEX (2020-2024)

Poles and Towers CAPEX	2020	2021	2022	2023	2024	InnPower Average	Peer Group Average	Ontario Industry Average
Cost ($1,000) – USoA [5315]	4,018.48	4,034.42	3,566.87	5,242.29	5,737.05	4,519.82		
Scale (1,000 Customers)	335.00	286.00	242.00	335.00	250.00	289.60		
Unit Cost($/Customer)	11,995.45	14,106.35	14,739.12	15,648.64	22,948.19	15,887.55	12,595.89	11,272.73
Year-over year change		18%	4%	6%	47%			
Cumulative change (2020-2024)					91%			

- **Meters CAPEX**

The Meters CAPEX unit cost is the sum of USofA 1860 - Meters divided by the total customer count. The Meters CAPEX includes installation costs for meters or devices used in measuring electricity delivery to customers. Meters CAPEX unit cost increased due to a higher volume of scheduled legacy meter upgrades necessary to ensure ongoing regulatory and industry compliance.

Table 6: InnPower vs. Industry and Peer Group Meters CAPEX (2020-2024)

Meters CAPEX	2020	2021	2022	2023	2024	InnPower Average	Peer Group Average	Ontario Industry Average
Cost ($1,000) – USoA [5315]	262.25	268.89	228.50	844.70	177.84	356.44		
Scale (1,000 Customers)	19.28	19.70	20.51	22.34	23.51	21.07		
Unit Cost($/Customer)	13.60	13.65	11.14	37.82	7.57	16.75	11.01	12.76
Year-over year change		0%	-18%	240%	-80%			
Cumulative change (2020-2024)					-44%			

9 PRODUCTIVITY AND CONTINUOUS IMPROVEMENT INITIATIVES

Productivity and continuous improvement are at the heart of InnPower's management philosophy and *"doing more with less"* has been its core mantra. As such, InnPower staff are continuously assessing policies, procedures, and processes to challenge each other to achieve the best value-for-money for InnPower's customers and return for the shareholder.

InnPower's early of artificial intelligence (AI) has added productivity and continuous improvement gains in the utility. Over the next several years, InnPower plans to expand its use of AI throughout the organization. InnPower also plans to make further investments in process optimization and project management in order to identify processes across the organization with multiple touchpoints and room for efficiency.

The information contained in this Exhibit is intended to assist the OEB's assessment of InnPower's productivity and continuous improvement initiatives.

COLLABORATION WITH AFFILIATE ORGANIZATIONS

InnPower is a participating member of GridSmartCity, a collaborative network of Ontario electricity utilities that work together to advance innovation, digital transformation, and data-driven decision-making across the distribution sector, including the exploration and implementation of smart grid technologies, advanced analytics, and modern asset management practices. Additionally, InnPower is a participating member of the Cornerstone Hydro Electric Concepts Association (CHEC), a cooperative that provides shared resources and encourages collaboration between its fifteen (15) LDC members representing more than 100,000 customers.

Beyond these core collaborations, InnPower actively participates in several key industry organizations that support standardized practices, knowledge sharing, and sector-wide coordination. InnPower has access to a common set of design, construction, and material standards, as per its membership with Utilities Standards Forum (USF). InnPower is also an active member of the Electricity Distributors Association (EDA), the Utility Advisory Council at the Electrical Safety Authority (ESA), and the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE) Group.

A more recent example of such collaboration is the development of a buying group through USF. Establishing this arrangement has increased the buying power of the collective and reduced costs for participant utilities. Finally, InnPower is in the process of exploring a shared control room initiative with several interested utilities. This initiative, if successful, would be a game-changer for the industry and would provide several benefits for Ontario electricity ratepayers and other stakeholders.

PRODUCTIVITY AND CONTINUOUS IMPROVEMENT INITIATIVES BY DEPARTMENT

Below is a non-exhaustive list of notable productivity and improvement examples. Management continues to praise the hardworking staff for their diligence, creativity, and drive to continue to maximize value for InnPower’s customers, employees, and its shareholder.

The column entitled 'Efficiency / Productivity Outcome' indicates where these innovative initiatives have helped shape this application.

Table 13: Finance & Regulatory Productivity and Continuous Improvement

Item	Timing	Description of Item	Efficiency / Productivity Outcome
Prophix Financial Reporting and Planning Platform	Present (ongoing expansion)	InnPower has used Prophix as its financial planning and reporting platform for several years, continuously expanding its capabilities in response to organizational growth and increasing complexity. Prophix is used by Finance, as well as managers and staff across the organization. The platform supports various reporting such as, budgeting, financial reporting, capital and WIP tracking, fixed asset, long-range planning, and regulatory reporting.	Enables Finance and operational managers to access timely, accurate financial and operational data. Supports monthly financial reporting, capital and WIP reporting, long-range financial planning, and scorecard and RRR reporting. Continued expansion of cubes and reports year over year reflects Finance's ongoing commitment to efficiency and innovative initiatives as the organization grows.

Item	Timing	Description of Item	Efficiency / Productivity Outcome
Enterprise Resource Planning (ERP) System	2026-2027	Following a review of business processes, InnPower identified the need to replace its existing ERP system. The scope has evolved from a finance-focused implementation to a broader enterprise-wide initiative encompassing multiple departments. Business process mapping and requirements definition commenced in late 2026, with implementation advancing through 2027 and beyond.	A comprehensive implementation will reduce manual workarounds, improve data integrity across departments, and support the organization’s scalability requirements. Aligns with the operational optimisation priorities of the 2027–2031 Business Plan.

Table 14: HR and IT Productivity and Continuous Improvement

Item	Timing	Description of Item	Efficiency/Productivity Outcome
Efficiency Initiatives	2024 - Present	Implementation of multiple IT-driven efficiency initiatives, including single sign-on (SSO) across	Applies targeted digital improvements and process optimization to reduce friction in daily operations and

Item	Timing	Description of Item	Efficiency/Productivity Outcome
		applications, business process mapping, VPN access improvements, automation of calendar invites, form automation and upgraded boardroom technology.	improve user experience across the organization. Reduced time accessing systems and completing routine tasks, streamlined business processes, improved meeting efficiency, and decreased IT support requirements.
Business Intelligence	2024-present	Implementation of a centralized data warehouse within the Microsoft Fabric platform, with Power BI dashboards to support reporting and analytics.	Reduced manual reporting effort, improved access to real-time data, enhanced decision-making through standardized dashboards, and increased data consistency across the organization.
Corporate Digital Transformation	2025-2027	Corporate digital transformation initiative, including the addition of a Project & Transformation Specialist to lead process mapping, streamline operations, and support the replacement of core systems (ERP, Customer Information System, customer portal, and work management systems).	Streamlined and standardized business processes, increased automation, reduced manual effort, improved data consistency across systems, and enhanced operational efficiency through modern, integrated platforms.

Item	Timing	Description of Item	Efficiency/Productivity Outcome
BambooHR	2025	HRIS system that we use for time off requests, performance management and feedback, documentation, demographic tracking, employee history, policy sign offs, etc.	Automated rollout of performance management cycles and efficiency for policy sign offs – eliminating paper files. Applicant Tracking System used for recruitment to streamline interview process.

Table 15: Corporate Services and Metering Productivity and Continuous Improvement

Item	Timing	Description of Item	Efficiency/Productivity Outcome
Updating three (3) phase services	2025 - 2027	Changing three (3) phase metering technology so it is updated to current standards.	Brings meters up to standard and removes the need for additional material stocking. The upgrade will prevent InnPower from investing in older technology for future installation of meters.
Upgrade Primary Metering Units (wholesale points)	2023-2025	Replacement of old outdated equipment which had no replacements available	Brings meters up to standard and removes the need for additional material stocking. The upgrade will prevent InnPower from investing in older technology for future installation of meters. Will allow for pre-stocked items for emergency failures

Item	Timing	Description of Item	Efficiency/Productivity Outcome
Revenue Protection	Ongoing	Analysis of three (3) phase services	Allows the ability to ensure equipment is functioning properly and that usage is within allowable measurement ranges.
Supervisor Safety Credibility Program	Ongoing	Supervisors are evaluated on field presence, quality of job planning, and coaching effectiveness, including worker feedback.	Shifts Supervisors from administrative to operational safety leaders. • Field presence (not desk work) • Quality of job plans • Coaching workers
Monthly "One Hazard Deep Dives"	Ongoing	Focus on one key hazard each month with detailed discussion and lessons learned: 1. Incident examples (if any) or use a scenario 2. What goes wrong, could go wrong, works well 3. What controls fail, work well, need improvement or added measures	Keeps staff up to date on hazards and opens dialogue and participation
Root Cause → System Fix	Ongoing	Enhances incident review and proper root cause analysis to identify proper causes and corrective actions	**Not:** "Worker made mistake" **Instead:** "What in the system allowed this?"

Table 16: Other Productivity and Continuous Improvement

Item	Timing	Description of Item	Efficiency/Productivity Outcome
Enhanced Collaboration with Affiliates and Partners	On-going	Membership across the organization in the Electricity Distributors Association (EDA) councils, Utility Standards Forum (USF) and Cornerstone Hydro Electric Concepts (CHEC) and GridSmartCity organizations to inform public policy.	Increases public policy involvement and prevents duplication of effort with respect to submissions to various industry consultations

10 FACILITATING INNOVATION

The Filing Requirements for Electricity Distribution Rate Applications – 2026 Edition for 2027 Rate Applications state:

> "Distributors are encouraged to include in their cost-based applications a description of the ways that their approach to innovation has shaped the application. This could include explanations of their approach to innovation or keeping up with innovation in their business more generally; of specific projects or technologies for enhancing the provision of distribution services in a way that benefits customers or facilitating their customers' ability to innovate in how they receive electricity services; and of enabling characteristics or constraints in their ability to undertake innovative solutions. Distributors should include an explanation of how innovative alternatives have been considered in place of traditional investments." [22]

[22] Ontario Energy Board, Filing Requirements for Electricity Distribution Rate Applications – 2027 Edition for 2026 Rate Applications (December 16, 2025), page 14.

This exhibit will highlight InnPower's innovative initiatives and how they have resulted in productivity gains that benefit its customers and employees.

InnPower continues to innovate. Most notably, the organization is leading the way in artificial intelligence (AI) adoption and has met with several other utilities and presented at conferences to demonstrate its successes and opportunities for further development. AI use in engineering and asset management has saved labour hours by assisting teams with business decisions around asset management and cost. AI has also assisted in storm hardening efforts and will continue to be highly useful with the rollout of the OEBs VASH model. The next phase of AI rollout in the organization will be in the customer service department where InnPower plans to elevate the customer service team and the customer service experience by providing tools such as chatbot, real-time dynamic scripting for customer service representatives (CSRs), real-time bill usage analysis and troubleshooting – all in an effort to achieve higher first contact resolution results.

11 DISTRIBUTOR CONSOLIDATION

During its Business Planning process with its Board of Directors, InnPower discussed options for growth of the utility either organically (through real growth) or inorganically (through mergers, acquisitions and amalgamation). As InnPower continues to be one of the fastest growing utilities in Ontario, it was decided that over the next five years, a greater emphasis would be placed on organic growth and the challenges and opportunities that arise with that. That being said, InnPower remains open to exploring any inorganic opportunities that arise in this respect.

InnPower remains committed to identifying and working on collaborative opportunities with its affiliates, industry partners\groups and development communities to mitigate growth, costs and risks, as well as provide maximum value to its stakeholders. The following are a few examples of InnPower's commitment to identifying collaboration opportunities:

- One such example that InnPower is excited about exploring is a shared services model for a control room. Staff plans to explore this model with several utilities and more broadly, with the OEB around incentivization for innovation.

- GridSmartCity represents one of InnPower's key sector collaborations, bringing together a network of Ontario electricity utilities focused on advancing innovation, digital transformation, and data-driven decision-making within the distribution sector.

GridSmartCity brings together participating utilities to jointly explore and implement emerging technologies, including smart grid applications, advanced data analytics, and asset management tools that support improved system planning and operational efficiency.

- Cornerstone Hydro Electric Concepts (CHEC) represents another important collaboration for InnPower, bringing together a network of Ontario electricity distributors to share resources, expertise, and operational support. CHEC currently includes 16 small and mid-sized LDCs that work collaboratively across a range of activities, including regulatory support, operational initiatives, and the development of common tools and processes. Through this partnership, member utilities share best practices and technical expertise, allowing participants such as InnPower to leverage collective knowledge and reduce duplication of effort. Participation helps create operational efficiencies and supports workload sharing across member utilities.

12 CUSTOMER ENGAGEMENT

InnPower actively engages with the communities it serves and its customers on a regular basis through community events, charity and volunteering, social media outreach, bill inserts, educational programming, consultation with relevant entities (e.g. municipalities, landowner groups), public information sessions, in-person customer service, and customer satisfaction surveys. This ongoing practice of customer engagement serves as the primary foundation for InnPower's understanding of its customers, their needs, and their preferences with respect to InnPower's priorities moving forward. In addition, InnPower completed surveys in March and May of 2026 to specifically inform this 2027 Cost of Service application.

Of note, InnPower's overall approach and strategy with respect to customer engagement has not materially changed since its 2024 Cost of Service application (EB-2023-0033). Rather, the information provided in this application is a demonstration of InnPower carrying out its commitment to continuously improve customer engagement and ensure it is aware of, and responsive to, customer priorities and preferences.

Please see Exhibit 1, Appendix 2 for a summary of InnPower's ongoing customer engagement over the 2024 to 2025 period, as well as the results of InnPower's March and May 2026 surveys relating to this application. Please also see OEB Appendix 2-AC – Customer Engagement

Activities Summary within the Chapter 2 Appendices model filed with this application as IPC_2027COS_Chapter_2_Appendices_20260724.

13 FINANCIAL INFORMATION

1. INTRODUCTION

Appended to this Schedule are the following copies of audited financial statements for InnPower:

- Appendix 4 2024 Audited Financial Statements
- Appendix 5 2025 Audited Financial Statements

InnPower does not produce annual reports.

InnPower also provides information on:

- Accounting Orders (Section 13)
- Accounting Standard Used (Section 14)
- Accounting Treatment for Non-Utility Business (Section 15)

Changes to Accounting Policies used in Previous Applications (Section 16)

14 ACCOUNTING ORDERS

InnPower confirms that it maintains compliance with the Uniform System of Accounts ("USofA"), as set out in the OEB's Accounting Procedures Handbook ("APH").

As part of the OEB's Decision and Order on InnPower's 2024 distribution rate application, InnPower received the following utility-specific accounting order:

1. Sub-Account 1508 – Other Regulatory Assets – Barrie Area Transformer Upgrade (BATU) Installment, Revenue Requirement Impact
2. Sub-Account 1508 – Other Regulatory Assets – Barrie Area Transformer Upgrade (BATU) Installment, Rate Rider Revenues
3. Sub-Account 1508 – Other Regulatory Assets – Barrie Area Transformer Upgrade (BATU) Installment, Carrying Charges

As outlined in the InnPower Corporation's 2024 Cost of Service Application settlement (EB-2023-0033), the BATU Installments Deferral Account was approved by the OEB to manage timing and costs associated with InnPower's capital contribution payments to Hydro One for the BATU project, while mitigating significant near-term rate impacts during the 2025 to 2027 incentive period. It allows a portion of the revenue requirement to be recovered on an interim basis and the remainder to be deferred for future prudence review and final disposition, ensuring fairness to both customers and the utility.

Effective January 1, 2024, InnPower Corporation established the 1508 sub-accounts for the BATU Installments. The account captures the incremental revenue requirement for a half-year in 2024 (due to the OEB half-year rule) and for the 2025 to 2027 incentive period, as approved through the settlement in EB-2023-0033.

InnPower hereby confirms compliance with OEB accounting orders as well as the foregoing utility-specific accounting orders.

15 ACCOUNTING STANDARDS

Since the filing of InnPower's last rebasing Application submitted in 2024, the utility has adopted the following new accounting standards as required by the International Accounting Standards Board.

- **Classification of Liabilities as Current or Non-Current – Amendments to IAS 1** On January 1, 2024, InnPower adopted amendments to IAS 1 – Presentation of Financial Statements, which clarify the requirements for classifying liabilities as current or non-current. The amendments specify that classification is based on rights that exist at the end of the reporting period and provide additional guidance on the impact of covenants on classification. The adoption of these amendments did not result in any material changes to the classification of liabilities or to the financial statements. Consequently, there is no impact to revenue requirement.

- **Lease Liability in a Sale and Leaseback – Amendments to IFRS 16** On January 1, 2024, InnPower adopted amendments to IFRS 16 – Leases, which provide guidance on the subsequent measurement of lease liabilities arising from sale and leaseback transactions. The amendments clarify that lease liabilities should be measured in a manner that does not result in the recognition of gains or losses related to retained rights of use. The adoption of these amendments did not have an impact on InnPower's financial statements, as the Corporation does not currently have material sale and leaseback transactions. Consequently, there is no impact to revenue requirement.

- **Supplier Finance Arrangements – Amendments to IAS 7 and IFRS 7** On January 1, 2024, InnPower adopted amendments to IAS 7 – Statement of Cash Flows and IFRS 7 – Financial Instruments: Disclosures, which introduce enhanced disclosure requirements for supplier finance arrangements. These amendments are intended to improve transparency regarding the effects of such arrangements on liabilities, cash flows, and liquidity risk. InnPower does not have material supplier finance arrangements; therefore, the adoption of these amendments did not have an impact on the financial statements. Consequently, there is no impact to revenue requirement.

- **Lack of Exchangeability – Amendments to IAS 21** On January 1, 2025, InnPower adopted amendments to IAS 21 – The Effects of Changes in Foreign Exchange Rates, which provide guidance on determining the exchange rate when a currency is not exchangeable. The amendments introduce requirements for estimating spot exchange rates and additional disclosure requirements. The adoption of these amendments did not have an impact on InnPower's financial statements, as the Corporation does not have material foreign currency transactions in jurisdictions where exchangeability is restricted. Consequently, there is no impact to revenue requirement.

16 ACCOUNTING TREATMENT OF NON-UTILITY BUSINESS

InnPower confirms that the accounting treatment used by the utility segregates the business activities of its non-utility business from its rate-regulated business.

17 CHANGES TO ACCOUNTING POLICIES USED IN PREVIOUS APPLICATIONS

Please see 15.Accounting Standards above.

18 CORPORATE GOVERNANCE OVERVIEW

1. INTRODUCTION

Corporate governance is defined as a *system of direction and control of the organization.* The better an organization is governed, the better decisions it makes, the more investment it attracts and the better it will perform over time. InnPower's Board of Directors remain committed to providing *strong ethics, values, transparency* and a *focus on the spirit and aspirations of the*

Corporation's stakeholders. This includes an ongoing commitment to making corporate sustainability initiatives a priority topic of discussion and action.

In 2025, the Town of Innisfil (InnPower's shareholder) undertook a comprehensive governance review of its utility companies. As a result of this review, several improvements were made to the InnPower Board. First, the Board expanded from five (5) members to seven (7), which created two (2) additional director seats, which were filled with skill-based independent directors. Second, InnPower updated its shareholder direction and bylaws based on leading governance practices. Finally, InnPower updated its new director onboarding program to include more 1:1 discussion with various members of the utility's leadership team as well as field trips and progressive exposure to key topics of discussion.

A successful contracted services model currently exists between InnPower, InnServices and InnTerprises. Contracted resources include a common executive team and support staff across the various entities. Technology (hardware and software) is also shared across the three organizations to realize synergies. The cost savings realized are reinvested into specialized resources in each organization.

2. CORPORATE STRUCTURE

With respect to the Corporate organizational structure, InnPower Corporation (InnPower) is a wholly owned corporation of the Town of Innisfil (Town), and was incorporated on October 5, 2000, under the laws of the Province of Ontario. The principal activity of InnPower is to provide safe and reliable electrical power distribution throughout the Town of Innisfil and South Barrie.
Other wholly owned utility and energy services subsidiaries of the Town include InnServices Utilities Inc. (InnServices) and InnTerprises Inc. (InnTerprises) Incorporated. InnServices is a municipal services corporation (MSC) incorporated under the Municipal Act which provides safe and reliable drinking water supply, treatment, transmission, and distribution along with sanitary (wastewater) collection and treatment throughout the Town and neighbouring municipalities. InnTerprises is a telecommunications and energy services company currently responsible for facilitating cellular services throughout the Town by owning, operating and maintaining a fleet of telecommunication towers. InnTerprises also owns, operates and

maintains a fleet of electric vehicle (EV) chargers throughout the Town and installs and leases sentinel lights to residents in areas where streetlights are not practical.

In addition, InnTerprises wholly owns InnTerprises InnVestCo Inc. (InnVestCo) and InnTerprises Services Inc. (ServiceCo). InnVestCo, in turn, holds the limited partner interest in InnPower Transmission LP (Transmission LP) and wholly owns InnPower Transmission GP Inc. (Transmission GP), which is the sole general partner of Transmission LP. Transmission LP was established to develop transmission facilities to address the large load growth proposed in the Innisfil and South Barrie region.

Figure 10 below shows the corporate entity structure.

Figure 10 InnPower Corporate Structure

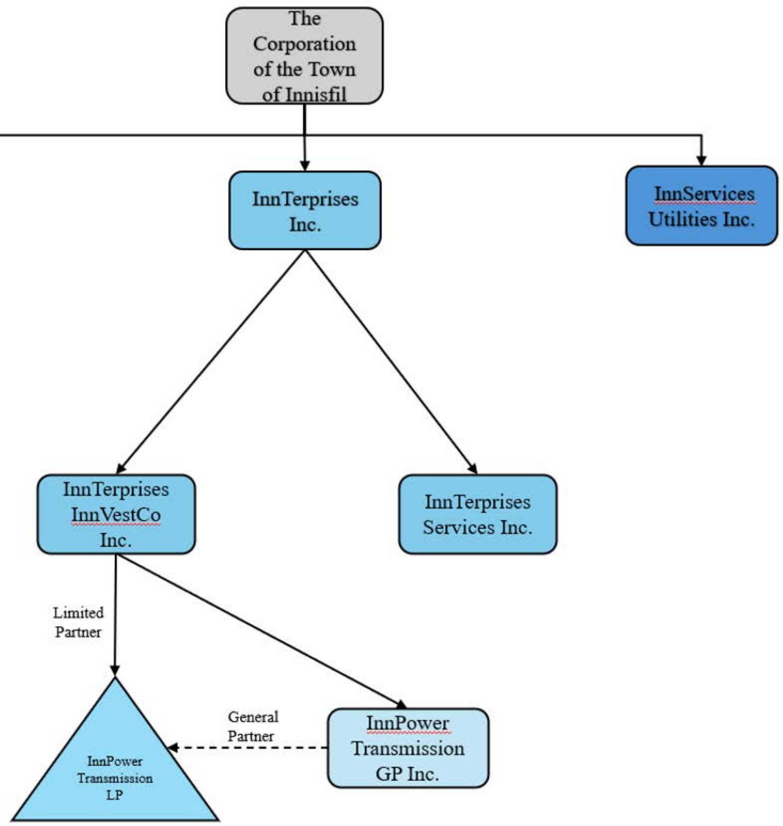
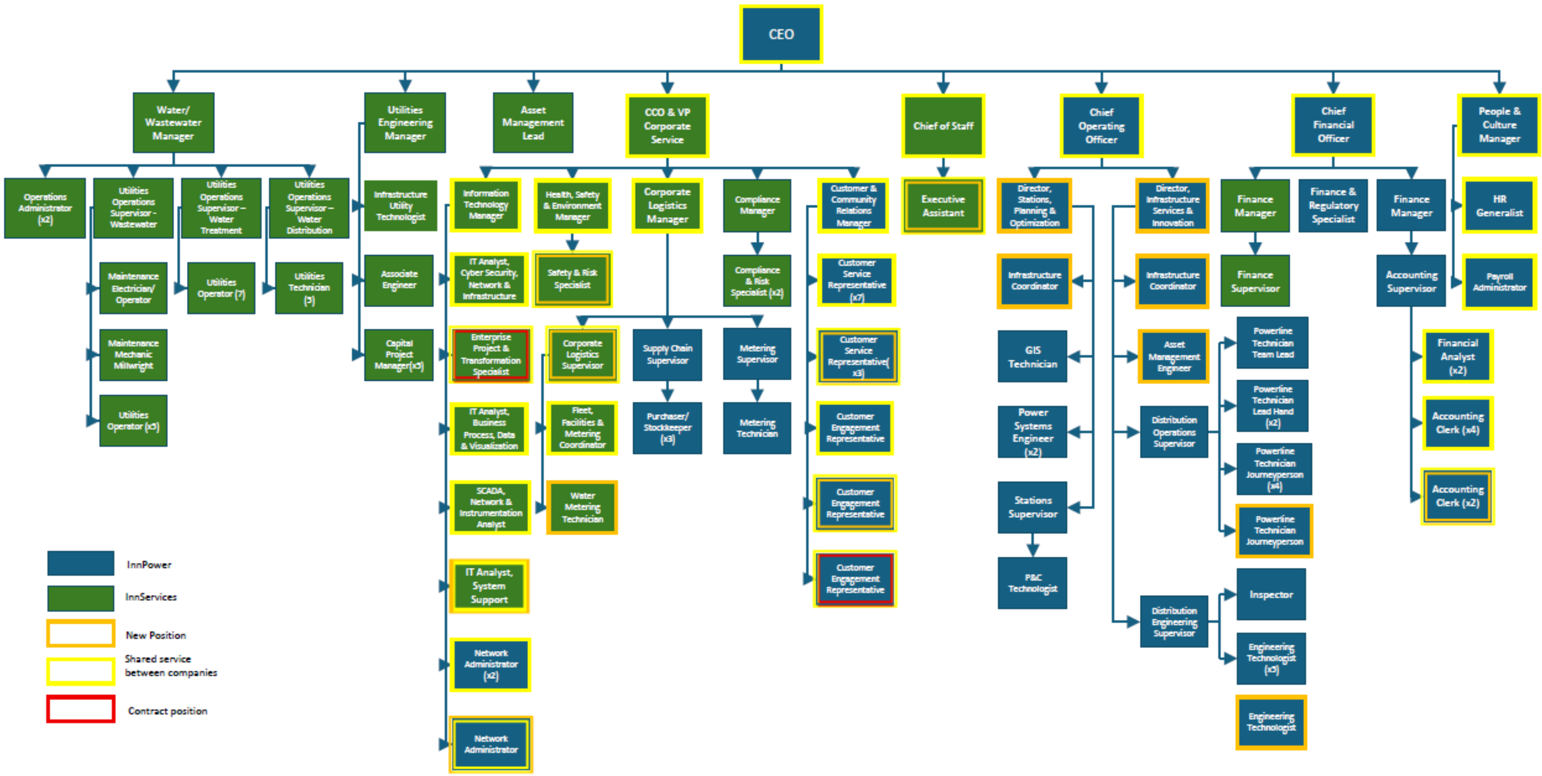


Figure 11 below shows the corporate organizational structure:

Figure 11 InnPower Corporate Organizational Structure



5. APPENDICES

The following items have been added as appendices to this Exhibit:

1. Appendix 1 InnPower's 2024 OEB Scorecard
2. Appendix 2 2024 Customer Engagement and 2027 Customer Survey
3. Appendix 3: BLG Transmission Connection Review Presentation
4. Appendix 4: 2024 Audited Financial Statements
5. Appendix 5: 2025 Audited Financial Statements
6. Appendix 6: Economic Conditions, Growth Outlook and Economics Benefits Assessment
7. Appendix 7: InnPower 2027 – 2031 Business Plan

APPENDIX 1 InnPower's 2024 OEB Scorecard

Scorecard - InnPower Corporation

9/22/2025

Performance Outcomes	Performance Categories	Measures		2020	2021	2022	2023	2024	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	**Service Quality**	New Residential/Small Business Services Connected on Time		100.00%	99.50%	95.83%	99.42%	99.63%	↓	90.00%	
		Scheduled Appointments Met On Time		99.51%	100.00%	100.00%	100.00%	99.76%	↑	90.00%	
		Telephone Calls Answered On Time		92.53%	90.18%	82.96%	79.26%	82.45%	↓	65.00%	
	Customer Satisfaction	First Contact Resolution		99.95	99.95	99.9	99.9	99.91			
		Billing Accuracy		99.90%	99.83%	99.87%	99.93%	99.75%	↓	98.00%	
		Customer Satisfaction Survey Results		A	B+	B+	B+	B+			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	**Safety**	Level of Public Awareness		84.00%	83.00%	83.00%	83.00%	83.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	→		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	2	1	↑		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	1.366	0.558	↑		0.191
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		1.81	1.78	1.04	1.29	1.60	↓		1.49
		Average Number of Times that Power to a Customer is Interrupted [2]		1.10	0.70	0.87	0.87	1.64	↑		0.83
	Asset Management	Distribution System Plan Implementation Progress		93%	109%	62%	90.6%	156.1%			
	Cost Control	Efficiency Assessment		3	3	3	3	3			
		Total Cost per Customer [3]		$852	$897	$961	$1,122	$1,250			
		Total Cost per Km of Line [3]		$11,219	$12,072	$13,471	$13,986	$16,211			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	**Connection of Renewable Generation**	New Micro-embedded Generation Facilities Connected On Time						100.00%	●	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.84	0.48	1.03	0.42	0.49			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.42	1.27	1.09	1.21	1.28			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.78%	8.78%	8.78%	8.78%	9.21%			
			Achieved	9.69%	9.26%	12.82%	10.04%	6.77%			

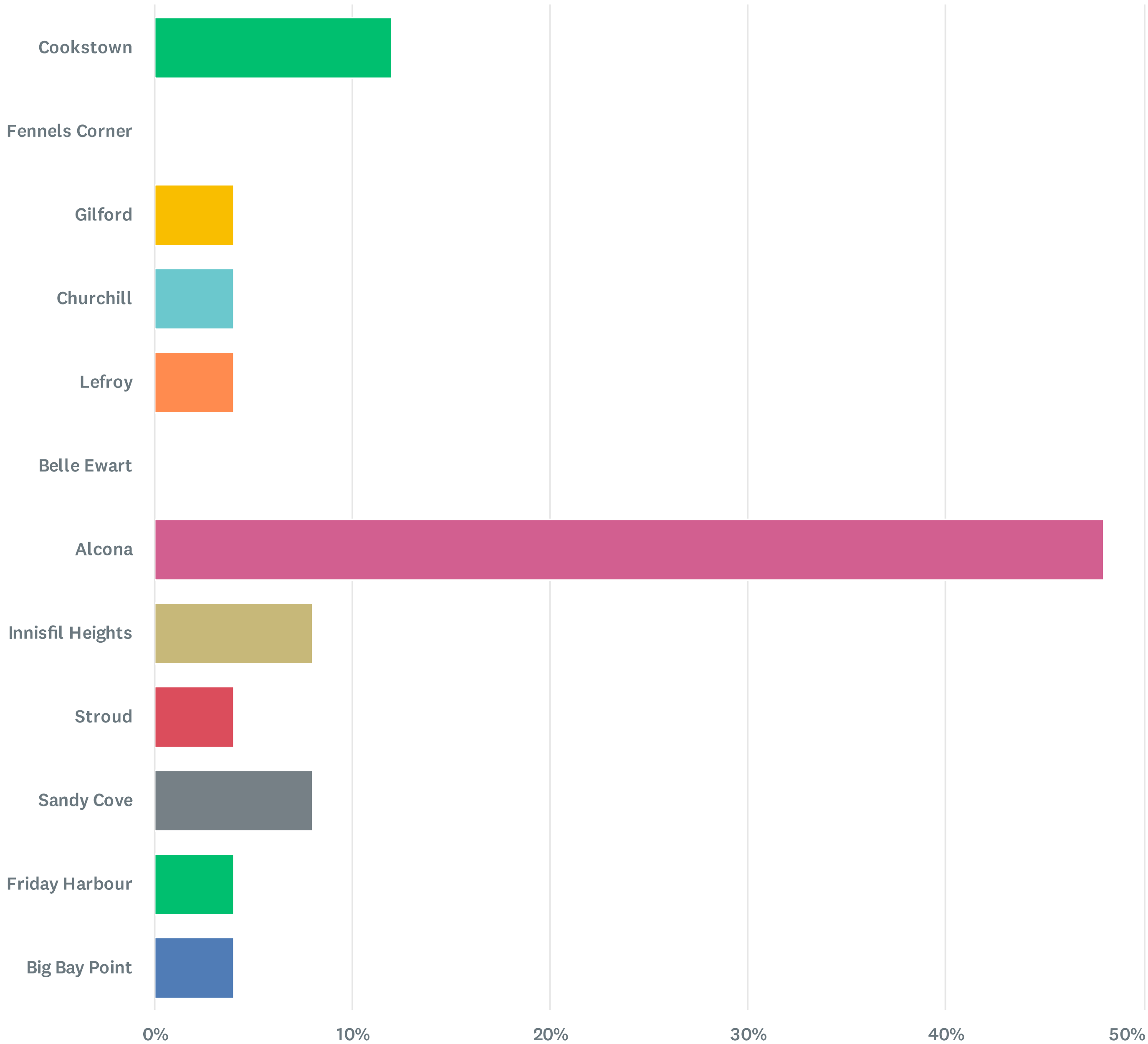
1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.

Legend:
5-year trend
↑ up ↓ down → flat
Current year
● target met ● target not met

APPENDIX 2 2024 CUSTOMER ENGAGEMENT

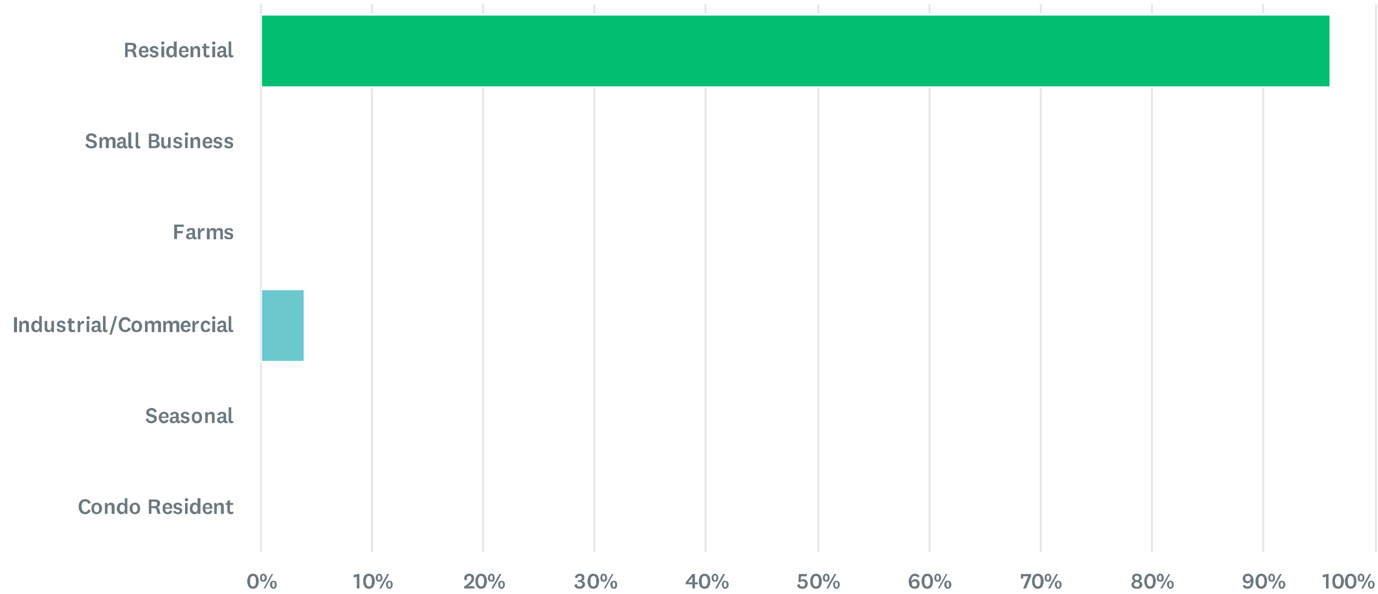
Q1 25 responses

Please select which area of InnPower's service territory that you reside in or are located nearest to.



