CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

EXHIBIT 1:
ADMINISTRATIVE DOCUMENTS

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LIST OF ATTACHMENTS

Attachment 1-A:	Customer Summary
Attachment 1-B:	CNPI Business Plan (with Appendices)
Attachment 1-C:	Completed 2027 checklist
Attachment 1-D:	Executive and Board Certifications/Confirmations
Attachment 1-E:	PDF and Excel Copy of Current (2026) Tariff
Attachment 1-F:	2025 Audited Financial Statements
Attachment 1-G:	Reconciliation – AFS to RRR
Attachment 1-H:	Copy of Distribution License
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1.0 INTRODUCTION

Canadian Niagara Power Inc. ("CNPI" or the "Applicant") is pleased to present its cost of service application (the "Application") for rates effective January 1, 2027. This Application consists of the following Exhibits, and live Excel models in support of the evidence presented in this Application.

A table of contents outlining the main sections and subsections presented in each Exhibit is included as Attachment 1-I.

Exhibits:

- Exhibit 1: Administrative Documents
- Exhibit 2: Rate Base and DSP
- Exhibit 3: Revenues
- Exhibit 4: Operating Expenses
- Exhibit 5: Cost of Capital and Capital Structure
- Exhibit 6: Revenue Requirement
- Exhibit 7: Cost Allocation
- Exhibit 8: Rate Design
- Exhibit 9: Deferral and Variance Accounts

Models:

- CNPI 2027 Benchmarking Forecast Model
- CNPI 2027 Cost Allocation
- CNPI 2027 PILs Workform
- CNPI 2027 Revenue Requirement Workform
- CNPI 2027 RTSR Workform
- CNPI 2027 Load Forecast Model
- CNPI 2027 COS Checklist
- CNPI 2027 DVA Continuity Schedule
- CNPI 2027 GA Analysis Workform
- CNPI 2027 1595 Workform
- CNPI 2027 Chapter 2 Appendices -excluding Appendix 2-C
- CNPI 2027 Depreciation Schedules (Appendix 2-C filed stand-alone from Ch 2 Appendices)
- CNPI 2027 Tariff Schedule and Bill Impact Model
- CNPI 2027 Tariff (Generated from OEB Model)

All documents and models have been submitted to the Ontario Energy Board (the "OEB" or the "Board") via the RESS filing system.

The application along with all supporting evidence will also be posted on CNPI's website, at the latest when CNPI is directed to do so by the OEB.

1.1 EXECUTIVE SUMMARY AND BUSINESS PLAN

CNPI has developed a Business Plan, included as Attachment 1-B, to address the expectations of the OEB's *Handbook for Utility Rate Applications*, issued October 13, 2016 as further refined in section 2.1.2 of the *Filing Requirements*.

Key elements of the Application and Business Plan are:

1. Identification of the following strategic objectives that drive capital and O&M plans and related investments over the 2027-2031 period:

   With a commitment to continued public and worker safety, environmental stewardship, cybersecurity and cost efficiency:

   - Invest to improve reliability compared to historic levels, including considering opportunities for improved system resilience against climate vulnerabilities.
   - Invest to meet growing customer base and increasing load in areas of the system.
   - Leverage opportunities for improving system resilience against extreme weather, as a consideration in projects that are driven by other factors.
   - Maintain strong **customer experience** performance**,** through investments in key **software systems**. Pursue initiatives to enhance the customer experience.
   - Continue and enhance CNPI's risk-based approach to replacement of aging assets.
   - Leverage technology to improve the management and visibility of distributed assets.
   - Promote employee engagement to support a safe, productive workplace.

2. A Distribution System Plan ("DSP") with projects and programs aligned with the applicable strategic objectives listed above;

3. CNPI's goals for the 2027-2031 period are to implement its planned projects and programs that are aligned with the objectives identified above, and to meet or exceed all targets for performance metrics identified in the DSP and the Business Plan;

4. Enhanced customer engagement to ensure that the preferences of CNPI's customers were identified and customers' input was considered in determining the DSP projects;

5. Evaluation and forecasting of performance metrics that are consistent with the OEB's Renewed Regulatory Framework ("RRF"); and

6. A 2027 Cost Allocation Study and proposed Rate Design that is consistent with OEB policy and CNPI's approach in its prior application, with updates to reflect rate design commitments made in the last application.

1.2 APPLICATION SUMMARY

The table below summarizes the main elements of the Application for which CNPI is seeking OEB approval, with additional detail provided in Sections 1.3.4 and 1.2.

Table 1- 1: Application Summary

	2027 Test Year	Exhibit
Revenue Requirement Component		
OM&A Expenses (Incl LEAP)	$12,383,274	4
Amortization/Depreciation	$6,819,285	2.2
Property Taxes	$143,019	6.5
Income Taxes (Grossed Up)	$484,384	6.4
Regulated Return on Rate Base:		
Deemed Interest	$4,337,837	5
Return on Deemed Equity	$6,195,653	
Service Revenue Requirement	**$30,363,451**	6.2
Revenue Offsets	-$1,349,599	6.7
Base Revenue Requirement (Excl Transformer Ownership Allowance)	**$29,013,852**	6.2
TOTAL Customer (Excl SL, Sent, USL)	31,576	3.1
TOTAL SL, Sent Connections	6,894	
Total kWh Deliveries	493,220,667	3.1
Total Billed kW (for demand-billed classes)	582,273	
Standby kW (not included above)	78,288	
Test Year Fixed Rates		
Residential	$ 52.45	8.1
GS < 50	$ 40.24	
GS 50 to 4,999 kW	$ 194.73	
Embedded Distributor	$ 700.69	
Street Light	$ 5.13	
Sentinel Light	$ 7.01	
USL	$ 61.23	
Test Year Variable Rates		
Residential	$ -	8.1
GS < 50	$ 0.0376	
GS 50 to 4,999 kW	$ 9.4448	
Embedded Distributor	$ 12.0496	
Street Light	$ 10.2320	
Sentinel Light	$ 14.3182	
USL	$ 0.0411	
Standby Rate	$ 9.4448	

1.2.1 REVENUE REQUIREMENT

CNPI's proposed Service Revenue Requirement of $30,363,451 for the 2027 Test Year reflects an increase of $7,178,476 or 31.3% relative to 2022 Board Approved. This is a compound annual growth rate of 5.5%. CNPI's proposed Base Revenue Requirement is $ 29,013,852 reflecting other revenue offsets of $1,349,599.

Applying CNPI's 2026 approved rates to its 2027 forecast of load, demand and customer counts produces a forecasted distribution "revenue at existing rates" of $25,514,253 resulting in a net revenue deficiency of $3,499,599. CNPI is applying for 2027 rates to eliminate this deficiency and recover its forecasted revenue requirement. The table below shows the trend in the calculation of CNPI's revenue requirement from 2022 Board Approved to the 2027 Test Year amount forecasted in this Application.

Table 1- 2: 2022-2027 Revenue Requirement Trend

Revenue Requirement Component	2022 Board Appr	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2026 Bridge	2027 Test
OM&A Expenses (Incl LEAP)	9,599,168	9,784,453	10,897,520	11,247,955	11,711,630	11,450,096	12,383,274
Amortization/Depreciation	5,577,375	5,252,704	5,268,232	5,449,191	5,866,296	6,275,873	6,819,285
Property Taxes	105,100	108,513	113,284	121,125	133,361	123,548	143,019
Income Taxes (Grossed Up)	442,125	543,477	113,751	233,706	223,116	431,359	484,384
Regulated Return on Rate Base:							
Deemed Interest	2,967,107	2,864,591	3,079,198	3,338,755	3,575,328	3,714,909	4,337,837
Return on Deemed Equity	4,494,100	4,338,825	4,663,878	5,057,012	5,415,335	5,626,750	6,195,653
Service Revenue Requirement	**23,184,975**	**22,892,562**	**24,135,863**	**25,447,744**	**26,925,066**	**27,622,536**	**30,363,451**
Revenue Offsets	-1,341,251	-1,239,780	-1,740,524	-1,647,298	-1,720,635	-1,347,001	-1,349,599
Base Revenue Requirement (Excl Transformer Ownership Allowance)	**21,843,724**	**21,652,783**	**22,395,339**	**23,800,446**	**25,204,431**	**26,275,535**	**29,013,852**

The primary drivers of the change in revenue requirement are an increased return on rate base, and an increase in OM&A. The return on rate base increase is associated both with an increase in weighted average cost of capital, and with increases in the rate base itself, driven in turn by increases in Net Fixed Assets resulting from CNPI's capital additions over the most recent historic DSP period.

An increase in depreciation expense and income taxes (grossed- up PILS) contribute to a lesser degree. Depreciation expense increases are associated with the historic period capital additions. Income taxes have increased due to changes in return and have also been affected by the proposed smoothing mechanism applied in relation to the Reaccelerated Investment Incentive Property (RIIP), as further outlined in Exhibit 6. .

Each of these contributing factors is summarized in Section 6.3.2 of Exhibit 6. The table below compares each component of CNPI's proposed 2027 revenue requirement to 2022 Board Approved amounts.

Table 1- 3: Change in Revenue Requirement from 2022 Board-Approved

Driver	2022 Board Appr	2027 Test Year	Difference		Reference
			Absolute	%	
Long Term Debt Rate	4.00%	4.36%	0.36%	9%	5.1.2
Short Term Debt Rate	1.17%	2.72%	1.55%	132%	5.1.2
Weighted Average Debt Rate	3.81%	4.25%	0.44%	12%	5.1.2
Rate of Return on Equity	8.66%	9.11%	0.45%	5%	5.1.2
Regulated Rate of Return on Rate	**5.75%**	**6.20%**	**0.44%**	**8%**	**5.1.2**
Controllable Expenses	$9,704,268	$12,526,292	$2,822,024	29%	4.2
Power Supply Expense	$56,477,556	$63,169,504	$6,691,947	12%	2.4.3
Working Capital Base	**$66,181,824**	**$75,695,796**	**$9,513,972**	**14%**	**2.4**
Working Capital Allowance Rate	7.50%	7.50%	0.00%	0%	2.4
Working Capital Allowance ("WCA"	**$4,963,637**	**$5,677,185**	**$713,548**	**14%**	**2.4**
Net Fixed Assets Opening Test Year	$120,754,187	$158,008,290	$37,254,103	31%	2.1
Net Fixed Assets Closing Test Year	$128,793,147	$170,684,152	$41,891,005	33%	2.1
Average Net Fixed Assets	$124,773,667	$164,346,221	$39,572,554	32%	2.1
Working Capital Allowance	$4,963,637	$5,677,185	$713,548	14%	2.4
Rate Base	**$129,737,304**	**$170,023,406**	**$40,286,102**	**31%**	**2.1**
Deemed Interest Expense	$2,967,107	$4,337,837	$1,370,729	46%	5.1.2
Target Return on Deemed Equity	$4,494,100	$6,195,653	$1,701,553	38%	5.1.2
Regulated Return on Rate Base	**$7,461,208**	**$10,533,490**	**$3,072,282**	**41%**	5.1.2
Regulated Return on Rate Base	$7,461,208	$10,533,490	$3,072,282	41%	5.1.2
OM&A	$9,599,168	$12,383,274	$2,784,106	29%	4.2
Property Taxes	$105,100	$143,019	$37,919	36%	6.5
Depreciation Expense	$5,577,375	$6,819,285	$1,241,910	22%	2.2
Income Taxes	$442,125	$484,384	$42,259	10%	6.4
Service Revenue Requirement	**$23,184,975**	**$30,363,451**	**$7,178,476**	**31%**	**6.2**
Revenue Offset	-$1,341,251	-$1,349,599	-$8,348	1%	6.7
Base Revenue Requirement	**$21,843,724**	**$29,013,852**	**$7,170,128**	**33%**	**6.2**

BUDGETING AND ACCOUNTING ASSUMPTIONS

In preparing its cost forecasts for the Application, CNPI has considered an assumed inflation rate range of 2.0% to 2.5%[1]. CNPI is experiencing a modest increasing trend in residential customer counts, combined with a relatively flat trend in overall system energy use as described in Exhibit 3.

CNPI adopted MIFRS and confirms that it made the required changes to its capitalization policies and depreciation rates in 2013. These changes were reflected and approved within CNPI's 2013 cost of service proceeding (EB-2012-0112). Values presented in both CNPI's 2022 cost of service application (EB-2021-0011) and in this Application have also been reported using the same methodology. There are therefore no impacts resulting from a change in accounting standard.

1.2.2 LOAD FORECAST SUMMARY

CNPI's load forecast for 2027 is based on a methodology that predicts class-specific consumption using a multivariate regression analysis that relates historical monthly wholesale kWh usage to historical weather and other factors.

In CNPI's case, variation in monthly electricity consumption is influenced by several factors – weather (i.e. heating and cooling degree days), the number of days in a given month, spring/fall flag and summer flag (i.e. lower consumption during shoulder months and higher in summer months), number of customers, and an economic variable, Manufactured Goods Sold. The most significant variables used in weather related regressions are monthly historical heating degree days and cooling degree days.

Weather normalized values are determined by using the regression equation with 10-year average monthly heating and cooling degree days for 2016-2025. The 10-year average reflects recent years' weather and has been used in other electricity distribution rate applications accepted by the Board.