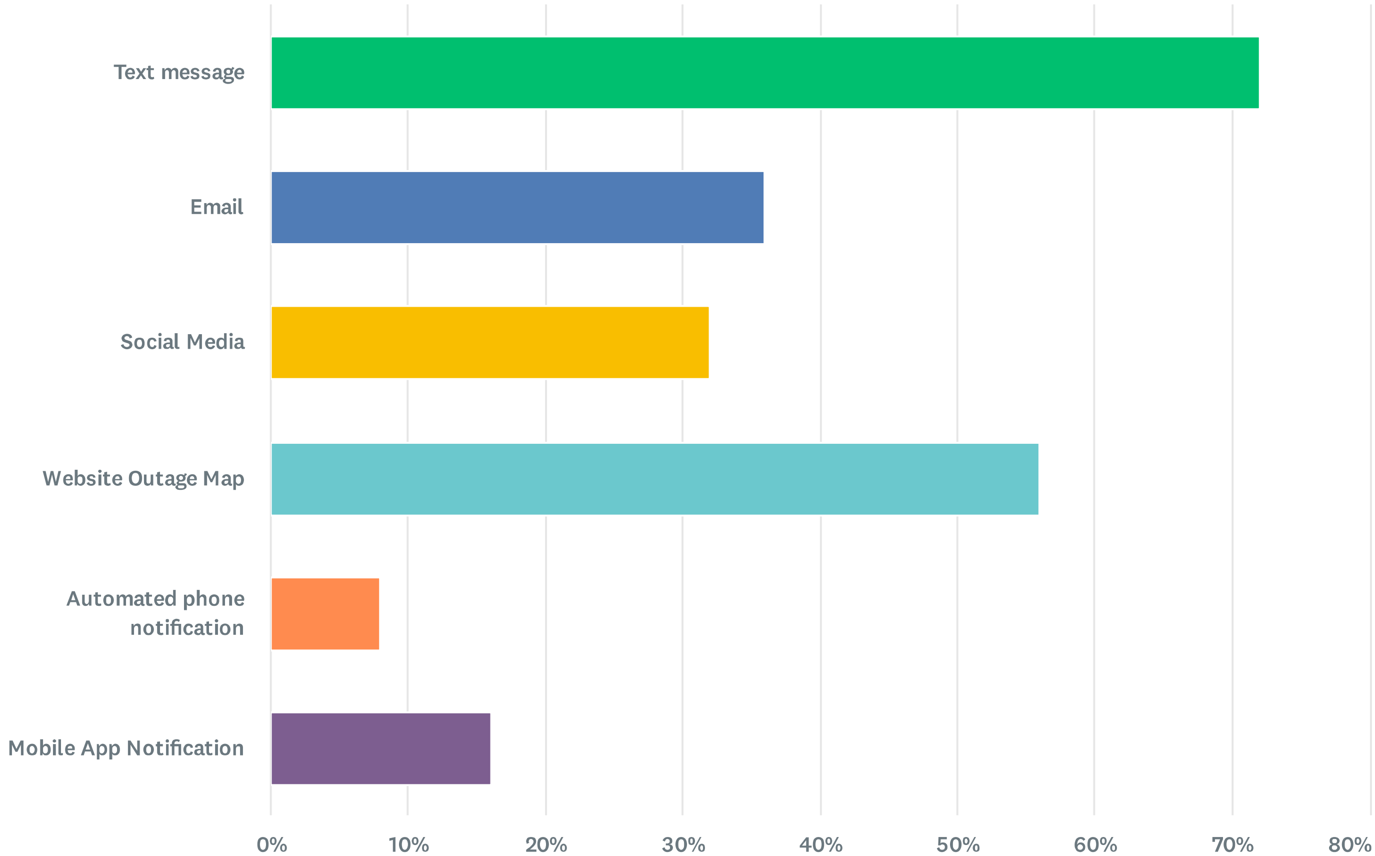
Q2 25 responses

Please confirm your customer segment/type



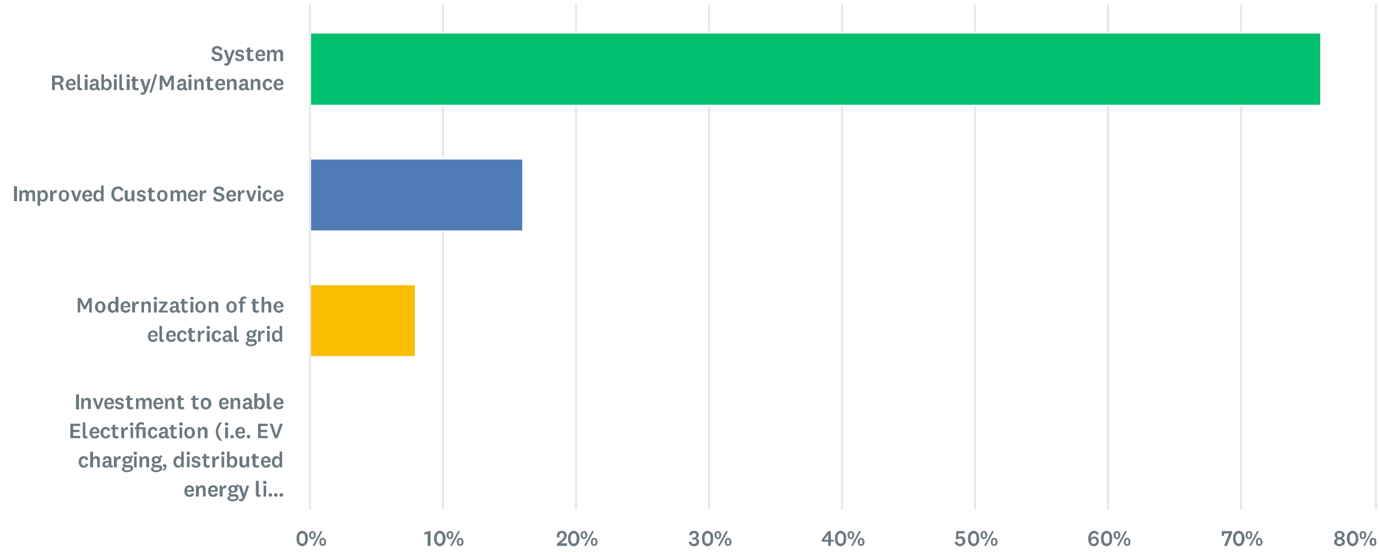
Q3 25 responses

During Outages, how would you prefer to receive updates?(select all that apply)



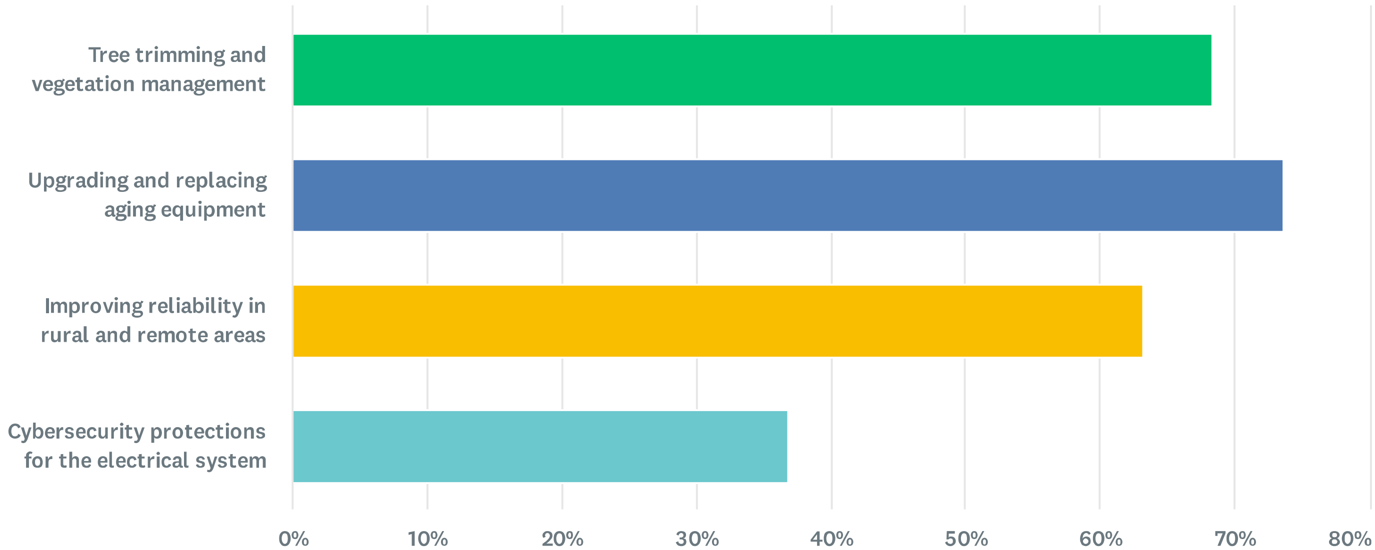
Q4 25 responses

What is the most important to you? (select one)



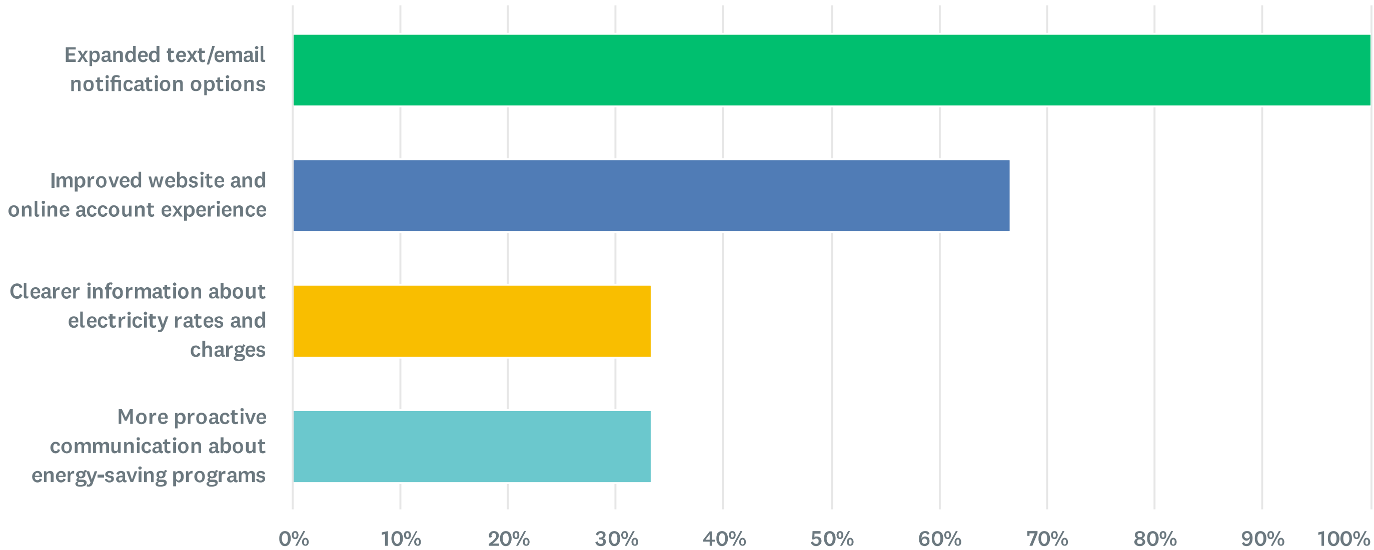
Q5 19 responses

If you selected “System Reliability & Maintenance,” what improvements would you most like to see?(select all that apply)



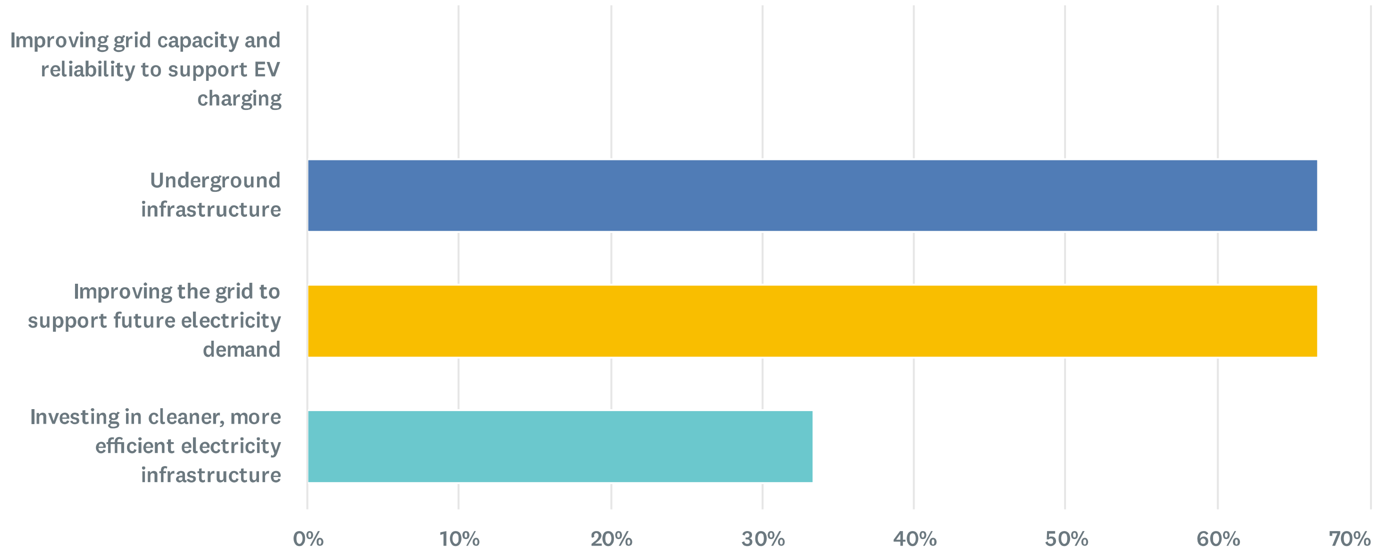
Q6 3 responses

If you selected "Improved Customer Service," what improvements would you most like to see?(select all that apply)



Q7 3 responses

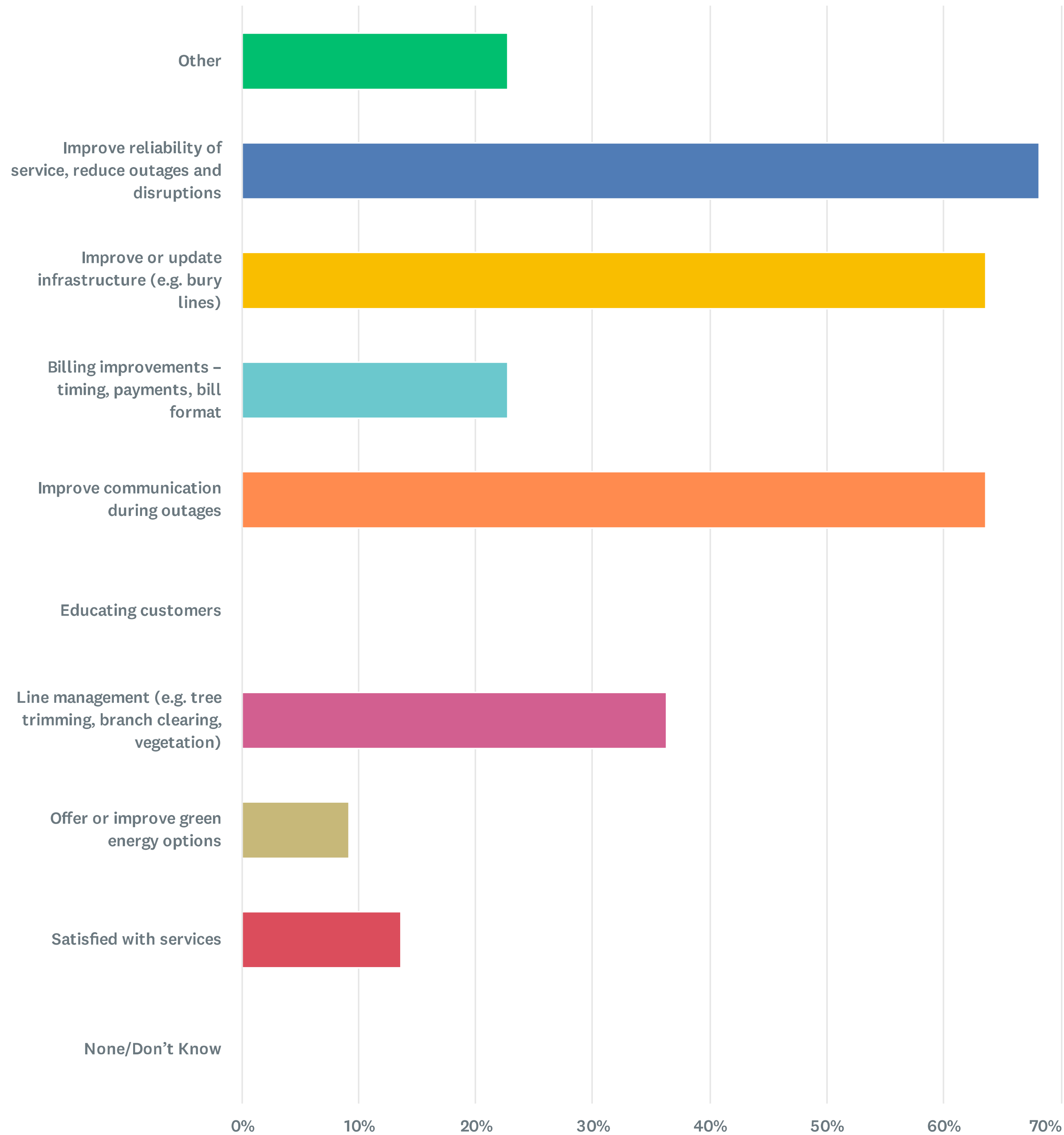
If you selected “Modernization of the electrical grid,” what improvements would you most like to see?(select all that apply)



⚠ No matching responses.

Q9 22 responses

What would you like InnPower to do to improve its services to you?(select all that apply)



#	OTHER	DATE

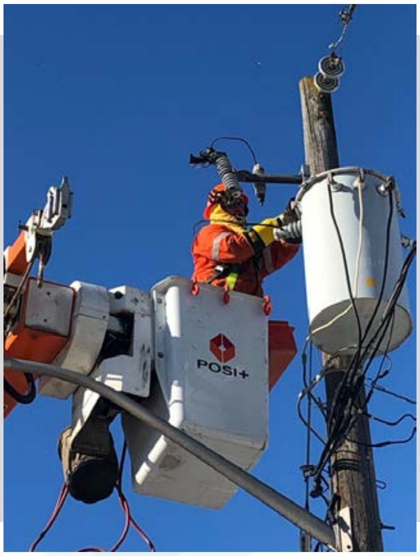
1	reduce costs to customers	5/24/2026 7:21 AM
2	Fix the website so it is reliable and gives the actual cost of the electricity used per property	5/23/2026 7:21 AM
3	Lower your prices	5/21/2026 10:24 PM
4	Lower cost especially water	5/20/2026 3:12 PM
5	Lower price so people can afford electricity	5/20/2026 11:22 AM

Understanding InnPower Corporation's 2024 Cost of Service Application

About InnPower Corporation

InnPower is in the business of electricity distribution, **delivering safe, reliable, cost-efficient, and innovative electricity services** to over 20,000 customers in Innisfil and South Barrie. We are a private business corporation that is 100% owned by our shareholder, the Town of Innisfil.

As one of the **fastest growing electrical utilities in Ontario**, InnPower maintains a service territory of 292 square kilometers (the same size as Mississauga). This includes over 10,000 poles, close to 1,000 kilometers of power lines and 10 distribution stations each with an incoming voltage of 44,000 volts.



The following table provides an overview of the assets InnPower currently manages:

20,771	**Customers**
292	**Sq. Km. Service area (sq. km.) (same size as Mississauga)**
9,587	**Distribution Poles**
3,382	**Distribution Transformers**
1,031	**Distribution Switches (44kV, 27.6kV and 8.32kV)**
637	**Overhead Primary Circuit Wire Length (km)**
219	**Underground Primary Circuit Wire Length (km)**
64	**Peak Power Demand (MW)**
10	**Distribution Stations**

Mission

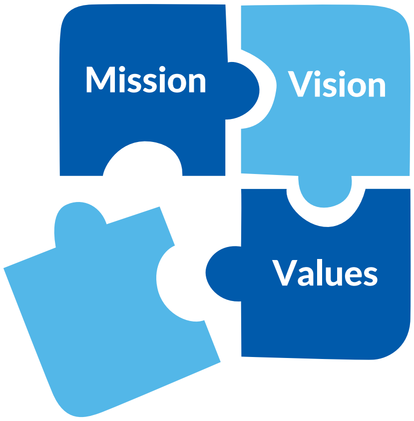
To deliver the energy our communities depend on to grow & prosper, with a commitment to safety & reliability, and a passion for value-added services to our customers, employees, and shareholder.

Vision

To be one of Canada's most innovative utilities, committed to boldly leading change, to create maximum value for our stakeholders.

Values

- Health, Safety, & Environmental (HSE) Stewardship
- Innovation & Sustainability
- Fiscal Prudence
- Fostering a Collaborative & Respectful Culture
- Community Leadership & Presence



2024 Cost of Service Application

The electricity industry in Ontario is regulated by the OEB. One of the OEB's roles is to review the business and distribution plans of all electricity distributors and approve the rates they charge customers.

Local distribution companies (LDCs) such as InnPower, are funded by the distribution rates included in the delivery charge paid by their customers. InnPower is seeking approval from the Ontario Energy Board (OEB) for the distribution rates that will be charged to customers for the 2024-2028 period.

How We Plan

InnPower is proposing a plan that is responsive to:

Legal and regulatory requirements ensuring InnPower continues to follow guidelines and meet obligations.

Business requirements that address operational, safety, business, and technical needs.

Customer input collected through the application process and ongoing engagement initiatives.

InnPower's 5 Year Plan

Over the past years, InnPower has invested in improving our distribution system and business practices. This includes replacing aging infrastructure, new infrastructure, system upgrades, improvements to customer facing and billing systems, and more!

Over the next 5 years, InnPower will need to continue to invest in our in distribution system and company.

Continually aging infrastructure, unfaltering population growth, an increasing number of severe weather events, and technological innovation are just a few factors that drive InnPower to continue investing and improving.

As a result, key initiatives of InnPower's plan includes:

- Maintaining and upgrading equipment to enhance reliability, safety and capacity
- Strengthening the grid's ability to withstand severe weather events
- Investing in solutions to enhance the customer experience and self-serve options
- Improving response time and communication for outages
- Investing in systems to accommodate new technologies
- Maintaining a focus on continuous improvement, efficiency, and productivity
- Making prudent investments into non-distribution system assets (e.g. tools, vehicles, software) to enhance service offerings and support resource planning

How Customer's Impacted InnPower's Plan

At InnPower, our customers are important to us. Committed to engaging with customers, we ran a Customer Priorities survey from August - October 2022. The survey established what is most important to our customers. Top priorities included price, reliability, communication and investments in new technology.

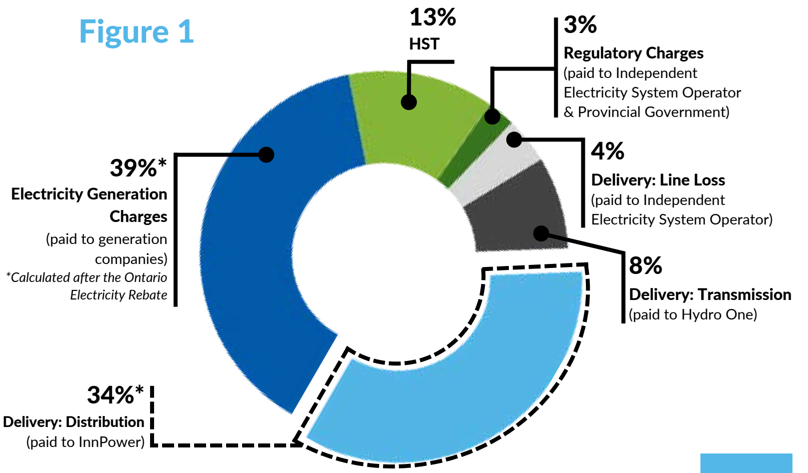
Using these results, InnPower's plan was established; making the changes customers want to see while ensuring that we continue to provide safe, reliable electricity distribution.

InnPower's Bill Breakdown

Electricity distributors like InnPower are funded are funded by the distribution rates included in the delivery charge paid by their customers. InnPower does not receive taxpayer money to fund its operations or investments in the distribution system. While InnPower is responsible for collecting payment for the entire electricity bill, it retains only a portion of the delivery charge representing approximately 34% of the bill

Figure 1 provides a breakdown of InnPower's bill for electricity charges for the average residential customer using 750 kWh per month at the proposed 2024 rates.

Figure 1



Expected Costs of InnPower's Plan

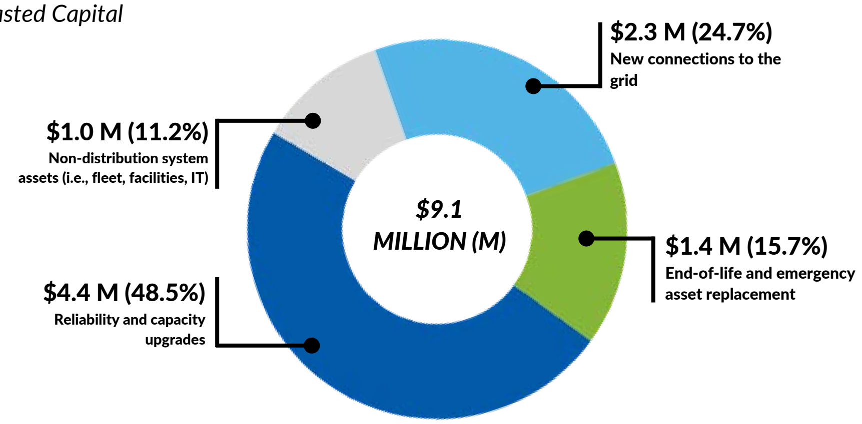
Like most businesses, InnPower manages both a capital and an operating budget.

Capital costs are assets that have lasting benefits over many years (e.g. poles, powerlines, etc.). Operating costs are recurring expenses for day-to-day operations (e.g. vegetation management, billing, etc.)

For the 2024 period, the capital required to maintain system reliability, safety, and invest in infrastructure priorities is $9.1 million.

Figure 2

2024 Forecasted Capital Investments



In order to move forward with our proposals, we're seeking approval from the OEB to change our rates.
The expected impacts on the distribution portion of customers bills for the proposed rates are shown in the table below:

	Change in Distribution Charge	2024 Proposed
Residential	**$/Month**	$1.43
	Percentage %	2.97%
General Service (<50 kW)	**$/Month**	$1.97
	Percentage %	2.87%

Expected Benefits to Customers

Our five-year plan will allow InnPower to maintain and improve reliability, service offerings and the overall customer experience, while ensuring costs are kept as low as possible. With our customers at the forefront of what we do, the proposed plan is designed to provide benefits including:

- *Improved reliability (fewer and shorter outages, improved response times, severe weather resilience)*
- *Greater capacity to sustain population growth*
- *Enhanced customer experience and self-serve options*
- *Increased ability to connect new, renewable energy technologies to the grid*
- *More options for managing and monitoring energy use*
- *Lower costs, relative to other investment scenarios*

Get Involved

The OEB will review InnPower's plan and proposed rates in an open and transparent public process.

For more information on how you can participate in the process, visit www.innpower.ca or www.oeb.ca/particpate.

Appendix 3: BLG_Tx_Con_Rvw_PPT-20250613

Transmission Connections Review

PRESENTATION TO THE WORKING GROUP

Presented By

John Vellone

June 13, 2025

Borden Ladner Gervais

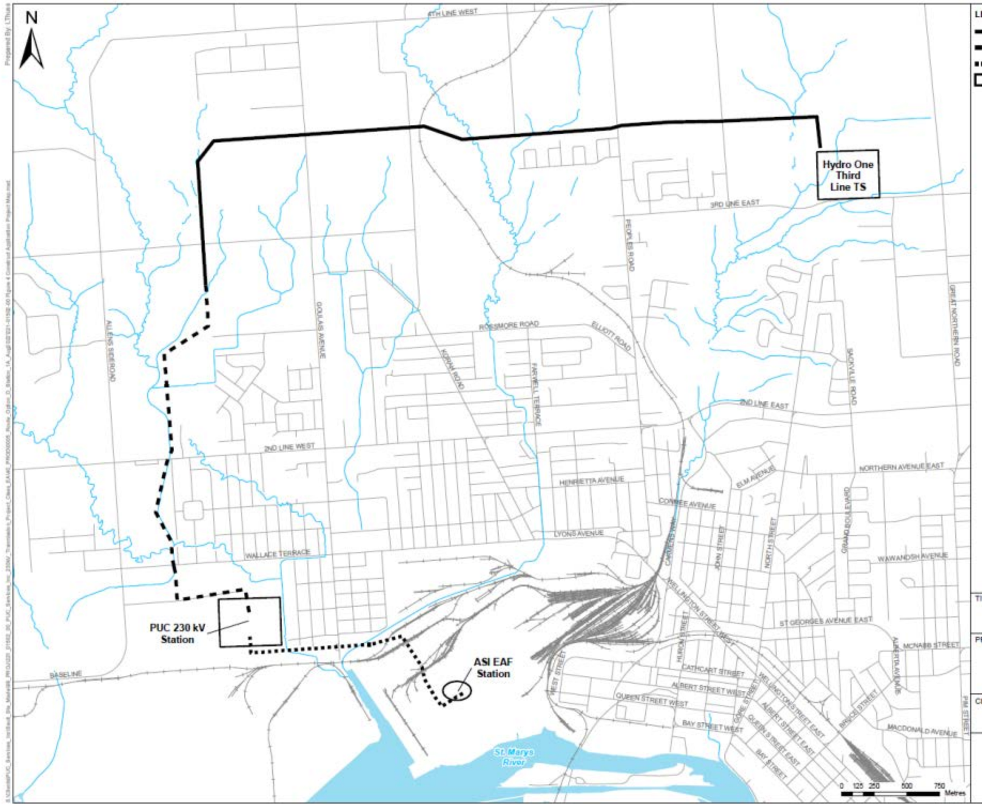
Who do we represent?

PUC (Transmission) LP

- PUC Distribution Inc. is the licensed distributor serving approximately 33,500 customers in and around Sault Ste. Marie, Ontario.
  - Wholly owned by the City of Sault Ste. Marie.

- Special purpose entity - obtained leave to construct a new 10 km, 230 kV transmission line and associated transformer station in Sault Ste. Marie, Ontario (EB-2023-0360) Link

- Licensed electricity transmitter (ET-2021-0088) Link



Who do we represent?

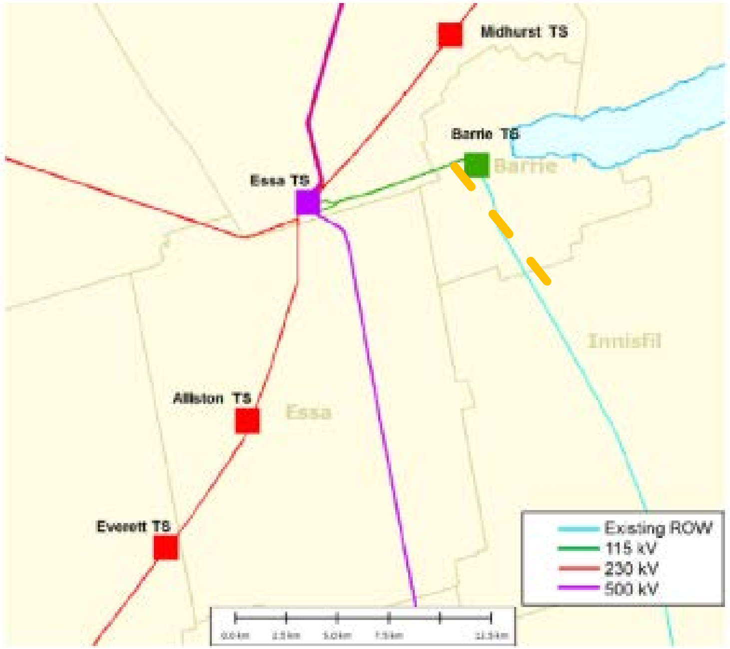
InnPower Corporation

- Licensed distributor serving approximately 26,000 customers in and around Innisfil, Ontario.
  - Wholly owned by the Town of Innisfil.

- Has paid a material capital contribution in support of Hydro One's Barrie Area Transmission Upgrade project, upgrading capacity between Essa TS to Barrie TS. [Link].

- Working now with Hydro One on upgrading an existing 115 kV line to 230kV from Barrie TS southwards to service load growth in Innsifl and the south end of Barrie. (orange dashed line)

Figure 1: Map of the Barrie/Innisfil Area



The TSC Definition for a *Network Facility*

The following provisions in the TSC are used to define a *network facility*:

- Facilities that are shared by all users, serve no one in particular, and are comprised of *network stations* and the transmission lines connecting them [2.0.45]
- Includes any line that forms part of the physical path between (i) two *network stations* or (ii) a *network station* and the transmission system of a *Neighbouring Ontario Transmitter* (NOT) or transmission system outside Ontario [3.0.14 (a)]
- A *network station* is a station with switching elements that step down the voltage from a higher transmission voltage to a lower transmission voltage and, among other things, includes any station with an autotransformer [2.0.45A & 3.0.14 (b)]

For discussion:

- Could these provisions be relied upon to reclassify facilities, which are necessary to connect a customer to the transmission system, as network facilities?
- Is this just and reasonable to ratepayers?

Why did we ask to speak

PUC (Transmission) LP

- PUC (Transmission) LP applied the autotransformer definitions in the TSC to the facts and provided a proposed allocation to the OEB in its leave to construct application.
  - (We obtained guidance from OEB Staff before applying to ensure we did it properly)
- OEB Leave to Construct Decision and Order
  - does not refer to the definitions of “network facilities” or “network station” in the TSC at all;
  - found that the project was a network facility by looking more broadly at the function of the facilities;
  - Found that PUC (Transmission)’s proposal to allocate a portion of the network costs to Algoma Steel as “minimum connection requirements” was appropriate.
- Conclusion:
  - Licensed entities must comply with the TSC.
  - The OEB determines what is just and reasonable, based on the particular facts.

Why did we ask to speak

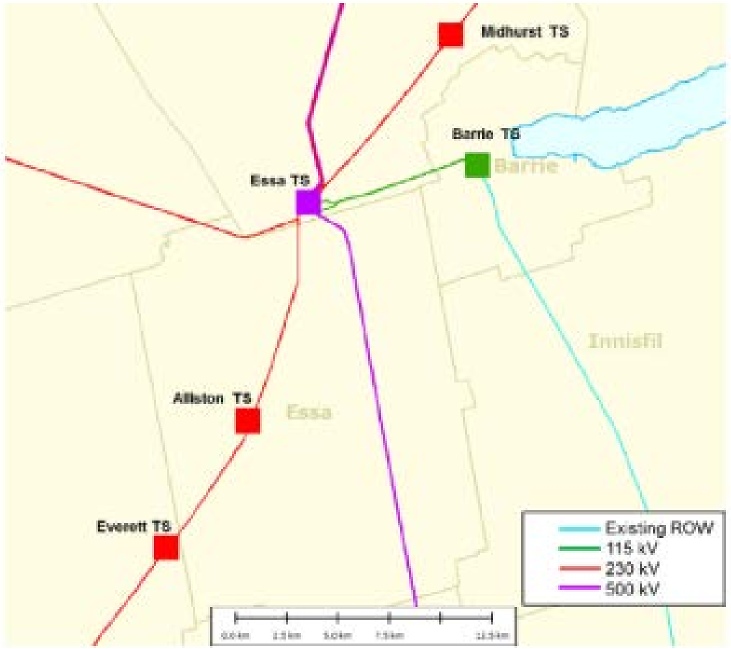
InnPower Corporation

- 230 kV tap transmission line to serve Innisfil service area
  - Original cost estimated at $14 million.
  - Source: [2022 South Georgian Bay-Muskoka RIP] (page 33)

- Hydro One cost estimates for the line have ballooned!
  - Now $100 million +

- Exploring the use of the neighbouring Ontario transmitter rule to help reduce the impact on local ratepayers.

Figure 1: Map of the Barrie/Innisfil Area



How are Customers Leveraging the Network Facility Definition?

Figure 1: Typical Double Circuit 230 kV Customer Connection

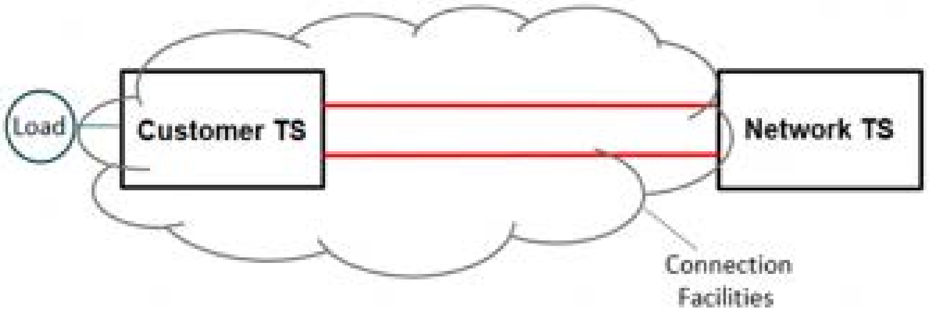
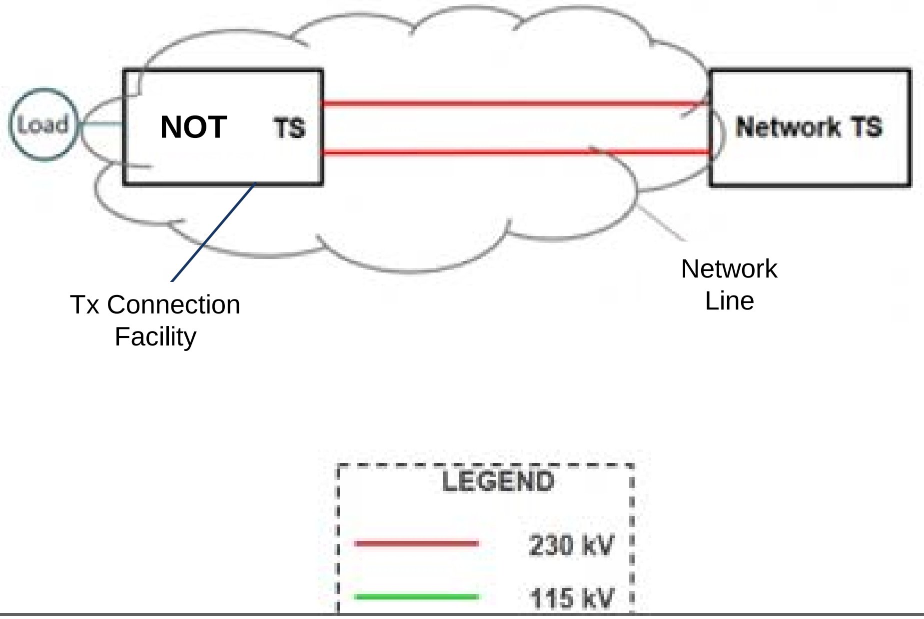


Figure 2: Double Circuit 230 kV Customer & NOT Connection



- Customer (or a 3rd party) applies to become a licensed transmitter or NOT
- NOT builds a station to include certain elements, such as an autotransformer, so that the station would automatically qualify as a network station
  - As per the TSC, any line connecting a network station to another transmitter's system is designated a network facility
  - If a network facility enables their connection, the customer would pay an appropriate share of the costs

Key Discussion Point

- What are the implications if this approach were replicated across the province?
- How do we ensure that dual function assets being assessed and treated consistently and appropriately?

Why did we ask to speak

InnPower Corporation

- OEB Industry Relations Guidance:

  "The enquiry asks whether the line between Essa and the proposed MTS would be classified as a network facility if that proposed MTS was owned and operated by a neighbouring Ontario transmitter.

  In OEB staff's view, the line would be classified as a network facility with InnPower LDC being the sole beneficiary. As noted above, OEB staff's view, as expressed in the Bulletin and based on precedent, is that if a connecting customer is the sole beneficiary of a network facility investment, then it should pay for the investment.

  In OEB staff's view, the beneficiary pays principle is more determinative of cost responsibility than network facility classification. In OEB staff's view, the line between Essa TS and the proposed MTS would not be eligible for recovery as a network facility because a single transmission customer would be the sole beneficiary."

- Uses the existing rules in the Transmission System Code
  - Section 6.3.5 of the TSC - enables a transmitter to require a customer to make a capital contribution to network facilities in "exceptional circumstances"
  - OEB Staff Bulletin issued September 29, 2022 provides further guidance:
    - *Where a connecting customer is the sole beneficiary of the investment in a network facility, then the connecting customer should be required to pay for the investment*

The Problem for InnPower

No cross-subsidization between rate pools

DCF Results (25 years)

Network: shared use of the province-wide grid
($6.37/kW/month)

$48.8 million

Line Connection: use of point-to-point transmission lines
($1.00/kW/month)

$10.2 million

Transformation Connection: use of transformer stations
($3.37/kW/month)

$25.6 million

Figure 1: Typical Double Circuit 230 kV Customer Connection

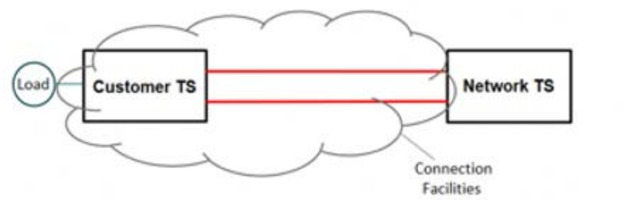
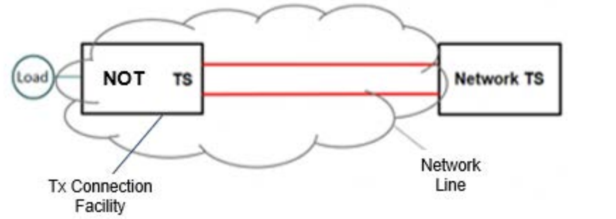


Figure 2: Double Circuit 230 kV Customer & NOT Connection



"Typical" result: *InnPower customers incremental UTRs to be paid = $84.6M. EE model DCF credit = $35.8M.*
The case of the "missing network fees" - $48.8 million.

NOT result: *NOT customers incremental UTRs to be paid - $74.4M. EE model DCF credit - $74.4M*

Scoping Question

The definition of “network” facility is not in scope for Stream 2

Stream 2: Review cost allocation policies for new or modified connections

a. *Review section 6.3.5 of the TSC on allocation of network upgrade costs*
   i. Whether section 6.3.5 of the TSC should be strengthened to provide greater clarity about the circumstances and methodology for allocating network costs.

b. *Review TSC Appendix 4 Customer Financial Risk Classification*
   i. Whether the OEB’s risk assessment methodology, which is set out in Appendix 4 of the TSC, needs to be updated.
   ii. Whether and how additional factors that reduce the risk for some load customers should be included.
   iii. Whether economic evaluation periods for low-risk customers should be extended beyond the existing 20 years.

c. *Review payment options for capital contributions*
   i. Whether capital contribution payment options should be developed for load customers and, if so, what would be the appropriate criteria, terms, and risk mitigations.

- Watay referred to both the neighbouring Ontario transmitter and the autotransformer rules in the TSC (Link here).
- They are not part of this working group.
- Who else has not been properly notified of this expanded scope for Stream 2?

Our position

- The “network” definition in the TSC is not in scope of this Stream 2 consultation.
  - We have concerns about the issue being raised without appropriate historical context – see Appendix A.
  - Put all of our cards on the table - there is no problem with the current definitions.
  - The OEB continues to determine cost responsibility on a case by case basis based on facts and policy.

- Beneficiary pays has a natural corollary.
  - Customers (the beneficiary) should get full benefit for the incremental rates they have to pay in the EE models.
  - The case of the “missing network fees” for new Connection Facilities needs to be resolved.
    - *For InnPower: $48.8M in incremental network rates to be paid but are not accounted for in any EE models.*

- Economic evaluation period for low risk customers should be extended from 25 to 40 years.
  - To align with recent DSC amendments increasing the EE period from 25 to 40 years.
  - Otherwise LDCs will face a “cash crunch”. LDCs would be adding to rate base the results of a 40 years DCF under the DSC. But will only get the benefit of a 25-year DCF under the TSC, increasing the capital contribution required and adding even more to the LDC rate base.

Thank You

For more information, contact:

John Vellone
Partner and National Leader, Energy, Resources & Renewables

416.367.6730
jvellone@blg.com

Borden Ladner Gervais

Appendix A – Historical Background

Staff Discussion Paper – Regulatory Framework for Regional Planning for Electricity Infrastructure

Auto-transformers as Network assets

- The Board has recognized in the past that assets such as 230/115 kV auto-transformers are unique and the Board has identified that an adjustment to cost responsibility should be made for them where they are Connection assets (OEB Decision EB-2006-0189 / EB-2006-0200).
- Current classification of certain transmission assets across the province was not ensuring that “all customers must pay their fair share”, including 115/230 kV auto-transformers across Ontario (link to Staff Paper).
- HONI provided an example where 115/230 kV auto-transformers were being categorized both as line connection (e.g., New Hamburg) and network (e.g., Hawthorne TS) despite both being the same size and performing the same transmission function. 500/230 kV auto-transformers and neighbouring connections were always network (Appendix 2)
  - This resulted in inconsistent treatment of capital contributions paid by LDCs at these stations. A distributor (and hence its customers) would not be required to provide a capital contribution to upgrade the network station, unlike customers connected to a line connection station.
- **Reclassification of existing transformers:** HONI stated there were approximately 90 such autotransformers throughout the Hydro One system and almost half of the 230/115 kV autotransformers are already categorized as Network assets while the other half are Line Connection assets.
- **OEB Staff Supported Reclassification:** OEB Staff agreed that the reclassification of assets such as 230/115 kV auto-transformers and the associated switchgear is desirable in order to optimize use of the transmission system. Such reclassification involving assets where there are multiple beneficiaries would be consistent with the beneficiary pays principle and support achievement of the Board’s goal of optimal investments for this regional planning initiative.

Staff Discussion Paper – Regulatory Framework for Regional Planning for Electricity Infrastructure

OEB Staff believed that reallocating a small subset of Connection assets to the Network pool would: (i) support the Board's goal of achieving optimal transmission and distribution solutions over the long term; (ii) more appropriately recognize the broader group of beneficiaries of those assets and thus better reflect the beneficiary pays principle; and (iii) address the issue identified by stakeholders related to the inconsistent treatment of certain transmission assets in the province.

Specifically, OEB Staff provided the justification for network categorization of auto-transformers:

> "Given the relatively significant cost of a 230/115 kV auto-transformer for a single distributor, continuing to define such transmission assets as Line Connection could create incentives for distributors to make less costly short term investments in their distribution systems to avoid a significant capital contribution, even though the distribution investment is sub-optimal within the context of the overall system."
>
> "Board staff therefore proposes that all 230/115 kV auto-transformers and the associated switchgear be classified as Network assets."

Report of the Board – Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach

- OEB noted inconsistent categorization 115/230 kV auto-transformers. All distributors in a region benefit from a 115/230 kV auto-transformer, and that it is essentially impossible to determine the extent to which each transmission customer benefits from such an asset. The OEB discussed ‘partial’ province-wide pooling, a concept similar to the “minimum connection requirement” bulletin at page 44 (link to report).

- The Board concluded that all 115/230 kV auto-transformers and the associated switchgear should consistently be defined as network assets. The rationale for classifying this subset of transmission assets as network assets was explained by the Board as follows:

> “These unique system elements in some instances accommodate loads that are beyond a customer’s requirement (e.g., autotransformers connecting the 230 kV transmission system to the 115 kV transmission system) [….] In particular, use of autotransformers is seen as a means to optimize use of the transmission system as a whole in accommodating new loads safely and reliably and, most of all, in a timely manner.”

- OEB directed the establishment of the Asset Redefinition Working Group to advise on change to TSC. Changes are expected to apply on a go forward basis only (i.e., to new line connection assets or to upgrades to existing line connection assets that are built after the amendment comes into force).

Amendments to DSC

All the forgoing consultation culminated in the following amendments to the TSC (2013 notices here and here):

- **Broaden the definition of “network facilities”** in new section 3.0.14(a) of the TSC to include any line that forms part of the physical path between (i) two network stations; or (ii) a network station and the transmission system of a neighbouring Ontario transmitter or a transmission system outside Ontario. Also, the TSC was amended to include the phrase that network facilities have “…the extended meaning given to it in section 3.0.14.”
  - This would apply regardless of whether it reflects normal operating conditions.
- Amend definition of “connection facilities” to exclude any lines that would be included in this broadened definition of “network facilities”.
- **At the time, no definition of “network station” in the TSC**. For the purpose of adding clarity to the TSC, particularly in the context of the proposal to expand the concept of “network station”, the Board added a new definition of “network station”, which explicitly included a broader definition of “network station” in new section 3.0.14(b).
  - The Board understood the definition comprises of what are normally understood by the industry to be “network stations” and is consistent with previous Board Decisions.

Wataynikaneyap Power LP (EB-2018-0190)

In response to an OEB Staff interrogatory ([link here]), Wataay provided the following justification that the Line to Pickle Lake within the meaning of "network facilities" in section 2.0.45 of the TSC:

> As indicated, the meaning of "network facilities" relies on the meaning of "network station". Although the Code describes a number of scenarios where a station will be characterized as a "network station", of particular relevance is that a "network station" includes any station with a 230 kV or 115 kV element that switches a 230 kV or 115 kV line that **connects with the transmission system of a neighbouring Ontario transmitter** (Section 2.0.45A(a)(iii)). **The proposed new HONI and WPLP stations at each of Dinorwic and Pickle Lake would all meet this definition of "network station"**. Also relevant is that "network station" also **includes any station with an autotransformer that steps down voltage from a higher transmission level to a lower transmission level** (Section 3.0.14(b)(ii)). **WPLP's Wataynikaneyap TS at Pickle Lake includes a 230/115 kV autotransformer, as does HONI's Mackenzie TS. HONI's Dryden TS includes two such autotransformers**.

Implications

BLG

- Concerns previously existed about Ontario ratepayers not paying their fair share for assets that served a network function. The burden was unfairly falling upon individual customers (primarily LDCs).
- In 2013, after 2.5 years of consultations, the OEB intentionally broadened the definition of “network facilities” and “network station” to address LDC issues of affordability. This included expanding the definition to include a neighbouring Ontario transmitter. This was supported by Hydro One.
- Since 2013 Hydro One has been able to double the number of 230/115 kV auto-transformer stations allocated to the network pool.
- To-date, various customers and transmitters, including Hydro One and Watay, have relied on both the neighbouring Ontario transmitter and auto-transformer rules in the TSC. Unclear why this needs to change now

Appendix 4: 2024 Audited Financial Statements

Financial Statements of
(Expressed in thousands of dollars)

INNPOWER CORPORATION

And Independent Auditor's Report thereon

Year ended December 31, 2024

KPMG LLP
120 Victoria Street South
Suite 600
Kitchener, ON N2G 0E1
Canada
Telephone 519 747 8800
Fax 519 747 8811

INDEPENDENT AUDITOR'S REPORT

To the Shareholder of InnPower Corporation

Opinion

We have audited the financial statements of InnPower Corporation (the Entity), which comprise:

- the statement of financial position as at December 31, 2024
- the statement of comprehensive income for the year then ended
- the statement of changes in equity for the year then ended
- the statement of cash flows for the year then ended
- and notes to the financial statements, including a summary of material accounting policy information

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2024 and its results of operations and its cash flows for the year then ended in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the ***"Auditor's Responsibilities for the Audit of the Financial Statements"*** section of our auditor's report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Emphasis of Matter - Comparative Information

We draw attention to Note 21 to the financial statements (“Note 21”), which explains that certain comparative information presented:

- for the year ended December 31, 2023 has been restated.
- as at January 1, 2023 has been derived from the financial statements for the year ended December 31, 2022 which have been restated (not presented herein).

Note 21 explains the reason for the restatement and also explains the adjustments that were applied to restate certain comparative information. Our opinion is not modified in respect of this matter.

Other Matter - Comparative Information

As part of our audit of the financial statements for the year ended December 31, 2024, we also audited the adjustments that were applied to restate certain comparative information presented:

- for the year ended December 31, 2023
- as at January 1, 2023

In our opinion, such adjustments are appropriate and have been properly applied.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

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

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

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

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

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Entity to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

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

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Kitchener, Canada

May 23, 2025

INNPOWER CORPORATION

Statement of Financial Position
(Expressed in thousands of dollars)

December 31, 2024, with comparative information for 2023

	2024	2023 (Restated, note 21)
Assets		
Current assets:		
Cash	$ -	$ 3,623
Restricted cash	27,712	15,101
Accounts receivable (note 4)	11,338	10,397
Income taxes receivable	163	196
Unbilled revenue	6,558	4,277
Materials and supplies	6,786	3,691
Prepaid expenses	965	832
Total current assets	53,522	38,117
Non-current assets:		
Property, plant and equipment (note 6)	168,800	139,543
Intangible assets (note 7)	8,230	4,610
Right of use assets (note 8)	8	81
Total non-current assets	177,038	144,234
Total assets	230,560	182,351
Regulatory debit balances (note 9)	10,948	12,776
Total assets and regulatory balances	$ 241,508	$ 195,127

See accompanying notes to financial statements.

INNPOWER CORPORATION

Statement of Financial Position
(Expressed in thousands of dollars)

December 31, 2024, with comparative information for 2023

		2024		2023 (Restated, note 21)
Liabilities				
Current liabilities:				
Bank indebtedness (note 11)	$	828	$	-
Accounts payable and accrued liabilities (note 10)		15,347		10,295
Current portion of long-term debt (note 11)		37,063		42,127
Due to developer		16,982		11,247
Current portion of customer deposits		122		122
Current portion of construction deposits		27,643		20,862
Current portion of lease liabilities (note 8)		34		23
Total current liabilities		98,019		84,676
Non-current liabilities:				
Customer deposits		5,520		2,601
Long-term debt (note 11)		10,691		333
Post employment benefits (note 5)		188		172
Contributions in aid of construction (note 12)		74,773		56,147
Construction deposits		8,553		8,904
Deferred tax liability (note 14)		4,608		4,005
Lease liabilities (note 8)		-		58
		104,333		72,220
		202,352		156,896
Equity:				
Share capital (note 13)		10,852		10,852
Contributed surplus		1,600		1,600
Accumulated other comprehensive income		93		84
Retained earnings		24,847		22,657
		37,392		35,193
Subsequent events (notes 11 and 13)				
Regulatory credit balances (note 9)		1,764		3,038
Total liabilities, equity and regulatory balances	$	241,508	$	195,127

See accompanying notes to financial statements.

On behalf of the Board:

______________________ Director ______________________ Director

INNPOWER CORPORATION

Statement of Comprehensive Income
(Expressed in thousands of dollars)

Year ended December 31, 2024, with comparative information for 2023

	2024	2023 (Restated, note 21)
Revenue:		
Sale of energy	$ 44,376	$ 35,416
Distribution revenue	14,897	14,392
Other (note 15)	4,086	1,948
	18,983	16,340
	63,359	51,756
Operating expenses:		
Cost of power purchased	45,234	38,973
Operating (note 16)	9,307	8,295
Depreciation and amortization	5,097	4,329
Loss on disposal of property, plant and equipment, intangible assets, and right-of-use leases	71	53
	14,475	12,677
	59,709	51,650
Income from operating activities	3,650	106
Finance costs (note 17)	(2,115)	(1,552)
Finance income (note 17)	93	398
Income (loss) before income taxes and undernoted items	1,628	(1,048)
Income tax expense (note 14)	707	818
Net income (loss) for the year before movement in regulatory deferral account balances	921	(1,866)
Other income:		
Net movement in regulatory balances (note 9)	1,694	4,451
Net income for the year and net movement in regulatory balances	2,615	2,585
Other comprehensive income (loss):		
Remeasurement of post-employment benefits, net of tax	9	(8)
Other comprehensive income (loss) for the year	9	(8)
Total comprehensive income for the year	$ 2,624	$ 2,577

See accompanying notes to financial statements.

INNPOWER CORPORATION

Statement of Changes in Equity
(Expressed in thousands of dollars)

Year ended December 31, 2024, with comparative information for 2023

	Share capital	Retained earnings	Contributed surplus	Accumulated other comprehensive income (loss)	Total (Restated, note 21)
Balance at January 1, 2023	$ 10,852	$ 20,391	$ 1,600	$ 92	$ 32,935
Net income and net movement in regulatory balances	-	2,585	-	-	2,585
Other comprehensive loss	-	-	-	(8)	(8)
Dividends	-	(319)	-	-	(319)
Balance at December 31, 2023	$ 10,852	$ 22,657	$ 1,600	$ 84	$ 35,193

	Share capital	Retained earnings	Contributed surplus	Accumulated other comprehensive income (loss)	Total (Restated, note 21)
Balance at January 1, 2024	$ 10,852	$ 22,657	$ 1,600	$ 84	$ 35,193
Net income and net movement in regulatory balances	-	2,615	-	-	2,615
Other comprehensive income	-	-	-	9	9
Dividends	-	(425)	-	-	(425)
Balance at December 31, 2024	$ 10,852	$ 24,847	$ 1,600	$ 93	$ 37,392

See accompanying notes to financial statements.

INNPOWER CORPORATION

Statement of Cash Flows
(Expressed in thousands of dollars)

Year ended December 31, 2024, with comparative information for 2023

	2024	2023 (Restated, note 21)
Cash provided by (used in):		
Operating activities:		
Total comprehensive income	$ 2,624	$ 2,577
Items not involving cash:		
Depreciation and amortization	5,476	4,655
Depreciation and amortization right of use asset	48	29
Amortization of contributions in aid of construction	(1,754)	(1,399)
Post-employment benefits	16	29
Loss on disposal of assets	71	53
Net finance costs	2,022	1,154
Income tax expense	706	818
Income tax expense within net movement in regulatory balances	(600)	(786)
	8,609	7,130
Changes in non-cash operating working capital:		
Restricted cash	(12,611)	(15,101)
Accounts receivable	(941)	51
Unbilled revenue	(2,281)	(506)
Materials and supplies	(3,095)	(1,290)
Prepaid expenses	(133)	(511)
Accounts payable and accrued liabilities	5,052	101
Construction deposits	6,430	14,739
Customer deposits	2,919	(347)
	(4,660)	(2,864)
Income tax paid	(70)	(151)
Interest received	93	398
Interest paid	(2,115)	(1,552)
Regulatory balances	1,154	(87)
	3,011	2,874
Financing activities:		
Repayment of long-term debt	(1,908)	(1,513)
Proceeds of long-term debt	7,202	8,000
Repayment of lease liabilities	(47)	(31)
Dividends paid	(425)	(319)
	4,822	6,137
Investing activities:		
Purchase of property, plant and equipment	(28,622)	(21,360)
Proceeds on disposal of property, plant and equipment	34	-
Purchase of intangible assets	(4,076)	(4,264)
Construction contributions received	20,380	13,765
	(12,284)	(11,859)
Decrease in cash	(4,451)	(2,848)
Cash, beginning of year	3,623	6,471
Cash (bank indebtedness), end of year	$ (828)	$ 3,623

See accompanying notes to financial statements.

Reporting entity:

InnPower Corporation (the "Corporation") is a rate regulated, municipally owned hydro distribution company incorporated under the laws of Ontario, Canada. The Corporation is located in the Town of Innisfil (“the Town”). The address of the Corporation’s registered office is 7251 Yonge Street, Innisfil, Ontario.

The Corporation delivers electricity and related energy services to residential and commercial customers in the Town and South Barrie. The Corporation is wholly owned by the Town of Innisfil.

The financial statements are for the Corporation as at and for the year ended December 31, 2024.

1. Basis of presentation:

(a) Statement of compliance:

The Corporation's financial statements have been prepared in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board ("IFRS").

The financial statements were approved by the Board of Directors on April 28, 2025.

(b) Basis of measurement:

These financial statements have been prepared on the historical cost basis, unless otherwise stated.

(c) Functional and presentation currency:

These financial statements are presented in Canadian dollars, which is the Corporation's functional currency. All financial information presented in Canadian dollars has been rounded to the nearest thousand.

(d) Use of estimates and judgments:

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses and disclosure of contingent assets and liabilities. Actual results may differ from those estimates.

Information about assumptions and estimation uncertainties that have a significant risk of resulting in material adjustment is included in the following notes:

1. Basis of presentation (continued):

(d) Use of estimates and judgments (continued):

Information about assumptions and estimation uncertainties that have a significant risk of resulting in material adjustment is included in the following notes:

(i) Note 2(b) - measurement of unbilled revenue
(ii) Note 2(b) - determination of the performance obligation for contributions from customers and the related amortization period.
(iii) Notes 2 (k), 8 - leases: whether an arrangement contains a lease
(iv) Notes 6, 7 - estimation of useful lives of its property, plant and equipment and intangible assets
(v) Note 9 - recognition and measurement of regulatory balances
(vi) Note 5 - measurement of defined benefit obligations: key actuarial assumptions
(vii) Note 18 - recognition and measurement of provisions and contingencies

(e) Rate regulation:

The Corporation is regulated by the Ontario Energy Board ("OEB"), under the authority granted by the Ontario Energy Board Act, 1998. Among other things, the OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for electricity consumers in Ontario, and ensuring that transmission and distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies ("LDCs"), such as the Corporation, which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

1. Basis of presentation (continued):

(e) Rate regulation (continued):

Distribution revenue

For the distribution revenue included in sale of energy, the Corporation files a "Cost of Service" ("COS") rate application with the OEB every five years where rates are determined through a review of the forecasted annual amount of operating and capital expenditures, debt and shareholder's equity required to support the Corporation's business. The Corporation estimates electricity usage and the costs to service each customer class to determine the appropriate rates to be charged to each customer class. The COS application is reviewed by the OEB and interveners and rates are approved based upon this review, including any revisions resulting from that review.

In the intervening years an Incentive Rate Mechanism application ("IRM") is filed. An IRM application results in a formulaic adjustment to distribution rates that were set under the last COS application. The previous year's rates are adjusted for the annual change in the Gross Domestic Product Implicit Price Inflator for Final Domestic Demand ("GDP IPI-FDD") net of a productivity factor and a "stretch factor" determined by the relative efficiency of an electricity distributor.

As a licensed distributor, the Corporation is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Corporation is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Corporation ultimately collects these amounts from customers.

The Corporation last filed a COS application in 2023 for rates effective January 1, 2024. On December 12, 2025, the Corporation received its decision on rates from its most recent IRM filing for rates effective January 1, 2025.

Electricity rates

The OEB sets electricity prices for low-volume consumers twice each year based on an estimate of how much it will cost to supply the province with electricity for the next year. All remaining consumers pay the market price for electricity. The Corporation is billed for the cost of the electricity that its customers use and passes this cost on to the customer at cost without a mark-up.

2. Material accounting policies:

The accounting policies set out below have been applied consistently in all years presented in these financial statements.

(a) Financial instruments:

At initial recognition, the Corporation measures it's financial assets at fair value plus, in the case of a financial asset not at fair value through profit or loss, transaction costs that are directly attributable to the acquisition of the financial asset. Transaction costs of financial assets carried at fair value through profit or loss are expensed in profit or loss.

Subsequent measurement of the financial asset depends on the classification determined on initial recognition. Financial assets are classified as either amortized cost, fair value through other comprehensive income ("OCI") or fair value through profit or loss, depending on its business model for managing the financial assets and the contractual cash flow characteristics of the financial assets. Financial assets are not reclassified subsequent to their initial recognition, unless the Corporation changes its business model for managing financial assets.

Financial liabilities are initially measured at fair value, net of transaction costs incurred. They are subsequently carried at amortized cost using the effective interest rate method; any difference between the proceeds (net of transaction costs) and the redemption value is recognized as an adjustment to interest expense over the period of the borrowings.

The Corporation has not entered into derivative instruments.

(b) Revenue recognition:

Sale and distribution of electricity

The performance obligations for the sale and distribution of electricity are recognized over time using an output method to measure the satisfaction of the performance obligation. The value of the electricity services transferred to the customer is determined on the basis of cyclical meter readings plus estimated customer usage since the last meter reading date to the end of the year and represents the amount that the Corporation has the right to bill. Revenue includes the cost of electricity supplied, distribution, and any other regulatory charges. The related cost of power is recorded on the basis of power used.

For customer billings related to electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties, the Corporation has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

2. Material accounting policies (continued):

(b) Revenue recognition (continued):

Customer billings for debt retirement charges are recorded on a net basis as the Corporation is acting as an agent for this billing stream.

Capital contributions

Developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. The developer is not a customer and therefore the contributions are scoped out of IFRS 15 Revenue from Contracts with Customers. Cash contributions, received from developers are recorded as deferred revenue. When an asset other than cash is received as a capital contribution, the asset is initially recognized at its fair value, with a corresponding amount recognized as deferred revenue. The deferred revenue, which represents the Corporation's obligation to continue to provide the customers access to the supply of electricity, is amortized to income on a straight-line basis over the useful life of the related asset.

Certain customers are also required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. These contributions fall within the scope of IFRS 15 Revenue from Contracts with Customers. The contributions are received to obtain a connection to the distribution system in order receive ongoing access to electricity. The Corporation has concluded that the performance obligation is the supply of electricity over the life of the relationship with the customer which is satisfied over time as the customer receives and consumes the electricity. Revenue is recognized on a straight-line basis over the useful life of the related asset.

Other revenue

Revenue earned from the provision of services is recognized as the service is rendered.

Government grants and the related performance incentive payments under CDM programs are recognized as revenue in the year when there is reasonable assurance that the program conditions have been satisfied and the payment will be received.

Unbilled revenue

Unbilled revenue represents amounts for which the Corporation has a contractual right to receive cash through future billings and are unbilled at the year-end date. Unbilled revenue is recorded based on preliminary consumption for any period not yet billed.

2. Material accounting policies (continued):

(c) Materials and supplies:

Materials and supplies, the majority of which is consumed by the Corporation in the provision of its services, is valued at the lower of cost and net realizable value, with cost being determined on an average cost basis, and includes expenditures incurred in acquiring the materials and supplies and other costs incurred in bringing them to their existing location and condition.

(d) Property, plant and equipment:

Items of property, plant and equipment ("PP&E") used in rate-regulated activities and acquired prior to January 1, 2015 are measured at the deemed cost (carrying value as elected under IFRS 1) established on the transition date, less accumulated depreciation. All other items of PP&E are measured at cost, or, where the item is contributed by customers, its fair value, less accumulated depreciation.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes contracted services, materials and transportation costs, direct labour, overhead costs, borrowing costs and any other costs directly attributable to bringing the asset to a working condition for its intended use.

Borrowing costs on qualifying assets are capitalized as part of the cost of the asset based upon the weighted average cost of debt incurred on the Corporation's borrowings. Qualifying assets are considered to be those that take in excess of 12 months to construct.

When parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components) of PP&E.

When items of PP&E are retired or otherwise disposed of, a gain or loss on disposal is determined by comparing the proceeds from disposal, if any, with the carrying amount of the item, and such gain or loss on disposal is included in profit or loss.

Major spare parts and standby equipment are recognized as items of PP&E.

The cost of replacing a part of an item of PP&E is recognized as a capital addition in the net book value of the item if it is probable that the future economic benefits embodied within the part will flow to the Corporation, and its cost can be measured reliably. In this event, the replaced part of PP&E is written off, and the related gain or loss is included in profit or loss. The costs of the day-to-day servicing of PP&E are recognized as repairs and maintenance in profit or loss, as incurred.

(Expressed in thousands of dollars)

2. Material accounting policies (continued):

(d) Property, plant and equipment (continued):

The need to estimate the decommissioning costs at the end of the useful lives of certain assets is reviewed periodically.

Depreciation is calculated to write off the cost of items of PP&E using the straight-line method over their estimated useful lives, and is generally recognized in profit or loss. Depreciation methods, useful lives, and residual values are reviewed at each reporting date and adjusted prospectively if appropriate. Land is not depreciated. Construction-in-progress assets are not depreciated until the project is complete and the asset is available for use.

The estimated useful lives are as follows:

Asset	Rate
Buildings and fixtures	50 years
Substations	30 years
Distribution lines	15-60 years
Distribution transformers	40-50 years
Meters	15-25 years
Office equipment	10 years
Computer equipment	5 years
Transportation equipment	10 years
Small tools and miscellaneous equipment	10 years
System supervisory	15 years

(e) Intangible assets:

Intangible assets used in rate-regulated activities and acquired prior to January 1, 2015 are measured at deemed cost (carrying value as elected under IFRS 1) established on the transition date, less accumulated amortization. All other intangible assets are measured at cost.

Computer software that is acquired or developed by the Corporation after January 1, 2015, including software that is not integral to the functionality of equipment purchased which has finite useful lives, is measured at cost less accumulated amortization.

Payments to obtain rights to access land ("land rights") are classified as intangible assets. These include payments made for easements, right of access and right of use over land for which the Corporation does not hold title. Land rights are measured at cost less accumulated amortization.

2. Material accounting policies (continued):

(e) Intangible assets (continued):

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets from the date that they are available for use. Amortization methods and useful lives of all intangible assets are reviewed at each reporting date and adjusted prospectively if appropriate. The estimated useful lives are:

Asset	Rate
Computer software	5 years
Land rights	50 years
Contribution asset	25 Years

(f) Impairment:

(i) Financial assets measured at amortized cost:

A loss allowance for expected credit losses on financial assets measured at amortized cost is recognized at the reporting date. The loss allowance is measured at an amount equal to the lifetime expected credit losses for the asset.

(ii) Non-financial assets:

The carrying amounts of the Corporation's non-financial assets, other than materials and supplies and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or “CGU”). The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

2. Material accounting policies (continued):

(f) Impairment (continued):

(ii) Non-financial assets (continued):

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss.

An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no previous impairment loss had been recognized.

(g) Customer deposits:

Customer deposits represent cash deposits from electricity distribution customers and retailers to guarantee the payment of energy bills. Interest is paid on customer deposits.

Deposits are refundable to customers who demonstrate an acceptable level of credit risk as determined by the Corporation in accordance with policies set out by the OEB or upon termination of their electricity distribution service.

(h) Provisions:

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

2. Material accounting policies (continued):

(i) Regulatory balances:

Regulatory deferral account debit balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. Regulatory deferral account credit balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Corporation.