Allocation of wholesale kWh to specific weather-sensitive rate classes (e.g. Residential, GS<50 is based on a weather sensitivity factor for each class. For the Street Lighting, Sentinel Lighting and Unmetered Scattered Load rate classes, which are not weather-sensitive, the forecasted 2026 and 2027 load is based on average consumption per connection/account from 2025, multiplied by the number of forecasted connections/accounts for 2026 and 2027.

Customer and connection counts are forecasted by determining the geomean growth rate for the 2017-2025 period, and applying this rate to 2025 actual customer/connection counts to forecast 2026 and 2027 values.

CNPI observed moderate fluctuations in its wholesale purchases during 2020 as a result of the COVID-19 pandemic. Despite these reductions, year-over-year variations and differences between actual and predicted wholesale kWh for 2020 were comparable to other years used in the wholesale regression

[1] Inflation of 2.0% was applied to Test Year OM&A budgets where known price increases were unavailable (ex: signed contract), while 2.5% annual compounding inflation was applied to develop the five-year capital additions forecast for the DSP and rate base calculations. Assumed contingency of Tariffs/Buy Canadian/ Global economic impacts of 10% were incorporated into Test Year pricing.

analysis. While fluctuations in wholesale kWh were minimal, CNPI observed noticeable shifts in consumption between rate classes as a percentage of wholesale purchases.

CNPI used historic billed energy to wholesale purchase data, forecasted customer growth, average usage per customer, and weather sensitivity ratios to allocate 2026 and 2027 predicted wholesale purchases to each of its classes.

Standby kW have been forecasted based on historical average Standby kW billing in recent years (2022-2024).

CNPI's 2027 load forecast and customer forecast is summarized in the table below. Detailed explanations of the load forecast can be found in Exhibit 3.

Table 1- 4: Load Forecast Summary

	2022 Board Appr	2027 Test	Change	% Change
Customers / Connections				
Residential	27,382	28,818	1,436	5.2%
General Service <50 kW	2,523	2,556	33	1.3%
General Service >50kW	205	201	-4	-2.0%
Unmetered Scattered Load (accounts)	46	45	-1	-2.8%
Sentinel Lighting (devices)	620	593	-27	-4.4%
Street Lighting (devices)	6,043	6,257	214	3.5%
Embedded Distributor	1	1	0	0.0%
Grand Total	**36,820**	**38,470**	**1,650**	**4.5%**
kWh			0	
Residential	204,961,138	237,403,471	32,442,333	15.8%
General Service <50 kW	67,870,625	67,709,853	-160,772	-0.2%
General Service >50kW	198,090,372	179,251,887	-18,838,485	-9.5%
Unmetered Scattered Load	1,271,802	1,347,134	75,332	5.9%
Sentinel Lighting	522,271	409,776	-112,495	-21.5%
Street Lighting	1,444,204	1,461,700	17,496	1.2%
Embedded Distributor	5,149,219	5,636,847	487,628	9.5%
TOTAL	**479,309,631**	**493,220,667**	**13,911,036**	**2.9%**
kW				
Residential				
General Service <50 kW				
General Service >50kW	605,696	561,368	-44,328	-7.3%
Unmetered Scattered Load				
Sentinel Lighting	1,596	1,339	-257	-16.1%
Street Lighting	4,412	4,448	36	0.8%
Embedded Distributor	13,766	15,118	1,352	9.8%
TOTAL	**625,470**	**582,273**	**-43,197**	**-6.9%**
Standby Statistics				
Standby KW	75,172	78,288	3,116	4.1%
GS>50 including Standby	680,868	639,656	-41,212	-6.1%
Total kW including Standby	**700,642**	**660,561**	**-40,081**	**-5.7%**

1.2.3 RATE BASE AND DSP

CNPI's proposed Rate Base for the 2027 Test Year of $170,023,406 reflects an increase of $40,286,102 or 31% relative to 2022 Board Approved (compound annual growth rate of 5.6%). CNPI's 2022-2027 rate base trend is presented in the following table:

Table 1- 5: 2022-2027 Rate Base Trend

Description	2022 BA	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2026 Bridge	2027 Test
Gross Fixed Assets - Opening	199,484,718	192,967,571	204,067,728	219,511,108	234,773,508	249,242,312	258,523,170
Gross Fixed Assets - Closing	213,572,515	204,067,728	219,511,108	234,773,508	249,242,312	258,523,170	278,470,353
Accumulated Depreciation -	-78,127,605	-76,849,152	-78,891,068	-84,216,127	-88,410,617	-93,308,690	-100,124,510
Accumulated Depreciation -	-84,218,955	-78,891,068	-84,216,127	-88,410,617	-93,308,690	-100,124,510	-107,438,343
Gross Fixed Assets - Average	206,528,616	198,517,649	211,789,418	227,142,308	242,007,910	253,882,741	268,496,762
Gross Write Up - Average	-1,400,000	-1,400,000	-1,400,000	-1,400,000	-1,400,000	-1,400,000	-1,400,000
Accumulated Depreciation -	-81,173,280	-77,870,110	-81,553,597	-86,313,372	-90,859,654	-96,716,600	-103,781,426
Accumulated Depreciation W	818,331	818,331	860,842	903,353	945,864	988,375	1,030,886
Net Fixed Assets - Average	124,773,667	120,065,870	129,696,662	140,332,288	150,694,120	156,754,516	164,346,221
Allowance for Working Capita	4,963,637	5,188,890	4,941,838	5,655,368	5,637,735	5,680,539	5,677,185
Total Rate Base	**129,737,304**	**125,254,760**	**134,638,500**	**145,987,656**	**156,331,855**	**162,435,055**	**170,023,406**

The decrease from 2022 Board Approved to 2022 Actual is primarily due to lower than forecasted capital additions in 2021. Year over year increases in rate base are primarily driven by System Access and System Renewal capital investments. CNPI experienced a relatively high volume of connection requests, particularly as it relates to new subdivisions and upgrades, which resulted in higher than forecast System Access work. Continued investments in voltage conversion project together with investments in end-of-life assets through line rebuilds and pole replacement resulted in a high level of system renewal investments. Several factors drove higher than planned levels of investments including: a higher level of customer-related investments in system access; unexpectedly high levels of inflation; COVID-related delays causing projects from the prior DSP to be completed in 2022; and a significant severe storm requiring investments in 2022/2023. The table below reproduces portions of OEB Appendix 2-AB, comparing planned vs. actual spending over the historical period:

Table 1- 6: Historical Planned vs. Actual Capital and O&M

	2022	2022	%Var	2023	2023	%Var	2024	2024	%Var	2025	2025	%Var	2026	2026	%Var
	Plan	Actual		Plan	Actual		Plan	Actual		Plan	Actual		Plan	Bridge	
System Access	$ 1,771	$ 3,174	79%	$ 1,718	$ 2,571	50%	$ 1,710	$ 3,310	94%	$ 1,711	$ 3,834	124%	$ 1,711	$ 3,883	127%
System Renewal	$ 7,259	$ 11,175	54%	$ 6,537	$ 11,065	69%	$ 7,826	$ 11,867	52%	$ 6,865	$ 11,193	63%	$ 6,865	$ 4,325	-37%
System Service	$ 3,305	$ 317	-90%	$ 1,695	$ 2,374	40%	$ 1,345	$ 1,694	26%	$ 1,295	$ 304	-76%	$ 1,845	$ 816	-56%
General Plant	$ 2,007	$ 1,662	-17%	$ 1,846	$ 2,171	18%	$ 1,851	$ 1,432	-23%	$ 1,708	$ 3,574	109%	$ 1,578	$ 1,907	21%
TOTAL IN SERVICE ADDITIONS	**$ 14,343**	**$ 16,328**	**14%**	**$ 11,796**	**$ 18,180**	**54%**	**$ 12,732**	**$ 18,302**	**44%**	**$ 11,579**	**$ 18,906**	**63%**	**$ 11,999**	**$ 10,931**	**-9%**
Capital Contributions	-$ 900	-$ 1,410	57%	-$ 850	-$ 1,925	126%	-$ 850	-$ 1,036	22%	-$ 850	-$ 2,838	234%	-$ 850	-$ 1,650	94%
NET ADDITIONS	**$ 13,443**	**$ 14,918**	**11%**	**$ 10,946**	**$ 16,255**	**49%**	**$ 11,882**	**$ 17,266**	**45%**	**$ 10,729**	**$ 16,068**	**50%**	**$ 11,149**	**$ 9,281**	**-17%**
System O&M	**$ 4,125**	**$ 4,249**	**3%**	**$ 4,208**	**$ 4,876**	**16%**	**$ 4,292**	**$ 4,571**	**6%**	**$ 4,378**	**$ 4,775**	**9%**	**$ 4,465**	**$ 4,638**	**4%**

	2027	2028	2029	2030	2031
System Access	$ 4,075	$ 4,177	$ 4,281	$ 4,388	$ 4,498
System Renewal	$10,151	$10,227	$11,254	$14,930	$10,993
System Service	$ 2,355	$ 751	$ 908	$ 851	$ 889
General Plant	$ 4,617	$ 3,059	$ 8,953	$ 1,959	$ 2,825
TOTAL IN SERVICE ADDITIONS	**$21,197**	**$18,214**	**$25,395**	**$22,129**	**$19,205**
Capital Contributions	-$ 1,250	-$ 1,281	-$ 1,313	-$ 1,346	-$ 1,380
NET ADDITIONS	**$19,947**	**$16,932**	**$24,082**	**$20,782**	**$17,826**
System O&M	**$ 5,052**	**$ 5,191**	**$ 5,334**	**$ 5,481**	**$ 5,631**

Proposed Test Year capital additions are $19,947,184 net of capital contributions. Key test year projects include: System Access additions to meet customer requests for connections, expansions and upgrades; System Renewal investments in end of life Smart Meters, Voltage Conversion, Line Rebuilds, Pole Replacement and a project regarding Tie Lines between Gilmore and Rosehill Stations; System Service investments in the Gananoque Main Distribution Station and Distribution Automation, and General Plant expenditures including a facilities project to reconfigure the Fort Erie garage, and enhancements to modernize the Fort Erie Control Room.

In developing its 2027-2031 DSP and Business Plan, CNPI identified the following strategic customer focused objectives that drive capital and O&M plans and related investments over the forecast period, as outlined below.

With a commitment to continued public and worker safety, environmental stewardship, cyber security and cost efficiency:

- Invest to **improve reliability** compared to historic levels, including considering opportunities for improved system resilience against climate vulnerabilities.
- Invest to **meet growing customer base** and increasing load in areas of the system.
- Maintain strong **customer experience** performance through investments in key **software systems**. Pursue initiatives to enhance the customer experience.
- Continue and enhance CNPI's risk-based approach to replacement of **aging assets**.
- **Leverage technology** to improve the management and visibility of distributed assets.
- Promote **employee engagement** to support a safe, productive workplace.

CNPI's 2027 Business Plan, included as Attachment 1-B describes how the strategic objectives listed above are consistent with its core values and principles, the objectives of the OEB's Renewed Regulatory Framework, as well as the identified preferences of CNPI's customers.

Details on historical capital variances and details on forecasted capital spending are included in Exhibit 2 and the DSP.

CNPI is not requesting approvals for any renewable energy connections/expansions, smart grid projects, or regional planning initiatives with this Application.

1.2.4 OPERATION, MAINTENANCE AND ADMINISTRATION EXPENSE

CNPI's proposed OM&A expenses for the 2027 Test Year of $12,383,274 represent an increase of $2,784,106 or 29% relative to 2022 Board Approved (compound average growth rate of 5.2%). The following table summarizes CNPI's OM&A trend from 2022 Board Approved to the 2027 Test Year.

Table 1- 7: 2022-2027 OM&A Trend

	2022 Last Rebasing Year OEB Approved	2022 Last Rebasing Year Actuals	2023 Actuals	2024 Actuals	2025 Actuals	2026 Bridge Year	2027 Test Year
Operations	$1,911,789	$2,009,458	$ 2,109,545	$ 2,194,331	$ 2,322,507	$ 2,410,236	$ 2,570,922
Maintenance	$2,056,623	$2,239,433	$ 2,766,105	$ 2,376,646	$ 2,452,663	$ 2,227,905	$ 2,481,211
Billing and Collecting	$1,736,564	$1,542,005	$ 1,752,600	$ 1,756,504	$ 1,911,880	$ 1,859,907	$ 1,870,476
Community Relations	$ 78,761	$ 129,992	$ 61,474	$ 81,964	$ 150,083	$ 93,991	$ 92,089
Administrative and General	$3,815,430	$3,863,564	$ 4,207,796	$ 4,838,510	$ 4,874,497	$ 4,858,057	$ 5,368,575
Total	**$9,599,168**	**$9,784,453**	**$ 10,897,520**	**$11,247,955**	**$11,711,630**	**$11,450,096**	**$12,383,274**
%Change (year over year)		1.9%	11.4%	3.2%	4.1%	-2.2%	8.1%

Historical year-over-year variances from 2022 board-approved to 2025 actuals have ranged from -2.2% to 11.4%, mainly due compensation fluctuations in historical years. The most significant drivers of year over year changes in OM&A costs include:

- Labour costs relating to annual variations in FTE count and average compensation rates, including pension increases, as more fully analyzed in OEB Appendix 2-K. These represent the costs required for CNPI to recruit and retain the expertise required to safely and efficiently expand, operate and maintain the distribution system, respond to customer requests and preferences as well as providing timely and accurate bills, and the various functions which support these key activities.