Regulatory deferral account debit balances are recognized if it is probable that future billings in an amount at least equal to the deferred cost will result from inclusion of that cost in allowable costs for rate-making purposes. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. When the customer is billed at rates approved by the OEB for the recovery of the deferred costs, the customer billings are recognized in revenue. The regulatory debit balance is reduced by the amount of these customer billings with the offset to net movement in regulatory balances in profit or loss or OCI.

Regulatory deferral account debit balances are recognized if it is probable that future billings in an amount at least equal to the deferred cost will result from inclusion of that cost in allowable costs for rate-making purposes. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. When the customer is billed at rates approved by the OEB for the recovery of the deferred costs, the customer billings are recognized in revenue. The regulatory debit balance is reduced by the amount of these customer billings with the offset to net movement in regulatory balances in profit or loss or OCI.

The probability of recovery of the regulatory deferral account debit balances is assessed annually based upon the likelihood that the OEB will approve the change in rates to recover the balance. The assessment of likelihood of recovery is based upon previous decisions made by the OEB for similar circumstances, policies or guidelines issued by the OEB. Any resulting impairment loss is recognized in profit or loss in the year incurred.

When the Corporation is required to refund amounts to ratepayers in the future, the Corporation recognizes a regulatory deferral account credit balance. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. The amounts returned to the customers are recognized as a reduction of revenue. The credit balance is reduced by the amount of these customer repayments with the offset to net movement in regulatory balances in profit or loss or OCI.

2. Material accounting policies (continued):

(j) Post-employment benefits:

(i) Pension plan

The Corporation provides a pension plan for all its full-time employees through Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund"), and provides pensions for employees of Ontario municipalities, local boards and public utilities. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. To the extent that the Fund finds itself in an over or under-funded position, contribution rates may be assessed to participating employers and members.

OMERS is a defined benefit plan. However, as OMERS does not segregate its pension asset and liability information by individual employers, there is insufficient information available to enable the Corporation to directly account for the plan. Consequently, the plan has been accounted for as a defined contribution plan. The Corporation is not responsible for any other contractual obligations other than the contributions. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in profit or loss when they are due.

(ii) Post-employment benefits, other than pension

The Corporation provides some of its retired employees with life insurance and medical benefits beyond those provided by government sponsored plans.

The obligations for these post-employment benefit plans are actuarially determined by applying the projected unit credit method and reflect management's best estimate of certain underlying assumptions. Remeasurements of the net defined benefit obligations, including actuarial gains and losses and the return on plan assets (excluding interest), are recognized immediately in other comprehensive income. When the benefits of a plan are improved, the portion of the increased benefit relating to past service by employees is recognized immediately in profit or loss.

2. Material accounting policies (continued):

(k) Leased assets:

At inception of a contract, the Corporation assesses whether the contract is or contains a lease. A contract is determined to contain a lease if it provides the Corporation with the right to control the use of an identified asset for a period of time in exchange for consideration. Contracts determined to contain a lease are accounted for as leases. For leases and contracts that contain a lease, the Corporation recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured at cost which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received.

The right-of-use asset is subsequently depreciated using the straight-line method from the commencement date to the earlier of the end of the useful life of the right-of-use asset or the end of the lease term. The estimated useful lives of right-of-use assets are determined on the same basis as those of property, plant and equipment. Subsequent to initial recognition, the right-of-use asset is recognized at cost less any accumulated depreciation and any accumulated impairment losses, adjusted for certain remeasurements of the corresponding lease liability.

The lease liability is initially measured at the present value of the lease payments that are unpaid at the commencement date, discounted using the interest rate implicit in the lease. If that rate cannot be readily determined, the Corporation's incremental borrowing rate is used.

The lease liability is subsequently measured at amortized cost using the effective interest method. It is remeasured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Corporation's estimate of the amount expected to be payable under a residual value guarantee, or if the Corporation changes its assessment of whether it will exercise a purchase, extension or termination option. When the lease liability is remeasured in this way, a corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero.

2. Material accounting policies (continued):

(l) Finance income and finance costs:

Finance income is recognized as it accrues in profit or loss, using the effective interest method. Finance income comprises interest earned on cash.

Finance costs comprise interest expense on borrowings and net interest expense on post-employment benefits. Finance costs are recognized in profit or loss unless they are capitalized as part of the cost of qualifying assets.

(m) Income taxes:

The income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case, it is recognized in equity.

The Corporation is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act (collectively the “Tax Acts”). Under the Electricity Act, 1998, the Corporation makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (“OEFC”). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Tax Acts as modified by the Electricity Act, 1998, and related regulations. Prior to October 1, 2001, the Corporation was not subject to income or capital taxes. Payments in lieu of taxes are referred to as income taxes.

Current tax comprises the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized in respect of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Deferred tax assets are recognized for unused tax losses, unused tax credits and deductible temporary differences to the extent that it is probable that future taxable profits will be available against which they can be used. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, using tax rates enacted or substantively enacted, at the reporting date.

(Expressed in thousands of dollars)

3. Changes to accounting policies:

The International Accounting Standards Board ("IASB") has issued the following Standards, Interpretations and Amendments to Standards that were adopted by the Corporation effective January 1, 2024. The amendments and clarifications did not have an impact on the financial statements.
(a) Non-current Liabilities with Covenants (Amendments to IAS 1)
(b) Classification of Liabilities as Current or Non-current (Amendments to IAS 1)
(c) Lease Liability in a Sale and Leaseback (Amendments to IFRS 16)
(d) Supplier Finance Arrangements (Amendments to IAS 7 and IFRS 7)

Emerging accounting changes:

At the date of authorization of these financial statements, several new, but not yet effective, Standards and amendments to existing Standards, and Interpretations have been published by the IASB. None of these Standards or amendments to existing Standards have been adopted early by the Corporation and it is still to be determined if any will have a material impact on the Corporation's financial statements.
(a) Lack of Exchangeability (Amendments to IAS 21)
(b) Classification and Measurement of Financial Instruments (Amendments to IFRS 9 and IFRS 7)
(c) Annual Improvements to IFRS Accounting Standards (Volume 11)
(d) IFRS 18 Presentation and Disclosure in Financial Statements
(e) IFRS 19 Subsidiaries without Public Accountability
(f) Sale or Contribution of Assets between an investor and its Associate or Joint Venture (Amendments to IFRS 10 and IAS 28)

4. Accounts receivable:

	2024	2023 (Restated, note 21)
Trade customer accounts receivable	$ 6,558	$ 5,897
Other receivables	2,982	2,579
Due from related parties (note 19)	1,798	1,921
	$ 11,338	$ 10,397

(Expressed in thousands of dollars)

5. Post-employment benefits:

(a) OMERS pension plan:

The Corporation provides a pension plan for its employees through OMERS. The plan is a multi-employer, contributory defined pension plan with equal contributions by the employer and its employees. In 2024, the Corporation made employer contributions of $680 to OMERS (2023 - $666) which has been recognized in profit or loss. The Corporation estimates that a contribution of $665 to OMERS will be made during the next fiscal year.

As at December 31, 2024, OMERS had approximately 640,000 members, of whom 62 are current employees of the Corporation. The most recently available OMERS annual report is for the year ended December 31, 2024, which reported that the plan was 98% funded, with an unfunded liability of $2.9 billion. This unfunded liability may result in extra future payments by participating employers and members.

(b) Post-employment benefits other than pension:

The Corporation pays certain medical and life insurance benefits on behalf of some of its retired employees. The Corporation recognizes these post-employment benefits in the year in which employees' services were rendered. The Corporation is recovering its post-employment benefits in rates based on the expense and remeasurements recognized for post-employment benefit plans.

Reconciliation of the obligation	2024	2023
Defined benefit obligation, beginning of year	$ 172	$ 143
Included in profit or loss:		
Current service cost	16	13
Interest cost	9	8
	25	21
Included in OCI		
Actuarial losses arising from:		
Changes in financial assumptions	(9)	8
	$ 188	$ 172

(Expressed in thousands of dollars)

5. Post-employment benefits (continued):

(b) Post-employment benefits other than pension (continued):

Actuarial assumptions	2024	2023
Discount (interest) rate	4.70 %	4.60 %
Salary levels	3.10 %	3.10 %
Medical costs	5.50 %	6.50 %
Dental costs	4.00 %	4.00 %

A 1% increase in the assumed discount rate would result in the defined benefit obligation decreasing by $20. A 1% decrease in the assumed discount rate would result in the defined benefit obligation increasing by $25.

(Expressed in thousands of dollars)

6. Property, plant and equipment:

		Land and buildings		Distribution equipment		Other fixed assets		Construction-in-progress		Total
Cost of deemed cost										
Balance at January 1, 2024	$	15,088	$	134,251	$	8,416	$	8,375	$	166,130
Additions		97		29,070		1,054		4,136		34,357
Disposals/ retirements		-		(106)		(34)		-		(140)
Balance at December 31, 2024	$	15,185	$	163,215	$	9,436	$	12,511	$	200,347
Balance at January 1, 2023	$	15,067	$	111,549	$	7,182	$	6,007	$	139,805
Additions		21		22,842		1,234		2,368		26,465
Disposals/ retirements		-		(140)		-		-		(140)
Balance at December 31, 2023	$	15,088	$	134,251	$	8,416	$	8,375	$	166,130
Accumulated depreciation										
Balance at January 1, 2024	$	2,401	$	19,488	$	4,698	$	-	$	26,587
Depreciation		290		3,922		808		-		5,020
Disposals		-		(60)		-		-		(60)
Balance at December 31, 2024	$	2,691	$	23,350	$	5,506	$	-	$	31,547
Balance at January 1, 2023	$	2,114	$	16,194	$	4,029	$	-	$	22,337
Depreciation		287		3,381		669		-		4,337
Disposals		-		(87)		-		-		(87)
Balance at December 31, 2023	$	2,401	$	19,488	$	4,698	$	-	$	26,587
Carrying amounts										
At December 31, 2024	$	12,494	$	139,865	$	3,930	$	12,511	$	168,800
At December 31, 2023		12,687		114,763		3,718		8,375		139,543
At January 1, 2023		12,953		95,355		3,153		6,007		117,468

(Expressed in thousands of dollars)

7. Intangible assets:

	Computer software	Land rights	Contribution assets	Total
Cost of deemed cost				
Balance at January 1, 2024	$ 1,927	$ 397	$ 4,118	$ 6,442
Additions	65	5	4,006	4,076
Balance at December 31, 2024	$ 1,992	$ 402	$ 8,124	$ 10,518
Balance at January 1, 2023	$ 1,781	$ 397	$ -	$ 2,178
Additions	146	-	4,118	4,264
Balance at December 31, 2023	$ 1,927	$ 397	$ 4,118	$ 6,442
Accumulated amortization				
Balance at January 1, 2024	$ 1,619	$ 130	$ 83	$ 1,832
Amortization	192	13	251	456
Balance at December 31, 2024	$ 1,811	$ 143	$ 334	$ 2,288
Balance at January 1, 2023	$ 1,397	$ 117	$ -	$ 1,514
Amortization	222	13	83	318
Balance at December 31, 2023	$ 1,619	$ 130	$ 83	$ 1,832
Carrying amounts				
At December 31, 2024	$ 181	$ 259	$ 7,790	$ 8,230
At December 31, 2023	308	267	4,035	4,610

(Expressed in thousands of dollars)

8. Leases:

Right-of-use Asset		Vehicle Leases
Cost of deemed cost		
Balance at January 1, 2024	$	141
Deletions		(65)
Balance at December 31, 2024	$	76
Balance at January 1, 2023	$	236
Deletions		(95)
Balance at December 31, 2023	$	141
Accumulated amortization		
Balance at January 1, 2024	$	60
Amortization		48
Deletions		(40)
Balance at December 31, 2024	$	68
Balance at January 1, 2023	$	126
Amortization		29
Deletions		(95)
Balance at December 31, 2023	$	60
Carrying amounts		
At December 31, 2024	$	8
At December 31, 2023		81

(Expressed in thousands of dollars)

8. Leases (continued):

Lease Liability		Vehicle Leases
Balance at January 1, 2024	$	81
Repayments		(50)
Interest		3
Balance at December 31, 2024	$	34

Balance at January 1, 2023	$	112
Repayments		(35)
Interest		4
Balance at December 31, 2023	$	81

Lease liabilities include a current portion of $34 (2023 - $23). Certain leases held by the Corporation provide the Corporation with extension options and termination options that may impact the term of the Lease which can impact the finance lease liability recognized in the statement of financial position. The Corporation has determined the lease term for all contracts based on all available information as at the reporting date.

9. Regulatory account balances:

Reconciliation of the carrying amount for each class of regulatory balances:

Regulatory deferral account debit balances		January 1, 2024		Additions		Recovery/ reversal		December 31, 2024	Remaining recovery/ reversal years
Retail settlement variances	$	7,222	$	908	$	(3,304)	$	4,826	2-3
Regulatory asset associated with deferred taxes		5,448		820		-		6,268	-
Regulatory variances disposition		-		-		(62)		(62)	-
Other		106		22		(212)		(84)	1-3
	$	12,776	$	1,750	$	(3,578)	$	10,948	

(Expressed in thousands of dollars)

9. Regulatory account balances (continued):

Regulatory deferral account debit balances	January 1, 2023	Additions	Recovery/ reversal	December 31, 2023	Remaining recovery/ reversal years
Retail settlement variances	$ 6,720	$ 1,488	$ (986)	$ 7,222	2-3
Regulatory asset associated with deferred taxes	4,379	1,069	-	5,448	-
Other	261	-	(155)	106	1-3
	$ 11,360	$ 2,557	$ (1,141)	$ 12,776	

Regulatory deferral account credit balances	January 1, 2024	Additions	Recovery/ reversal	December 31, 2024	Remaining recovery/ reversal years
Retail settlement variances	$ 107	$ -	$ (24)	$ 83	2-3
Deferred income tax on regulatory asset	1,455	220	-	1,675	-
Regulatory variances disposition	167	-	-	167	-
Other	1,309	5	(1,475)	(161)	-
	$ 3,038	$ 225	$ (1,499)	$ 1,764	

Regulatory deferral account credit balances	January 1, 2023	Additions	Recovery/ reversal	December 31, 2023	Remaining recovery/ reversal years
Retail settlement variances	$ 73	$ 34	$ -	$ 107	2-3
Deferred income tax on regulatory asset	1,172	283	-	1,455	-
Regulatory variances disposition	61	106	-	167	
Other	1,189	221	(101)	1,309	-
	$ 2,495	$ 644	$ (101)	$ 3,038	

(Expressed in thousands of dollars)

9. Regulatory account balances (continued):

For 2024, the net movement in regulatory deferred account balances net of taxes of $1,694 consists of the regulatory deferred tax expense of $600, the difference between the Power Purchased and the Sale of Electricity of $851, and approximately $243 in other carrying charges.

For 2023, the net movement in regulatory deferred account balances net of taxes of $4,451 consists of the regulatory deferred tax expense of $628, the difference between the Power Purchased and the Sale of Electricity of $3,557, and approximately $266 in other carrying charges

The regulatory balances are recovered or settled through rates approved by the OEB which are determined using estimates of future consumption of electricity by its customers. Future consumption is impacted by various factors including the economy and weather. The Corporation has received approval from the OEB to establish its regulatory balances.

Settlement of the Group 1 deferral accounts is done on an annual basis through application to the OEB. The OEB requires the Corporation to estimate its income taxes when it files a COS application to set its rates. As a result, the Corporation has recognized a regulatory deferral account for the amount of deferred taxes that will ultimately be recovered from/paid back to its customers. This balance will fluctuate as the Corporation's deferred tax balance fluctuates.

Regulatory deferral accounts attract interest at OEB prescribed rates, which was 5.49% from January 1, 2024 to March 31, 2024, 5.49% from April 1, 2024 to June 30, 2024, 5.20% from July 1, 2024 to September 30, 2024, and 4.40% from October 1, 2024 to December 31, 2024.

10. Accounts payable and accrued liabilities:

		2024		2023 (Restated, note 21)
Power purchases	$	3,342	$	2,966
Trade payables		8,026		3,718
Due to related parties (note 19)		3,444		3,170
Other		535		441
	$	15,347	$	10,295

(Expressed in thousands of dollars)

11. Long-term debt:

		2024		2023 (Restated, note 21)
Term loan, interest at 1.92%, payable in monthly instalments. Amortization maturity: October 29, 2030. Contract maturity: October 29, 2025, renewable	$	782	$	905
Term loan, interest at 5.27%, payable in monthly instalments. Amortization maturity: September 7, 2037; Contract maturity: September 7, 2026, renewable		2,540		2,675
Term loan, interest at bank prime.Contract maturity 2024		-		2,417
Term loan, interest at 6.25%.Contract maturity 2024		-		2,192
Term loan, interest at 3.96%.Contract maturity 2024		-		1,605
Term loan, interest at 3.91%. Contract maturity 2024		-		1,619
Term loan, interest at 3.68%, payable in monthly instalments. Amortization maturity: January 9, 2045. Contract maturity: January 9, 2025, renewable		1,566		1,617
Term loan, interest at 2.88%, payable in monthly instalments. Amortization maturity: June 26, 2045. Contract maturity: June 26, 2025, renewable		9,391		9,722
Term loan, interest at 3.48%, payable in monthly instalments. Amortization maturity: February 14, 2046. Contract maturity: February 14, 2026, renewable		2,380		2,454
Term loan, interest at 3.60%, payable in monthly instalments. Amortization maturity: January 28, 2047. Contract maturity: January 28, 2027, renewable		2,574		2,648
Ontario Infrastructure loan, interest at 3.91%, payable in semi-annual instalments.		-		500
Term loan, interest at 4.09%, payable in monthly Instalments. Amortization maturity: March 26, 2048. Contract maturity: March 26, 2028, renewable		1,469		1,505
Term loan, interest at 3.28%, payable in monthly instalments. Amortization maturity: August 26, 2049. Contract maturity: August 26, 2029, renewable		2,121		2,176
Term loan, interest at 2.45%, payable in monthly instalments. Contract maturity 2024.		-		2,432
Term loan, interest at 6.29%, payable in monthly instalments. Amortization maturity: November 1, 2053. Contract maturity: November 1, 2025, renewable		3,951		3,993
Carried forward		26,774		38,460

(Expressed in thousands of dollars)

11. Long-term debt (continued):

		2024		2023 (Restated, note 21)
Carried forward		26,774		38,460
Term loan, interest at 5.55%, payable in monthly instalments. Amortization maturity: December 14, 2043. Contract maturity: December 14, 2025, renewable		3,948		4,000
Term loan, interest at 4.59%, payable in monthly instalments, Amortization maturity: December 24, 2047. Contract maturity: December 23, 2025, renewable		17,032		-
		47,754		42,460
Less current portion of long-term debt		37,063		42,127
	$	10,691	$	333

The bank term loans holds as security a general security agreement representing a first charge on all assets and undertakings of the Corporation.

The agreement with respect to the bank term loans contain certain covenants regarding (i) regulatory compliance, (ii) reporting, (iii) change in status of business, (iv) change in ownership, and (v) limitations on additional debt and encumbrance of assets.

(Expressed in thousands of dollars)

11. Long-term debt (continued):

The agreement with bank also contains financial covenants that require the Corporation to maintain a maximum debt to capital ratio of 0.60 to 1 and a minimum debt service coverage ratio of 1.20x to be tested and calculated on a quarterly basis. The Corporation was in compliance of the covenants as at December 31, 2024.

On May 9, 2024, the Corporation obtained an amendment to the bank term loan agreement which revises the calculation of the debt service coverage ratio to consider unfinanced capital expenditures. This amendment, if in place as at December 31, 2023, would have resulted in the debt service coverage ratio being in compliance.

Principal payment due in each of the next five years are as follows:

2025	$	37,063
2026		4,877
2027		2,517
2028		1,412
2029		1,885
	$	47,754

As of December 31, 2024, the Corporation has a bank overdraft of $828 (2023 - $nil). Bank overdrafts are repayable on demand and form an integral part of the Corporation's cash management. Interest accrues daily at Prime less 1.90%.

12. Contributions in aid of construction:

		2024		2023 (Restated, note 21)
Contributions in aid of construction, beginning of year	$	56,147	$	43,207
Contributions received		20,380		14,339
Amortization		(1,754)		(1,399)
Contributions in aid of construction, end of year	$	74,773	$	56,147

(Expressed in thousands of dollars)

13. Share capital:

		2024		2023
Authorized:				
Unlimited number of common shares				
Unlimited number of preferred shares				
Issued:				
1,000 common shares, no par value	$	10,852	$	10,852

On April 20, 2023, a dividend equal to 15% of deemed adjusted regulated net income, totalling $319, was declared.

On April 26, 2024, a dividend equal to 20% of deemed adjusted regulated net income, totalling $425, was declared.

On April 28, 2025, a dividend totalling $450 was declared.

14. Income tax expense:

Income tax expense:

		2024		2023
Current tax expense (recovery)	$	(104)	$	(32)
Deferred tax expense		(603)		(786)
Income tax expense	$	(707)	$	(818)

(Expressed in thousands of dollars)

14. Income tax expense (continued):

Reconciliation of effective tax rate:

		2024		2023 (Restated, note 21)
Income before taxes	$	3,322	$	3,403
Statutory income tax rates		26.5 %		26.5 %
Expected tax provision on income at statutory rates	$	(880)	$	(902)
Increase (decrease) in income taxes resulting from:				
Permanent differences		62		48
Other		111		36
Income tax expense	$	(707)	$	(818)

Significant components of the Corporation's deferred tax balances:

		2024		2023
Deferred tax assets (liabilities):				
Property, plant and equipment	$	(4,658)	$	(4,048)
Post-employment benefits		50		43
	$	(4,608)	$	(4,005)

(Expressed in thousands of dollars)

15. Other revenue:

		2024		2023
Collection and other service charges	$	308	$	293
Related party billing and other services		1,738		1,250
Related party billing and other services expenses		(1,276)		(1,114)
Rent		518		474
Thermal and gas billing and other services		60		19
Recognition of contributions in aid of construction		1,754		1,399
Other		984		(373)
Total other revenue	$	4,086	$	1,948

Related party revenue has been disclosed in note 19 and is included within the above categories based on the type of revenue.

16. Expenses by nature:

		2024		2023
Salaries, wages and benefits (Note 19 (d))	$	6,345	$	5,795
CPP and EI remittances		457		451
Contributions to OMERS		680		666
Less amounts capitalized		(2,699)		(2,615)
	$	4,783	$	4,297

(Expressed in thousands of dollars)

16. Expenses by nature (continued):

Operating expenses

		2024		2023
Employee salaries and benefits	$	4,783	$	4,297
Subcontractor costs		1,477		1,368
Repairs, maintenance and tooling		929		893
Professional fees		166		174
Other taxes		201		175
Insurance		208		199
Depreciation		427		355
Other general administration		1,116		834
	$	9,307	$	8,295

17. Finance income and costs:

		2024		2023
Finance income:				
Interest income on bank deposits	$	93	$	398
Finance costs:				
Interest expense on long-term debt		(2,031)		(1,492)
Interest expense on customer deposits		(48)		(48)
Other		(34)		(8)
Interest expense on capital lease		(2)		(4)
		(2,115)		(1,552)
Net finance costs recognized in profit or loss	$	(2,022)	$	(1,154)

(Expressed in thousands of dollars)

18. Commitments and contingencies:

General Liability Insurance:

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange ("MEARIE"). MEARIE is a pooling of public liability insurance risks of many of the LDCs in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members, on a pro-rata basis based on the total of their respective service revenues. As at December 31, 2024, no assessments have been made.

19. Related party transactions:

(a) Parents and ultimate controlling party:

The sole shareholder of the Corporation is the Town of Innisfil. The Town produces consolidated financial statements that are available for public use.

(b) Outstanding balances with related parties:

	2024	2023
Town of Innisfil - receivable	$ 507	$ 876
InnServices Utilities Inc. - receivable	578	567
InnServices Utilities Inc. - payable	(3,444)	(3,170)
InnTerprises Inc. - receivable	713	478
	$ (1,646)	$ (1,249)

(c) Transactions with related parties:

The Corporation delivers electricity to the Town throughout the year for the electricity needs of the Town and its related organizations. Electricity delivery charges are at prices and under terms approved by the OEB.

The Corporation also provides electricity and other services, including water and wastewater billing and collection, to InnServices Utilities Inc, an affiliate company. Electricity delivery charges are at prices and under terms approved by the OEB. Revenue includes $1,420 (2023 - $1,082) from InnServices Utilities Inc. for financial, billing and other services. The Corporation is provided water and wastewater services and recoverable works from InnServices Utilities Inc throughout the year. Services billed during the year were $7 (2023 - $7) for water and wastewater services, and $480 (2023 - $346) for recoverable work orders.

(Expressed in thousands of dollars)

19. Related party transactions (continued):

(c) Transactions with related parties (continued):

The Corporation also provides billing and financial services to InnTerprises Inc., an affiliate company. Charges for these services during the year were $153 (2023 - $168).

(d) Key management personnel:

The key management personnel of the Corporation have been defined as members of its board of directors and executive management team members. The compensation paid or payable is as follows:

	2024	2023
Directors' fees	$ 55	$ 50
Salaries and other benefits	664	622
	$ 719	$ 672

20. Financial instruments and risk management:

Fair value disclosure:

The carrying values of cash, accounts receivable, unbilled revenue, due from/to related parties and accounts payable and accrued liabilities approximate fair value because of the short maturity of these instruments. The carrying value of the customer deposits approximates fair value because the amounts are payable on demand.

The fair value of the long-term debt at December 31, 2024 is $47,755 (2023 - $42,244). The fair value is calculated based on the present value of future principal and interest cash flows, discounted at the current rate of interest at the reporting date.

Financial risks:

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation's exposure to a variety of risks such as credit risk, interest rate risk, and liquidity risk, as well as related mitigation strategies are discussed below.

20. Financial instruments and risk management (continued):

(a) Credit risk:

Financial assets carry credit risk that a counterparty will fail to discharge an obligation which could result in a financial loss. Financial assets held by the Corporation, such as accounts receivable, expose it to credit risk. The Corporation earns its revenue from a broad base of customers located in the Town of Innisfil and South Barrie. As at December 31, 2024, no single customer accounts for a balance in excess of 10% of total accounts receivable (2023 - nil).

The carrying amount of accounts receivable is reduced through the use of an allowance for impairment and the amount of the related impairment loss is recognized in profit or loss. Subsequent recoveries of receivables previously provisioned are credited to profit or loss. The balance of the allowance for impairment at December 31, 2024 is $140 (2023 - $73). An impairment loss of $182 (2023 - $194) was recognized during the year.

The Corporation's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2024, approximately $327 (2023 - $241) is considered 90 days past due. The Corporation has over 20,000 customers, the majority of whom are residential. Credit risk is managed through collection of security deposits from customers in accordance with directions provided by the OEB and through credit insurance. As at December 31, 2024, the Corporation holds security deposits in the amount of $39 (2023 - $122).

(b) Market risk:

Market risks primarily refer to the risk of loss resulting from changes in commodity prices, foreign exchange rates, and interest rates. The Corporation currently does not have any material commodity or foreign exchange risk. The Corporation is exposed to fluctuations in interest rates as the regulated rate of return for the Corporation's distribution business is derived using a complex formulaic approach which is in part based on the forecast for long term Government of Canada bond yields. This rate of return is approved by the OEB as part of the approval of distribution rates.

A 1% increase in the interest rate at December 31, 2024, would have increased interest expense on the long-term debt by $451, assuming all other variables remain constant. A 1% decrease in the interest rate would have an equal but opposite effect.

20. Financial instruments and risk management (continued):

(c) Liquidity risk:

The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure. The Corporation has access to a $6,000 line of credit facility and monitors cash balances to ensure that a sufficient level of liquidity is on hand to meet financial commitments as they become due. As at December 31, 2024, $828 had been drawn under the Corporation's credit facility (2023 - $nil), however the availability is reduced by a $1,045 letter of credit with the IESO and a $1,130 letter of credit with Hydro One which have been issued to support the prudential requirements, of which $nil has been drawn and posted (2023 - $nil).

The Corporation also has an undrawn fixed-term loans of $6,000 and $3,200 to finance capital expenditures.

The majority of accounts payable, as reported on the statement of financial position, are due within 30 days.

(d) Capital disclosures:

The main objectives of the Corporation, when managing capital, are to ensure ongoing access to funding to maintain and improve the electricity distribution system, compliance with covenants related to its credit facilities, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

The Corporation's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2024, shareholder's equity amounts to $37,392 (2023 - $35,151) and long-term debt amounts to $46,305 (2023 - $333).

(Expressed in thousands of dollars)

21. Restatement:

During 2024, the Company identified that certain capital assets acquired were not recorded at the date they were energized between 2021 and 2023 which resulted in an understatement of assets, contributions, and the associated liabilities . As a consequence, assets, contributions and the associated liability have been understated. The errors have been corrected by restating each of the affected financial statement line items for prior periods. The following tables summarize the impacts on the Company's financial statements.

Statement of Financial Position:

	December 31, 2023			January 1, 2023		
	As previously reported	Adjustments	As restated	As previously reported	Adjustments	As restated
Assets						
Current assets:						
Cash	$ 3,623	$ -	$ 3,623	$ 6,471	$ -	$ 6,471
Restricted cash	15,101	-	15,101	-	-	-
Accounts receivable (note 4)	10,397	-	10,397	10,448	-	10,448
Income taxes receivable	155	41	196	-	76	76
Unbilled revenue	4,277	-	4,277	3,771	-	3,771
Materials and supplies	3,691	-	3,691	2,401	-	2,401
Prepaid expenses	832	-	832	321	-	321
	38,076	41	38,117	23,412	76	23,488
Non-current assets:						
Property, plant and equipment (note 6)	126,403	13,140	139,543	110,834	6,634	117,468
Intangible assets (note 7)	4,610	-	4,610	664	-	664
Right of use assets (note 8)	81	-	81	110	-	110
Regulatory debit balances (note 9)	12,425	351	12,776	11,120	240	11,360
Total assets	$ 181,595	$ 13,532	$ 195,127	$ 146,140	$ 6,950	$ 153,090

(Expressed in thousands of dollars)

21. Restatement (continued):

Statement of Financial Position (continued):

	December 31, 2023			January 1, 2023		
	As previously reported	Adjustments	As restated	As previously reported	Adjustments	As restated
Liabilities and Shareholder's Deficiency						
Current liabilities:						
Accounts payable and accrued liabilities (note 10)	$ 10,295	$ -	$ 10,295	$ 10,194	$ -	$ 10,194
Current portion of long-term debt (note 11)	42,127	-	42,127	3,696	-	3,696
Due to Developer	-	11,247	11,247	-	6,142	6,142
Income taxes payable (recoverable)	-	-	-	21	(21)	-
Current portion of construction deposits	20,862	-	20,862	7,637	-	7,637
Current portion of customer deposits	122	-	122	39	-	39
Current portion of lease liabilities (note 8)	23	-	23	30	-	30
	73,429	11,247	84,676	21,617	6,121	27,738
Non-current liabilities:						
Customer deposits	2,601	-	2,601	3,031	-	3,031
Construction deposits	8,904	-	8,904	7,390	-	7,390
Long-term debt (note 11)	333	-	333	32,277	-	32,277
Post employment benefits (note 5)	172	-	172	143	-	143
Contributions in aid of construction (note 12)	53,956	2,191	56,147	43,207	574	43,781
Deferred tax liability (note 14)	3,747	258	4,005	3,042	176	3,218
Lease liabilities (note 8)	58	-	58	82	-	82
	69,771	2,449	72,220	89,172	750	89,922
Total liabilities	143,200	13,696	156,896	110,789	6,871	117,660
Shareholder's deficiency:						
Share capital (note 13)	10,852	-	10,852	10,852	-	10,852
Contributed surplus	1,600	-	1,600	1,600	-	1,600
Accumulated other comprehensive income	84	-	84	92	-	92
Retained earnings	22,913	(256)	22,657	20,375	16	20,391
	35,449	(256)	35,193	32,919	16	32,935
Regulatory credit balances (note 9)	2,946	92	3,038	2,432	63	2,495
Total liabilities and shareholder's deficiency	$ 181,595	$ 13,532	$ 195,127	$ 146,140	$ 6,950	$ 153,090

(Expressed in thousands of dollars)

21. Restatement (continued):

Statement of Comprehensive Income:

			2023
	As previously reported	Adjustments	As restated
Revenue:			
Sale of energy	$ 35,416	$ -	$ 35,416
Distribution revenue	14,392	-	14,392
Other (note 15)	1,913	35	1,948
	51,721	35	51,756
Expenses:			
Cost of power purchased	38,973	-	38,973
Operating (note 16)	8,295	-	8,295
Depreciation and amortization	4,077	252	4,329
Loss on sale of property, plant and equipment and intangible assets	53	-	53
	51,398	252	51,650
Income (loss) from operations	323	(217)	106
Finance income	(1,552)	-	(1,552)
Finance costs	398	-	398
	(1,154)	-	(1,154)
Loss before income taxes	(831)	(217)	(1,048)
Income tax expense (note 14)	(681)	(137)	(818)
Net loss for the year before movement in regulatory	(1,512)	(354)	(1,866)
Other income:			
Net movement in regulatory balances (note 9)	4,369	82	4,451
Net income for the year and net movement in regulatory	2,857	(272)	2,585
Other comprehensive income (loss):			
Remeasurement of post-employment benefits, net of tax	(8)	-	(8)
Total comprehensive income (loss)	$ 2,849	$ (272)	$ 2,577

(Expressed in thousands of dollars)

21. Restatement (continued):

Statement of Cash Flows:

			2023
	As previously reported	Adjustments	As restated
Cash provided by (used in):			
Operating activities:			
Total comprehensive income	$ 2,849	$ (272)	$ 2,577
Items not involving cash:			
Depreciation and amortization	4,403	252	4,655
Depreciation and amortization right of use asset	29	-	29
Amortization of contributions in aid of construction	(1,364)	(35)	(1,399)
Post-employment benefits	29	-	29
Loss on disposal of property, plant and equipment	53	-	53
Net finance costs	1,154	-	1,154
Income tax expense	681	137	818
Income tax expense within net movement in regulatory	(704)	(82)	(786)
Changes in non-cash operating working capital:			
Restricted cash	(15,101)	-	(15,101)
Accounts receivable	51	-	51
Unbilled revenue	(506)	-	(506)
Materials and supplies	(1,290)	-	(1,290)
Prepaid expenses	(511)	-	(511)
Prepaid expenses	101	-	101
Construction deposits	14,392	347	14,739
Customer deposits	-	(347)	(347)
	4,266	-	4,266
Income tax recovered (paid)	(151)	-	(151)
Interest paid	(1,154)	-	(1,154)
Regulatory balances	(87)	-	(87)
	2,874	-	2,874

(Expressed in thousands of dollars)

21. Restatement (continued):

Statement of Cash Flows (continued):

			2023
	As previously reported	Adjustments	As restated
Financing activities:			
Repayment of long-term debt	$ (1,513)	$ -	$ (1,513)
Proceeds of long-term debt	8,000	-	8,000
Repayment of lease liabilities	(31)	-	(31)
Dividends paid	(319)	-	(319)
	6,137	-	6,137
Investing activities:			
Purchase of property, plant and equipment	(19,708)	(1,652)	(21,360)
Purchase of intangible assets	(4,264)	-	(4,264)
Construction contributions received	12,113	1,652	13,765
	(11,859)	-	(11,859)
Decrease in cash	(2,848)	-	(2,848)
Cash, beginning of year	6,471	-	6,471
Cash, end of year	$ 3,623	$ -	$ 3,623

Appendix 5: 2025 Audited Financial Statements

Financial Statements of
(Expressed in thousands of dollars)

INNPOWER CORPORATION

And Independent Auditor's Report thereon

Year ended December 31, 2025

KPMG LLP
120 Victoria Street South
Suite 600
Kitchener, ON N2G 0E1
Canada
Telephone 519 747 8800
Fax 519 747 8811

INDEPENDENT AUDITOR'S REPORT

To the Shareholder of InnPower Corporation

Opinion

We have audited the financial statements of InnPower Corporation (the Entity), which comprise:

- the statement of financial position as at December 31, 2025
- the statement of comprehensive income for the year then ended
- the statement of changes in equity for the year then ended
- the statement of cash flows for the year then ended
- and notes to the financial statements, including a summary of material accounting policy information

(Hereinafter referred to as the ''financial statements'').