- Increases in third party Enterprise Technology costs, Telecommunications Costs and Cyber Security, which support CNPI's ability to protect privacy and operational technology security, to support and enhance service delivery and customer outcomes, and to efficiently operate the distribution system.

- Increases in LEAP funding, in order to provide as much funding as necessary to accommodate the level of qualified applicants, in compliance with OEB expectations.

- Increase in regulatory expenses as a result of increased policy activity and filing requirements, and associated increased OEB assessment costs, to support CNPI's continued public policy responsiveness and compliance.

The following table summarizes CNPI's 2022-2027 OM&A cost drivers, consistent with OEB Appendix 2-JB. Further cost driver analysis is provided in Section 4.22 of Exhibit 4.

Table 1- 8: 2022-2027 OM&A Cost Drivers

OM&A	2022 Actuals	2023 Actuals	2024 Actuals	2025 Actuals	2026 Bridge Year	2027 Test Year
Reporting Basis	ASPE	ASPE	ASPE	ASPE	ASPE	ASPE
Opening Balance[2]	$ 9,599,168	$ 9,784,453	$ 10,897,520	$ 11,247,955	$ 11,711,630	$ 11,450,096
Bad Debt Expense	-$ 65,000	$ 134,000	-$ 31,000	$ 190,000	-$ 185,000	$ 30,000
Third Party Locates Program	$ 114,000	-$ 30,000	-$ 38,000	$ 18,000	$ 6,000	$ -
Third Party Disconnection	$ 8,000	$ 42,000	$ 18,000	$ 27,000	-$ 28,000	-$ 40,000
Meter Maintenance Costs (Excluding Internal Labour)	$ 40,000	-$ 8,000	$ 46,000	-$ 17,000	-$ 62,000	$ 3,000
Cybersecurity	$ 44,000	$ 9,000	$ 64,000	-$ 5,000	$ 70,000	$ 2,000
Telecommunications	-$ 6,000	$ 107,000	-$ 39,000	-$ 44,000	$ 27,000	$ 6,000
Third Party Software Subscription and ET Based Consultant Fees	$ 49,000	$ 98,000	$ 33,000	$ 17,000	$ 9,000	$ 22,000
Regulatory Expenses	-$ 10,000	$ 18,000	$ 36,000	$ 2,000	$ 48,000	$ 142,000
App 2-K Impact on OM&A	-$ 161,000	$ 498,000	$ 3,000	-$ 36,000	$ 338,000	$ 428,000
Training and Travel	-$ 49,000	$ 100,000	-$ 58,000	$ 56,000	$ 25,000	$ 49,000
One-time Recruiting	$ 62,000	-$ 41,000	-$ 21,000	$ 8,000	-$ 8,000	$ -
Building Repairs and Maintenance	-$ 35,000	$ 50,000	-$ 6,000	$ 64,000	-$ 79,000	$ 79,000
Third Party Customer Engagement	$ 53,000	-$ 53,000	$ -	$ -	$ -	$ -
Third Party February 22 to 23, 2023 Wind Storm	$ -	$ 70,000	-$ 70,000	$ -	$ -	$ -
Inventory Adjustments	$ -	$ -	$ 171,000	-$ 171,000	$ -	$ -
One-Time Distribution Station Repairs	$ -	$ -	$ -	$ 77,000	-$ 77,000	$ -
2-N Rent True-up	$ -	$ -	$ -	$ 75,000	-$ 75,000	$ -
LEAP Funding	$ -	$ -	$ -	$ -	$ -	$ 127,000
Miscellaneous	$ 141,285	$ 119,067	$ 242,436	$ 202,674	-$ 270,533	$ 85,177
Closing Balance[2]	$ 9,784,453	$ 10,897,520	$ 11,247,955	$ 11,711,630	$ 11,450,096	$ 12,383,274

2027 total compensation of $11,369,498 reflects an increase of $1,760,579 or 18.3% relative to 2022 Board Approved (compound annual growth rate of 3.4%). Total compensation is summarized in the table below, and analyzed in detail in Section 4.4 of Exhibit 4.

Table 1- 9: 2022-2027 Compensation Summary

	2022 Board Approved	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2026 Bridge	2027 Test
Number of Full Time-Equivalent Employees	68	68	68	70	69	73	73
Total Salary and Wages	$ 7,638,152	$ 7,694,641	$ 7,936,872	$ 8,304,693	$ 8,321,996	$ 8,839,588	$ 9,008,304
Total Benefits	$ 1,970,764	$ 1,606,314	$ 1,970,025	$ 1,827,605	$ 1,870,821	$ 1,982,567	$ 2,361,194
Total Compensation	**$ 9,608,916**	**$ 9,300,955**	**$ 9,906,897**	**$ 10,132,298**	**$ 10,192,817**	**$ 10,822,155**	**$ 11,369,498**

1.2.5 COST OF CAPITAL

In this application, CNPI is proposing to recover a weighted average cost of capital of 6.20% through rates in the 2027 Test Year. CNPI has followed the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities*, December 11, 2009 and subsequent update in the OEB's Decision in EB-2024-0063, March 27, 2025 in determining the applicable cost of capital.

In calculating the applicable cost of capital, CNPI has used the OEB's deemed capital structure of 56% long-term debt, 4% short-term debt, and 40% equity, in conjunction with the cost of capital parameters in the OEB's letter of October 31, 2025, for the deemed debt rates (where applicable) and allowed return on equity. The weighted average cost of debt includes consideration of a new affiliated loan to be taken out in the test year, with a forecasted principal amount of $50,000,000 at the OEB's deemed long term debt rate of 4.73%. The following table summarizes CNPI's capital structure, cost of capital, and the associated return on rate base included in its 2027 revenue requirement.

Table 1- 10: Summary of 2027 Capital Structure and Cost of Capital

	Capitalization Ratio		Cost Rate	Return
	(%)	($)	(%)	($)
Debt				
Long-term Debt (Actual)	56.00%	$95,213,107	4.36%	$4,152,851
Short-term Debt	4.00%	$6,800,936	2.72%	$184,985
Total Debt	60.00%	$102,014,043	4.25%	$4,337,837
Equity				
Common Equity	40.00%	$68,009,362	9.11%	$6,195,653
Preferred Shares	0.00%	$ -	0.00%	$ -
Total Equity	40.00%	$68,009,362	9.11%	$6,195,653
Total	100.00%	$170,023,406	6.20%	$10,533,490

CNPI acknowledges that the OEB will update the cost of capital parameters applicable to rate changes effective in 2027, and therefore expects to update the Application to reflect the revised 2027 parameters as required.

CNPI has not deviated from the OEB's cost of capital methodology.

1.2.6 COST ALLOCATION AND RATE DESIGN

CNPI has prepared and is filing a 2027 Cost Allocation Study consistent with its understanding of the Directions and Policies in the Board's Reports of November 28, 2007 Application of Cost Allocation for Electricity Distributors and March 31, 2011 Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219) (the "Cost Allocation Reports") and all subsequent updates.

The cost allocation study accepted in CNPI's 2022 cost of service application (EB-2021-0011) resulted in revenue-to-cost ratios within the OEB's policy guidelines, as summarized in the table below.

Table 1- 11: 2022 Revenue-to-Cost Ratios

Customer Class	2022 Approved R/C Ratio
Residential	95.70%
GS < 50	108.59%
GS 50 to 4,999 kW	104.75%
Embedded Distributor	97.80%
Street Light	120%
Sentinel Light	102.11%
USL	96.18%

CNPI proposes to make adjustments to the Embedded Distributor revenue to cost ratio to bring it within the OEB's Policy Range maximum. Additionally CNPI has adjusted the Street Lighting revenue to cost ratio as a bill mitigation measure. An offsetting increase to the residential class revenue to cost ratio (the lowest of the ratios) has been proposed so that the entire revenue requirement is allocated among the classes.

Table 1- 12: 2027 Revenue-to-Cost Ratios

Name of Customer Class	2022 Approved Ratios	2027 Status Quo Ratios	2027 Proposed Ratios	Policy Range
Residential	95.70%	94.08%	94.17%	85% - 115%
General Service <50 kW	108.59%	114.61%	114.61%	80% - 120%
General Service >50kW	104.75%	110.47%	110.47%	80% - 120%
Unmetered Scattered Load	96.18%	115.34%	115.34%	80% - 120%
Sentinel Lighting	102.11%	99.13%	99.13%	80% - 120%
Street Lighting	120.00%	107.54%	103.60%	80% - 120%
Embedded Distributor	97.80%	120.61%	120.00%	80% - 120%

CNPI completed its transition to fully fixed residential rates in its 2020 IRM application (EB-2019-0024),and continues to propose fixed monthly service charges that will recover 100% of the revenue requirement allocated to this rate class.

Maintaining status quo fixed/variable percentages would result in monthly service charges for CNPI's General Service less than 50 kW, General Service 50 to 4,999 kW, Embedded Distributor, Sentinel and USL customer classes that are higher than the ceiling identified in the cost allocation study. This is also the case the Residential class, where this is an intentional outcome of the OEB's rate design policy, discussed further in Exhibit 8. For the General Service 50 to 4,999 kW, Embedded Distributor, Sentinel and USL customer classes, CNPI proposes to maintain the fixed charges at the 2026 approved charges in order to avoid further increasing those charges above the ceiling identified in the cost allocation study. For the General Service less than 50 kW class, CNPI proposes to updated the fixed rate to match the ceiling value, which is higher than the 2026 approved rate, but lower than the status quo rate. For the Street Lighting class, the resulting monthly service charges are within the floor to ceiling ranges identified in the cost allocation study, therefore CNPI proposes to maintain the current fixed/variable proportions.

CNPI is proposing to update the definition of the General Service 50 to 4,999 kW to remove the ceiling applicable to that rate class. Accordingly, CNPI is requesting to update the name of the class to General Service Greater than or equal to 50 kW. CNPI is also proposing to update the definition of the Standby class to better reflect the broader applicability of this class.

Consistent with its commitments outlined in section 1.3.9 below, CNPI has included in Exhibit 8 a proposed approach to setting the Standby charge. CNPI is proposing to apply this approach and requests that the OEB deem the proposed Standby charge as final. CNPI has also included an explanation in Exhibit 8

regarding its investigations into establishing a separate "larger customer" class. For the reasons outlined in Exhibit 8, CNPI is not proposing to establish such a class.

The table below shows CNPI's existing rates in comparison to the 2027 proposed rates:

Table 1- 13: 2027 Distribution Rate Summary

Customer Class	Determinant	Bridge Year Approved		Test Year Proposed	
		Fixed Charge	Variable Rate	Fixed Charge	Variable Rate
Residential	kWh	$ 46.08	$ -	$ 52.45	$ -
GS < 50	kWh	$ 38.83	$ 0.0315	$ 40.24	$ 0.0376
GS 50 to 4,999 kW	kW	$ 194.73	$ 9.1941	$ 194.73	$ 9.4448
Embedded Distributor	kW	$ 700.69	$10.5874	$ 700.69	$12.0496
Street Light	kW	$ 4.69	$ 9.3574	$ 5.13	$10.2320
Sentinel Light	kW	$ 7.01	$ 8.1011	$ 7.01	$14.3182
USL	kWh	$ 61.23	$ 0.0332	$ 61.23	$ 0.0411
Standby	kW	$ -	$ 1.5104	$ -	$ 9.4448

As outlined in section 1.2.8 below, CNPI is proposing bill mitigation for its street lighting rate class.

1.2.7 DEFERRAL AND VARIANCE ACCOUNTS

CNPI proposes to dispose of a debit of $150,266 related to Group 1 and debit of $48,239 related to Group 2 Deferral and Variance Accounts ("DVA"). These balances include carrying charges up to and including December 31, 2025, as well as interest projected to December 31, 2026.

For the Account 1508 sub-accounts for pole attachment charges, CNPI has forecasted 2026 costs and revenue and incorporated this into the balance for disposition.

CNPI has not included any claim related to LRAMVA amounts in this Application.

Group 1 and Group 2 DVA balances are proposed to be disposed of over a period of 12 months.

Exhibits 4 and 9 also contains CNPI's explanation, as outlined in section 1.3.9 above, regarding four legacy sub-accounts of 1508 related to pension and OPEBS deferrals. CNPI is proposing to continue to record amounts in these accounts, but is not proposing to dispose of the account balances in this Application, or in the future.

Separate adjustments for CBR and Global adjustment have been assessed for three Class A/B transition customers during the disposition period.

Based on CNPI's billing process, there is no Global Adjustment ("GA") variance for Class A customers. For Class B customers, OEB Account 1589 captures the difference between GA amounts billed to non-RPP customers and the actual GA amount paid for those customers to the IESO. The rate rider for disposition of OEB Account 1589 is therefore applicable to Class B non-RPP customers only. CNPI applied historical

RPP/non-RPP percentages to the 2027 load forecast amounts to arrive at estimated non-RPP kWhs for calculation of the 2027 rate rider.

CNPI is also proposing to record variances into Account 1592 related to the Reaccelerated Investment Incentive Property Program, which received Royal Assent on March 26, 2026. CNPI plans to use the account to record amounts in 2026, related to tax variances due to new laws applicable to the 2025 and 2026 tax years.

CNPI is not requesting to create any new accounts. Exhibit 9 outlines several accounts which are no longer applicable and therefore CNPI is requesting to discontinue their use.