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2025 and its results of operations and its cash flows for the year then ended in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the ***''Auditor's Responsibilities for the Audit of the Financial Statements''*** section of our auditor's report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

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

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

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

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

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Entity to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Kitchener, Canada

April 29, 2026

INNPOWER CORPORATION

Statement of Financial Position
(Expressed in thousands of dollars)

December 31, 2025, with comparative information for 2024

		2025		2024
Assets				
Current assets:				
Cash	$	1,193	$	-
Restricted cash		20,829		27,712
Accounts receivable (note 4)		13,759		11,338
Payment in lieu of tax receivable		677		163
Unbilled revenue		5,814		6,558
Materials and supplies		6,317		6,786
Prepaid expenses		845		965
Total current assets		49,434		53,522
Non-current assets:				
Property, plant and equipment (note 6)		197,685		168,800
Intangible assets (note 7)		13,317		8,230
Right of use assets (note 8)		-		8
Total non-current assets		211,002		177,038
Total assets		260,436		230,560
Regulatory debit balances (note 9)		9,727		10,948
Total assets and regulatory balances	$	270,163	$	241,508

See accompanying notes to financial statements.

INNPOWER CORPORATION

Statement of Financial Position
(Expressed in thousands of dollars)

December 31, 2025, with comparative information for 2024

	2025	2024
Liabilities		
Current liabilities:		
Bank indebtedness (note 11)	$ -	$ 828
Accounts payable and accrued liabilities (note 10)	16,929	15,347
Current portion of long-term debt (note 11)	4,568	37,063
Due to developer	15,080	16,982
Current portion of customer deposits	122	122
Current portion of construction deposits	19,689	27,643
Current portion of lease liabilities (note 8)	-	34
Total current liabilities	56,388	98,019
Non-current liabilities:		
Customer deposits	1,350	5,520
Long-term debt (note 11)	57,360	10,691
Post employment benefits (note 5)	204	188
Contributions in aid of construction (note 12)	94,041	74,773
Construction deposits	13,654	8,553
Deferred tax liability (note 14)	5,146	4,608
	171,755	104,333
	228,143	202,352
Equity:		
Share capital (note 13)	10,852	10,852
Contributed surplus	1,600	1,600
Accumulated other comprehensive income	99	93
Retained earnings	26,318	24,847
	38,869	37,392
Subsequent events (note 13)		
Regulatory credit balances (note 9)	3,151	1,764
Total liabilities, equity and regulatory balances	$ 270,163	$ 241,508

See accompanying notes to financial statements.

On behalf of the Board:

_______________________________ Director _______________________________ Director

INNPOWER CORPORATION

Statement of Comprehensive Income
(Expressed in thousands of dollars)

Year ended December 31, 2025, with comparative information for 2024

	2025	2024
Revenue:		
Sale of energy	$ 47,803	$ 44,376
Distribution revenue	15,667	14,897
Other (note 15)	3,670	4,086
	19,337	18,983
	67,140	63,359
Operating expenses:		
Cost of power purchased	47,967	45,234
Operating (note 16)	9,202	9,307
Depreciation and amortization	5,969	5,097
Loss on disposal of property, plant and equipment, intangible assets, and right-of-use leases	19	71
	15,190	14,475
	63,157	59,709
Income from operating activities	3,983	3,650
Finance costs (note 17)	(2,606)	(2,115)
Finance income (note 17)	126	93
Income before payments in lieu of taxes and undernoted items	1,503	1,628
Payments in lieu of taxes (note 14)	335	707
Net income for the year before movement in regulatory deferral account balances	1,168	921
Other income:		
Net movement in regulatory balances (note 9)	803	1,694
Net income for the year and net movement in regulatory balances	1,971	2,615
Other comprehensive income (loss):		
Remeasurement of post-employment benefits, net of tax	6	9
Other comprehensive income (loss) for the year	6	9
Total comprehensive income for the year	$ 1,977	$ 2,624

See accompanying notes to financial statements.

INNPOWER CORPORATION

Statement of Changes in Equity
(Expressed in thousands of dollars)

Year ended December 31, 2025, with comparative information for 2024

	Share capital	Retained earnings	Contributed surplus	Accumulated other comprehensive income (loss)	Total
Balance at January 1, 2024	$ 10,852	$ 22,657	$ 1,600	$ 84	$ 35,193
Net income and net movement in regulatory balances	-	2,615	-	-	2,615
Other comprehensive income, net of tax	-	-	-	9	9
Dividends	-	(425)	-	-	(425)
Balance at December 31, 2024	$ 10,852	$ 24,847	$ 1,600	$ 93	$ 37,392

	Share capital	Retained earnings	Contributed surplus	Accumulated other comprehensive income (loss)	Total
Balance at January 1, 2025	$ 10,852	$ 24,847	$ 1,600	$ 93	$ 37,392
Net income and net movement in regulatory balances	-	1,971	-	-	1,971
Other comprehensive income, net of tax	-	-	-	6	6
Dividend	-	(500)	-	-	(500)
Balance at December 31, 2025	$ 10,852	$ 26,318	$ 1,600	$ 99	$ 38,869

See accompanying notes to financial statements.

INNPOWER CORPORATION

Statement of Cash Flows
(Expressed in thousands of dollars)

Year ended December 31, 2025, with comparative information for 2024

	2025	2024
Cash provided by (used in):		
Operating activities:		
Total comprehensive income	$ 1,977	$ 2,624
Items not involving cash:		
Depreciation and amortization	6,403	5,476
Depreciation and amortization right of use asset	8	48
Amortization of contributions in aid of construction	(2,194)	(1,754)
Post-employment benefits	16	16
Loss on disposal of assets	19	71
Net finance costs	2,480	2,022
Payments in lieu of tax expense	335	706
Payments in lieu of tax expense within net movement in regulatory balances	(552)	(600)
	8,492	8,609
Changes in non-cash operating working capital:		
Restricted cash	6,883	(12,611)
Accounts receivable	(2,421)	(941)
Unbilled revenue	744	(2,281)
Materials and supplies	469	(3,095)
Prepaid expenses	120	(133)
Accounts payable and accrued liabilities	1,582	5,052
Due to developer	(1,902)	-
Construction deposits	(2,853)	6,430
Customer deposits	(4,170)	2,919
	(1,548)	(4,660)
Payments in lieu of tax recovered (paid)	(311)	(70)
Interest received	126	93
Interest paid	(2,606)	(2,115)
Regulatory balances	3,160	1,154
	7,313	3,011
Financing activities:		
Repayment of long-term debt	(1,826)	(1,908)
Proceeds of long-term debt	16,000	7,202
Repayment of lease liabilities	(34)	(47)
Dividends paid	(500)	(425)
	13,640	4,822
Investing activities:		
Purchase of property, plant and equipment	(34,798)	(28,622)
Proceeds on disposal of property, plant and equipment	96	34
Purchase of intangible assets	(5,692)	(4,076)
Construction contributions received	21,462	20,380
	(18,932)	(12,284)
Increase (decrease) in cash	2,021	(4,451)
Cash (bank indebtedness), beginning of year	(828)	3,623
Cash (bank indebtedness), end of year	$ 1,193	$ (828)

See accompanying notes to financial statements.

Reporting entity:

InnPower Corporation (the "Corporation") is a rate regulated, municipally owned hydro distribution company incorporated under the laws of Ontario, Canada. The Corporation is located in the Town of Innisfil (“the Town”). The address of the Corporation’s registered office is 7251 Yonge Street, Innisfil, Ontario.

The Corporation delivers electricity and related energy services to residential and commercial customers in the Town and South Barrie. The Corporation is wholly owned by the Town of Innisfil.

The financial statements are for the Corporation as at and for the year ended December 31, 2025.

1. Basis of presentation:

(a) Statement of compliance:

The Corporation's financial statements have been prepared in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board ("IFRS").

The financial statements were approved by the Board of Directors on April 20, 2026.

(b) Basis of measurement:

These financial statements have been prepared on the historical cost basis, unless otherwise stated.

(c) Functional and presentation currency:

These financial statements are presented in Canadian dollars, which is the Corporation's functional currency. All financial information presented in Canadian dollars has been rounded to the nearest thousand.

(d) Use of estimates and judgments:

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses and disclosure of contingent assets and liabilities. Actual results may differ from those estimates.

Information about assumptions and estimation uncertainties that have a significant risk of resulting in material adjustment is included in the following notes:

1. Basis of presentation (continued):

(d) Use of estimates and judgments (continued):

Information about assumptions and estimation uncertainties that have a significant risk of resulting in material adjustment is included in the following notes:

(i) Note 2(b) - measurement of unbilled revenue
(ii) Note 2(b) - determination of the performance obligation for contributions from customers and the related amortization period.
(iii) Notes 2 (k), 8 - leases: whether an arrangement contains a lease
(iv) Notes 6, 7 - estimation of useful lives of its property, plant and equipment and intangible assets
(v) Note 9 - recognition and measurement of regulatory balances
(vi) Note 5 - measurement of defined benefit obligations: key actuarial assumptions
(vii) Note 18 - recognition and measurement of provisions and contingencies

(e) Rate regulation:

The Corporation is regulated by the Ontario Energy Board ("OEB"), under the authority granted by the Ontario Energy Board Act, 1998. Among other things, the OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for electricity consumers in Ontario, and ensuring that transmission and distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies ("LDCs"), such as the Corporation, which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

1. Basis of presentation (continued):

(e) Rate regulation (continued):

Distribution revenue

For the distribution revenue included in sale of energy, the Corporation files a “Cost of Service” (“COS”) rate application with the OEB every five years where rates are determined through a review of the forecasted annual amount of operating and capital expenditures, debt and shareholder’s equity required to support the Corporation’s business. The Corporation estimates electricity usage and the costs to service each customer class to determine the appropriate rates to be charged to each customer class. The COS application is reviewed by the OEB and interveners and rates are approved based upon this review, including any revisions resulting from that review.

In the intervening years an Incentive Rate Mechanism application (“IRM”) is filed. An IRM application results in a formulaic adjustment to distribution rates that were set under the last COS application. The previous year’s rates are adjusted for the annual change in the Gross Domestic Product Implicit Price Inflator for Final Domestic Demand (“GDP IPI-FDD”) net of a productivity factor and a “stretch factor” determined by the relative efficiency of an electricity distributor.

As a licensed distributor, the Corporation is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Corporation is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Corporation ultimately collects these amounts from customers.

The Corporation last filed a COS application in 2023 for rates effective January 1, 2024. On December 12, 2024, the Corporation received its decision on rates from its most recent IRM filing for rates effective January 1, 2025.

Electricity rates

The OEB sets electricity prices for low-volume consumers twice each year based on an estimate of how much it will cost to supply the province with electricity for the next year. All remaining consumers pay the market price for electricity. The Corporation is billed for the cost of the electricity that its customers use and passes this cost on to the customer at cost without a mark-up.

2. Material accounting policies:

The accounting policies set out below have been applied consistently in all years presented in these financial statements.

(a) Financial instruments:

At initial recognition, the Corporation measures it’s financial assets at fair value plus, in the case of a financial asset not at fair value through profit or loss, transaction costs that are directly attributable to the acquisition of the financial asset. Transaction costs of financial assets carried at fair value through profit or loss are expensed in profit or loss.

Subsequent measurement of the financial asset depends on the classification determined on initial recognition. Financial assets are classified as either amortized cost, fair value through other comprehensive income (“OCI”) or fair value through profit or loss, depending on its business model for managing the financial assets and the contractual cash flow characteristics of the financial assets. Financial assets are not reclassified subsequent to their initial recognition, unless the Corporation changes its business model for managing financial assets.

Financial liabilities are initially measured at fair value, net of transaction costs incurred. They are subsequently carried at amortized cost using the effective interest rate method; any difference between the proceeds (net of transaction costs) and the redemption value is recognized as an adjustment to interest expense over the period of the borrowings.

The Corporation has not entered into derivative instruments.

(b) Revenue recognition:

Sale and distribution of electricity

The performance obligations for the sale and distribution of electricity are recognized over time using an output method to measure the satisfaction of the performance obligation. The value of the electricity services transferred to the customer is determined on the basis of cyclical meter readings plus estimated customer usage since the last meter reading date to the end of the year and represents the amount that the Corporation has the right to bill. Revenue includes the cost of electricity supplied, distribution, and any other regulatory charges. The related cost of power is recorded on the basis of power used.

For customer billings related to electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties, the Corporation has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

2. Material accounting policies (continued):

(b) Revenue recognition (continued):

Customer billings for debt retirement charges are recorded on a net basis as the Corporation is acting as an agent for this billing stream.

Capital contributions

Developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. The developer is not a customer and therefore the contributions are scoped out of IFRS 15 Revenue from Contracts with Customers. Cash contributions, received from developers are recorded as deferred revenue. When an asset other than cash is received as a capital contribution, the asset is initially recognized at its fair value, with a corresponding amount recognized as deferred revenue. The deferred revenue, which represents the Corporation's obligation to continue to provide the customers access to the supply of electricity, is amortized to income on a straight-line basis over the useful life of the related asset.

Certain customers are also required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. These contributions fall within the scope of IFRS 15 Revenue from Contracts with Customers. The contributions are received to obtain a connection to the distribution system in order receive ongoing access to electricity. The Corporation has concluded that the performance obligation is the supply of electricity over the life of the relationship with the customer which is satisfied over time as the customer receives and consumes the electricity. Revenue is recognized on a straight-line basis over the useful life of the related asset.

Other revenue

Revenue earned from the provision of services is recognized as the service is rendered.

Government grants and the related performance incentive payments under CDM programs are recognized as revenue in the year when there is reasonable assurance that the program conditions have been satisfied and the payment will be received.

Unbilled revenue

Unbilled revenue represents amounts for which the Corporation has a contractual right to receive cash through future billings and are unbilled at the year-end date. Unbilled revenue is recorded based on preliminary consumption for any period not yet billed.

2. Material accounting policies (continued):

(c) Materials and supplies:

Materials and supplies, the majority of which is consumed by the Corporation in the provision of its services, is valued at the lower of cost and net realizable value, with cost being determined on an average cost basis, and includes expenditures incurred in acquiring the materials and supplies and other costs incurred in bringing them to their existing location and condition.

(d) Property, plant and equipment:

Items of property, plant and equipment (“PP&E”) used in rate-regulated activities and acquired prior to January 1, 2015 are measured at the deemed cost (carrying value as elected under IFRS 1) established on the transition date, less accumulated depreciation. All other items of PP&E are measured at cost, or, where the item is contributed by customers, its fair value, less accumulated depreciation.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes contracted services, materials and transportation costs, direct labour, overhead costs, borrowing costs and any other costs directly attributable to bringing the asset to a working condition for its intended use.

Borrowing costs on qualifying assets are capitalized as part of the cost of the asset based upon the weighted average cost of debt incurred on the Corporation’s borrowings. Qualifying assets are considered to be those that take in excess of 12 months to construct.

When parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components) of PP&E.

When items of PP&E are retired or otherwise disposed of, a gain or loss on disposal is determined by comparing the proceeds from disposal, if any, with the carrying amount of the item, and such gain or loss on disposal is included in profit or loss.

Major spare parts and standby equipment are recognized as items of PP&E.

The cost of replacing a part of an item of PP&E is recognized as a capital addition in the net book value of the item if it is probable that the future economic benefits embodied within the part will flow to the Corporation, and its cost can be measured reliably. In this event, the replaced part of PP&E is written off, and the related gain or loss is included in profit or loss. The costs of the day-to-day servicing of PP&E are recognized as repairs and maintenance in profit or loss, as incurred.

(Expressed in thousands of dollars)

2. Material accounting policies (continued):

(d) Property, plant and equipment (continued):

The need to estimate the decommissioning costs at the end of the useful lives of certain assets is reviewed periodically.

Depreciation is calculated to write off the cost of items of PP&E using the straight-line method over their estimated useful lives, and is generally recognized in profit or loss. Depreciation methods, useful lives, and residual values are reviewed at each reporting date and adjusted prospectively if appropriate. Land is not depreciated. Construction-in-progress assets are not depreciated until the project is complete and the asset is available for use.

The estimated useful lives are as follows:

Asset	Rate
Buildings and fixtures	50 years
Substations	30 years
Distribution lines	15-60 years
Distribution transformers	40-50 years
Meters	15-25 years
Office equipment	10 years
Computer equipment	5 years
Transportation equipment	10 years
Small tools and miscellaneous equipment	10 years
System supervisory	15 years

(e) Intangible assets:

Intangible assets used in rate-regulated activities and acquired prior to January 1, 2015 are measured at deemed cost (carrying value as elected under IFRS 1) established on the transition date, less accumulated amortization. All other intangible assets are measured at cost.

Computer software that is acquired or developed by the Corporation after January 1, 2015, including software that is not integral to the functionality of equipment purchased which has finite useful lives, is measured at cost less accumulated amortization.

Payments to obtain rights to access land ("land rights") are classified as intangible assets. These include payments made for easements, right of access and right of use over land for which the Corporation does not hold title. Land rights are measured at cost less accumulated amortization.

2. Material accounting policies (continued):

(e) Intangible assets (continued):

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets from the date that they are available for use. Amortization methods and useful lives of all intangible assets are reviewed at each reporting date and adjusted prospectively if appropriate. The estimated useful lives are:

Asset	Rate
Computer software	5 years
Land rights	50 years
Contribution asset	25 years

(f) Impairment:

(i) Financial assets measured at amortized cost:

The Corporation recognizes a loss allowance for expected credit losses (“ECLs”) on financial assets measured at amortized cost in accordance with IFRS 9 Financial Instruments.

The Corporation applies the simplified approach to trade receivables and unbilled revenue, under which lifetime expected credit losses are recognized from initial recognition.

Expected credit losses are measured using a provision matrix based on the Corporation’s historical credit loss experience, adjusted as appropriate for current conditions and reasonable and supportable forward-looking information relevant to the Corporation’s customers and operating environment. Historical loss rates are determined separately for customer classes with similar credit risk characteristics and are reviewed at each reporting date to ensure they remain appropriate.

(ii) Non-financial assets:

The carrying amounts of the Corporation's non-financial assets, other than materials and supplies and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated.

2. Material accounting policies (continued):

(f) Impairment (continued):

(ii) Non-financial assets (continued):

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or “CGU”). The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss.

An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no previous impairment loss had been recognized.

(g) Customer deposits:

Customer deposits represent cash deposits from electricity distribution customers and retailers to guarantee the payment of energy bills. Interest is paid on customer deposits.

Deposits are refundable to customers who demonstrate an acceptable level of credit risk as determined by the Corporation in accordance with policies set out by the OEB or upon termination of their electricity distribution service.

(h) Provisions:

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

2. Material accounting policies (continued):

(i) Regulatory balances:

Regulatory deferral account debit balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. Regulatory deferral account credit balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Corporation.

Regulatory deferral account debit balances are recognized if it is probable that future billings in an amount at least equal to the deferred cost will result from inclusion of that cost in allowable costs for rate-making purposes. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. When the customer is billed at rates approved by the OEB for the recovery of the deferred costs, the customer billings are recognized in revenue. The regulatory debit balance is reduced by the amount of these customer billings with the offset to net movement in regulatory balances in profit or loss or OCI.

The probability of recovery of the regulatory deferral account debit balances is assessed annually based upon the likelihood that the OEB will approve the change in rates to recover the balance. The assessment of likelihood of recovery is based upon previous decisions made by the OEB for similar circumstances, policies or guidelines issued by the OEB. Any resulting impairment loss is recognized in profit or loss in the year incurred.

When the Corporation is required to refund amounts to ratepayers in the future, the Corporation recognizes a regulatory deferral account credit balance. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. The amounts returned to the customers are recognized as a reduction of revenue. The credit balance is reduced by the amount of these customer repayments with the offset to net movement in regulatory balances in profit or loss or OCI.

2. Material accounting policies (continued):

(j) Post-employment benefits:

(i) Pension plan

The Corporation provides a pension plan for all its full-time employees through Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund"), and provides pensions for employees of Ontario municipalities, local boards and public utilities. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. To the extent that the Fund finds itself in an over or under-funded position, contribution rates may be assessed to participating employers and members.

OMERS is a defined benefit plan. However, as OMERS does not segregate its pension asset and liability information by individual employers, there is insufficient information available to enable the Corporation to directly account for the plan. Consequently, the plan has been accounted for as a defined contribution plan. The Corporation is not responsible for any other contractual obligations other than the contributions. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in profit or loss when they are due.

(ii) Post-employment benefits, other than pension

The Corporation provides some of its retired employees with life insurance and medical benefits beyond those provided by government sponsored plans.

The obligations for these post-employment benefit plans are actuarially determined by applying the projected unit credit method and reflect management's best estimate of certain underlying assumptions. Remeasurements of the net defined benefit obligations, including actuarial gains and losses and the return on plan assets (excluding interest), are recognized immediately in other comprehensive income. When the benefits of a plan are improved, the portion of the increased benefit relating to past service by employees is recognized immediately in profit or loss.

2. Material accounting policies (continued):

(k) Leased assets:

At inception of a contract, the Corporation assesses whether the contract is or contains a lease. A contract is determined to contain a lease if it provides the Corporation with the right to control the use of an identified asset for a period of time in exchange for consideration. Contracts determined to contain a lease are accounted for as leases. For leases and contracts that contain a lease, the Corporation recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured at cost which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received.

The right-of-use asset is subsequently depreciated using the straight-line method from the commencement date to the earlier of the end of the useful life of the right-of-use asset or the end of the lease term. The estimated useful lives of right-of-use assets are determined on the same basis as those of property, plant and equipment. Subsequent to initial recognition, the right-of-use asset is recognized at cost less any accumulated depreciation and any accumulated impairment losses, adjusted for certain remeasurements of the corresponding lease liability.

The lease liability is initially measured at the present value of the lease payments that are unpaid at the commencement date, discounted using the interest rate implicit in the lease. If that rate cannot be readily determined, the Corporation’s incremental borrowing rate is used.

The lease liability is subsequently measured at amortized cost using the effective interest method. It is remeasured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Corporation’s estimate of the amount expected to be payable under a residual value guarantee, or if the Corporation changes its assessment of whether it will exercise a purchase, extension or termination option. When the lease liability is remeasured in this way, a corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero.

2. Material accounting policies (continued):

(l) Finance income and finance costs:

Finance income is recognized as it accrues in profit or loss, using the effective interest method. Finance income comprises interest earned on cash.

Finance costs comprise interest expense on borrowings and net interest expense on post-employment benefits. Finance costs are recognized in profit or loss unless they are capitalized as part of the cost of qualifying assets.

(m) Payments in lieu of tax expense:

The payments in lieu of tax expense comprises current and deferred tax. Payments in lieu of tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case, it is recognized in equity.

The Corporation is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act (collectively the “Tax Acts”). Under the Electricity Act, 1998, the Corporation makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (“OEFC”). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Tax Acts as modified by the Electricity Act, 1998, and related regulations. Prior to October 1, 2001, the Corporation was not subject to income or capital taxes. Payments in lieu of taxes are referred to as income taxes.

Current tax comprises the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized in respect of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Deferred tax assets are recognized for unused tax losses, unused tax credits and deductible temporary differences to the extent that it is probable that future taxable profits will be available against which they can be used. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, using tax rates enacted or substantively enacted, at the reporting date.

(Expressed in thousands of dollars)

3. Changes to accounting policies:

The International Accounting Standards Board ("IASB") has issued the following Standards, Interpretations and Amendments to Standards that were adopted by the Corporation effective January 1, 2025. The amendments and clarifications did not have an impact on the financial statements.

(a) Lack of Exchangeability- Amendments to IAS 21 The Effects of Changes in Foreign Exchange Rates.

Emerging accounting changes:

At the date of authorization of these financial statements, several new, but not yet effective Standards and amendments to existing Standards and interpretations have been published by the IASB. None of these Standards or amendments to existing Standards have been adopted early by the Corporation and it is still to be determined if any will have a material impact on the Corporation's financial statements.

Effective date	New accounting standards or amendments
January 1, 2027	*IFRS 18 Presentation and Disclosure in Financial Statements*
January 1, 2027	*IFRS 19 Subsidiaries without Public Accountability: Disclosures IAS21 The Effects of Changes in Foreign Exchange Rates*
January 1, 2027	*IFRS for SMES third edition*
January 1, 2026	*Classification and Measurement of Financial Instruments - Amendments to IFRS 9 Financial Instruments and IFRS 7 Financial Instruments: Disclosures*
January 1, 2027	*Annual improvements to IFRS Accounting Standards - Volume 11*
January 1, 2027	*Contracts Referencing Nature-dependent Electricity - Amendments to IFRS 9 and IFRS 7*
Available for optional Adoption	*Sale or Contribution of Assets between an Investor and its deferre*d i*ndefinitely Associate or Joint Venture - Amendments to IFRS 10 and IAS 28*

(Expressed in thousands of dollars)

4. Accounts receivable:

	2025	2024
Trade customer accounts receivable	$ 8,658	$ 6,558
Other receivables	2,187	2,982
Due from related parties (note 19)	2,914	1,798
	$ 13,759	$ 11,338

5. Post-employment benefits:

(a) OMERS pension plan:

The Corporation provides a pension plan for its employees through OMERS. The plan is a multi-employer, contributory defined benefit pension plan with equal contributions by the employer and its employees. In 2025, the Corporation made employer contributions of $748 to OMERS (2024 - $680) which has been recognized in profit or loss. The Corporation estimates that a contribution of $804 to OMERS will be made during the next fiscal year.

As at December 31, 2025, OMERS had approximately 665,000 members, of whom 63 are current employees of the Corporation. The most recently available OMERS annual report is for the year ended December 31, 2025, which reported that the plan was 99% funded, with an unfunded liability of $1.3 billion. This unfunded liability may result in extra future payments by participating employers and members.

(Expressed in thousands of dollars)

5. Post-employment benefits (continued):

(b) Defined pension and benefits plan:

The Corporation pays certain medical and life insurance benefits on behalf of some of its retired employees. The Corporation recognizes these post-employment benefits in the year in which employees' services were rendered. The Corporation is recovering its post-employment benefits in rates based on the expense and remeasurements recognized for post-employment benefit plans.

Reconciliation of the obligation		2025		2024
Defined benefit obligation, beginning of year	$	188	$	172
Included in profit or loss:				
Current service cost		15		16
Interest cost		9		9
		24		25
Included in OCI				
Actuarial losses arising from:				
Changes in financial assumptions		(8)		(9)
	$	204	$	188

Actuarial assumptions	2025	2024
Discount (interest) rate	4.70 %	4.70 %
Salary levels	3.10 %	3.10 %
Medical costs	5.50 %	5.50 %
Dental costs	4.00 %	4.00 %

A 1% increase in the assumed discount rate would result in the defined benefit obligation decreasing by $20. A 1% decrease in the assumed discount rate would result in the defined benefit obligation increasing by $25.

(Expressed in thousands of dollars)

6. Property, plant and equipment:

		Land and buildings		Distribution equipment		Other fixed assets		Construction-in-progress		Total
Cost of deemed cost										
Balance at January 1, 2025	$	15,185	$	163,215	$	9,436	$	12,511	$	200,347
Additions/Transfers		39		30,984		609		3,166		34,798
Disposals/ retirements		-		(141)		(223)		-		(364)
Balance at December 31, 2025	$	15,224	$	194,058	$	9,822	$	15,677	$	234,781
Balance at January 1, 2024	$	15,088	$	134,251	$	8,416	$	8,375	$	166,130
Additions/Transfers		97		29,070		1,054		4,136		34,357
Disposals/ retirements		-		(106)		(34)		-		(140)
Balance at December 31, 2024	$	15,185	$	163,215	$	9,436	$	12,511	$	200,347
Accumulated depreciation										
Balance at January 1, 2025	$	2,691	$	23,350	$	5,506	$	-	$	31,547
Depreciation		291		4,582		925		-		5,798
Disposals		-		(76)		(173)		-		(249)
Balance at December 31, 2025	$	2,982	$	27,856	$	6,258	$	-	$	37,096
Balance at January 1, 2024	$	2,401	$	19,488	$	4,698	$	-	$	26,587
Depreciation		290		3,922		808		-		5,020
Disposals		-		(60)		-		-		(60)
Balance at December 31, 2024	$	2,691	$	23,350	$	5,506	$	-	$	31,547
Carrying amounts										
At December 31, 2025	$	12,242	$	166,202	$	3,564	$	15,677	$	197,685
At December 31, 2024		12,494		139,865		3,930		12,511		168,800

(Expressed in thousands of dollars)

7. Intangible assets:

	Computer software	Land rights	Contribution assets	Total
Cost of deemed cost				
Balance at January 1, 2025	$ 1,992	$ 402	$ 8,124	$ 10,518
Additions	228	-	5,464	5,692
Balance at December 31, 2025	$ 2,220	$ 402	$ 13,588	$ 16,210
Balance at January 1, 2024	$ 1,927	$ 397	$ 4,118	$ 6,442
Additions	65	5	4,006	4,076
Balance at December 31, 2024	$ 1,992	$ 402	$ 8,124	$ 10,518
Accumulated amortization				
Balance at January 1, 2025	$ 1,811	$ 143	$ 334	$ 2,288
Amortization	161	13	431	605
Balance at December 31, 2025	$ 1,972	$ 156	$ 765	$ 2,893
Balance at January 1, 2024	$ 1,619	$ 130	$ 83	$ 1,832
Amortization	192	13	251	456
Balance at December 31, 2024	$ 1,811	$ 143	$ 334	$ 2,288
Carrying amounts				
At December 31, 2025	$ 248	$ 246	$ 12,823	$ 13,317
At December 31, 2024	181	259	7,790	8,230

(Expressed in thousands of dollars)

8. Leases:

Right-of-use Asset		Vehicle Leases
Cost of deemed cost		
Balance at January 1, 2025	$	76
Disposals		(76)
Balance at December 31, 2025	$	-
Balance at January 1, 2024	$	141
Deletions		(65)
Balance at December 31, 2024	$	76
Accumulated amortization		
Balance at January 1, 2025	$	68
Amortization		8
Disposals		(76)
Balance at December 31, 2025	$	-
Balance at January 1, 2024	$	60
Amortization		48
Deletions		(40)
Balance at December 31, 2024	$	68
Carrying amounts		
At December 31, 2025	$	-
At December 31, 2024		8

(Expressed in thousands of dollars)

8. Leases (continued):

Lease Liability		Vehicle Leases
Balance at January 1, 2025	$	34
Repayments		(34)
Balance at December 31, 2025	$	-

Balance at January 1, 2024	$	81
Repayments		(50)
Interest		3
Balance at December 31, 2024	$	34

Lease liabilities include a current portion of $nil (2024 - $34). Certain leases held by the Corporation provide the Corporation with extension options and termination options that may impact the term of the Lease which can impact the finance lease liability recognized in the statement of financial position. The Corporation has determined the lease term for all contracts based on all available information as at the reporting date.

9. Regulatory account balances:

Reconciliation of the carrying amount for each class of regulatory balances:

Regulatory deferral account debit balances	January 1, 2025	Additions	Recovery/ reversal	December 31, 2025	Remaining recovery/ reversal years
Retail settlement variances	$ 4,826	$ 543	$ (3,405)	$ 1,964	2-3
Regulatory asset associated with deferred taxes	6,268	733	-	7,001	-
Regulatory variances disposition	(62)	554	-	492	-
Other	(84)	354	-	270	1-3
	$ 10,948	$ 2,184	$ (3,405)	$ 9,727	

(Expressed in thousands of dollars)

9. Regulatory account balances (continued):

Regulatory deferral account debit balances	January 1, 2024	Additions	Recovery/ reversal	December 31, 2024	Remaining recovery/ reversal years
Retail settlement variances	$ 7,222	$ 908	$ (3,304)	$ 4,826	2-3
Regulatory asset associated with deferred taxes	5,448	820	-	6,268	-
Regulatory variances disposition	-	-	(62)	(62)	-
Other	106	22	(212)	(84)	1-3
	$ 12,776	$ 1,750	$ (3,578)	$ 10,948	

Regulatory deferral account credit balances	January 1, 2025	Additions	Recovery/ reversal	December 31, 2025	Remaining recovery/ reversal years
Retail settlement variances	$ 83	$ 809	$ (33)	$ 859	2-3
Deferred income tax on regulatory asset	1,675	181	-	1,856	-
Regulatory variances disposition	167	264	-	431	-
Other	(161)	166	-	5	1-3
	$ 1,764	$ 1,420	$ (33)	$ 3,151	

Regulatory deferral account credit balances	January 1, 2024	Additions	Recovery/ reversal	December 31, 2024	Remaining recovery/ reversal years
Retail settlement variances	$ 107	$ -	$ (24)	$ 83	2-3
Deferred income tax on regulatory asset	1,455	220	-	1,675	-
Regulatory variances disposition	167	-	-	167	
Other	1,309	5	(1,475)	(161)	-
	$ 3,038	$ 225	$ (1,499)	$ 1,764	

(Expressed in thousands of dollars)

9. Regulatory account balances (continued):

For 2025, the net movement in regulatory deferred account balances net of taxes of $803 consists of the regulatory deferred tax expense of $552, the difference between the Power Purchased and the Sale of Electricity of $164, and approximately $87 in other carrying charges

For 2024, the net movement in regulatory deferred account balances net of taxes of $1,694 consists of the regulatory deferred tax expense of $600, the difference between the Power Purchased and the Sale of Electricity of $851, and approximately $243 in other carrying charges.

The regulatory balances are recovered or settled through rates approved by the OEB which are determined using estimates of future consumption of electricity by its customers. Future consumption is impacted by various factors including the economy and weather. The Corporation has received approval from the OEB to establish its regulatory balances.

Settlement of the Group 1 deferral accounts is done on an annual basis through application to the OEB. The OEB requires the Corporation to estimate its income taxes when it files a COS application to set its rates. As a result, the Corporation has recognized a regulatory deferral account for the amount of deferred taxes that will ultimately be recovered from/paid back to its customers. This balance will fluctuate as the Corporation’s deferred tax balance fluctuates.

Regulatory deferral accounts attract interest at OEB prescribed rates, which was 3.64% from January 1 to March 31, 2025, 3.16% from April 1 to June 30, 2025, 2.91% from July 1 to September 30, 2025, and 2.91% from October 1 to December 31, 2025.

10. Accounts payable and accrued liabilities:

	2025	2024
Power purchases	$ 3,942	$ 3,342
Trade payables	7,406	8,026
Due to related parties (note 19)	4,094	3,444
Other	1,487	535
	$ 16,929	$ 15,347

(Expressed in thousands of dollars)

11. Long-term debt:

	2025	2024
Term loan, interest at 1.92%, payable in monthly installments. Amortization maturity: October 29, 2030. Contract maturity: October 29, 2025, renewable	$ -	$ 782
Term loan, interest at 5.27%, payable in monthly installments. Amortization maturity: September 7, 2037; Contract maturity: September 7, 2032, renewable	2,396	2,540
Term loan, interest at 3.68%, payable in monthly instalments. Amortization maturity: January 9, 2045. Contract maturity: January 9, 2025, renewable	-	1,566
Term loan, interest at 2.88%, payable in monthly installments. Amortization maturity: June 26, 2045. Contract maturity: June 26, 2025, renewable	-	9,391
Term loan, interest at 3.48%, payable in monthly installments. Amortization maturity: February 14, 2046. Contract maturity: February 14, 2026, renewable	2,302	2,380
Term loan, interest at 3.60%, payable in monthly installments. Amortization maturity: January 28, 2047. Contract maturity: January 28, 2027, renewable	2,496	2,574
Term loan, interest at 4.09%, payable in monthly Installments. Amortization maturity: March 26, 2048. Contract maturity: March 26, 2028, renewable	1,431	1,469
Term loan, interest at 3.28%, payable in monthly installments. Amortization maturity: August 26, 2049. Contract maturity: August 26, 2029, renewable	2,065	2,121
Term loan, interest at 6.29%, payable in monthly installments. Amortization maturity: November 1, 2053. Contract maturity: November 1, 2025, renewable	-	3,951
Term loan, interest at 5.55%, payable in monthly installments. Amortization maturity: December 14, 2043. Contract maturity: December 14, 2025, renewable	-	3,948
Term loan, interest at 4.59%, payable in monthly installments, Amortization maturity: December 24, 2047. Contract maturity: December 23, 2030, renewable	16,603	17,032
Carried forward	27,293	47,754

(Expressed in thousands of dollars)

11. Long-term debt (continued):

	2025	2024
Carried forward	27,293	47,754
Term loan, interest at 4.45%, payable in monthly installments. Amortization maturity: October 30, 2030. Contract maturity: October 30, 2030	653	-
Term loan, interest at 4.45%, payable in monthly installments. Amortization maturity: August 9,2025. Contract maturity: September 7, 2030, renewable	1,956	-
Term loan, interest at 4.45%, payable in monthly installments. Amortization maturity: January 9, 2049. Contract maturity: May 15, 2035, renewable	3,891	-
Term loan, interest at 4.45%, payable in monthly installments. Amortization maturity: January 1, 2053. Contract maturity: November 1, 2030, renewable	3,894	-
Term loan, interest at 4.45%, payable in monthly installments. Amortization maturity: January 1, 2053. Contract maturity: June 19, 2030, renewable	9,834	-
Term loan, interest at 4.45%, payable in monthly installments. Amortization maturity: July 19, 2055. Contract maturity: June 26, 2035, renewable	8,991	-
Term loan, interest at 4.45%, payable in monthly installments. Amortization maturity: February 25, 2050. Contract maturity: May 16, 2035, renewable	1,504	-
Term loan, interest at 4.45%, payable in monthly installments. Amortization maturity: August 9 2055. Contract maturity: May 16, 2035, renewable	3,912	-
	61,928	47,754
Less current portion of long-term debt	4,568	37,063
	$ 57,360	$ 10,691

The bank term loans holds as security a general security agreement representing a first charge on all assets and undertakings of the Corporation.

The agreement with respect to the bank term loans contain certain covenants regarding (i) regulatory compliance, (ii) reporting, (iii) change in status of business, (iv) change in ownership, and (v) limitations on additional debt and encumbrance of assets.

(Expressed in thousands of dollars)

11. Long-term debt (continued):

The agreement with bank also contains financial covenants that require the Corporation to maintain a maximum debt to capital ratio of 0.60 to 1 and a minimum debt service coverage ratio of 1.20x to be tested and calculated on a quarterly basis. The Corporation was in compliance of the covenants as at December 31, 2025.

Principal payment due in each of the next five years are as follows:

2026	$	4,568
2027		4,633
2028		3,560
2029		4,064
2030		26,121
Thereafter		18,982
	$	61,928

As of December 31, 2025, the Corporation has a bank overdraft of $nil (2024 - $828). Bank overdrafts are repayable on demand and form an integral part of the Corporation's cash management. Interest accrues daily at Prime less 1.90%.

12. Contributions in aid of construction:

		2025		2024
Contributions in aid of construction, beginning of year	$	74,773	$	56,147
Contributions received		21,462		20,380
Amortization		(2,194)		(1,754)
Contributions in aid of construction, end of year	$	94,041	$	74,773

(Expressed in thousands of dollars)

13. Share capital:

		2025		2024
Authorized:				
Unlimited number of common shares				
Unlimited number of preferred shares				
Issued:				
1,000 common shares, no par value	$	10,852	$	10,852

On April 28, 2025, a dividend totalling $ 500 was declared.

On April 20, 2026, a dividend totalling $ 500 was declared.

14. Payments in lieu of tax expense:

Payments in lieu of tax expense:

		2025		2024
Current tax expense (recovery)	$	201	$	(103)
Deferred tax expense		(536)		(604)
Payments in lieu of tax expense	$	(335)	$	(707)

(Expressed in thousands of dollars)

14. Payments in lieu of tax expense (continued):

Reconciliation of effective tax rate:

	2025	2024
Income before payments in lieu of tax and net movement in regulatory	$ 1,503	$ 1,628
Net movement in regulatory, net of tax	803	1,694
Deduct: Tax in net movement in regulatory	(552)	(600)
Income before payments in lieu of tax	$ 1,754	$ 2,722
Statutory tax rates	26.5 %	26.5 %
Expected tax provision on income at statutory rates	409	721
Increase (decrease) in taxes resulting from:		
Permanent differences	3	1
Other	(1)	(2)
Adjustment for prior years	(76)	(13)
Payments in lieu of tax expense	$ 335	$ 707

Significant components of the Corporation’s deferred tax balances:

	2025	2024
Deferred tax assets (liabilities):		
Property, plant and equipment	$ (5,247)	$ (4,658)
Post-employment benefits	54	50
Tax credits	47	-
	$ (5,146)	$ (4,608)

(Expressed in thousands of dollars)

15. Other revenue:

		2025		2024
Collection and other service charges	$	363	$	308
Related party billing and other services		1,781		1,738
Related party billing and other services expenses		(1,778)		(1,276)
Rent		613		518
Thermal and gas billing and other services		32		60
Recognition of contributions in aid of construction		2,194		1,754
Other		465		984
Total other revenue	$	3,670	$	4,086

Related party revenue has been disclosed in note 19 and is included within the above categories based on the type of revenue.

16. Expenses by nature:

		2025		2024
Salaries, wages and benefits (Note 19 (d))	$	5,937	$	6,345
CPP and EI remittances		545		457
Contributions to OMERS		748		680
Less amounts capitalized		(2,927)		(2,699)
	$	4,303	$	4,783

(Expressed in thousands of dollars)

16. Expenses by nature (continued):

Operating expenses

		2025		2024
Employee salaries and benefits	$	4,303	$	4,783
Subcontractor costs		1,652		1,477
Repairs, maintenance and tooling		926		929
Professional fees		423		166
Other taxes		198		201
Insurance		335		208
Depreciation		442		427
Other general administration		923		1,116
	$	9,202	$	9,307

17. Finance income and costs:

		2025		2024
Finance income:				
Interest income on bank deposits	$	126	$	93
Finance costs:				
Interest expense on long-term debt		(2,511)		(2,031)
Interest expense on customer deposits		(31)		(48)
Other		(64)		(34)
Interest expense on lease liability		-		(2)
		(2,606)		(2,115)
Net finance costs recognized in profit or loss	$	(2,480)	$	(2,022)

(Expressed in thousands of dollars)

18. Commitments and contingencies:

General Liability Insurance:

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange ("MEARIE"). MEARIE is a pooling of public liability insurance risks of many of the LDCs in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members, on a pro-rata basis based on the total of their respective service revenues. As at December 31, 2025, no assessments have been made.

19. Related party transactions:

(a) Parents and ultimate controlling party:

The sole shareholder of the Corporation is the Town of Innisfil. The Town produces consolidated financial statements that are available for public use.

(b) Outstanding balances with related parties:

		2025		2024
Town of Innisfil - receivable	$	260	$	507
Town of Innisfil - payable		(6)		-
InnServices Utilities Inc. - receivable		1,399		578
InnServices Utilities Inc. - payable		(4,088)		(3,444)
InnTerprises Inc. - receivable		1,255		713
InnServics Utilities Inc.- deposit		(1,301)		-
	$	(2,481)	$	(1,646)

(c) Transactions with related parties:

The Corporation delivers electricity to the Town throughout the year for the electricity needs of the Town and its related organizations. Electricity delivery charges are at prices and under terms approved by the OEB.

The Corporation also provides electricity and other services, including water and wastewater billing and collection, to InnServices Utilities Inc, an affiliate company. Electricity delivery charges are at prices and under terms approved by the OEB. Revenue includes $1,828 (2024 - $1,082) from InnServices Utilities Inc. for financial, billing and other services. The Corporation is provided water and wastewater services and recoverable works from InnServices Utilities Inc throughout the year. Services billed during the year were $6 (2024 - $7) for water and wastewater services, and $394 (2024 - $357) for recoverable work orders.

(Expressed in thousands of dollars)

19. Related party transactions (continued):

(c) Transactions with related parties (continued):

The Corporation also provides billing and financial services to InnTerprises Inc., an affiliate company. Charges for these services during the year were $150 (2024 - $129).

(d) Key management personnel:

The key management personnel of the Corporation have been defined as members of its board of directors and executive management team members. The compensation paid or payable is as follows:

	2025	2024
Directors' fees	$ 72	$ 55
Salaries and other benefits	629	664
	$ 701	$ 719

20. Financial instruments and risk management:

Fair value disclosure:

The carrying values of cash, accounts receivable, unbilled revenue, due from/to related parties and accounts payable and accrued liabilities approximate fair value because of the short maturity of these instruments. The carrying value of the customer deposits approximates fair value because the amounts are payable on demand.

The fair value of the long-term debt at December 31, 2025 is $61,480 (2024 - $47,755). The fair value is calculated based on the present value of future principal and interest cash flows, discounted at the current rate of interest at the reporting date.

Financial risks:

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation's exposure to a variety of risks such as credit risk, interest rate risk, and liquidity risk, as well as related mitigation strategies are discussed below.

20. Financial instruments and risk management (continued):

(a) Credit risk:

Financial assets carry credit risk that a counterparty will fail to discharge an obligation which could result in a financial loss. Financial assets held by the Corporation, such as accounts receivable, expose it to credit risk. The Corporation earns its revenue from a broad base of customers located in the Town of Innisfil and South Barrie. As at December 31, 2025, no single customer accounts for a balance in excess of 10% of total accounts receivable (2024 - nil).

The carrying amount of accounts receivable is reduced through the use of an allowance for impairment and the amount of the related impairment loss is recognized in profit or loss. Subsequent recoveries of receivables previously provisioned are credited to profit or loss. The balance of the allowance for impairment at December 31, 2025 is $264 (2024 - $140). An impairment loss of $124 (2024 - $182) was recognized during the year.

The Corporation's credit risk associated with accounts receivable is primarily related to payments from distribution customers. At December 31, 2025, approximately $244 (2024 - $327) is considered 90 days past due. The Corporation has over 20,000 customers, the majority of whom are residential. Credit risk is managed through collection of security deposits from customers in accordance with directions provided by the OEB and through credit insurance. As at December 31, 2025, the Corporation holds security deposits in the amount of $39 (2024 - $39).

(b) Market risk:

Market risks primarily refer to the risk of loss resulting from changes in commodity prices, foreign exchange rates, and interest rates. The Corporation currently does not have any material commodity or foreign exchange risk. The Corporation is exposed to fluctuations in interest rates as the regulated rate of return for the Corporation's distribution business is derived using a complex formulaic approach which is in part based on the forecast for long term Government of Canada bond yields. This rate of return is approved by the OEB as part of the approval of distribution rates.

A 1% increase in the interest rate at December 31, 2025, would have increased interest expense on the long-term debt by $619, assuming all other variables remain constant. A 1% decrease in the interest rate would have an equal but opposite effect.

20. Financial instruments and risk management (continued):

(c) Liquidity risk:

The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure. The Corporation has access to a $8,000 line of credit facility and monitors cash balances daily to ensure that a sufficient level of liquidity is on hand to meet financial commitments as they become due. As at December 31, 2025, $nil had been drawn under the Corporation's credit facility (2024 - $nil), however the availability is reduced by $1,344 letter of credit with the IESO and a $1,130 letter of credit with Hydro One.

The Corporation also has an undrawn fixed-term loan of $4,000 to finance capital expenditures.

The majority of accounts payable, as reported on the statement of financial position, are due within 30 days.

(d) Capital disclosures:

The main objectives of the Corporation, when managing capital, are to ensure ongoing access to funding to maintain and improve the electricity distribution system, compliance with covenants related to its credit facilities, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

The Corporation's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2025, shareholder's equity amounts to $38,869 (2024 - $37,392) and long-term debt amounts to $57,360 (2024 - $46,305).

Appendix 6: Economic Conditions, Growth Outlook and Economics Benefits Assessment

Economic Conditions, Growth Outlook and Economic Benefits Assessment

InnPower Service Territory

Petramala Research Inc

Prepared by
Diana Petramala

343 Shaw Street, Toronto, Ontario

416.562.7823
www.dpeconomics.ca

Prepared for
InnPower Corporation

July 2026

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EXECUTIVE SUMMARY

InnPower Corporation ("InnPower") retained Petramala Research Inc. to assess the economic conditions affecting residential and employment growth within its service territory and to evaluate the economic benefits enabled by InnPower's planned gross capital investments over the next five years. InnPower's service territory includes the Town of Innisfil ("Innisfil") and the South Barrie lands within the City of Barrie ("Barrie").

This study examines recent housing market conditions, population and employment growth prospects, municipal and provincial planning objectives, and the role of electricity infrastructure in supporting long-term economic development within InnPower's service territory.

Recent economic conditions have created challenges for housing development across Ontario. Higher interest rates, reduced housing affordability, and changes to federal immigration policy contributed to weaker new home sales and housing absorptions between 2023 and 2025. While these factors have moderated the pace of new development, they are expected to be cyclical rather than structural.

The long-term outlook for InnPower's service territory remains strong. Municipal and provincial planning policies continue to support significant population, housing, and employment growth through 2051. The planned expansion of the Innisfil Heights Employment Area represents an important shift toward industrial development that will increase demand for electricity infrastructure while supporting broader economic growth. Housing completions and building permits remained elevated through 2025 and the first half of 2026, reflecting a substantial pipeline of approved developments and prospects for continued long-term growth in the area.

Figure E1: Summary of Economic Benefits Enabled by InnPower Capital Expenditures

	One-Time Benefits 2026-2031	OnGoing Benefits Beyond 2031
	Thousands of C$	
Direct Spending & Capital Investments	337,967	118,548
Gross Domestic Product (at basic price	238,772	85,391
Jobs	1,261	1,093

Statistics Canada, Tables 36-10-0113-01 (Input-output multipliers, provincial and territorial, summary level) and 36-10-0595-01 (Input-output multipliers, provincial and territorial, detail level); Statistics Canada custom model results received June 15, 2026

The study concludes that InnPower's planned capital investments will enable significant economic activity by supporting residential, commercial, and industrial development. These investments generate both one-time construction impacts and ongoing economic activity as new development becomes occupied and operational. Based on Statistics Canada's Input-Output modelling framework, every $10 million invested by InnPower is estimated to enable approximately **$239 million in GDP** and **1,261 person-years of employment** during the development and construction phase. Once these developments are fully occupied, the same investment is estimated to support approximately **$85 million in annual GDP** and **1,093 permanent jobs**. This activity will also generate substantial household income and government revenues across Ontario.

INTRODUCTION

InnPower Corporation ("InnPower") retained Petramala Research Inc. ("Petramala Research") to assess the economic conditions affecting residential and employment growth within its service territory and to evaluate the economic benefits enabled by InnPower's planned capital investments over the next five years. InnPower's service territory includes the Town of Innisfil ("Innisfil") and the lands within the City of Barrie ("Barrie") known as South Barrie.

This study examines recent and projected trends in housing, population, and employment growth, together with municipal and provincial planning policies, to assess the role of electricity infrastructure in supporting future development within Innisfil and South Barrie. Electricity infrastructure is a fundamental prerequisite for residential, commercial, industrial, and institutional development, making InnPower's planned investments a critical enabler of long-term economic growth.

Purpose of Study

InnPower is seeking approval from the Ontario Energy Board ("OEB") for an early rebasing of its distribution rates through a Cost-of-Service application. As part of that application, InnPower retained Petramala Research to evaluate:

- The economic conditions affecting residential, commercial, industrial, and institutional development within its service territory, including the long-term outlook for population, housing, employment, and economic growth within Innisfil and South Barrie; and
- The long-term economic benefits enabled by InnPower's planned capital investments, including the residential, commercial, and industrial development supported by the expansion of electricity infrastructure.

Expert Witness Acknowledgment

I, Diana Petramala, am the founder of Petramala Research Inc., a small boutique economic firm in Toronto, Ontario. I am an economist who helps clients with research related to land economics, infrastructure investment and real estate and demographic trends.

I am engaged in the field of economics. I am a Professional Land Economist, with the Ontario Land Economist Association. I am past Vice President and current board member of the Toronto Association of Business Economics.

I have over 18 years of experience in economic and real estate analysis. I was an economist with TD Bank from 2008-2017, where I led the Bank's real estate and demographic research. In this role, I gained expertise in statistical and market analysis. I was a senior economist at the Centre for Research and Land Development at Toronto Metropolitan University from 2017-2022, where I applied my statistical and market analysis expertise in leading research on policy issues related to urban planning. I was Director of Economic Consulting at Altus Group from 2022-2024, where I managed the company's portfolio of housing and land needs analysis, economic and fiscal impact analysis and demographic projections. I continue to provide these services to clients under the Petramala Research brand.

My expertise is modelling the impact of macroeconomic, demographic and policy trends on demand for various goods, services and investments.

I hold a Bachelor of Arts (major in Economics and Financial Management) from Wilfrid Laurier University, and a Master of Business Economics from Wilfrid Laurier.

I take pride in my professional and research integrity. Petramala Research Inc. provides services as an independent expert. All opinions will reflect professional judgment and available evidence, regardless of client position.

My professional qualifications are set out in my curriculum vitae, which is attached as Appendix A to this report. My Acknowledgement of Expert's Duty is also attached as Appendix B.

Information Used in Study

The analysis in this report draws upon a range of planning, economic, demographic, financial, and municipal infrastructure information, including:

- Barrie Official Plan as amended May 2024;
- Innisfil Official Plan and Official Plan Update Material;
- Statistics Canada data on employment, place of work status, annual population estimates, labour force characteristics, commuting behaviour, and interest rates;
- Statistics Canada Economic Input-Output modelling;
- Hemson Consulting Population and Employment Forecasts for Barrie and Innisfil;
- BILD and Altus Group New Home Sales Updates (2022-2026); and

- Supporting market and economic trends reports from various economic analysts, including: TD Bank, BMO Financial Group, Scotiabank, RBC Financial and CIBC Economics.

A comprehensive list of data tables and sources can be found in Appendix F of this report, titled Sources.

Summary of Findings

- Housing activity has slowed across Innisfil and South Barrie as higher interest rates, reduced housing affordability, and changes to federal immigration policy weakened new home sales and housing demand. These factors are expected to represent a cyclical slowdown rather than a change in the region's long-term growth outlook.
- Despite weaker new home sales and slower housing absorption since 2022, housing completions and issued building permits have remained elevated, reflecting a substantial pipeline of previously approved developments and continued confidence in the area's long-term growth prospects.
- Municipal and provincial growth objectives remain unchanged, with the Town of Innisfil and the City of Barrie expected to accommodate significant population, housing, and employment growth through 2031.
- Employment growth and industrial development are emerging as key drivers of future electricity demand within InnPower's service territory. In particular, the expansion of employment lands in South Barrie and the Innisfil Heights Employment Area will reinforce the need for long-term electricity infrastructure investment.
- Continued investment in electricity infrastructure will be necessary to accommodate long-term population, employment, and economic growth within InnPower's service territory.
- Every **$10 million in gross capital expenditures** by InnPower is estimated to enable approximately **$338.0 million in one-time construction activity**, generate **$238.8 million in GDP** across Ontario, support **1,261 years of employment**, and produce significant household income, business profits, and government revenues through direct, indirect, and induced economic effects.
- At full build-out, the population and employment growth enabled by these investments is projected to generate approximately **$85.3 million in annual GDP**, support **1,093 permanent jobs**, and contribute more than **$12.3 million in annual wages and salaries** across the regional economy.

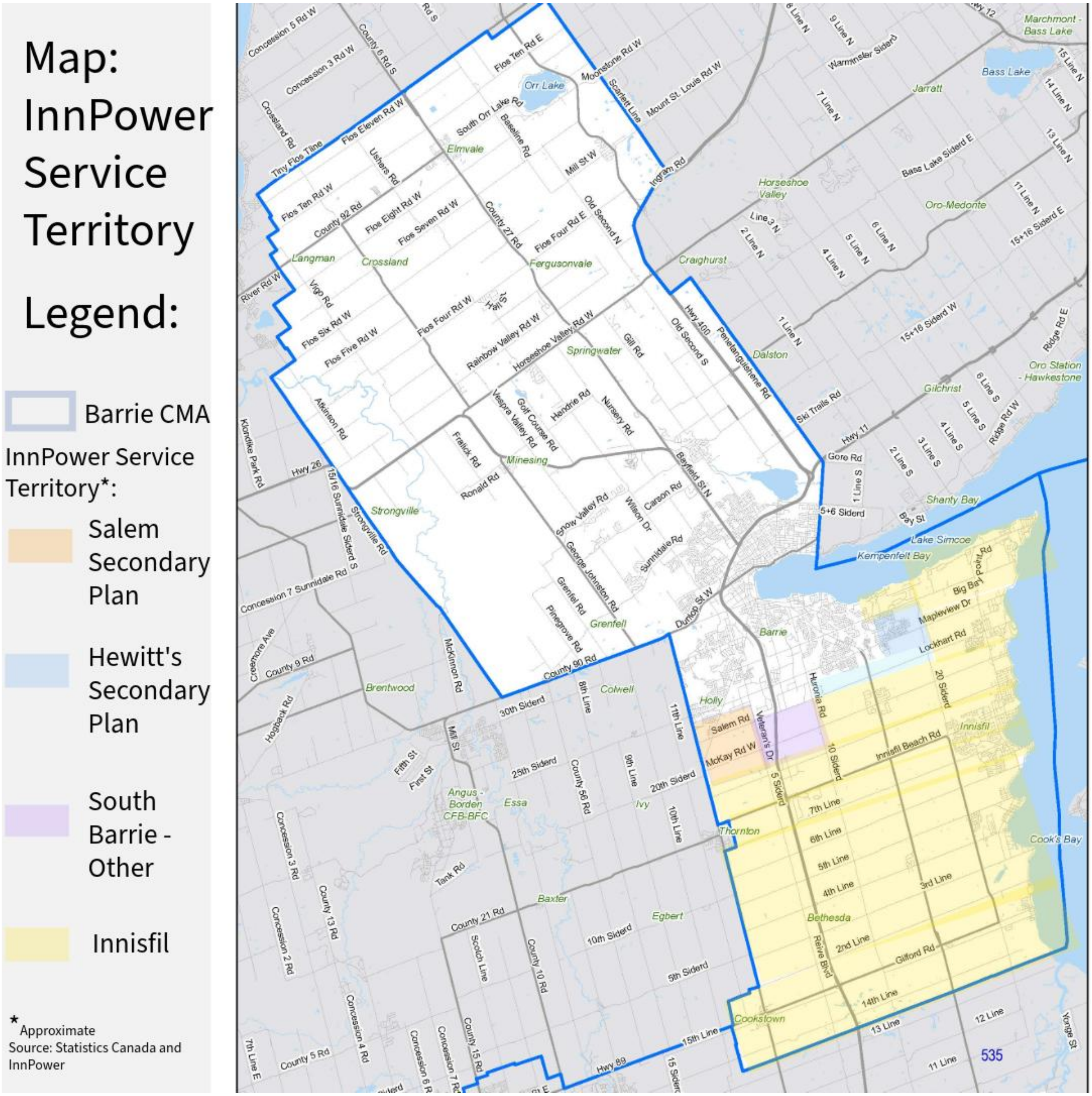
INNPOWER SERVICE TERRITORY

InnPower is an electricity distribution company serving households and businesses within the Town of Innisfil and the South Barrie area. As illustrated in **Map 1**, InnPower's service territory is located within the Barrie Census Metropolitan Area (CMA), which comprises of the City of Barrie, the Town of Innisfil, and the Township of Springwater. Statistics Canada defines a CMA as a large urban centre and the surrounding municipalities that are highly integrated with the urban core through commuting patterns.

The Barrie CMA encompasses approximately 897 square kilometres, while InnPower's service territory covers approximately 292 square kilometres, representing roughly one-third of the CMA. InnPower’s service territory is highlighted in yellow on Map 1, while the overall CMA boundary is outlined in blue.

The map also identifies the lands transferred from the Town of Innisfil to the City of Barrie through the 2010 municipal boundary adjustment. Following the annexation, the City adopted the Salem Secondary Plan (shown in peach on Map 1) and the Hewitt's Secondary Plan (shown in purple). Although these lands are now within the City of Barrie, they remain part of InnPower's electricity distribution service territory and represent a significant share of the area's planned future residential and employment growth.

Map 1: Barrie CMA and InnPower Service Territory



MACROECONOMIC CONTEXT SINCE 2022

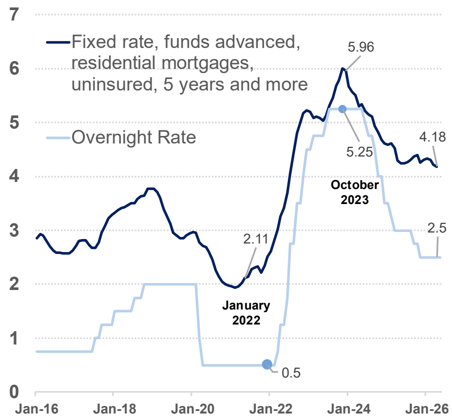
Interest Rates and Housing Affordability

The most significant economic development affecting Ontario's housing market since 2023 has been the rapid increase in interest rates. In early 2022, the Bank of Canada began raising its key policy interest rate (the overnight rate) to combat rising inflation. As a result, mortgage interest rates also increased, with the average 5-year fixed mortgage rate on new mortgages reaching nearly 6% by the end of 2023—approximately three times higher than the rates available in 2022.

Although borrowing costs have declined from their peak, interest rates are not expected to return to the exceptionally low levels seen during the pandemic, as those rates were considered emergency measures to support the economy. Current forecasts instead suggest a more stable long-term interest rate environment.

Figure 1: Canadian Interest Rates

A. Canadian Interest Rates, %
As of May 2026



Source: Statistics Canada. Table 10-10-0122-01 Financial market statistics, last Wednesday unless otherwise stated, Bank of Canada and Statistics Canada. Table 10-10-0006-01 Funds advanced, outstanding balances, and interest rates

B. Bank of Canada Overnight Rate, %, Annual Average
Forecasts by Canadian Economic Forecasters, as of July 2026

	2026	2027	2028-2031F
Low	2.25	2.25	2.25
High	3.00	3.25	3.25
Average	2.40	2.70	2.70
Mortgage Rate	3.97	4.27	4.17

*F=Forecast
Source: TD Bank, Scotiabank, Royal Bank of Canada, CIBC, and BMO Financial Group, as of the period between March – May 2026.

Higher borrowing costs have reduced housing affordability across Ontario by increasing mortgage payments and limiting purchasing power. However, lower and more stable interest rates are expected to support housing demand and improve market conditions going forward.

Immigration and Population Growth

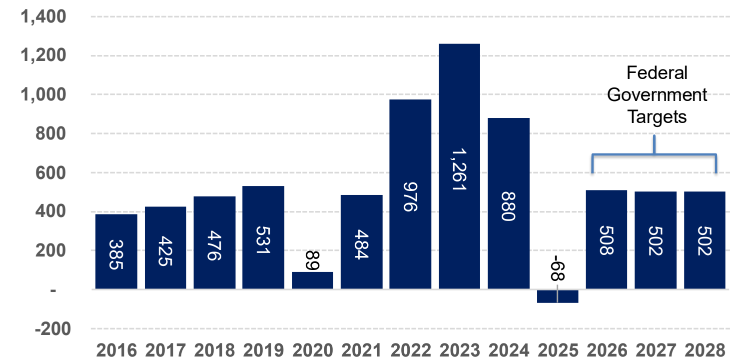
Population growth accelerated significantly following the pandemic as Canada experienced historically high levels of immigration.

Canada ramped up its immigration policies between 2022 and 2024. In response to infrastructure, housing and affordability pressures, the federal government paused immigration[1] in 2025. Immigration targets were also revised for the 2026-2028 period, though these revisions are best characterized as a return to more sustainable growth[2]. Figure 2 illustrates that Canada is still planning to receive more immigration in this period than has historically been the case.

While population growth is expected to moderate from the rates reached during 2022 and 2023, immigration levels remain historically elevated and will continue to support long-term population growth, housing demand, labour force growth and economic expansion in Canada.

Figure 2: Federal Immigration Targets

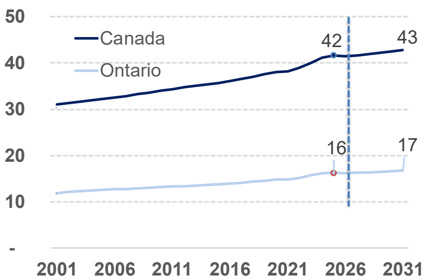
Immigration, Actual and Targets, Canada
000s of Persons



Source: Statistics Canada. Table 17-10-0040-01 Estimates of the components of international migration, quarterly and Government of Canada supplementary Information for the 2026-2028 Immigration Plan

Figure 3: Population and Immigration Levels

A. Population, Historical and Projections*, Canada and Ontario
Millions of Persons



B. 5-Year Change in the Population
Millions of Persons

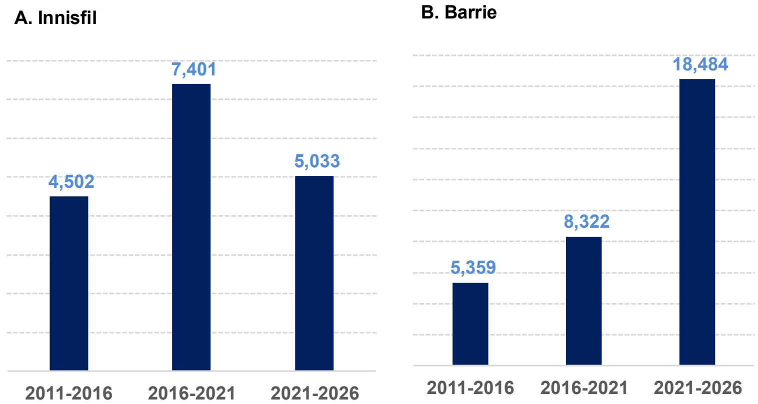
	2016-2021	2021-2026E**	2026-2031P***
Canada (Total)	2.13	3.26	1.38
Ontario (Total)	0.97	1.28	0.68
Canada (Immigration)	2.00	3.55	2.51

*Based on Medium-Growth Scenario, M4
**E=estimate
***=Projection
Source: Statistics Canada. Table 17-10-0162-01 Projected population for census divisions and census subdivisions, 2021 boundaries, by projection scenario, age and gender, as of July 1 and Table 17-10-0009-01 Population estimates, quarterly and Government of Canada Supplementary Information for the 2026-2028 Immigration Levels Plan.

[1] Government of Canada, Immigration, Refugees and Citizenship Canada (IRCC), "Supplementary Information for the 2025–2027 Immigration Levels Plan," October 2024.
[2] Government of Canada, Immigration, Refugees and Citizenship Canada (IRCC), "Supplementary Information for the 2026–2028 Immigration Levels Plan," November 2025.

Innisfil (+5,033) and Barrie (+18,484), combined, still experienced significant population growth in the 2021-2026 period. Note, population growth between 2016 and 2021 was heavily skewed upward as the COVID-19 pandemic resulted in a shift to work-from-home for several years. This encouraged an acceleration in residents residing in more expensive places in Ontario, moving into more affordable areas, such as the Town of Innisfil[3].

Figure 4: Population Growth, 5-Year Periods
Persons



Source: Statistics Canada. Table 17-10-0162-01 Projected population for census divisions and census subdivisions, 2021 boundaries, by projection scenario, age and gender, as of July 1 and Table 17-10-0009-01 Population estimates, quarterly

[3] Petramala, D. and Clayton, F. (2022), "Affordability Issues, Not the Pandemic, Drive Population from the City of Toronto and Peel Region," Centre for Urban Research and Land Development, Toronto Metropolitan University, January 14, 2022. Based on Statistics Canada intraprovincial migration data, the report finds that migration from the Greater Toronto Area toward more affordable locations such as Simcoe County reflected a trend that began prior to the pandemic and was primarily driven by housing affordability.

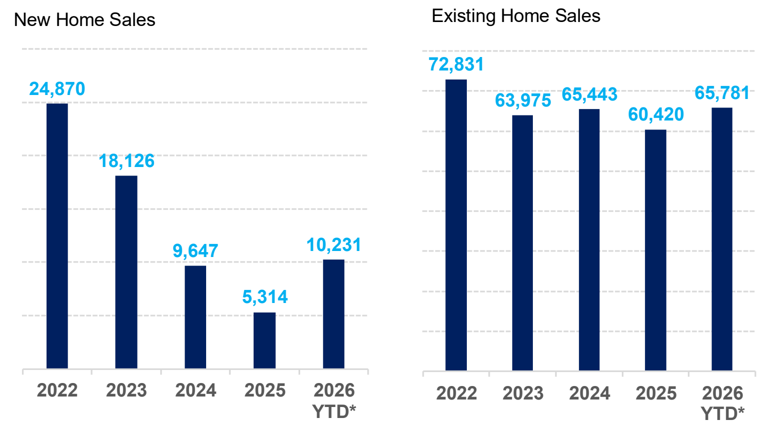
HOUSING MARKET SLOWDOWN AND MARKET ABSORPTION

Weakness in Home Sales

The impact of higher borrowing costs and slower population growth was most evident in the housing market. Figure 5 illustrates annual existing and new home sales in the Greater Toronto Area (GTA) from 2022 to 2025, along with an estimate for 2026 based on sales activity during the first half of the year. Existing home sales represent transactions completed through the Multiple Listing Service (MLS) and reflect activity in the resale housing market.

Housing demand weakened across both the new and resale markets between 2022 and 2025 as higher interest rates and slower population growth reduced buyer demand. While market conditions have improved during the first half of 2026, the recovery remains gradual.

Figure 5: Greater Toronto Area, Home Sales
Units



* YTD is based on Y/Y% change from January 2026 to April 2026, annualized.
Source: BILD GTA and Altus Group New Home Monthly Market Report, May 2026, January 2025 and January 2024

* YTD is based on Y/Y% change from January 2026 to June 2026, annualized.
Source: Toronto Regional Real Estate Board

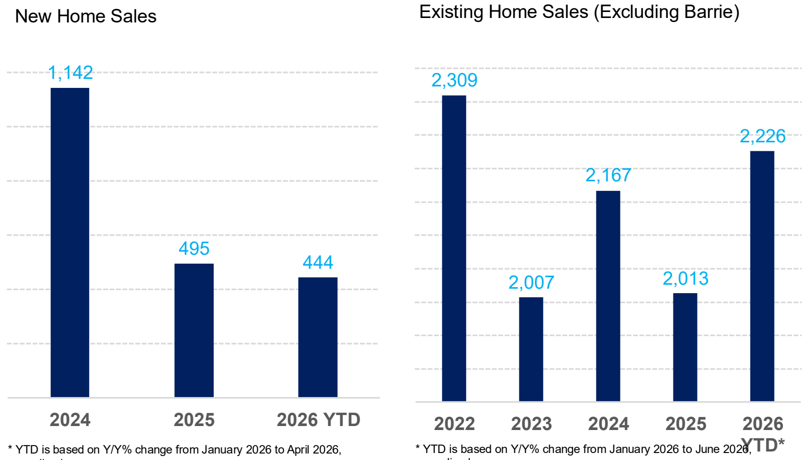
The downturn was significantly more severe in the new home market than in the resale market. New home sales declined from 24,871 units in 2022 to just 5,314 units in 2025. Based on sales activity during the first half of 2026, annual sales are projected to reach approximately 10,231 units, indicating that the market is beginning to recover.