The following table summarizes the DVA balances sought for disposition in 2027. Exhibit 9 provides detailed calculation of the resulting rate riders, all of which have been factored into 2027 bill impact calculations.

Table 1- 14: DVA Balances for 2027 Disposition

Account Descriptions	Account Number	Closing Principal Balance as of Dec-31-25	Closing Interest Amounts as of Dec-31-25	Closing Principal + Interest Balance as of Dec-31-25	Accounts to Dispose Yes/No	Total $ Claim	Allocator	Continued or Discontinued	Other Notes
Group 1 Accounts									
LV Variance Account	1550	(92,398)	(1,272)	(93,670)	Yes	(96,284)	kWh		
Smart Metering Entity Charge Variance Account	1551	(41,669)	(1,629)	(43,298)	Yes	(13,776)	# of Customers	Continued	
RSVA - Wholesale Market Service Charge	1580	(1,069,136)	(15,871)	(1,085,007)	Yes	(894,467)	kWh	Continued	
Variance WMS – Sub-account CBR Class A	1580	-	-	-	No	-	N/A	Continued	
Variance WMS – Sub-account CBR Class B	1580	360,280	7,031	367,311	Yes	191,931	kWh	Continued	
RSVA - Retail Transmission Network Charge	1584	701,451	6,686	708,137	Yes	758,889	kWh	Continued	
RSVA - Retail Transmission Connection Charge	1586	139,162	(12,055)	127,107	Yes	472,602	kWh	Continued	
RSVA - Power (excluding Global Adjustment)	1588	(776,186)	26,741	(749,445)	Yes	(119,759)	kWh	Continued	
RSVA - Global Adjustment	1589	(782,344)	(40,327)	(822,671)	Yes	(155,398)	Non-RPP kWh	Continued	
Disposition and Recovery/Refund of Regulatory Balances (2020 and pre-2020)[3]	1595	-	-	-	No	-	N/A	Discontinued	
Disposition and Recovery/Refund of Regulatory Balances (2021)	1595	(26,673)	(453)	(27,126)	No	-	N/A	Continued	Last rider expired Dec 31, 2024.
Disposition and Recovery/Refund of Regulatory Balances (2022)	1595	(13,162)	(48,430)	(61,592)	No	-	N/A	Discontinued	Riders expired Dec 31, 2022.
Disposition and Recovery/Refund of Regulatory Balances (2023)	1595	7,030	(681)	6,349	Yes	6,528	1595 share alln	Discontinued	Riders expired Dec 31, 2023.
Disposition and Recovery/Refund of Regulatory Balances (2024)	1595	(49,948)	47,324	(2,624)	No	-	N/A	Continued	Riders expired Dec 31, 2024.
Disposition and Recovery/Refund of Regulatory Balances (2025)	1595	64,381	(11,552)	52,829	No	-	N/A	Continued	Riders expired Dec 31, 2025.
Disposition and Recovery/Refund of Regulatory Balances (2026)	1595			-	No	-	N/A	Continued	
Total Group 1 Accounts		**(1,579,212)**	**(44,488)**	**(1,623,700)**		**150,266**			
Group 2 Accounts									
Pole Attachment Revenue Variance	1508	488,288	38,267	526,555	Yes	539,006	Distribution Rev.	Discontinued	
Other Regulatory Assets, sub-account LEAP EFA Funding Deferal Account[17]	1508	234,646	7,444	242,090	Yes	248,073	kWh	Discontinued	
Other Regulatory Assets - Sub-Account - Pension Accumulated Actuarial Gains a	1508	-		-	No			Continued	
Other Regulatory Assets - Sub-Account - OPEB Accumulated Actuarial Gains an	1508	121,300	16,542	137,842	No			Continued	
Other Regulatory Assets - Sub-Account - Pension Deferral	1508	3,790,682	-	3,790,682	No			Continued	
Other Regulatory Assets - Sub-Account - Pension Expense Variance	1508	(5,535,067)	-	(5,535,067)	No			Continued	
Other Regulatory Assets - Sub-Account - Other Post Employment Benefits Defen	1508	1,986,200	-	1,986,200	No			Continued	
Other Regulatory Assets - Sub-Account - Other Post Employment Benefits Exper	1508	(2,308,215)	-	(2,308,215)	No			Continued	
Other Regulatory Assets - NIA - LTLT Rate Impact Mitigation	1508	1,686	176	1,862	No	1,905	kWh	Continued	
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges	1522	-	(399,014)	(399,014)	Yes	(464,372)	kWh	Continued	
Extra-Ordinary Event Costs	1572	(3,829)	16,553	12,724	Yes	12,626	kWh	Continued	
PILs and Tax Variance for 2006 and Subsequent Years- Sub-account CCA Changes	1592	(294,426)	-	(294,426)	Yes	(301,934)	kWh	Continued	
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential	1522	(2,563,068)	-	(2,563,068)	No	-	N/A	Continued	
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Contra Account	1522	2,563,068		2,563,068	No	-	N/A	Continued	
Meter Cost Deferral Account (MIST Meters)[3]	1557	12,935	-	12,935	Yes	12,935	kWh	Discontinued	
Total Group 2 Accounts		**(1,505,800)**	**(320,032)**	**(1,825,832)**		**48,239**			

1.2.8 BILL IMPACTS

A summary of the bill impacts by rate class is presented in the table below. Detailed explanations of the bill impacts are presented in Section 8.6 of Exhibit 8. CNPI has proposed rate mitigation measures to bring the bill impacts for Street Lighting to the 10% bill mitigation threshold.

Table 1- 15: Bill Impacts

Service Classification/ Category	Units	Assumed Consumption/ Demand	Sub-Total A		Sub-Total B		Sub-Total C		Total Bill	
			$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	750	$ 6.65	14.4%	$ 8.94	17.9%	$ 8.93	13.5%	$ 7.99	5.4%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kwh	2000	$ 13.61	13.4%	$ 19.33	17.3%	$ 19.50	13.1%	$ 17.44	4.7%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	60	$ 8.82	1.2%	$ 168.46	28.6%	$ 169.42	16.5%	$ 149.29	4.7%
EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION - Non-RPP (Other)	kw	1127	$ 1,491.92	11.8%	$ 5,136.07	57.0%	$ 5,153.99	29.8%	$ 5,754.80	6.7%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kwh	3500	$ 28.35	16.0%	$ 38.36	19.7%	$ 38.29	14.7%	$ 34.25	5.3%
STANDBY POWER SERVICE CLASSIFICATION - Non-RPP (Other)	kw	6000	$ 47,606.40	525.3%	$ 47,606.40	525.3%	$ 47,606.40	525.3%	$ 53,795.23	525.3%
SENTINEL LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kw	0.20	$ 1.37	15.9%	$ 1.55	17.5%	$ 1.56	15.4%	$ 1.39	8.9%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kw	0.10	$ 0.67	12.0%	$ 0.87	15.6%	$ 0.87	14.3%	$ 0.98	10.0%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kwh	750	$ 6.65	14.4%	$ 12.75	28.4%	$ 12.74	20.9%	$ 11.39	8.5%

1.2.9 MATERIALITY THRESHOLD

In accordance with the Minimum Filing Requirements and given that CNPI's revenue requirement falls within the $10 million to $200 million range, the following materiality threshold has been calculated.

Table 1- 16: Materiality Threshold Calculation

	2027 Test Year	
Base Revenue Requirement	$	29,013,852.30
x 0.5%	$	145,069.26
Materiality Threshold (Rounded Down)	$	145,000.00

Based on the above, CNPI has used a revenue requirement impact of $145,000 as a materiality threshold throughout this Application.

1.2.10 SUMMARY OF APPLICATION FOR CNPI CUSTOMERS

A brief, plain-language summary of the application is included as Attachment 1-A. The summary will be posted as a stand-alone document on the OEB's website for review by the general public and be made available to CNPI's customers via its website and social media. CNPI has also included this summary as a stand-alone pdf file to aid in website posting of this document.

1.3 ADMINISTRATION

1.3.1 CONTACT INFORMATION, INTERNET ADDRESS, AND SOCIAL MEDIA

Application contact information is as follows:

Applicant's Name:	Canadian Niagara Power Inc.
Applicant's Address:	1130 Bertie Street P.O. Box 1218 Fort Erie, Ontario L2A 5Y2 Phone: (905) 871-0330 Fax: (905) 994-2207
Applicant Primary Contact:	Oana Stefan Manager Regulatory Affairs Email: regulatoryaffairs@fortisontario.com Phone: (289)-230-9773
Applicant's Counsel:	Michael Buonaguro 24 Humber Trail Toronto, Ontario M6S 4C1 Email: mikebuonaguro@me.com Phone: (416) 767-1666

1.3.2 CONFIRMATION OF INTERNET ADDRESS

The application will be posted on CNPI's website address at www.cnpower.com and a message to that effect will be posted on the utilities Facebook page (https://facebook.com/CanadianNiagaraPower/) and X site.

1.3.3 STATEMENT OF PUBLICATION

For the Notice of Application related to customers residing in the Fort Erie area, CNPI recommends that it be published in the Fort Erie Observer, a free bi-weekly newspaper that is mailed to homes and businesses in the Fort Erie and surrounding areas with a circulation of approximately 14,000.

For the Port Colborne Area, CNPI recommends the Welland Tribune, which is printed six days a week and serves Welland and surrounding areas including Port Colborne, with a total circulation of 13,000-15,000.

For the Notice of Application related to customers residing in the Gananoque area, CNPI recommends that it be published in the Gananoque Reporter. The Gananoque Reporter also has online content at www.gananoquereporter.com. The Gananoque Reporter is a free publication.[2]

CNPI does not have a significant French-language customer base and therefore is not recommending French language specific notice publication.

[2] Based on the Ontario Community Newspapers Association, the Gananoque Reporter has a circulation of over 6,000. https://www.ocna.org/find-a-member-OCNA

1.3.4 LEGAL APPLICATION AND SPECIFIC APPROVALS REQUESTED

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

AND IN THE MATTER OF an application by Canadian Niagara Power Inc. for an Order or Orders, pursuant to section 78 of the Act, approving or fixing just and reasonable distribution rates effective January 1, 2027 and related matters;

APPLICATION:

1. The Applicant is a licensed distributor of electricity under distribution license ED-2002-0572 issued by the OEB under the Act.

2. The Application has been prepared pursuant to the OEB's Renewed Regulatory Framework for Electricity Distributors as detailed in the Report of the Board dated October 18, 2012 (the "RRFE"), and in accordance with *Chapter 2 (Cost of Service)* and *Chapter 5 (Consolidated Distribution System Plan)* of the OEB's *Filing Requirements for Electricity Distribution Rate Applications - 2025 Edition for 2026 Rate Applications* dated December 16, 2026, except as noted in Section 1.3.7.

3. The Applicant hereby applies to the Board for an order or orders made pursuant to Section 78 of the Act, approving just and reasonable rates for the distribution of electricity, and other rates and charges, effective January 1, 2027, as further detailed below.

4. In accordance with Section 2.1.4 of the Filing Requirements, the Applicant hereby applies to the Board for an order or orders made pursuant to Section 78 of the Act, related to the following list of specific approvals requested in this proceeding[3]:

    a. Approval to charge distribution rates effective January 1, 2027 to recover a base revenue requirement of $29,013,852, which includes a revenue deficiency of $3,499,599 , as detailed in Exhibit 6. The schedule of proposed rates is set out in Exhibit 8;

    b. Approval of the Distribution System Plan included in Exhibit 2;

    c. Approval to adjust the Retail Transmission Rates – Network and Connection as calculated in Exhibit 8;

    d. Approval of CNPI's proposed Standby Charge on a final basis, as described in Exhibits 7 and 8;

e. Approval to update the name of the current General Service 50 to 4,999 kW class, as well as updating the classification definitions for the General Service 50 to 4,999 kW Class and the Standby Class, as outlined in Exhibit 8;

f. Approval to continue to charge various Regulatory Charges and the Smart Meter Entity Charge identified in Exhibit 8, as amended by the Board from time to time;

g. Approval to continue the Specific Service Charges, Transformer Allowance and Primary Metering Allowance, identified in Exhibit 8;

h. Approval of inflationary adjustments to certain Retail Service Charges and Wireline Pole Attachment Charge as calculated in Exhibit 8;

i. Approval of Low Voltage Service Charges, as calculated in Exhibit 8;

j. Approval of the proposed loss factors as calculated in Exhibit 8;

k. Approval of the rate riders for disposition of the Deferral and Variance Accounts, as detailed in Exhibit 9;

l. Should a Decision and Order in this matter not be available at a timing that enables CNPI to implement rates by January 1, 2027, CNPI requests that the existing rates be deemed interim; and

m. Such other approvals that CNPI may request and that the OEB accepts.

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

6. This Application includes placeholders for cost of capital parameters, cost of power rates, inflation rates, and interest rates, based on the values most recently approved and/or published by the OEB. The Applicant acknowledges that the OEB will approve and/or publish updated values for rates effective in 2027, and that these updates may affect the revenue requirement and rates requested in this Application.

CERTIFICATION OF ACCURACY AND COMPLETENESS

The Applicant certifies that the Application has been reviewed and approved by the Vice President Finance and Chief Financial Officer. A signed certification statement is included in Attachment 1-D.

CONFIDENTIAL INFORMATION

CNPI has requested confidential treatment for certain attachments included with Exhibit 4. Details of the confidentiality request are outlined in the Covering Letter for this Application.

CNPI has reviewed all documentation filed as third party attachments and confirms it is not seeking confidential treatment for any other third party attachments.

1.3.5 BILL IMPACTS

For the purpose of the Notice of Application, the 2027 distribution rates proposed by CNPI will result in increases to the distribution portion of the bill (i.e. Subtotal A of the Bill Impact Model) for residential customers using 750 kWh per month (RPP-TOU) of $6.65 and for small commercial customers using 2000 kWh per month (RPP-TOU) of $13.61 . These figures include the impacts of Group 2 Rate Riders. The following table shows a summary of all components of the bill impacts for a range of consumption scenarios across all customer classes.

Further explanation of bill impacts is found in Section 8.6 of Exhibit 8.

Table 1- 17: Bill Impacts

Service Classification/ Category	Units	Assumed Consumption/ Demand	Sub-Total A		Sub-Total B		Sub-Total C		Total Bill	
			$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	750	$ 6.65	14.4%	$ 8.94	17.9%	$ 8.93	13.5%	$ 7.99	5.4%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kwh	2000	$ 13.61	13.4%	$ 19.33	17.3%	$ 19.50	13.1%	$ 17.44	4.7%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	60	$ 8.82	1.2%	$ 168.46	28.6%	$ 169.42	16.5%	$ 149.29	4.7%
EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION - Non-RPP (Other)	kw	1127	$ 1,491.92	11.8%	$ 5,136.07	57.0%	$ 5,153.99	29.8%	$ 5,754.80	6.7%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kwh	3500	$ 28.35	16.0%	$ 38.36	19.7%	$ 38.29	14.7%	$ 34.25	5.3%
STANDBY POWER SERVICE CLASSIFICATION - Non-RPP (Other)	kw	6000	$47,606.40	525.3%	$47,606.40	525.3%	$47,606.40	525.3%	$53,795.23	525.3%
SENTINEL LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kw	0.20	$ 1.37	15.9%	$ 1.55	17.5%	$ 1.56	15.4%	$ 1.39	8.9%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kw	0.10	$ 0.67	12.0%	$ 0.87	15.6%	$ 0.87	14.3%	$ 0.98	10.0%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kwh	750	$ 6.65	14.4%	$ 12.75	28.4%	$ 12.74	20.9%	$ 11.39	8.5%

Subtotal A represents the distributor's fixed and variable charges and Group 2 deferral and variance accounts.
Subtotal B includes Subtotal A plus rate riders associated with Group 1 deferral and variance accounts, cost of line losses (for most cases), and the SME charge
Subtotal C includes Subtotal B plus retail transmission service rates
Total Bill includes Subtotal C plus administrative and regulatory charges, commodity rates, OER (where applicable) and taxes

1.3.6 STATEMENT AS TO THE FORM OF HEARING REQUESTED

CNPI requests that pursuant to Section 34.01 of the Board's Rules of Practice and Procedure, this proceeding be conducted by way of written hearing in an effort to minimize costs. CNPI understands that if certain issues remain unsettled, the utility may be required to participate in an oral hearing.

1.3.7 DEVIATIONS FROM FILING REQUIREMENTS OR CHANGES TO MODELS

Except where specifically identified in the Application or noted below, CNPI followed the Filing Requirements and used the OEB-issued Cost of Service models in order to prepare this Application.

A live Excel version of the OEB's Cost of Service Checklist is being filed in conjunction with this application. In any case where a specific section of the Filing Requirements is not applicable to CNPI's circumstances, CNPI has indicated "N/A" and provided an accompanying explanation in the Cost of Service Checklist (Attachment 1-C).

CNPI confirms it has used the OEB-provided PILS model dated May 6, 2026 which reflects the Reaccelerated Investment Incentive (RII), consistent with the OEB's letter of May 6, 2026.

The following changes to OEB models, use of alternative models, or use of alternative inputs to the models were necessary to address CNPI's circumstances:

1. In the Cost Allocation model, the following items have been updated:

    a. Tab I6.1 Revenue: Cell L39 has been updated to correct a formula assumption that incorrectly assumed the billing unit for Unmetered Scattered Load class (CNPI's approved billing unit is number of accounts, and the updated formula reflects this).

    b. Various Output tabs ("O…."). In these tabs, references to accounts 1906 (Land Rights) and 1925 (Computer Software) were updated to 1612 and 1612 respectively, to correspond with the account numbers in the TB tab, and with current USOA accounts in use. This has allowed correct reconciliation of the allocated costs from these accounts in the model.

2. The DVA Continuity Model was updated for the following:

    a. Updated some vlookup formulas in Tab 7 (rate rider calculations) to refer to the correct subtotals in tab 5.

    b. Added account 1557 in Tab 5.

    c. Added linkages to the CBR B Allocation in cells C34-36.

    d. CBR rate rider calculations were not populating in the model, so the CBR rate riders have been calculated outside the DVA model.

3. The GA Workform was updated as follows:

a. Tab GA 2024- updated RRR statistics to match 2024 RRR filing (originally showed 2023 numbers).

b. Updated 2024 GA Rates in Cells G51-52 and I51-52, which were originally showing 0NIL.

c. Updated 2025 GA Rates in Cells G41-52 and I41-52, which previously had incorrect rates.

d. Updated Tab 1588-cell G18 to correct the 4705 value submitted.

4. The OEB's Benchmarking Forecast Model for 2026 filers was used, as an updated model for 2027 filers was not available.

5. The following tabs of the Chapter 2 Appendices model are not applicable to the Application: 2-FA, 2-FB, 2-FC (as CNPI is not proposing any Renewable Generation Connection Investments) and 2-Q (As CNPI has included its Embedded Distributor as a class in its Cost Allocation);

6. Updates to the calculations in Appendix 2-JA to correct reference years for year-over-year comparisons.

7. Fixed Asset Continuity and Depreciation schedules (OEB Appendix 2-BA and 2-C) were filed as a stand-alone workbook, instead of populating those tabs of the Chapter 2 Appendices model, together with a more detailed Appendix 2-BA (Fixed Asset Continuity) that delineates sub-accounts which CNPI uses to group some asset classes which contain groups of assets with different useful lives. CNPI experienced error with the Appendix 2-BA in the OEB's model, specifically unexpected data override/movement issues)

CNPI confirms this Application is not being filed earlier than scheduled. Furthermore, CNPI is not filing this Application after the commencement of the applicable rate year.

1.3.8 CHANGES IN METHODOLOGIES

CNPI has made changes to its practices regarding budgeting for capital, as outlined further in DSP section 5.4.1, including closer attention to using most recent comparable pricing, and applying appropriate inflationary and contingency provisions into the five-year forecast. The capital budgeting process has also included greater attention to the expected timing of in-service additions and fluctuations in construction work in process/assets under construction. Some changes regarding the classification of projects into investment categories (specifically System Renewal and System Service) are also being implemented.

In addition to these changes, CNPI has also incorporated new OEB policies into the preparation for this Application, including new requirements to conduct a pre-screening and Benefit Cost Analysis for the consideration of Non-Wires Solutions to distribution System Problems. CNPI has also incorporated, on a "best efforts basis"[4], the OEB's policies for Vulnerability Assessments and System Hardening.

[4] This is consistent with Chapter 5 of the Filing Requirements section 5.3.6, which indicate that the VASH requirements will apply on a best-efforts basis for applications for 2027 rates, and be mandatory with applications for 2028 rates.

As part of its Load Forecast, CNPI has applied a similar weather-normalized, multivariate regression model, but has made some non-material adjustments to its forecasting model.

In its Cost Allocation and Rate Design calculations, CNPI has completed the following:

- Cost Allocation Load Profiles have been updated based on three years of recent actual meter data. Previous Cost Allocation models had Load Profiles which were scaled from a historic Hydro One load profile study.

- CNPI has incorporated a proposed methodology to set the Standby service classification on a final basis. The rate design and cost allocation have been conducted as though the Standby class is a sub-class of the General Service 50 to 4,999 kW classification. Please see more details in Exhibits 7 and 8.

1.3.9 BOARD DIRECTIVE FROM PREVIOUS DECISIONS

The settlement proposal underpinning CNPI's 2022 cost of service application [5] contained several commitments between the Parties to the proposal, . CNPI outlines the steps taken towards those commitments below:

Conduct a review of the Short-Term Incentive Program to ensure that it doesn't incentivize capital over-spending and report on the review as part of this Application.

Since the last Cost Of Service, CNPI has completed a review of the Short-Term Incentive measure related to capital program.

CNPI has updated elements of the STI goal related to capital. The measure still reads "effectively manage/optimize consolidated capital plan", however, for the 100% payout, the corporate goal is to meet budget. The previous 50% minimum target was associated with 15% below the budgeted amount, while the 150% maximum was a subjective assessment. The updated 50% minimum target is now also a subjective assessment, and a footnote has been added to explain that the consolidated capital target will consider: "completing projects on scheduled timelines, quality of construction, effective project management especially with third party contractors, safety of construction, and consideration of distribution system plans"

Through this updated STI measure, CNPI has incorporated *adherence* to budget (and DSP) with several other important considerations that assess the quality of the work completed.

Continue the standby charge pending the development of a charge methodology.

Throughout the historic period, CNPI has continued the standby charge on an interim basis as approved in the previous cost of service. In Exhibits 7 and 8, CNPI has proposed an updated methodology for its

[5] Decision and Order in EB-2021-0011, dated December 16, 2021.

Standby charge, and is proposing to implement this methodology and deem the Standby rates as final. CNPI has worked with a third party to determine an appropriate proposed methodology for setting the Standby charge and updating it going forward.

CNPI Agreed to review the continued use of four legacy sub-accounts related to Pension and OPEBs deferrals, which had been established in EB-2013-0368/EB-2013-0369, and to bring forward the results of the review as part of this Application.

- **#C – Account 1508 – Other Regulatory Assets – Pension Deferral sub-account**
- **#D – Account 1508 – Other Regulatory Assets – OPEB Deferral sub-account**
- **#E – Account 1508 – Other Regulatory Assets – Pension Expense Variance subaccount**
- **#F – Account 1508 – Other Regulatory Assets – OPEB Expense Variance sub-account**

Please see Exhibits 4 and 9 for a discussion of the legacy accounts and their continued use.

The Parties Agreed that going forward, CNPI would invite its customers with demand greater than 1MW to an annual meeting with senior management to discuss progress and plans with respect to becoming more efficient and competitive with respect to distribution rates.

CNPI confirms it has held annual meetings with its customers with demand greater than 1MW, typically occurring in Q4 of each year. CNPI has hosted a lunch meeting with these customers, which have had successful attendance. During the meetings, CNPI typically presents updates to customers regarding recent and upcoming projects, efficiency measures, and select other topics, as well as round table discussions. Other topics have included presentations regarding storm response, and a presentation from a representative of the IESO regarding CDM programs for industrial customers.

Parties agreed that during the approved rate plan period CNPI will not change its default billing option from paper billing to e-billing.

CNPI confirms it has not changed its default billing option from paper billing to e-billing. CNPI has undertaken campaigns to improve its voluntary e-billing enrollment over the years, and the occurrence of two Canada Post service disruptions have bolstered e-billing uptake. Further discussion of the cost efficiencies related to e-billing uptake can be found in Exhibit 4.

The Parties further agreed that as part of its next cost of service application that CNPI will review the existing GS 50 to 4999 kW rate class with a view to exploring the possibility of a new rate class for its larger customers.

CNPI reviewed the existing General Service 50 to 4,999 kW Classification, with support from a third party firm knowledgeable in rate-setting. The review indicated that cost savings under a “bifurcated” large customer rate class were likely to be immaterial, while bill stability would likely be worse for some customers. Additionally, it is expected that a new large customer class would increase administrative

effort. For the reasons above, as further detailed in Exhibit 8, CNPI is not proposing to establish a new rate class for larger customers.

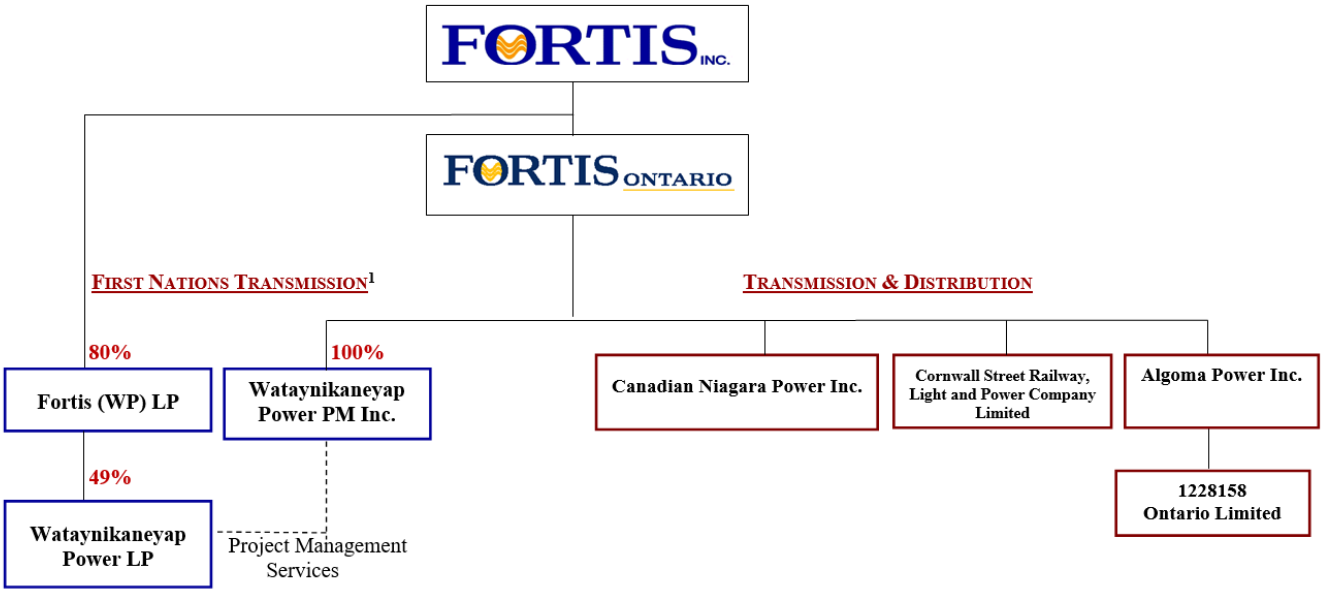
Additionally, in its 2024 License Exemption and Accounting Order application (EB-2025-0081), the OEB directed CNPI to make periodic updates to the OEB regarding the use of the International Power Line (IPL) to purchase power from National Grid in New York State, USA.