Figure 6 presents home sales in Simcoe County. Two data limitations should be noted:

- New home sales have only been tracked by Altus Group since 2024; and
- The Toronto Regional Real Estate Board (TRREB) is currently integrating data from the former Barrie Real Estate Board into its market reports. As a result, continuous historical resale market data are not publicly available.

New home sales in Simcoe County declined from 1,142 units in 2024 to 495 units in 2025. Based on sales activity during the first half of 2026, annual sales are projected to reach approximately 444 units. In contrast, resale market activity has recovered substantially and is approaching 2022 levels. The weaker performance of the new home market likely reflects a lagged response to improving demand in the resale market, suggesting that new home sales may strengthen as market conditions continue to improve.

Figure 6: Simcoe County, Home Sales
Units



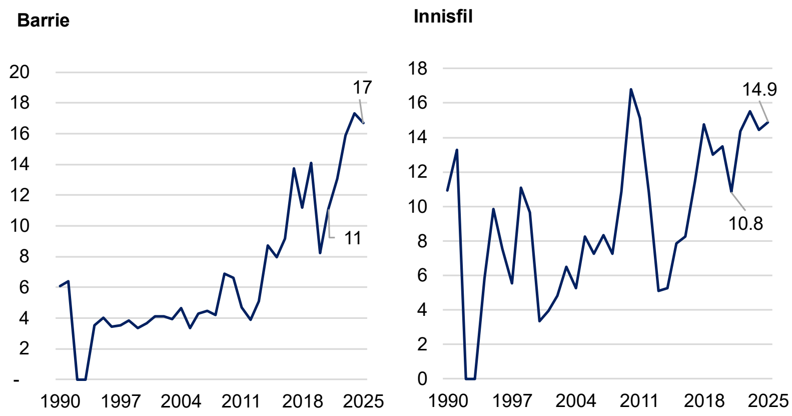
* YTD is based on Y/Y% change from January 2026 to April 2026, annualized.
Source: BILD GTA and Altus Group New Home Monthly Market Report, May 2026, January 2025 and January 2024

* YTD is based on Y/Y% change from January 2026 to June 2026, annualized.
Source: Toronto Regional Real Estate Board

Developers responded to weaker demand by delaying project launches, extending sales periods and adjusting construction schedules. The average months of construction for a new home to reach completion increased by:

- 6 months in Barrie between 2023 and 2025; and
- 4 months in Innisfil over the same period.

Figure 7: Length of Construction of New Homes
Months from Start of Construction to End



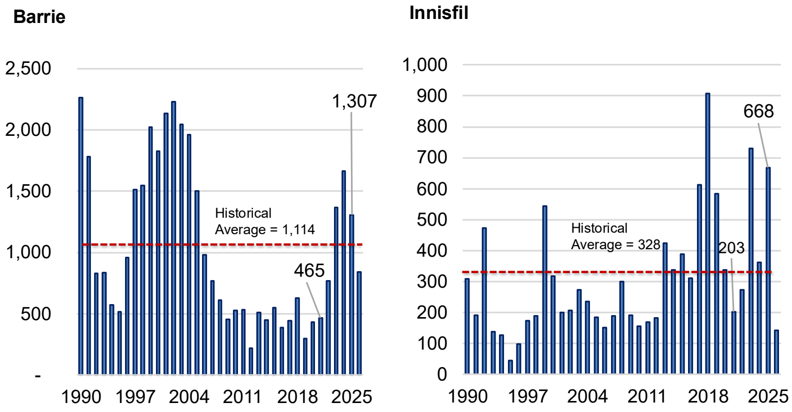
Source: CMHC Housing Market Portal

Housing Completions Remained Elevated

While new home sales weakened materially, housing completions remained comparatively strong, reflecting the large pipeline of residential projects approved over the previous decade in both the Town of Innisfil and the City of Barrie. Many developments that entered construction during the period of strong housing demand continued through the construction process and reached completion in 2025, despite weaker market conditions.

Figure 8 shows that housing completions in both 2024 and 2025 were approximately three times higher than at the time of the previous application for both municipalities. Completions are projected to return closer to historical norms in 2026 as the earlier construction pipeline is exhausted and the recent slowdown in new home sales works its way through the development process. This reflects a lag between changes in housing demand and housing completions.

Figure 8: Housing Completions
Units



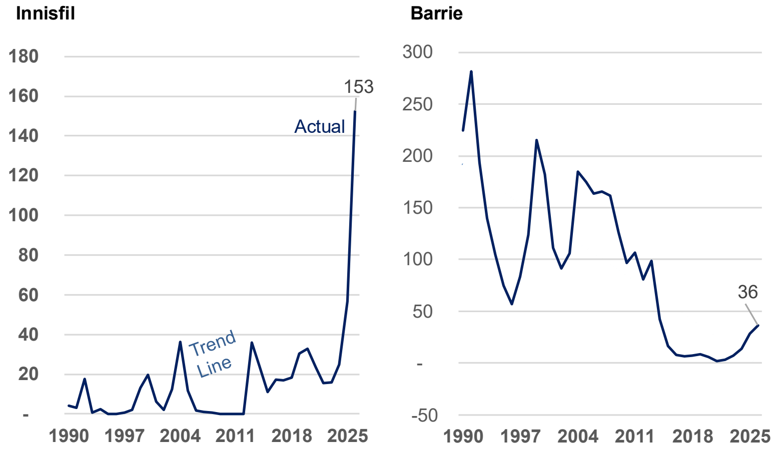
Source: CMHC Housing Market Portal, Annual Completions, Actual

Slower Housing Absorption

The combination of higher completions and weaker demand resulted in a rise in the number of newly completed, but unabsorbed housing. Unabsorbed units represent housing units that remain vacant at the time of completion.

A greater number of completed units remained vacant in 2025 and early 2026. This trend has been particularly pronounced in Innisfil, while there has been a trend change in direction in Barrie.

Figure 9: Unabsorbed (Vacant) Newly Built Homes
Units



Source: CMHC Housing Market Portal, Annual Unabsorbed Completions, Actual

Labour Market Resilience and Employment Growth

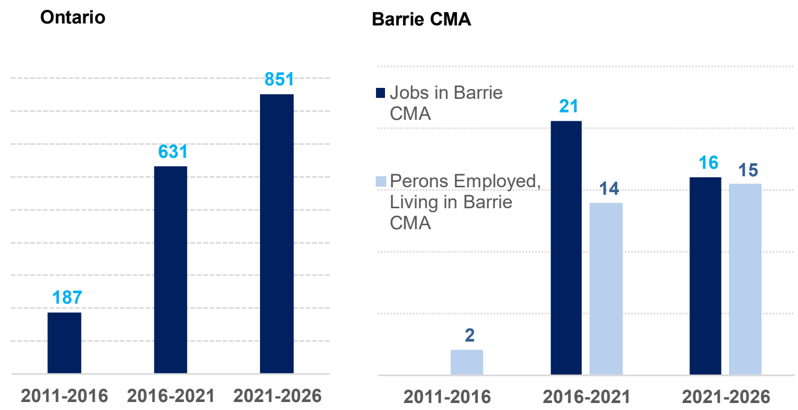
In contrast to housing market conditions, the labour market performance remained resilient. Employment data by CMA is presented in the Census with two definitions:

- Employment by place of residence: This is based on residency of the person holding the job, regardless of where that job is performed. For example, a person living in Barrie, but working in Toronto, would be counted as employed in Barrie.
- Employment by place of work: This reflects employment by where the job is performed. For example, a person living in Toronto, but working in Barrie would be counted as employed in Barrie.

The job market performance for the 2021-2026 period included:

- A gain of 851,000 jobs in Ontario, compared to 631,000 jobs created in the prior five years;
- A gain of 15,000 employed persons residing in the Barrie (CMA), compared to 14,000 in the prior five years; and
- Creation of 16,000[4] jobs within businesses operating in the Barrie CMA, compared to 21,000 created in the prior five-year period. The 2016-2021 period was highly influenced by the COVID-19 pandemic, in which the shift to work-from-home encouraged an influx of residents into the Barrie CMA, and a higher range of jobs being performed within the CMA.

Figure 10: Employment Growth, 5-Year Periods
000s of Persons Employed



Source: Statistics Canada. Table 14-10-0468-01 Employment characteristics by census metropolitan area, annual and Statistics Canada. Table 98-10-0491-01 Place of work status by industry sector, work activity during the reference year, age and gender: Canada, provinces and territories, census divisions and census subdivisions of work

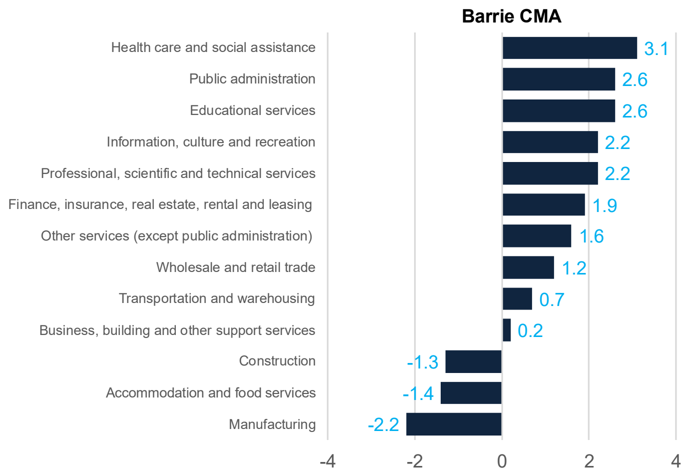
Employment data for the 2021–2026 period was estimated using monthly labour force data and proprietary employment forecasting models.

The evidence suggests that recent economic weakness was concentrated within interest-rate and tariff sensitive sectors of the economy rather than representing a broad-based deterioration in regional economic conditions.

[4] Author's estimate based on Statistics Canada employment data and forecast assumptions for the 2021–2026 period, reflecting existing information for employment growth in the Barrie CMA over this period.

Figure 11 highlights that job creation during the 2021-2026 period was largely driven by service and office jobs. Employment growth continued across a range of sectors, including health care, professional services, transportation and warehousing, education and public administration. In contrast, construction employment was largely negatively impacted by the slowdown in the new home market. Shaken business confidence and tariff uncertainty reduced employment in manufacturing across the CMA.

Figure 11: Change in Employment, 5-Year Period (2021-2026),000s of Persons Employed



Source: Statistics Canada. Table 14 -10-0468-01 Employment characteristics by census metropolitan area, annual and Statistics Canada. Table 14-10-0459-01 Labour force characteristics by census metropolitan area, three-month moving average, seasonally adjusted

GOVERNMENT POLICY OBJECTIVES AND LONG-TERM ECONOMIC GROWTH

Municipal Growth Objectives

Planning for future growth is a core responsibility of municipalities and is guided by the Provincial Planning Statement, 2024. Decisions regarding land use, infrastructure investment, municipal servicing, schools, parks, and transportation all depend on understanding how many people and jobs a municipality is expected to accommodate over the long term. To support these decisions, municipalities establish long-term population, employment, and housing growth forecasts through their planning frameworks. These forecasts guide Official Plans, infrastructure investment, and the identification of land required to accommodate future growth.

Despite the recent housing slowdown, municipal growth plans within InnPower's service territory remain largely unchanged.

Simcoe County, the upper-tier municipality, currently has planning authority over the lower-tier municipalities within the region, except for the City of Barrie and the Town of Orillia. As part of this role, the County prepares population and employment forecasts and allocates growth projections to its constituent municipalities, including the Town of Innisfil.

The Province of Ontario has introduced Bill 98, which would remove planning authority from Simcoe County and transfer greater planning responsibilities to lower-tier municipalities, including Innisfil. At the time of writing, Bill 98 had not yet received Royal Assent.

Simcoe County's most recent forecasts are found in Figure 12. According to the 2022 Growth Forecasts for Simcoe County[5], over the 2026-2031 period, the Town of Innisfil is expected to grow by:

- 2,600 households; and
- 3,382 jobs.

Figure 12: 5-Year Growth Forecasts for InnPower Service Territory

	Simcoe County				Innisfil
	2021	2026F	2031F	2026-2031F	2026-2031F
	Units			Change	Change
Households	132,480	150,850	168,010	17,160	2,600
Jobs	116,550	129,310	140,910	11,600	3,382
Of which are major office and employment lands	25,930	29,980	33,130	3,150	720

Source: City of Barrie and Town of Innisfil Growth Plan and Official Plans. Province of Ontario Housing Pledges Dashboard

[5] Hemson Consulting Ltd., Simcoe County Growth Forecasts to 2051, prepared for the County of Simcoe, 2022.

The Town of Innisfil is in the midst of an Official Plan Review. As part of this process, the Town of Innisfil engaged consultants to review its Land Needs Assessment (LNA) and strategy. The review concluded that:

"The County LNA's population and housing forecasts are considered appropriate and suitable for current planning, as they are well-supported and align with long-term household formation patterns."[6]

Figure 13: Urban Boundary Expansion, Innisfil Heights

Source: OPA - By-law No. 076-20
https://s3.ca-central-1.amazonaws.com/ehq-production-canada/c7c4b0cb9c48fff0295f830d3310189c57ca8344/original/1600278613/2020.09.09Notice_of_Adoption-Innisfil_Heights_Expansion.pdf_514c4768fa8680f95cf0c544527fbcae?1600278613

The municipality has also advanced plans for the expansion of the Innisfil Heights Employment Lands, supporting future development. The Town of Innisfil has approved an urban boundary expansion to ensure the ability to accommodate 1,600 jobs in industrial and advanced manufacturing[7] on those lands.

With a focus on boosting global competitiveness, Invest Ontario is implementing a strategic plan to attract $3.9 billion of investment to create **3,700** jobs annually in life science[8], advanced manufacturing and technology. The Town of Innisfil is actively working on an economic development plan to attract 1,600 of these jobs over a 25-year period. It is reasonable to expect that Innisfil could attract a small fraction of the economic activity being planned for in Ontario more broadly.

This shift is economically significant because employment growth serves as a key driver of future population growth, household formation and housing demand.

The City of Barrie's growth forecasts are presented in Figure 14. Under the planning framework established in 2016, approximately 62% of the City's forecast household growth and 30% of its employment growth were allocated to the Salem and Hewitt Secondary Plan Areas in South Barrie. These communities were identified as the primary locations to

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[6] Dillon Consulting Limited, Town of Innisfil Official Plan Review – Land Needs Assessment Review and Growth Management Analysis, latest available draft/final report.
[7] urbanMetrics Inc., Innisfil Heights Strategic Employment Area / Urban Boundary Expansion Study (or final approved report title when released), Town of Innisfil.
[8] Invest Ontario, Strategic Plan 2025–2028. Investment attraction targets for life sciences, advanced manufacturing and technology sectors.

accommodate the City's long-term residential and employment growth through to the planning horizon.[9]

Between 2026 and 2031, South Barrie[10] is expected to grow by:

- nearly **4,118** new households; and
- **2,310** jobs.

The continued development of the Salem and Hewitt subdivisions remain important drivers of this growth.

An independent review of the City of Barrie's long-term growth projections reviewed them as "guided by smart planning principals"[11].

Figure 14: 5- Year Growth Forecasts for InnPower Service Territory

	Barrie				South Barrie
	2021	2026F	2031F	2026-2031F	2026-2031F
	Units			Change	Change
Households	55,316	6,398	27,772	13,726	4,118
Jobs	83,400	7,300	25,406	7,700	2,310
Of which are major office and employment lands	56,631	61,949	62,518	570	228

Source: City of Barrie and Town of Innisfil Growth Plan and Official Plans.
Province of Ontario Housing Pledges Dashboard

Provincial Housing Pledges

In addition to these growth objectives, both municipalities have also committed to accelerating the creation of housing supply to improve housing affordability concerns.

The Province of Ontario created a $1.2 Billion Building Faster Fund to encourage the development of new housing supply. The Province is committed to building 1.5 million homes by 2031. Municipalities have pledged to meet housing supply targets, and in return for achieving over 80% of their targets will receive provincial funding for housing related infrastructure. This policy is intended to improve affordability and accommodate future population growth.

The Town of Innisfil has pledged a 10-year target of 6,300 units and the City of Barrie has pledged to build 23,000 over the same period[12].

The Government of Canada and Province of Ontario have also announced two major measures that are expected to stimulate housing demand in the new home market in the next five years, including:

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[9] City of Barrie, Public Information Centre Presentation, September 2016.
[10] City of Barrie Official Plan, Staff Consolidation as of April 17, 2026, page 23.
[11] Hemson Consulting Ltd., Peer Review of Population, Housing and Employment Forecasts prepared for the Township of Oro-Medonte, latest available report.
[12] Province of Ontario, "Tracking Housing Supply Progress," Housing Supply Action Plan Dashboard, accessed June 2026.

- A reduction in HST paid on new homes; and
- An announced program to reduce development charges for a three-year period. Participating municipalities will get access to extra infrastructure funding if they reduce development charges by up to 50%.

Both of these measures are meant to stimulate construction activity in the next 3-5 years to boost economic activity, amid uncertainty around inflationary and trade tensions. By improving the relative affordability of new homes, these policies are expected to shift a greater share of housing demand from the resale market to the new home market.

Overall Policy Objectives for InnPower Service Area

Figure 15 illustrates the combined impact of municipal planning objectives and recent provincial housing policies on growth within the InnPower service territory. To achieve longer-term Growth Plan targets over the 2026–2031 period, municipalities within the service area will need to accommodate approximately 6,718 additional households, deliver 7,750 new housing units, and create 5,692 new jobs.

Despite softening market conditions, Innisfil and Barrie remain on track to meet their growth plan objectives.

Based on monthly building permit reports, between January 2025 and May 2026, the cities combined have approved building permits for the creation of 2,006 residential units and roughly 3.3 million square feet of non-residential space, enough non-residential space to accommodate 3,981 jobs.

Figure 15: 5-Year Growth Forecasts for InnPower Service Territory, Units

Innisfil and South Barrie

	2021-2026E	2026-2031F
Households	10,151	6,718
Housing Supply		7,750
Jobs	6,352	5,692
Of which are on employment lands		948

Source: City of Barrie and Town of Innisfil Growth Plan and Official Plans. Province of Ontario Housing Pledges Dashboard

Figure 16: Building Permits Issued between January 2025 and May 2026, Innisfil and Barrie

	Residential Units	Institutional, Commercial and Industrial Sq. Ft.
Barrie	1908	3,057,596
Innisfil	98	241,090
Total	2,006	3,298,686
Potenial Jobs (Total Sq. Ft/828*)		3,981

*Assuming each employee requires 828 sq. ft. of floor space
Source: City of Barrie and Town of Innisfil Monthly Building Permit Reports

ECONOMIC BENEFITS ASSESSMENT

InnPower's future gross capital investments will help support projected residential and employment growth in Innisfil and South Barrie. Reliable electricity infrastructure is essential for accommodating new housing and enabling business expansion. Households depend on electricity to meet their daily needs, while businesses rely on it to operate, invest, and create jobs.

This section estimates the economic impacts of InnPower's planned gross capital investments.

Direct Impact of InnPower's Investments

Between 2021 and 2026, InnPower invested approximately $114 million in gross capital expenditures to expand and enhance its electricity distribution system. These investments increased the capacity of the distribution network, enabling InnPower to connect new residential and business customers as growth occurred across its service territory.

Figure 17: InnPower 5-Year Customer Growth and Gross Capital Investment, 2021-2026E*

	2021	2026 Bridge Level	Actual 2021-2026 Change	Rescaled 2021-2026 Change
Customers				
Residential	18,253	23,656	5,402	474
General Service < 50 kW	1,191	1,336	145	13
General Service >= 50 kW	78	89	11	1
Total General Service	1,269	1,425	156	14
InnPower Gross Capital Expenditures (Mil C$) (System Access and System Expansion)			114	10

Source: InnPower Corporation and Petramala Research Inc.

During this period, InnPower connected 5,402 new residential customers and 156 new business customers (Figure 17).

While the number of new residential and business connections provides a measure of the development supported by InnPower's investments, the addition of new businesses also generates employment opportunities. Estimating the number of jobs associated with these new business connections provides a broader measure of the economic benefits enabled by the investments.

To do so, we consider the average employment per business in Innisfil and South Barrie using Statistics Canada data on active businesses (those with one or more employees) and employment in the Barrie CMA (Figure 18).

Figure 18: Assumption, Average Active Jobs per Business, Barrie CMA, 2021-2026E*

	2021	2026 E*	2021-2026
	Level		Change
Active Businesses	4,979	5,140	161
Total Employment (000s)	116,975	132,367	15,392
Total Employees/Business	23	26	96

364 jobs supported by $10 million in gross investments
(= 26 average jobs x 14 new active businesses)

****Adjusted to 353 to account for rounding errors**

*E=Estimate based on 5 months of employment data, annualized.
Source: Experimental estimates for business openings and closures by employment size for Canada, provinces and territories, census metropolitan areas, seasonally adjusted and Statistics Canada. Table 14-10-0459-01 Labour force characteristics by census metropolitan area, three-month moving average, seasonally adjusted

Statistics Canada data indicate that active businesses in the Barrie CMA employed an average of 26 workers per establishment in 2026 (Figure 18). Newly established businesses between 2021 and 2026 were considerably larger, averaging approximately 96 employees each. However, to avoid overstating the impacts, this assessment applies the more conservative average of 26 employees per business. Based on 156 new business connections, InnPower's gross capital investments between 2021 and 2026 are estimated to have enabled approximately 4,056 jobs within its service territory.

To estimate the impacts of future capital investments, the historical results are expressed on a standardized basis per $10 million of gross capital expenditure. Based on InnPower's 2021–2026 experience, every $10 million invested in the electricity distribution system supported approximately:

- 474 additional households locating within InnPower's service territory; and
- 353 net new jobs.

Spin-off Benefits of InnPower’s enabled growth – One-time economic benefits

While InnPower's capital investment funds the electricity distribution infrastructure, those investments enable substantially larger private-sector investments in residential and non-residential development by providing the servicing capacity required for growth

The households and jobs supported by InnPower’s investments generate both one-time and ongoing economic activity for InnPower’s service territory and the rest of Ontario.

One-time economic activity includes the capital expenditures required to construct InnPower’s electricity infrastructure, build the new housing units needed to accommodate population growth, and develop the non-residential buildings and facilities required to support the additional employment.

It is estimated that every $10 million invested by InnPower enables an even larger approximately **$338.0 million** in one-time construction spending in Innisfil and South Barrie, consisting of:

- $10.0 million in InnPower capital expenditures;
- Approximately $235.3 million in residential construction investment; and
- Approximately $92.6 million in non-residential construction investment.

These estimates include only the capital expenditures required to construct the physical assets associated with growth.

Figure 19: Assumption, Total Capital Expenditure Enabled by InnPower Gross Investments, 2021-2026E*

	2021-2026 $
InnPower Capital Expenditures	10,000,000
Residential Construction	235,325,238
Non-Residential Construction	92,641,458
Total Gross Capital Expenditures	337,966,696

*E=Estimate based on 5 months of employment data, annualized.
Source: Experimental estimates for business openings and closures by employment size for Canada, provinces and territories, census metropolitan areas, seasonally adjusted and Statistics Canada. Table 14-10-0459-01 Labour force characteristics by census metropolitan area, three-month moving average, seasonally adjusted
.

Residential investment reflects the construction of new dwelling units required to accommodate the additional households supported by InnPower's investments. Non-residential investment reflects the construction of commercial, industrial, institutional, and other employment-related floor space required to accommodate the additional jobs. Land acquisition costs, financing costs, and transfers of existing assets are excluded from the analysis because they do not represent new construction activity.

Residential construction investment is estimated by multiplying the number of additional housing units supported by InnPower's investments by the average residential floor area per dwelling and the average construction cost per square foot. The full calculation and assumptions are found in Appendix C and are based on the following formula:

Residential investment = Number of housing units × Average floor area per unit × Average construction cost per square foot.

Nonresidential construction investment is estimated by multiplying the average number of jobs that are accommodated by a floor space factor per job to get an estimate of floor space. The floor space is then multiplier by construction costs per unit. The full calculation and assumptions are found in Appendix C and are based on the following formula:

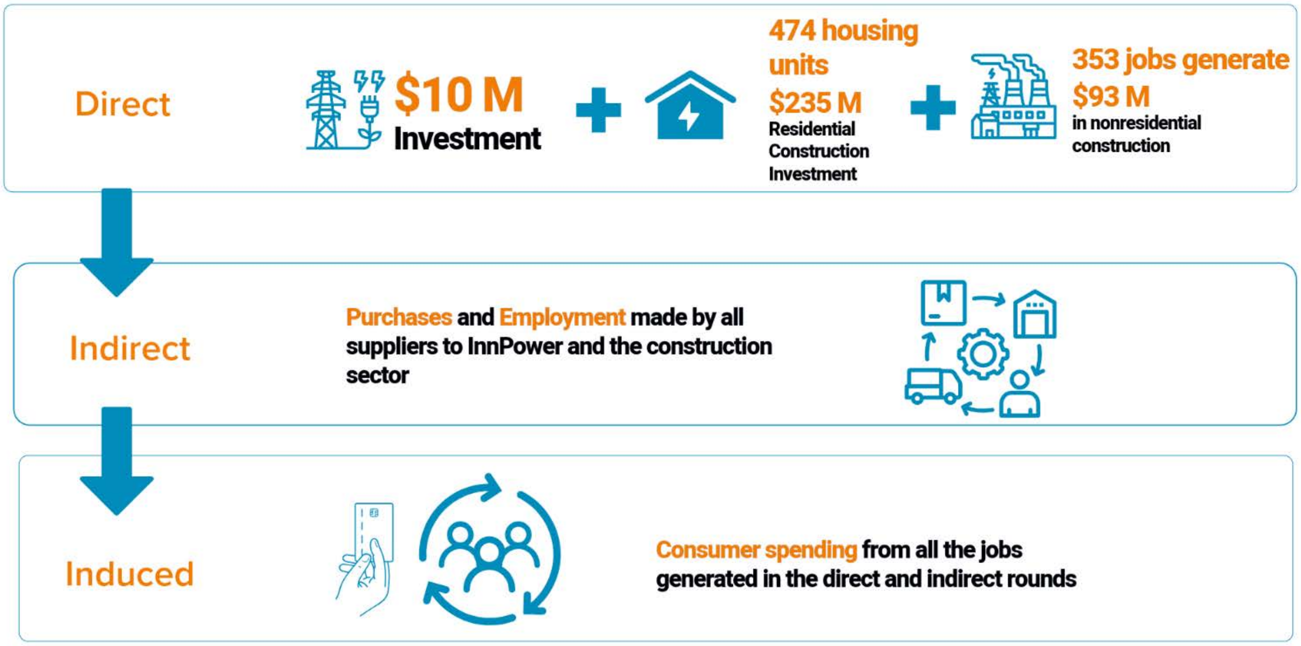
Non-residential investment = Number of jobs × Average non-residential floor area per job × Average construction cost per square foot.

There are three categories of economic impact associated with this one-time capital expenditure (Exhibit 1):

- **Direct impacts** represent the economic activity generated by the initial construction expenditures. In this analysis, direct impacts include InnPower's capital expenditures to construct electricity infrastructure, the residential construction required to accommodate new households, and the non-residential construction required to provide the floor space needed to support new employment.
- **Indirect impacts** measure the economic activity generated through supply chain purchases as directly affected industries procure goods and services from other businesses. These impacts capture the upstream production required to support the initial investments, including the activity generated by InnPower's suppliers and the suppliers of the construction sector throughout Ontario.
- **Induced impacts** measure the economic activity generated when workers employed through the direct and indirect activities spend their wages on goods and services throughout Ontario's economy.

These construction-related impacts occur only during the investment phase. Once construction is complete, the direct, indirect, and induced economic activity associated with these capital expenditures ceases. The completed infrastructure, however, continues to support households, businesses, and ongoing economic activity throughout their operating life.

Exhibit 1: One-Time Economic Benefits of Capital Expenditures



Spin-off Benefits of InnPower’s enabled growth – OnGoing economic benefits

While the construction impacts occur only during the investment phase, the households and businesses supported by InnPower's investments continue to generate ongoing economic activity after construction is complete through:

- Household spending by new residents; and
- The ongoing production of goods and services associated with business employment.

Household income provides an indication of the ongoing purchasing power introduced into the local economy as new residents locate within InnPower's service territory. Statistics Canada data indicate that the average household in the Barrie CMA earned $127,356 in 2024 (Figure 20). Adjusting for modest wage growth suggests that average household income reached approximately $130,441 in 2026. Across the 2021–2026 period, average household income is estimated at approximately $126,605.

Figure 20: Assumption, Total Household Income, 2021-2026E

		Annual Household Income, Barrie CMA $
2021		124,604
2022		123,791
2023		124,547
2024		127,356
2025	Adjusted for	128,889
2026	Inflation	130,441
2021-2026 Annual Average		126,605

$60,045,172 million in household incomes enabled by $10 million in gross investments
(= $126,605 average household income x 474 new households)

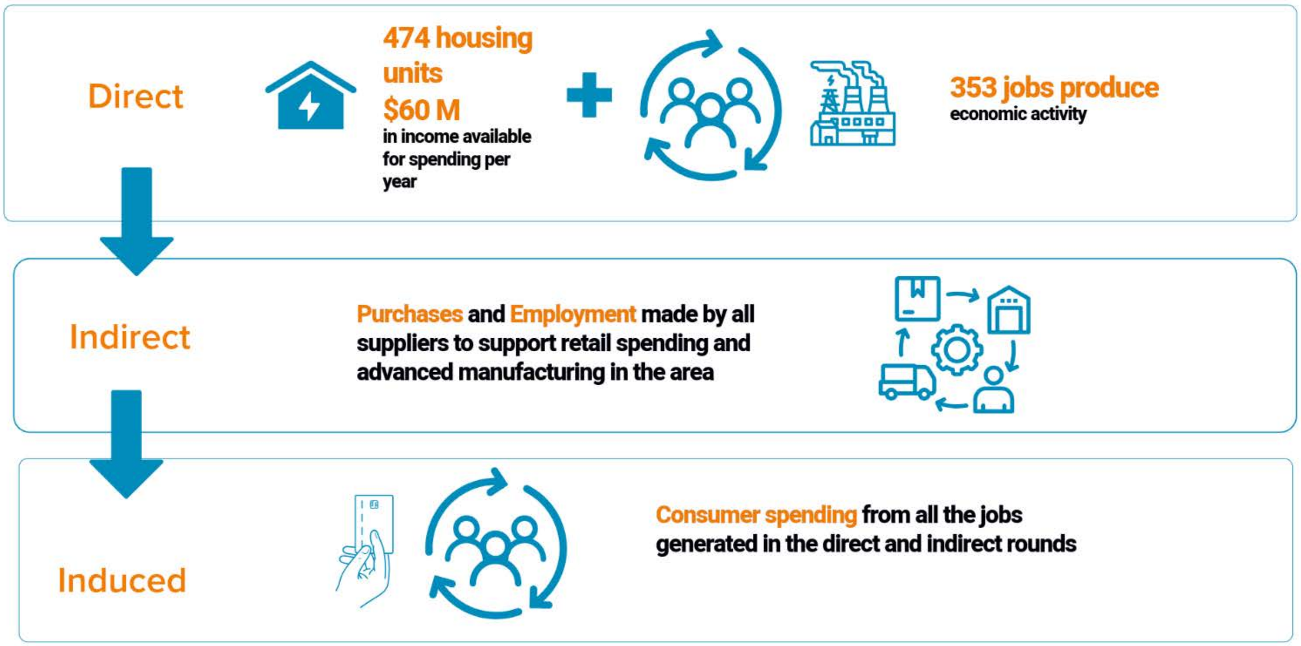
Source: Statistics Canada. Table 11 -10-0190-01 Market income, government transfers, total income, income tax and after -tax income by economic family type

Applying the average household income of $126,605 to the estimated 474 additional households indicates approximately $60 million in annual household income associated with every $10 million invested by InnPower. A significant proportion of this income is expected to be spent on goods and services, supporting local businesses and generating ongoing economic activity within the region.

Similarly, the estimated 353 jobs supported by each $10 million of InnPower investment generate ongoing economic output. Unlike the temporary employment associated with construction activity, these jobs continue to produce goods and services each year after construction is complete. They also generate ongoing labour income, business revenues, and tax revenues, which contribute to the long-term economic performance of InnPower's service territory and Ontario.

Similar to the one-time construction impacts, the ongoing economic impacts comprise direct, indirect, and induced effects. Unlike the temporary economic activity generated during the construction phase, however, these impacts persist over time, reflecting the continuing operation of businesses and the ongoing spending of households supported by InnPower's investments.

Exhibit 2: On-Going Economic Benefits



Statistics Canada’s Economic Impact Model

An economic impact assessment was undertaken to estimate the economic benefits associated with development activity supported by InnPower's investments within its service territory. The analysis considers both the one-time economic impacts associated with construction and development activity, and the ongoing economic impacts generated once residential, commercial, and industrial developments are occupied and operational.

The economic impacts were estimated using Statistics Canada's Input-Output (I-O) modelling framework. Statistics Canada is Canada's national statistical agency and the federal government's official source of economic, demographic, and social statistics. It develops and maintains the Interprovincial Input-Output Model, a nationally recognized economic accounting framework used to estimate the economic impacts of investments, projects, and public policies.

The Input-Output Model measures the relationships among industries, households, and governments within the Canadian economy. It estimates how an initial expenditure generates direct economic activity, supply-chain activity, and household spending effects as money circulates through the economy. The model is commonly used by governments, public agencies, utilities, and infrastructure providers to assess the economic effects of capital investments and development activity.

The model is based on Statistics Canada's Supply and Use Tables, which document the goods and services purchased and sold between industries. These relationships are used to estimate how an initial expenditure, such as construction spending on electricity infrastructure or new residential and non-residential buildings, creates additional economic activity as suppliers purchase inputs from other businesses and employees spend their earnings throughout the economy.

Statistics Canada develops industry-specific economic multipliers from the Input-Output model for each province and territory. These multipliers estimate the direct, indirect, and induced economic impacts associated with a given level of spending or production. The impacts reported in this analysis were estimated using the Ontario multipliers published in *Statistics Canada Table 36-10-0113-01* (summary multipliers) and *Table 36-10-0595-01* (detail multipliers).

Petramala Research provided Statistics Canada with the economic inputs for the analysis. Statistics Canada then produced the economic impact results using its standardized modelling framework. The results were returned on June 16, 2026. The direct files produced by Statistics Canada are included with this report as Attachment 1.

The economic impact model was based on the following assumptions developed by Petramala Research:

- $10 million in capital expenditures for electricity distribution infrastructure;
- Approximately $60 million in annual household income generated by new households; and
- 353 ongoing jobs supported within InnPower's service territory.

The model also incorporates the following assumptions based on Statistics Canada data:

- Approximately $60 million in annual household income generates roughly $54 million in annual household consumption expenditures; and
- 353 jobs generate approximately $64 million in annual economic output.