CNPI confirms it used the IPL to purchase power from National Grid in 2025. This fact has already been communicated to the OEB in CNPI's 2026 Incentive Rate-Making Application (EB-2025-0050). CNPI has reflected the impacts of the National Grid 2025 purchases in its RSVA balances, consistent with the OEB''s Decision and Accounting Order from EB-2025-0081. Further details can be found in Exhibit 9 of this Application.

1.3.10 CORPORATE ORGANIZATION

The following chart illustrates the relationship between CNPI, its shareholder, and its affiliates carrying on business in Ontario[6]:

Table 1- 18: Corporate Entities Relationship Chart



[1] FortisOntario has a 100% interest in Fortis (WP) GP Inc., the General Partner of Fortis (WP) LP.

[6] Please refer to OEB Case No. EB-2026-0122 for an overview of a proposed internal corporate reorganization affecting the organizational structure between FortisOntario and Fortis Inc.

ORGANIZATION OF ENTITIES

CNPI is a wholly-owned subsidiary of FortisOntario Inc. ("FortisOntario"), which is headquartered in Fort Erie, Ontario. FortisOntario owns and operates generation, transmission and distribution businesses in the province of Ontario. Founded in 1892, FortisOntario began generating electricity in 1905 from its Rankine Generating Station located on the Canadian side of the Niagara River and subsequently began distributing electricity to the Town of Fort Erie in 1907. The Rankine Generating Station ceased operations in 2005 and was transferred to the Niagara Parks Commission in 2009. Accordingly, FortisOntario's operations in Ontario are primarily transmission and distribution.

FortisOntario is the Ontario-based subsidiary of Fortis Inc. ("Fortis"), which is a well-diversified leader in the North American regulated electric and gas utility industry with 2025 revenue of $12 billion and total assets of $75 billion as at December 31, 2025. Its utilities account serve more than 3.5 million electricity and gas customers across Canada and in the United States and the Caribbean.

CNPI is a single corporate entity which has two internal business units: a distribution business (ED-2002-0572) and a transmission business (ET-2002-0073). CNPI's distribution business serves approximately 31,000 customers in the Town of Fort Erie, the City of Port Colborne, and the Town of Gananoque[7]. CNPI's transmission business owns and operates transmission assets in the Niagara Region.

FortisOntario also owns Algoma Power Inc. ("API") (ED-2009-0072), and Cornwall Street Railway Light and Power Company Limited ("Cornwall Electric") (ED-2004-0405). API serves approximately 12,600 customers in the Algoma District and Cornwall Electric serves approximately 26,000 customers in and around the City of Cornwall.

FortisOntario is a licensed generator (EG-2003-0107), which owns a 5 MW natural gas cogeneration district heating plant located in Cornwall, Ontario. The cogeneration district heating facility is an embedded generator selling district heating to local customers and electricity directly to Cornwall Electric, which is isolated from the IESO-controlled grid.

In addition, FortisOntario holds a ten percent (10%) interest[8] in Westario Power Inc. (ED-2002-0515), a 23,000 customer electricity distributor located in mid-western Ontario, a ten percent (10%) interest in Rideau St. Lawrence Holdings Inc. (ED-2003-0003), a 6,000 customer electricity distributor located in southeastern Ontario, and a ten percent (10%) interest in Grimsby Power Inc. (ED-2002-0554), a 11,000 customer electricity distributor located in the Niagara region. Accordingly, Westario Power Inc., Rideau St. Lawrence Holdings Inc. and Grimsby Power Inc. are not affiliates of CNPI as defined under the Ontario Energy Board Act, 1998.

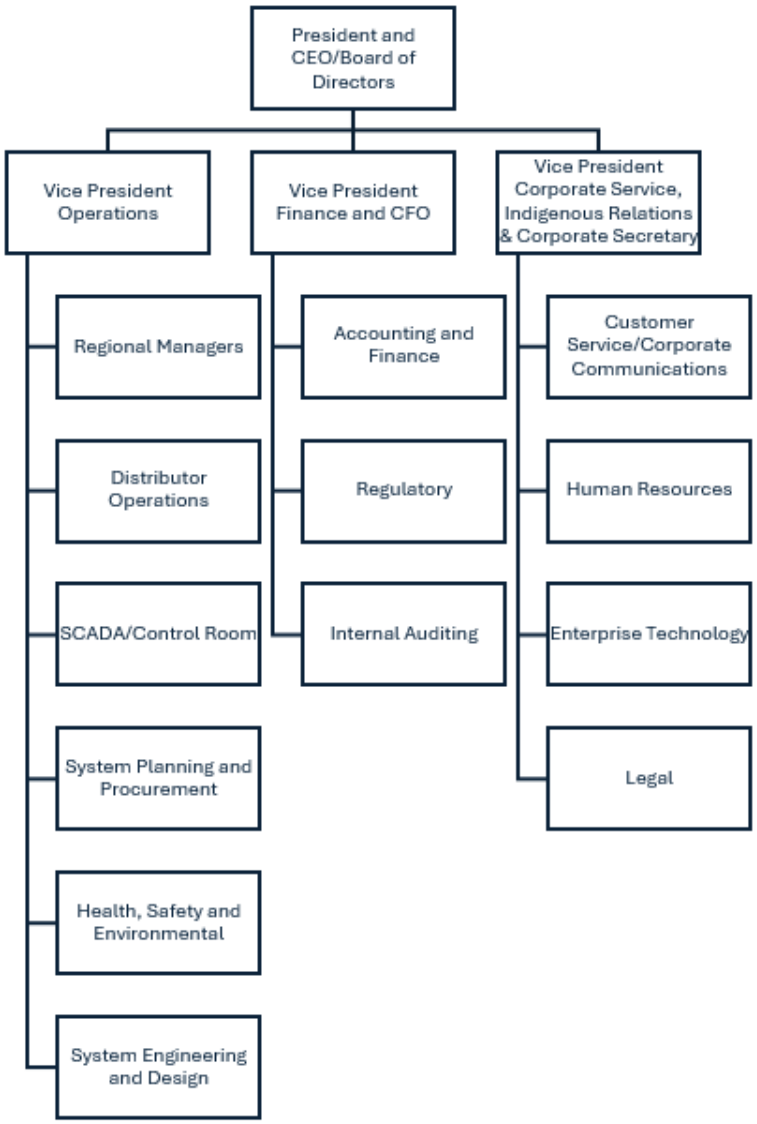
[7] CNPI operates as Eastern Ontario Power ("EOP") in the Town of Gananoque.
[8] Together with all shareholders, FortisOntario has entered into an agreement to sell its 10% interest in Westario Power, subject to Ontario Energy Board approval.

Fortis is also a partner in the First Nations-led Wataynikaneyap Power LP transmission partnership (ET-2015-0264) with 24 First Nations partners.

ORGANIZATIONAL STRUCTURE

The chart below illustrates the CNPI's organizational structure including main units and senior management positions. FortisOntario's CEO and Vice Presidents are also appointed as executive officers of CNPI (i.e. FortisOntario executive officers hold the same position with respect to CNPI).

Table 1- 19: CNPI Organizational Structure



SHARED CORPORATE SERVICES

Shared corporate services being provided to and from CNPI include the following:

- Executive Services
- Finance
- Information Technology
- Human Resources
- Health, Safety and Environment
- Regulatory
- Engineering
- Legal
- Corporate Secretariat

It is anticipated that shared corporate services will continue to be provided between CNPI and its affiliates in the future.

CORPORATE GOVERNANCE

The objective of effective and responsive corporate governance is achieved by continually reviewing structures, policies, and programs against best practices in utility governance.

One of those structures is CNPI's board of directors. CNPI has three directors who serve on its board of directors. Two of CNPI's directors are also executive officers of API, CNPI, FortisOntario, and Cornwall Electric and one other director is independent. The board is structured such that one third of its members are independent. CNPI's Articles of Incorporation indicates a minimum of one and a maximum of 10 directors.

BOARD OF DIRECTORS' MANDATE

FortisOntario ensures a level of consistency in key governance functions of its Ontario operating subsidiaries. The CNPI board does not have a written mandate. In fulfilling its fiduciary duties to CNPI, the CNPI board supervises the management of the business and affairs of CNPI. In doing so, the directors are required to act honestly and in good faith with a view to the best interests of CNPI. Both in legal and practical terms, this means that the board must have regard to the interests of varying CNPI stakeholders, including shareholders, customers, and creditors, as well as exercising independent judgement in determining the best interests of CNPI. In a number of respects, FortisOntario provides key services relating to CNPI's operations and strategic direction. This ensures that the CNPI board has the resources it requires to ensure that its strategy, risk management, internal controls, and processes are consistent and aligned with best practices.

BOARD MEETINGS

CNPI's board is scheduled to meet in Q2 and Q4 of 2025 and 2026.

QUALIFICATIONS AND CONTINUING EDUCATION

CNPI's non-independent directors are also executive officers and/or directors of CNPI, FortisOntario, and its affiliates. This ongoing active engagement on the boards and executive management of FortisOntario and its affiliates ensure that these directors possess and maintain the knowledge, skills, experience, and continuing education required to effectively fulfill their duties as directors of CNPI. The non-independent director is also expected to, and does, maintain the knowledge, skills, experience, and continuing education necessary to effectively discharge their responsibilities as a director. In addition, continuing education sessions are periodically included in CNPI board meetings to broaden the skill and knowledge of directors. CNPI's current independent director is a lawyer with expertise in corporate and commercial real estate law.

CODE OF CONDUCT AND ETHICS POLICY

CNPI has a written Code of Conduct for its directors, officers, and employees, (the "Code" or "Code of Conduct"). The Code is consistent between FortisOntario and all its wholly-owned subsidiaries. CNPI's parent company, FortisOntario, also supports the governance and monitoring of ethical business conduct of CNPI's directors, officers, and employees.

The CNPI board monitors compliance with its Code through board updates and reporting from executive officers of CNPI (who act in a dual capacity as executive officers of FortisOntario) on Code violations. CNPI also has a Policy on Reporting Allegations of Suspected Improper Conduct and Wrongdoing and an Anti-Corruption Policy. In practice, any alleged Code violations would be brought to the attention of the parent company, FortisOntario, and managed in accordance with its policies. Any alleged Code violation involving CNPI would be brought to the attention of the CNPI board by management of CNPI.

1.3.11 LETTERS OF COMMENT

CNPI has not received any letters from its customers related to this application as of the filing date. CNPI confirms that any responses to the matters raised in Letters of Comment will be filed on the public record, consistent with the Filing Requirements, section 2.1.6.

1.3.12 SMALL DISTRIBUTOR PROCESS ELIGIBILITY

CNPI is not submitting this application under the Very Small or Small Distributor processes.

1.4 DISTRIBUTION SYSTEM OVERVIEW

1.4.1 SERVICE AREA OVERVIEW

CNPI's service area generally includes the Town of Fort Erie, the City of Port Colborne, and the Town of Gananoque. Exclusions for certain addresses in these communities and inclusions of specific addresses in neighbouring communities resulting from historical arrangements and eliminations of long-term load transfers are set out in Schedule 1 of CNPI's distribution licence (ED-2002-0572).

The following 3 figures illustrate the general extent of CNPI's service area:

Table 1- 20: Overview of CNPI Service Area

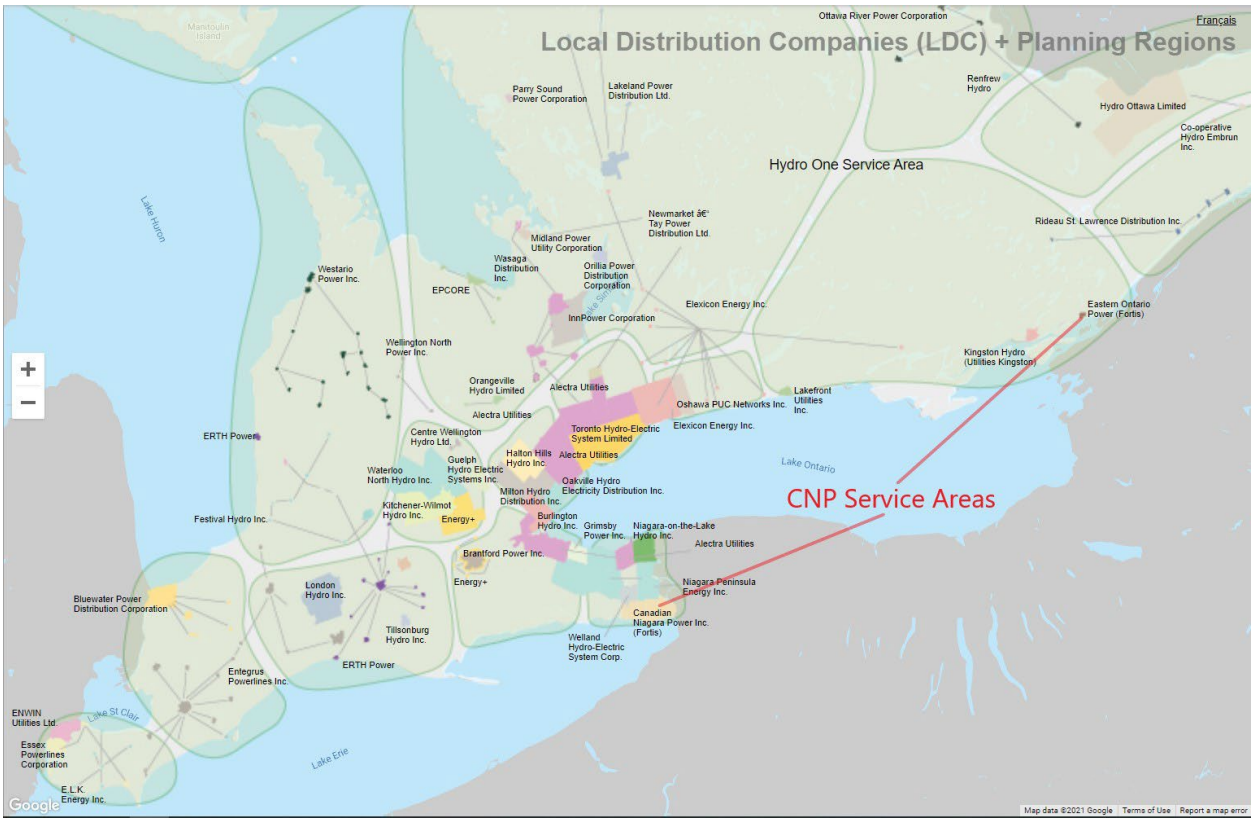


Table 1- 21: CNPI Service Area – Niagara Region

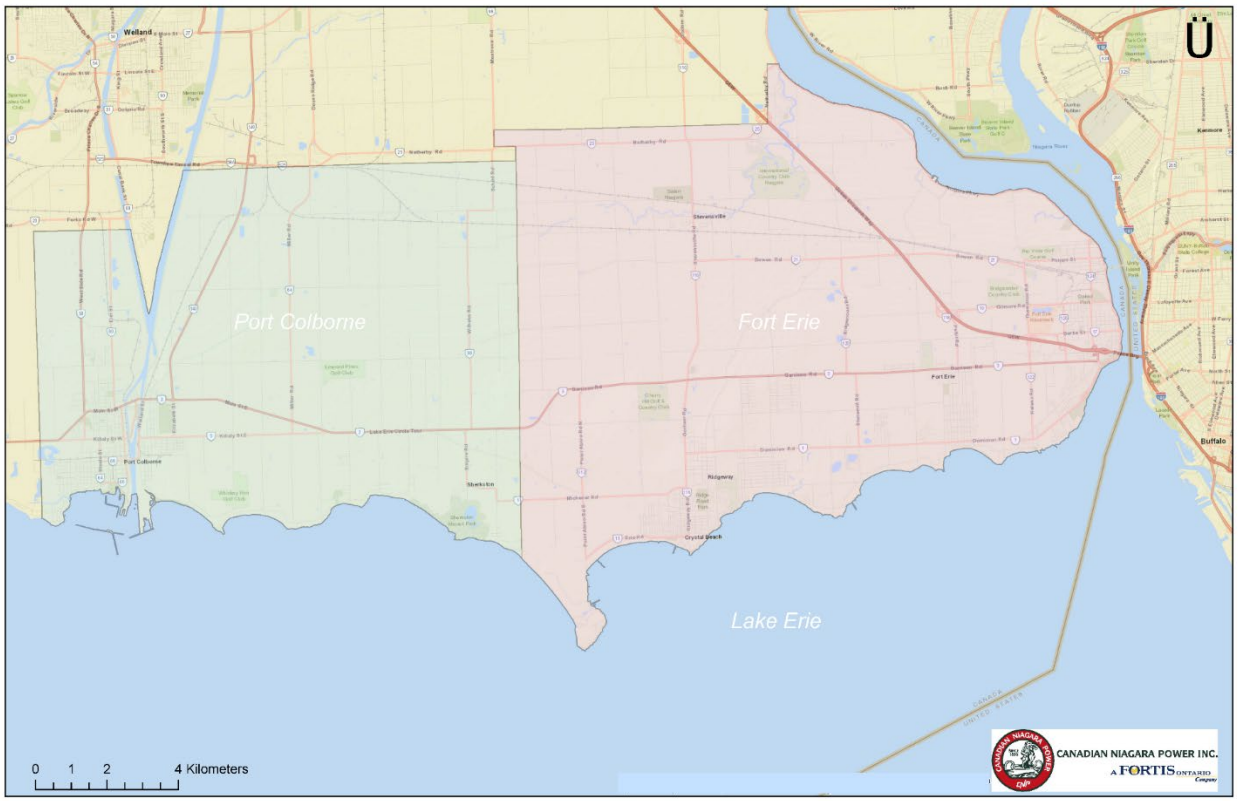
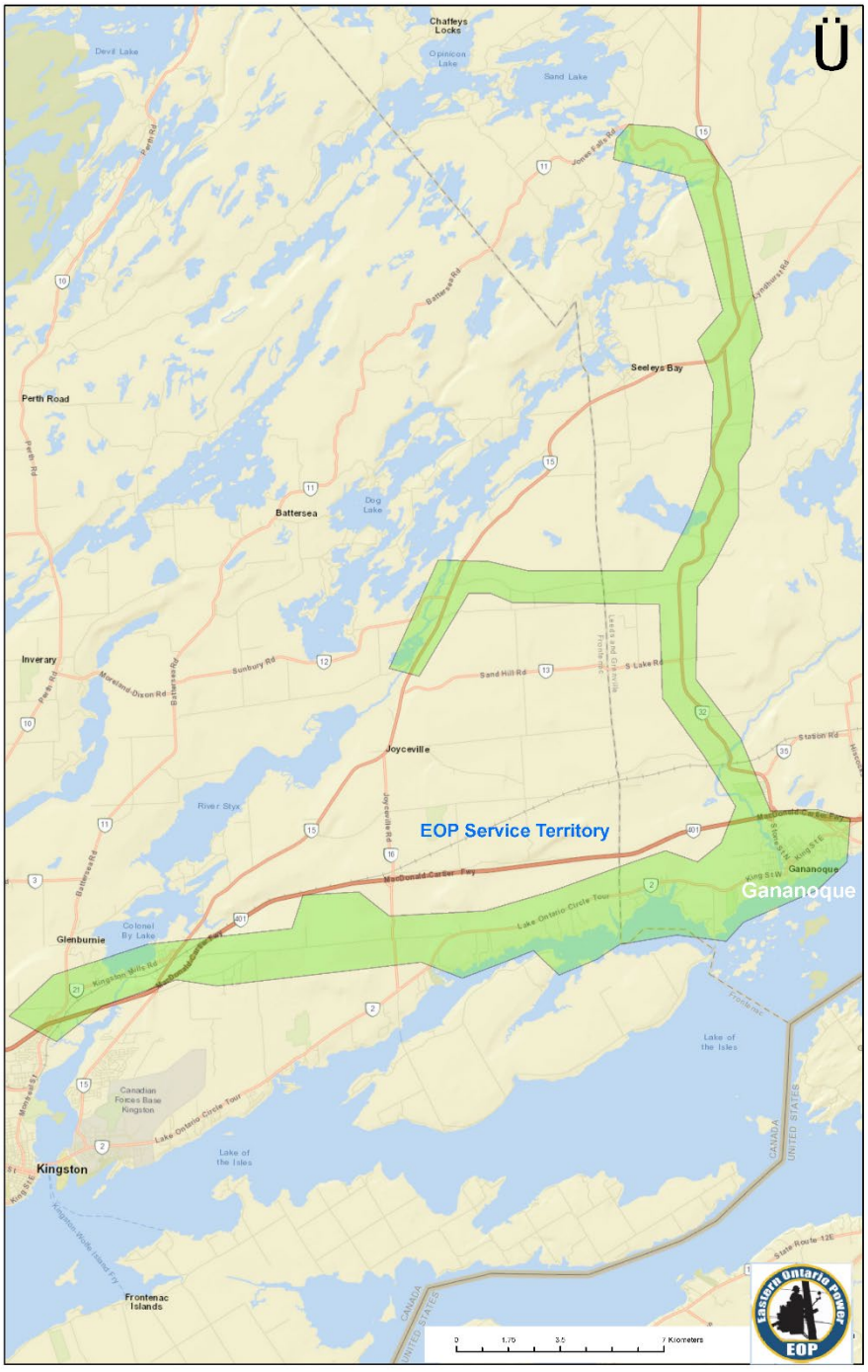


Table 1- 22: CNPI Service Area - Gananoque



1.4.2 HOST/EMBEDDED DISTRIBUTOR AND NEIGHBOURING UTILITIES

As outlined in Section 1.4.1 above CNPI has two distinct operating areas: the Niagara service area and the Gananoque area.[9]

In the Niagara Service area, CNPI is supplied the majority of its load from three transmission delivery points. In the city of Port Colborne, supply is primarily provided at Hydro One Networks' ("Hydro One") Port Colborne Transmission Station. A small proportion of CNPI's load in the Town of Port Colborne can be supplied from an embedded delivery point located on Hydro One's distribution system emanating from the Crowland Transmission Station.

In the Town of Fort Erie, the entire supply is provided from two CNPI Transmission Stations, Station 17 and Station 18, both located in the town of Fort Erie. These two transmission stations are owned and operated by CNPI's transmission business.

In instances where the CNPI Transmission system is under maintenance or construction, CNPI is able to purchase power through the International Power Line (IPL) from National Grid in the United States. This arrangement for temporary provision of power allows CNPI to avoid extended town-wide outages to the Town of Fort Erie when the typical transmission connection is unavailable for planned or unplanned outages.

In the Gananoque service area, CNPI (operating as EOP) is supplied entirely, as an embedded distributor, from Hydro One's 44 kV sub-transmission system.

In total, CNPI receives approximately 87% of its supply from the IESO-controlled grid, 10% of its supply as an embedded distributor to Hydro One, and 3% of its supply from a combination of embedded generation resources in all service areas.

In the Niagara service area, CNPI is a host distributor to Hydro One in the Wainfleet area. On an annual basis, CNPI provides approximately 5 GWh to the Hydro One distribution system at an average demand of 1 MW. CNPI established an Embedded Distributor rate class in its 2017 cost of service application for the purpose of developing rates that appropriately reflect the cost of serving this embedded supply point.

The following table summarizes the Embedded- Host Distributor relationships within CNPI.

[9] CNPI operates as Eastern Ontario Power ("EOP") in the Gananoque service area.

Table 1- 23: Host and Embedded Distribution Relationships

Location	Embedded Dist.	Host Dist.	Notes
Gananoque	CNPI (EOP)	Hydro One	Embedded distribution point is the only feed for all of EOP territory.
Crowland TS	CNPI (NIA)	Hydro One	Alternative feed for a portion of Port Colborne. Not typically in use.
Wainfleet	Hydro One	CNPI	

The following electricity distributors are adjacent to CNPI's service areas:

- Hydro One Networks Inc. (ED-2003-0043)
- Niagara Peninsula Energy Inc. (ED-2007-0749)
- Welland Hydro-Electric System Corp. (ED-2003-0002)

1.4.3 TRANSMISSION OR HIGH-VOLTAGE ASSETS

CNPI does not have any transmission or high voltage assets (i.e. assets operating at >50 kV) in its distribution system that have been deemed by the OEB as distribution assets. CNPI is not asking the OEB to deem any such assets as distribution assets in this Application.

1.4.4 CONDITIONS OF SERVICE

CNPI's conditions of service were last updated on a comprehensive basis in 2022, and are accessible on its website at:

https://www.cnpower.com/conditions-of-service

CNPI notes that in 2025, it made limited updates to its Conditions of Service in relation to the OEB's Electric Vehicles Connections Procedures, consistent with the requirements of the OEB's policy.

CNPI confirms that there are no rates or charges listed in the Conditions of Service that are not listed in its Tariff of Rates and Charges.

1.5 ACCOUNTING STANDARDS FOR REGULATORY AND FINANCIAL REPORTING

1.5.1 ACCOUNTING STANDARD USED IN APPLICATION

CNPI has reported under the Accounting Standards for Private Enterprises accounting standard since January 1, 2011. Previous to January 1, 2011, CNPI reported in accordance with the Canadian Generally Accepted Accounting Principles accounting standard. CNPI adopted MIFRS and confirms that it reflected the required changes to its capitalization policies and depreciation rates in its 2013 cost of service

application (EB-2012-0112). The values presented in CNPI's cost of service applications since EB-2012-0112 and the values presented within this Application have also been reported using this methodology.