Statistics Canada's Input-Output multipliers estimate the economic impact associated with a dollar of output delivered to final demand, including final consumption expenditures, capital formation, and exports. The multipliers measure how spending on one product or service generates additional economic activity through purchases from suppliers and spending by workers supported by the initial activity.

Economic impacts are reported using standard indicators, including total economic output, gross domestic product (GDP), employment, labour income, business profits, and government revenues. Unless otherwise noted, all impacts are expressed as total economic activity occurring within Ontario and include direct, indirect, and induced effects.

Statistics Canada estimated the impacts associated with InnPower's capital expenditures, household spending, and ongoing employment. Petramala Research estimated the economic impacts associated with residential and non-residential construction investment using publicly available Statistics Canada multipliers. These estimates were prepared separately because the calculation involves applying published construction-sector multipliers to the estimated value of residential and non-residential development activity enabled by InnPower's investments.

The use of Statistics Canada's Interprovincial Input-Output Model strengthens the reliability of the analysis because the model is based on official Canadian economic accounts rather than proprietary assumptions or multipliers developed specifically for this study. While the economic inputs were developed by Petramala Research, the impact estimates generated by Statistics Canada were produced using a standardized modelling framework that is consistent with Canada's national economic accounts.

Like all Input-Output models, Statistics Canada's model assumes that industries purchase inputs using fixed production relationships and that sufficient labour and productive capacity exist to meet increases in demand. Consequently, the model estimates the gross economic activity associated with an investment and does not account for changes in prices, resource constraints, or the displacement of economic activity elsewhere in the economy.

The economic impact analysis was originally completed using InnPower's total capital expenditures over the 2021–2026 period, which included retrofit-related expenditures. The results were therefore adjusted to reflect a standardized scenario of $10 million in system access and expansion expenditures. Because the Input-Output Model is linear, the results can be scaled based on the ratio between the assumptions used in the original scenario and those used in the standardized $10 million scenario. The adjusted results are provided in Attachment 2.

Economic Impact Assessment Results – One-Time Economic Impact

The estimated one-time economic impacts are presented in Figures 21 and 22. While the results include the total direct, indirect, and induced impacts, the discussion below focuses primarily on the combined direct and indirect impacts. These impacts are more directly attributable to InnPower's capital investments because they reflect the economic activity generated through the initial expenditures and the associated supply chain. They are also estimated with greater certainty than induced impacts. Induced impacts are presented for completeness but should be interpreted with greater caution. They depend on assumptions regarding how households spend the labour income generated through the direct and indirect activities, including where, when, and on what goods and services that income is spent.

Figures 21 and 22 show that every **$10 million** invested by InnPower generates:

- **$238.8** million in Gross Domestic Product (GDP) in Ontario;
- The creation of **1,261** years of employment during the construction phase;
- **$120.4** million in wages and salaries for households, equivalent to an average income of **$95,437**;
- **$67.9** million in corporate profits (gross operating surplus), and **$23** million in government revenues broken down as:
    - o **$5.4** million for the federal government;
    - o **$8.0** million for the provincial government; and
    - o **$9.8** million for municipal governments.

Figure 21: One-Time Economic Impact of Construction Investment Activity, GDP and Employment, Ontario, 2026–2031

Thousands of Canadian dollars, unless otherwise stated

Shock Value: $ 337,967

	Direct	Indirect	Induced	Total	Direct and
Gross domestic product (GDP) at basic prices	157,181	81,591	57,858	296,630	238,772
Jobs	806	455	310	1,571	1,261

Statistics Canada, Tables 36-10-0113-01 (Input-output multipliers, provincial and territorial, summary level) and 36-10-0595-01 (Input-output multipliers, provincial and territorial, detail level); Statistics Canada custom model results received June 15, 2026

Figure 22: One-Time Economic Impact of Construction Investment Activity, Income Based, Ontario, 2026–2031
Thousands of Canadian dollars, unless otherwise stated

	Wages and Salaries	Wages and Salaries Per Job Created*	Gross operating surplus	Government Revenue			
				Federal	Provincial	Municipal	Total
Total	143,074	91,089	94,531	9,764	16,476	11,877	38,117
Direct and Indirect	120,353	95,437	67,926	5,369	8,022	9,772	23,163

Statistics Canada, Tables 36-10-0113-01 (Input-output multipliers, provincial and territorial, summary level) and 36-10-0595-01 (Input-output multipliers, provincial and territorial, detail level); Statistics Canada custom model results received June 15, 2026

The one-time benefits will last for the construction phase of the investments enabled, lasting for a 1-to-5-year period.

A breakdown of the economic impact analysis by capital expenditure type is available in Appendix D.

Economic Impact Assessment Results – OnGoing Economic Impact

The estimated ongoing economic impacts are presented in Figures 23 and 24.

Figures 22 and 23 show that every **$10 million** invested by InnPower generates approximately:

- **$85.4** million in new GDP each year in Ontario;
- The creation of **1,093** permanent jobs;
- **$42.6** million in wages and salaries for households, equivalent to an average income of **$57,565**;
- Roughly **$30.7** million in corporate profits (gross operating surplus), and **$10.8** million in government revenues, including:
    - o **$2.7** million for the federal government;
    - o **$4.9** million for the provincial government; and
    - o **$3.2** million for municipal governments.

A breakdown of the economic impact analysis by residential and employment growth is available in Appendix E.

Figure 23: OnGoing Economic Impact of Developing Residential and Employment Lands, GDP and Employment, Ontario, 2026–2031

Thousands of Canadian dollars, unless otherwise stated

Shock Value: $ 118,548

	Direct	Indirect	Induced	Total	Direct and
Gross domestic product (GDP) at basic prices	61,607	23,784	20,481	105,872	85,391
Jobs	888	205	158	1,251	1,093

Statistics Canada, Tables 36-10-0113-01 (Input-output multipliers, provincial and territorial, summary level) and 36-10-0595-01 (Input-output multipliers, provincial and territorial, detail level); Statistics Canada custom model results received June 15, 2026

Figure 24: OnGoing Economic Impact of Developing Residential and Employment Lands, Income Based, Ontario, 2026–2031, Ontario, 2026-2031

Thousands of Canadian dollars, unless otherwise stated

	Wages and Salaries	Wages and Salaries Per Job Created*	Gross Operating Surplus	Government Revenue Federal	Provincial	Municipal	Total
Total	50,623	56,351	40,133	4,162	7,395	4,546	16,102
Direct and Indirect	42,598	57,565	30,694	2,737	4,860	3,222	10,820

*Calculated as total wages and salaries/jobs

Statistics Canada, Tables 36-10-0113-01 (Input-output multipliers, provincial and territorial, summary level) and 36-10-0595-01 (Input-output multipliers, provincial and territorial, detail level); Statistics Canada custom model results received June 15, 2026

CONCLUSION

The economic evidence indicates that the slowdown in housing activity experienced between 2022 and 2025 represents a cyclical adjustment rather than a fundamental change in the long-term growth outlook for Innisfil and South Barrie.

Higher interest rates, temporary changes to federal immigration policy, and broader economic uncertainty reduced housing affordability and weakened new home sales across Ontario. These factors slowed the pace of housing absorption and occupancy, resulting in development occurring more gradually than anticipated.

Despite these short-term market conditions, the long-term growth outlook remains largely unchanged. Municipal growth forecasts and Official Plans continue to identify significant population and employment growth within Innisfil and South Barrie. Provincial housing policies continue to support residential development, while municipalities have increasingly emphasized employment land development, industrial investment, and economic diversification as key components of future economic growth.

Taken together, the evidence suggests that recent market conditions have primarily affected the timing of development rather than the ultimate scale of growth expected within InnPower's service territory.

As housing market conditions normalize and employment growth continues, Innisfil and South Barrie remain well positioned to accommodate substantial population growth, employment expansion, residential and non-residential development, and continued economic activity over the coming decades.

Consequently, InnPower's planned investments in electricity distribution infrastructure are expected to provide benefits that extend well beyond the utility's core operations. By enabling future residential and employment growth, these investments will support significant one-time construction activity, ongoing business activity, employment, household income, and government revenues throughout InnPower's service territory and across Ontario.

Appendix

Appendix A: Diana Petramala CV

DIANA PETRAMALA, MABE, PLE

Economic Consultant | *Land Economist*

[redacted] | [redacted] | [redacted] | www.dpeconomics.ca

EXECUTIVE PROFILE

Senior housing and urban economist with more than 17 years of experience delivering applied economic, real estate, land-use planning, and public policy research across consulting, financial services, academia, and government-related projects. Recognized for translating complex economic analysis into actionable insights for municipalities, developers, utilities, institutional clients, and industry associations. Expertise includes economic impact analysis, fiscal impact modelling, housing needs assessments, demographic forecasting, development economics, municipal finance, labour market analysis, and strategic policy advisory.

AREAS OF EXPERTISE

Economic Impact & Fiscal Impact Analysis	Housing Market & Land Economics
Municipal Finance & Development Charges	Macroeconomic Forecasting & Scenario Analysis
Demographic & Labour Market Analysis	Land Needs & Growth Management Studies
Public Policy & Strategic Advisory	Stakeholder Engagement & Public Communications
Thought Leadership & Research Strategy	Expert Witness & Peer Review Support

PROFESSIONAL EXPERIENCE

Petramala Research Inc. | Founder & President, Lead Economist | 2025 – Present
Develop customized economic models and strategic research programs to support planning approvals, policy advocacy, and infrastructure investment decisions, with a focus on land economics.

Altus Group | Director, Economic Consulting | 2022 – 2024
Led multidisciplinary consulting teams delivering housing, land economics, and public policy research across Canada, involving demographic forecasting, housing need analysis, development economics, infrastructure planning, and municipal finance.

Centre for Urban Research & Land Development, Toronto Metropolitan University | Senior Economist | 2017 – 2022
Produced influential housing and urban policy research focused on affordability, land-use planning, demographic trends, and housing supply.

TD Bank Group | Canadian Macro & Real Estate Economist | 2008 – 2017

Led and developed the banks real estate economic models and produced special topic research reports on household debt, housing and real estate related topics.

SELECTED CONSULTING & RESEARCH ENGAGEMENTS

- Cemetery Land Needs Analysis and OLT expert witness work, Town of Bradford West Gwillimbury.
- Impact of AI on the Chatham-Kent Workforce, Chatham-Kent.
- Municipal Benchmarking Study (BILD & CHBA) – benchmarked municipalities across Canada on housing supply, development charges, and development approvals.
- Economic Impact of Lansdowne 2.0 Redevelopment (Ottawa Sports & Entertainment Group) – evaluated economic and housing market impacts of a major urban redevelopment project.
- Housing Needs Assessment (City of Windsor) – demographic and housing forecasting to support CMHC Housing Accelerator Fund application.
- Economic Impact of a Parking Levy in Toronto (REALPAC, BOMA, Downtown Toronto BIA) – assessed implications of parking taxation on investment and economic activity.
- Health & Wellness Village Land Needs Analysis (Collingwood) – economic and land-use analysis supporting investment and development approvals.
- Economic Obsolescence Research for Big Box Store Assessment Appeals (City of Toronto).
- Annual Canadian Macroeconomic Outlook & Real Estate Investment Trends presentations for private-sector clients.

SELECTED PUBLICATIONS & THOUGHT LEADERSHIP

- A Strategy for Significantly Increasing the Supply of Missing-Middle Housing in the City of Toronto (2019)
- How Land-Use is Fueling the Workplace Gender Gap in the Golden Horseshoe (2019)
- Millennials, A Generation Stuck in Apartments? (2018)
- Canadian and U.S. Millennials: One of These is Not Like the Other (2015)
- GTA Housing Boom Masks Growing Structural Challenges (2015)
- Tighter Mortgage Rules to Cool Debt Growth, but Higher Rates Ultimately Required (2012)

EDUCATION & PROFESSIONAL AFFILIATIONS

Master of Business Economics (MABE), Wilfrid Laurier University
Bachelor of Arts, Honours Economics & Financial Management, Wilfrid Laurier University
Professional Land Economist (PLE), Ontario Association of Land Economists

TEACHING & PROFESSIONAL LEADERSHIP

- Instructor, Housing Economics & Policy – Toronto Metropolitan University
- Research Advisor – Centre for Urban Research & Land Development
- Board Member – Toronto Association of Business Economics
- Director – WomEconomics Organization

Appendix B: Acknowledgement of Expert Witness Duty

FORM A

Proceeding: InnPower Corporation Cost of Service 2026 Application

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Diana Petramala. I live at [redacted].

2. I have been engaged by or on behalf of InnPower Corporation to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
(a) to provide opinion evidence that is fair, objective and non-partisan;

(b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

(c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date June 22, 2026

DPetramala

Signature

Appendix C: Calculation of Investment Expenditures

Assumptions for the estimate of construction investment relied on the following:

- Altus Group's 2026 Construction Cost Guide for cost of construction per square foot. Costs in the Barrie CMA were proxied by costs reported for the GTA.
- Statistics Canada National Housing Statistics Program data on average size of a home in the Barrie CMA.
- Jobs per square feet of non-residential space were taken from the Barie Development Charge Background Study.

Table A-C 1: Estimate of Residental Construction Spending Generated for every 482 homes Construction

Geography		
CMA	Barrie	
Province	Ontario	
	Formula	Calculation
Households		474
Construction Costs/Square Ft.		
Max		410
Min		150
Average Construction Cost/Square ft.		280
Average Size of a home		1,772
Total Residential Square Ft. Constructed	Avrg. Size x Number of homes	840,447
Total Residential Investment, $	Total sq. ft. constructed x average cost per sq. ft.	**235,325,238**

Source: Statistics Canada. Table 46-10-0093-01 Residential properties by characteristics, property use and ownership type, Altus Group 2026 Cost Guide

Table A-C 2: Estimate of Non-Residental Construction Spending Generated for every 482 homes Construction

Geography		
CMA	Barrie	
Province	Ontario	
	Formula	Calculation
Jobs		353
Jobs/Sq ft. of non-Residential Space		828.7
Total Non-Residential Square Ft. Constructed	jobs x sq. ft. per job*	292,418
Average Construction Cost/Square ft.	(blended rate of commercial and industrial)	317
Total Non-Residential Investment, $	Total sq. ft. constructed x average cost per sq. ft.	**92,641,458**

Source: Barrie DC Background Study, Altus 2026 Cost Guide

Appendix D: Detailed Breakdown of One-Time Economic Benefits

A-D1: One-Time Economic Impact of $10 million in Gross Capital Expenditure on Energy Infrastructure, GDP and Employment, Ontario, 2026-2031

Thousands of Canadian dollars, unless otherwise stated

Shock Value: $ 10,000

	Direct	Indirect	Induced	Total	Direct and Indirect
Gross domestic product (GDP) at basic prices	4,080	1,788	1,343	7,210	5,868
Jobs	17	14	10	42	31

A-D2:One-Time Economic Impact of Residential Construction Activity,GDP and Employment, Ontario, 2026-2031

Thousands of Canadian dollars, unless otherwise stated

Shock Value: $ 235,325

	Direct	Indirect	Induced	Total	Direct and Indirect
Gross domestic product (GDP) at basic prices	106,132	58,125	38,358	202,615	164,257
Jobs	539	310	194	1,043	850

A-D3: One-Time Economic Impact of Non-Residential Construction Activity,GDP and Employment, Ontario 2026-

Thousands of Canadian dollars, unless otherwise stated

Shock Value: $ 92,641

	Direct	Indirect	Induced	Total	Direct and Indirect
Gross domestic product (GDP) at basic prices	46,969	21,678	18,158	86,805	68,647
Jobs	249	131	106	486	380

Source: Statistics Canada. Table 36-10-0113-01 Input-output multipliers, provincial and territorial, summary level and Table 36-10-0595-01 Input-output multipliers, provincial and territorial, detail level, Statistics Model Results received June 15, 2026.

A-D4: One-Time Economic Impact of Gross Capital Expenditure, Income Based, Ontario, 2026–2031

Thousands of Canadian dollars, unless otherwise stated

	Wages and Salaries	Wages and Salaries Per Job Created*	Gross operating surplus	Government Revenue: Federal	Government Revenue: Provincial	Government Revenue: Municipal	Government Revenue: Total
Total	3,307	79,592	3,229	137	232	167	536
Direct and Indirect	2,780	89,208	2,611	44	66	81	191

A-D5: One-Time Economic Impact of Construction Investment Activity, Income Based, Ontario, 2026–2031

Thousands of Canadian dollars, unless otherwise stated

	Wages and Salaries	Wages and Salaries Per Job Created*	Gross operating surplus	Government Revenue: Federal	Government Revenue: Provincial	Government Revenue: Municipal	Government Revenue: Total
Total	94,836	90,909	64,714	6,992	11,800	8,506	27,298
Direct and Indirect	79,775	93,907	47,065	4,036	6,031	7,347	17,414

A-D6: One-Time Economic Impact of Construction Investment Activity, Income Based, Ontario, 2026–2031

Thousands of Canadian dollars, unless otherwise stated

	Wages and Salaries	Wages and Salaries Per Job Created*	Gross operating surplus	Government Revenue: Federal	Government Revenue: Provincial	Government Revenue: Municipal	Government Revenue: Total
Total	44,931	92,459	26,588	2,634	4,445	3,204	10,283
Direct and Indirect	37,798	99,365	18,250	1,288	1,925	2,345	5,558

Statistics Canada, Tables 36-10-0113-01 (Input-output multipliers, provincial and territorial, summary level) and 36-10-0595-01 (Input-output multipliers, provincial and territorial, detail level); Statistics Canada custom model results received June 15, 2026

Appendix E: Detailed Breakdown of OnGoing Economic Benefits

A-E1: OnGoing Economic Impact of Developing Residential , GDP and Employment, Ontario, 2026–2031

Thousands of Canadian dollars, unless otherwise stated

Shock Value: $ 54,270

	Direct	Indirect	Induced	Total	Direct and Indirect
Gross domestic product (GDP) at basic prices	23,187	8,876	6,181	38,245	32,064
Jobs	182	71	48	301	254

A-E2: OnGoing Economic Impact of Developing Employment Lands, GDP and Employment, Ontario, 2026–2031

Thousands of Canadian dollars, unless otherwise stated

Shock Value: $ 64,278

	Direct	Indirect	Induced	Total	Direct and Indirect
Gross domestic product (GDP) at basic prices	38,420	14,907	14,299	67,627	53,327
Jobs	706	133	111	950	839

Source: Statistics Canada. Table 36-10-0113-01 Input-output multipliers, provincial and territorial, summary level and Table 36-10-0595-01 Input-output multipliers, provincial and territorial, detail level, Statistics Model Results received June 15, 2026.

A-E3: OnGoing Economic Impact of Developing Residential Land, Income Based, Ontario, 2026–2031, Ontario, 2026-2031

Thousands of Canadian dollars, unless otherwise stated

				Government Revenue			
	Wages and Salaries	Wages and Salaries Per Job Created*	Gross Operating Surplus	Federal	Provincial	Municipal	Total
Total	15,175	50,337	17,468	2,637	4,697	2,448	9,783
Direct and Indirect	12,748	50,254	14,623	2,210	3,936	2,051	8,197

A-E4: OnGoing Economic Impact of Developing Employment Lands, Income Based, Ontario, 2026–2031, Ontario, 2026-2031

Thousands of Canadian dollars, unless otherwise stated

				Government Revenue			
	Wages and Salaries	Wages and Salaries Per Job Created*	Gross Operating Surplus	Federal	Provincial	Municipal	Total
Total	35,448	59,388	22,665	1,524	2,698	2,097	6,319
Direct and Indirect	29,850	61,379	16,072	527	924	1,172	2,623

*Calculated as total wages and salaries/jobs

Statistics Canada, Tables 36-10-0113-01 (Input-output multipliers, provincial and territorial, summary level) and 36-10-0595-01 (Input-output multipliers, provincial and territorial, detail level); Statistics Canada custom model results received June 15, 2026

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Appendix 7: InnPower 2027 – 2031 Business Plan

2027-2031 InnPower Business Plan

InnPower Corporation

Contents

Executive Summary

InnPower’s five-year business plan is focused on strengthening reliability, enabling growth, and building a high-performing organization that delivers value to its customers and communities.

At its foundation, the plan prioritizes service excellence and system reliability through investments in automation, grid modernization, and infrastructure upgrades. These efforts are complemented by a commitment to health, safety, and emergency preparedness. A primary goal is ensuring the organization is better equipped to respond proactively to major events, emerging directives and evolving operational risks.

To support growth, InnPower will focus on enterprise resiliency, including the development of a comprehensive people strategy, enhanced knowledge management practices, and strengthened cybersecurity capabilities. Addressing workforce capacity, leadership development, and institutional knowledge gaps will be critical to maintaining operational effectiveness in a high-growth environment.

The organization will advance operational optimization by expanding the use of artificial intelligence, modernizing enterprise systems, and establishing a project management and process improvement function. These initiatives are intended to improve efficiency, reduce costs, and enhance service delivery across all departments.

InnPower will enhance capital planning, explore innovative funding mechanisms, and advocate for regulatory solutions that support growth while balancing customer affordability. Overall, maintaining financial sustainability remains a key priority.

Recognizing that our people are fundamental to success, the business plan emphasizes employee development and engagement through increased training, improved communication, and a more robust, performance-driven culture aligned with corporate objectives. Our investment in our people is a key priority.

From a customer perspective, InnPower will continue to elevate the customer experience through technology-enabled solutions, improved responsiveness, and stronger engagement with communities and stakeholders. This includes investments in customer service platforms, communications, and conservation and sustainability programs.

The business plan also focuses on strengthening stakeholder relationships and community support, including the development of a key account function, enhanced partnerships, and exploration of new support models to address economic challenges faced by customers.

Finally, the business plan reinforces a disciplined approach to infrastructure management and system performance, leveraging data, advanced analytics, and new operational capabilities to optimize asset life, improve decision-making, and enhance storm response.

Collectively, these business priorities position InnPower to navigate industry transformation, support continued growth, and deliver safe, reliable, and innovative services to the communities it serves.

Investing in our People & our Communities

InnPower plans to focus on investing in its people and its communities, highlighted through eight business areas of focus. These priorities, which are highlighted below, are integral to an effectively managed utility.

Service Quality, Reliability & Safety

Reduce outage frequency and duration across the service territory.

Over the next five years, a key priority for InnPower will be to further improve system reliability across its service territory. In recent years, the utility has made meaningful progress through preventative maintenance, vegetation management, and targeted technological upgrades. Building on this foundation, InnPower will continue investing in system automation to reduce downtime and improve its System Average Interruption Duration Index (SAIDI). This includes advancing self-healing network capabilities to accelerate restoration and reduce the need for field deployment where possible. InnPower also plans to launch a major voltage conversion program in the Big Bay Point area to strengthen reliability and create greater system redundancy during sustained outages.

Further strengthen health and safety across the organization.

Over the past five years, InnPower established a dedicated Health, Safety and Environment department that has played a transformational role in strengthening the organization’s safety culture. Its efforts have contributed to WSIB improvements and success in provincial health and safety excellence programs. Over the next five years, InnPower will continue to build on this momentum by advancing standard operating procedures, strengthening contractor management, and implementing increasingly proactive measures to support both physical safety and workplace mental health.

Enhance emergency preparedness and stakeholder communications.

The unprecedented 2025 ice storm, which left many communities across Ontario without power, highlighted important lessons for InnPower's emergency response processes. In addition to significant damage to the distribution system, stations, supply feeders, and telecommunications infrastructure were also impacted, forcing the organization into a reactive, paper-based operating environment during

restoration. Since then, InnPower has made meaningful progress in strengthening its emergency preparedness and business continuity planning. Over the next five years, the organization will continue transitioning from a reactive to a proactive emergency management model through investments in technology, such as mass emergency notification software, additional human and operational resources, stronger communications processes and teams, improved customer relations and key account functions, and enhanced cross-stakeholder collaboration.

Enterprise Resiliency

Develop a people strategy to identify and address organizational gaps.

As a high-growth organization, InnPower recognizes that its people are central to its success. Many staff continue to work significant overtime, affecting work-life balance and mental health. At the same time, qualified talent remains in short supply, placing pressure on teams and resulting in some senior employees operating below their intended level of responsibility. While manageable in the short term, this creates leadership and mentorship gaps and reduces the time available for coaching and performance management. Over the next five years, InnPower will focus on developing a clear workforce roadmap to address staffing needs, funding requirements, workplace mental health, and the creation of dedicated capacity for enterprise risk and corporate strategy. This work will ensure that human resources are deployed ‘businessally’ in alignment with evolving processes and technologies.

Improve knowledge transfer and change management across the organization.

A significant challenge across the organization is the lack of standardized operating procedures and formal change management practices. As InnPower has grown, staff have appropriately focused on delivering work, but this has often come at the expense of documenting procedures, decisions, and institutional knowledge. As a result, the organization is more vulnerable when experienced staff leave or when major events occur. Over the next five years, InnPower will invest in process mapping, process optimization, records management, and documentation. This includes developing a knowledge-based SOP platform and leveraging artificial intelligence to provide real-time access to policies, processes, and procedures. These efforts will improve consistency, strengthen change management, reduce enterprise risk, and enhance customer service through better first-contact resolution.

Address emerging cybersecurity threats.

Cybersecurity remains one of the most significant enterprise risks facing utilities across the country. In recent years, InnPower and its affiliates have made substantial improvements to their IT and cybersecurity programs. However, as threat actors continue to evolve, the organization must continue to strengthen its defenses. Over the next five years, InnPower will advance cybersecurity initiatives in several areas, including the development of zero-trust environments, broader assessments of operational technology (OT) systems, and the segregation of critical IT and OT networks.

Operational Optimization

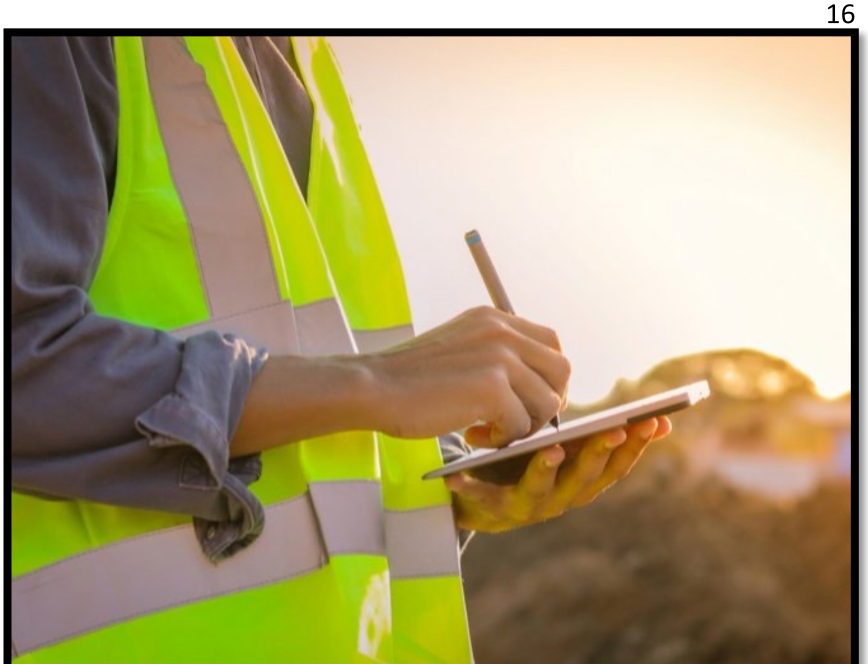
Integrate artificial intelligence across the organization to improve efficiency.

Over the past two years, InnPower has emerged as an industry leader in deploying artificial intelligence tools and has shared its experience through presentations across North America. As the organization continues to scale in response to growth, AI presents significant opportunities to improve productivity and service delivery.

Over the next five years, InnPower will implement a comprehensive enterprise AI strategy, deploying AI tools across departments and cross-functional processes. One key initiative is the introduction of a co-pilot model within customer service, which will support representatives through dynamic scripting, retrieval of records across multiple systems, access to mapping and street-view tools, and ticket generation where appropriate. This will help deliver a more consistent, responsive, and high-quality customer experience.

Establish a team focused on project management and process improvement.

Given the volume of projects underway across the organization, along with the growing importance of enterprise risk management, InnPower has begun mapping several existing and future-state processes. Early findings suggest there are substantial opportunities to improve efficiency and reduce both time and cost. Over the next five years, InnPower plans to establish a small project management office (PMO) to support enterprise-wide project delivery, particularly for IT initiatives, while also advancing process mapping, business optimization, documentation, records management, and internal controls to reduce human error.



Modernize enterprise resource planning and workforce management.

InnPower currently relies on several different software systems to manage resources across the organization. Some of these systems are reaching end-of-life and are increasingly difficult to maintain. In the field, crews often rely on multiple devices to complete their work. Over the next five years, InnPower will carefully transition toward more integrated enterprise-wide software solutions that are easier to administer, more scalable, and better suited to high-growth environments. The organization will also continue to deploy remote automation and protection and control solutions in the field to further improve reliability, reduce truck rolls, and enhance worker safety.

Financial Viability

Improve capital efficiency through stronger financial controls and planning.

InnPower continues to manage its cash flows responsibly and refine its long-term financial planning in a high-growth environment. However, rising costs and a temporary slowdown in new connections have introduced uncertainty around both revenues and expenses. Over the next five years, InnPower will develop tools and processes to improve capital efficiency, including tighter alignment between capital deployment and revenue recognition. Discretionary capital will be prioritized based on development connection timelines, and the utility will continue working with the development community on financing arrangements.

Strengthen growth funding while balancing profitability and affordability.

Over the next five years, InnPower will enhance its long-term financial plan by exploring new financial instruments and regulatory solutions that support growth management while minimizing the risk of customer rate spikes. The organization will continue advocating for regulatory mechanisms that better recognize growth pressures, while also exploring the new Capacity Allocation Model (CAM) and its potential role in supporting growth across the service territory while mitigating customer impacts.

Employee Development & Engagement

Improve organizational engagement and communication.

Over the next five years, InnPower plans to add resources that will strengthen employee engagement and both internal and external communications. These efforts are expected to support mental health and wellness, improve alignment across teams, and foster stronger interdepartmental collaboration and productivity.

Increase training and development opportunities for staff.

InnPower's skilled and knowledgeable staff are essential to delivering safe, reliable, and high-quality services to the communities it serves. Investing in people will remain a top priority. Over the next five years, the organization will increase its investment in employee training and development through both on-the-job learning and structured professional development opportunities.

Strengthen performance management and accountability.

Closely linked to staff development is the need for a stronger performance management framework aligned with the corporate business plan. Over the next five years, InnPower will further develop a goal-based performance management program that emphasizes accountability, supports organizational priorities, and includes appropriate incentive mechanisms.

Customer Satisfaction & Engagement

Strengthen customer experience through technology and process improvements.

Enhancing customer experience is one of the most important priorities of this business plan. InnPower must continue to demonstrate the value it provides to the communities it serves. Over the next five years, the organization will transform the customer experience through artificial intelligence and other tools that support timely, accurate, and consistent first-contact resolution. InnPower will also develop a ticket-based system for tracking customer inquiries, explore enhancements to its customer information system and workforce management platforms, and increase customer touchpoints through tools such as omnichannel chat capabilities.

Strengthen community and stakeholder engagement capacity.

InnPower plans to further strengthen its community and stakeholder engagement capabilities through the addition of new resources. These investments, combined with an enhanced public relations strategy, will help build the InnPower brand and improve corporate communications, stakeholder engagement, and government relations.

Advance conservation and environmental sustainability initiatives.

Building on the previous business plan, energy conservation and environmental sustainability remain key priorities for InnPower, particularly as the broader energy transition continues across the province. Over the next five years, the organization will continue expanding its carbon tracking and ESG programs, while also exploring initiatives through eDSM programs to help customers achieve their energy conservation and transition objectives.

Stakeholder Understanding & Support

Establish a key account function for major stakeholders.

As part of broader stakeholder engagement improvements, InnPower plans to establish a dedicated key account function to serve as a single point of contact for major stakeholders such as large customers, associations, and industry groups. This function will support stronger stakeholder relationships, business development, and long-term growth strategies.

Explore alternative community support models.

Given ongoing economic uncertainty and the pressures facing many households and businesses, InnPower recognizes the importance of evaluating additional ways to support its communities. In addition to existing programs such as LEAP, this business plan prioritizes the exploration of new support models, including potential financial assistance and arrears support initiatives.

Strengthen collaboration with other LDCs and associations.

To unlock further productivity gains and maximize available resources, InnPower plans to deepen collaborative partnerships with other local distribution companies and industry associations. These partnerships support knowledge sharing, access to innovative solutions, cross-training opportunities, and mutual support during high-stress events such as major storms.

Infrastructure Strategy & Performance

Optimize asset efficiency and longevity.

Value for money is a guiding principle for InnPower’s investments. Ensuring that the utility assets are maintained, optimized, and replaced businessally is therefore a key focus of this plan. Over the next five years, InnPower will implement solutions to improve asset efficiency and longevity, including the use of AI and LiDAR to validate asset and data integrity, the development of stronger asset management processes, and continued optimization of maintenance programs.

Improve operational decision-making through business intelligence.

InnPower plans to increase investment in operational business intelligence tools, including GIS, AI, Prophix, and related platforms, to support better decision-making across the organization. These tools will inform investment choices, including decisions related to asset replacement versus rehabilitation, and support more effective operational planning.

Strengthen network operations and storm response.

As InnPower continues to grow and expand its network, the need for a stronger network operations function will also grow. Over the next five years, the organization plans to establish a control room function to oversee day-to-day power system operations and significantly enhance storm response capabilities. This function will also help position the organization for future distribution system operator capabilities related to distributed energy resource management. In addition, InnPower plans to leverage its AI investments to support storm hardening and prepare for advanced metering infrastructure (AMI) 2.0.

Appendix 8: Certification of Evidence

innpower
Community-owned since 1993

INNPOWER CORPORATION
7251 Yonge St., Innisfil, ON, L9S 0J3
Tel: 705-431-4321
Fax: 705-431-6872

July 20, 2026

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

Attention: Board Secretary

Re: InnPower Corporation – Cost of Service Rate Application

Dear Board Secretary,

On behalf of the Board of Directors of InnPower Corporation (the “Board”), I am writing to confirm that the Board is aware of InnPower Corporation’s Cost of Service rate application to the Ontario Energy Board for electricity distribution rates effective January 1, 2027 and has approved InnPower’s submission of this application.

This letter is provided to meet the Ontario Energy Board’s filing requirement for a letter from the governing body certifying that it is aware of and approves the submission of the application

Yours truly,

Paul Harricks
Chair, Board of Directors
InnPower Corporation

CERTIFICATION OF EVIDENCE

TO: ONTARIO ENERGY BOARD

The undersigned, Wayde Putnam, being InnPower Corporation, Chief Financial Officer, hereby certifies that:

1. this certificate is given pursuant to Chapter 2 and Chapter 5 of the Ontario Energy Board's *Filing Requirements for Electricity Distribution Cost of Service Rate Applications - 2026 Edition for 2027 Rate Applications* (last revised on December 16, 2025); and

2. the evidence filed in support of InnPower Corporation’s 2027 Cost of Service application filed with the Ontario Energy Board is accurate, consistent and complete to the best of my knowledge; and

3. InnPower Corporation has processes and internal controls in place for the preparation, review, verification and oversight of account balances being disposed; and

4. the application and any evidence filed in support of InnPower’s 2027 Cost of Service application filed with the Ontario Energy Board does not include any personal information unless it is filed in accordance with Rule 9A of the Ontario Energy Board's Rules (and Practice Direction, as applicable).

DATED this 27°1 day of July 2026.

Wayde Putnam

Wayde Putnam
Chief Financial Officer
waydep@innpower.ca