1.5.2 COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS

With one exception, CNPI has followed the accounting principles and main categories of accounts as stated in the OEB's Accounting Procedures Handbook (the "APH") and the Uniform System of Accounts ("USoA") in the preparation of this Application. Due to the non-significant dollar value associated with Retail Service Charges, CNPI has not followed the Article 490, Retail Services and Settlement Variances of the Accounting Procedures Handbook for Account 1518 and Account 1548. Further explanation can be found in Exhibit 9.

CNPI has adopted the various account changes prescribed by the Board in relation to the USoA (Article 210 – Chart of Accounts and Account 220 – Account Descriptions).

CNPI confirms that it has implemented the OEB's accounting guidance related to Accounts 1588 (RSVA – Power) and 1589 (RSVA – Global Adjustment), as set out in the letter issued February 21, 2019, and that transactions recorded in these accounts are in accordance with this guidance.

The useful lives proposed by CNPI in this Application are generally consistent with the typical useful lives in the Kinectrics Report commissioned by the OEB dated July 8, 2010, with descriptions provided for any asset classes outside of the Kinectrics ranges. CNPI has not changed its depreciation rates since its last rebasing in 2022, with two exceptions which are further outlined in section 2.2.2 of Exhibit 2.

1.5.3 CHANGE IN TAX STATUS

CNPI is a corporation incorporated pursuant to the Ontario Business Corporations Act and has not had a change in tax status since its last Cost of Service application.

1.5.4 EXISTING / PROPOSED ACCOUNTING ORDERS

The following existing accounting orders apply to CNPI. CNPI is not applying for any accounting orders with this Application.

EB-2013-0369 PENSION AND OTHER POST-EMPLOYMENT BENEFITS DEFERRAL AND VARIANCE ACCOUNTS

On December 12, 2013, CNPI received a Decision and Order from the Board (EB-2013-0369) approving the establishment of specific deferral and variance 1508 accounts related to pension and other post-employment benefits ("P&OPEB"), subject to the conditions of the Order. The description of these deferral and variance accounts can be found in Section 9.2.2 of Exhibit 9. CNPI has continued to book journal entries in accordance with the Accounting Order to record the difference between P&OPEB expenses under Section 3461 and Section 3462. CNPI is not seeking recovery of any variances recorded in these accounts within this Application.

EB-2015-0040 REPORT OF THE OEB RE: REGULATORY TREATMENT OF PENSION AND OTHER POST-EMPLOYMENT BENEFITS ("P&OPEB")

In CNPI's 2017 cost of service application (EB-2016-0061), the OEB found that it was appropriate for CNPI to continue to account for P&OPEB expenses using the accrual method, pending the outcome of the OEB's generic policy consultation.

On September 14, 2017, the OEB issued a report regarding the regulatory treatment of P&OPEB Costs. Within the report, the OEB confirmed the continued use of accrual accounting for these expenses, and established the P&OPEB Forecast Accrual versus Actual Cash Payment Differential variance account on a generic basis, effective January 1, 2018. CNPI has been using the appropriate 1522 sub accounts and is requesting disposition of the accumulated carrying charges as described in Exhibit 9 of this Application.

EB-2015-0304, EB-2021-0302 WIRELINE POLE ATTACHMENT CHARGES

On July 20, 2018, the OEB issued a letter outlining accounting guidance in connection with the implementation of the new pole attachment charge. CNPI had been accumulating the excess incremental revenue along with applicable carrying charges in the 1508 sub accounts that have been prescribed by the OEB. The historical balances pre-2022 were approved for disposition in CNPI's 2022 cost of service application. However, within CNPI's proposed revenue requirement for 2022, a pole rental rate of $44.50 per attacher had been used. The OEB subsequently announced within Decision and Order of EB-2021-0302, that the rate to be charged was $34.76 per attacher for 2022. In accordance with the Accounting Guidance for Wireline Pole Attachment Charges issued on December 16, 2021, CNPI has been accumulating variances since 2022 and is requesting disposition of these sub-accounts, on a forecast basis, as described in Exhibit 9.

EB-2021-0011 PENSION AND OTHER POST-EMPLOYMENT BENEFITS AMORTIZATION OF ACTUARIAL GAINS AND LOSSES

On December 16, 2021, CNPI received the Order from the Board (EB-2021-0011) to remove the amortization of actuarial gains and losses related to Pensions and OPEB in the 2022 revenue requirement. CNPI has been accumulating all actual amortized gains and losses in the 1508 sub accounts and is seeking recovery of any amounts recorded in these accounts within this Application.

EB-2025-0081 APPLICATION FOR AMENDMENT TO ELECTRICITY DISTRIBUTION LICENSE AND AN ACCOUNTING ORDER

On June 17,2025, CNPI received the Order from the Board (EB-2025-0081) to approve the amendment to its distribution license which allowed CNPI to purchase power from National Grid through the New York Independent System Operator (NYISO) during periods when it is supplied by the International Power Line, and also to approve an Accounting Order to facilitate those power purchases. Details of the power purchases from National Grid in 2025 are outlined in Exhibit 9 in section 9.2.3.

1.5.5 ACCOUNTING TREATMENT OF NON-UTILITY BUSINESS

CNPI has transmission and distribution business units, both of which are regulated by the OEB. This Application has been prepared using accounting values attributable to the distribution division only; transmission has been appropriately excluded.

CNPI is not engaged in any other non-utility activities.

1.6 CUSTOMER ENGAGEMENT

1.6.1 OVERVIEW OF CUSTOMER ENGAGEMENT

Ongoing Customer Engagement

CNPI strives to continue to provide services that are valued by its customers, in a safe and cost-effective manner. This requires understanding customers' current and future needs. It also requires a culture of embracing continuous improvement in the services CNPI provides, especially the customer experience. Accordingly, CNPI has implemented a comprehensive customer engagement program, which has evolved in accordance with the expectations of the OEB's Renewed Regulatory Framework for Electricity Distributors.

CNPI's goal is to demonstrate a focus on long term value to customers and in to engage with customers to provide education and to solicit customer feedback. This will lead to the successful implementation of projects that customers consider meaningful.

The following subsections provide detail of CNPI's customer engagement activities across four categories: Customer Satisfaction Surveys, Community Outreach/Stakeholder Sessions, Application- specific Customer Engagement program and Other Supporting Engagement Activities.

1.6.2 CUSTOMER SATISFACTION SURVEYS

CNPI has engaged UtilityPULSE to conduct independent customer satisfaction surveys since 2015. The survey asks questions of both residential and general service customers on a wide range of topics, including: (a) power quality and reliability; (b) price; (c) billing and payment; (d) communications; and (e) the customer service experience. UtilityPULSE typically conducts the survey in the fall of a given year, with final results available in December. CNPI participates in the customer satisfaction survey annually, on a more frequent basis that the OEB's minimum requirement for bi-annual customer satisfaction surveys.

The results are compiled into a final report outlining the overall level of customer satisfaction within CNPI's service area, as well as benchmarking the results against other Provincial and National participants. These results are then used to support internal discussions surrounding what is currently being done well, any opportunities for improvement, and often times, feedback on specific topics or ideas selected by CNPI for a given year.

Table 1- 24: Customer Satisfaction Results 2021-2025

	2021	2022	2023	2024	2025
Customer Satisfaction Survey Results	95%	94%	89%	92%	92%

During this period, CNPI has consistently met its goal of exceeding the Ontario customer satisfaction benchmark, except in 2023. In that year, CNPI attributed the lower-than-benchmark results to significant outages in the previous year caused by a severe weather event occurring at the end of December 2022.

CNPI has established an "Accelerating the Customer Experience" or "ACE" committee. CNPI has selected three initiatives for the committee to pursue in 2026, having directly selected and tailored the initiatives based on feedback received as part of the 2025 and previous customer satisfaction survey results:

1) Improve customer notification mechanisms.

2) Website review and standardization.

3) Education regarding Conservation, Rates and Energy Efficiency.

Since its last Cost of Service application, CNPI has also implemented a customer-facing outage map which allows customers to quickly and easily obtain information regarding an outage in their area. CNPI had previously received customer feedback in support of this initiative. CNPI is also pursuing text-message based outage notifications in response to customer feedback regarding this communication initiative.

1.6.3 COMMUNITY OUTREACH/STAKEHOLDER SESSIONS

This form of engagement is very important to CNPI's understanding of customer and stakeholder needs through face to face interaction.

CNPI meets regularly with municipalities, regional planning authorities, road authorities and other stakeholders in its service areas. These meetings allow parties to communicate upcoming projects and other activities to better understand emerging issues, priority programs and opportunities for synergies.

CNPI also hosts a variety of orientation sessions, safety sessions, and information sessions with local contractors, joint-use partners, first responders and larger customers. These events allow CNPI to communicate key safety messages, discuss upcoming projects/programs and get a better understanding of future developments and work activity in its service areas. The sessions also include discussions on Public Safety issues, Customer Service topics regarding interactions between CNPI and the contractor community as well as any changes to CNPI's customer connection process.

In addition to meeting with stakeholders and larger groups, CNPI also arranges one-on-one meetings with customers as required.

As of 2026, CNPI has begun its involvement in stream 1 of distributor eDSM activities. CNPI has submitted, and the IESO has accepted a plan under which CNPI will support the IESO's eDSM activities through

targeted local marketing coordination. CNPI believes these activities will support customer satisfaction by increasing customers' awareness of programs and tools to reduce and manage their electricity consumption.

1.6.4 OTHER SUPPORTING ENGAGEMENT ACTIVITIES

Beyond the activities summarized above, the following additional customer engagement activities support customer outreach and engagement across a variety of platforms.

Social Media (Outage Communication) – CNPI provides **X** and Facebook updates on planned outages as well as periodic updates during significant storm events. Since CNPI customers also interact with the 24x7 call centre, ongoing dialogue will continue to ensure alignment of communication methods with customer preference is maintained.

Website (General Communication) – The CNPI website (www.cnpower.com) provides a consistent flow of updated customer-centric information. Topics such as distribution services, rates, regulatory matters and decisions, marketing campaigns, conservation and demand management programs are made available in this one-stop location.

Technology Based –CNPI has implemented a more comprehensive customer portal for e-billing and retrieving historical consumption data and is investigating increased self-service options that can be made available through this platform.

Phone and Online Support – CNPI provides telephone and online customer service support. Through these discussions, information is exchanged regularly with every customer interaction. Data gathered through these interactions can then be used to improve business outcomes. In this sense, front line staff becomes pivotal to the business and bridges the gap between the customer and other utility staff.

Publications –CNPI takes advantage of this opportunity to communicate additional information via messages on the outside of the envelope, separate inserts, and messages on the bill itself (or included electronically with e-bills). Many of these messages are coordinated with announcements from the OEB, IESO, and other agencies, and include information about retailers, rate changes, conservation and demand management programs, electrical safety, and references to our website. CNPI also publishes a newsletter (twice per year), which gives information on similar topics to those listed above.

Social Services – Financial Assistance Program: CNPI provides support through partnerships with the province's Low-income Energy Assistance Program (LEAP). Programs of this type are designed to help low-income customers who have difficulty making their electricity bill payments and are regularly communicated to CNPI customers via all media channels.

1.6.5 APPLICATION SPECIFIC ENGAGEMENT

In the process of preparing this Application, CNPI worked with a third-party research firm (Innovative Research Group) to facilitate the 2027 – 2031 DSP and rate application customer engagement. This involved customer workbook surveys intended to gain feedback from the three primary customer

categories: Residential, Small Business and Large Business. Each rate classification received a separate survey format containing the same questions, but reflecting bill and consumption levels appropriate to the rate class.

The response rate for the survey was very successful, with over 2,800 of CNPI's 31,000 customers responding to the survey. This indicated that the response feedback is considered statistically representative of CNPI's customer base and significantly exceeded CNPI's target response rate.

In planning for the future, seven key projects were asked in the workbooks to support participating customers' ability to make choices representative of rate impacts and ultimately drive Canadian Niagara Power Inc.'s spending decisions. The seven projects were as follows:

1. IMPROVING RESILIENCY TO SEVERE WEATHER (System Service- Rebuilds and O&M-Vegetation Management)
2. IMPROVING RELIABILITY USING INTELLIGENT SWITCHES (System Service-Distribution Automation)
3. MODERNIZING OLDER DISTRIBUTION LINES (System Renewal-Delta to Wye Voltage Conversion)
4. REPLACING AT-RISK POLES (System Renewal- Pole Replacement)
5. INVESTING IN ELECTRIC VEHICLES (General Plant- Fleet -Light Vehicles)
6. CONTROL ROOM ENHANCEMENTS (General Plant- Control Room Project)
7. METER REPLACEMENT PROGRAM (System Renewal – Smart Meter Replacement)

For each of these projects, CNPI outlined its proposed approach (and associated estimated cost impacts), as well as alternative options (with associated alternative cost impacts).

For all customer classes, the largest proportion of customers supported implementing the projects (with the exception of a marginally different response for severe weather resiliency- see below) as originally proposed by CNPI, as shown in the table below (an excerpt from the Innovative Research Report). A final question allowed customers to assess the cumulative impact of the overall plan, which most customers once again supported "spend according to draft plan".

Table 1- 25: Summary of 2026 Customer Survey

(%) indicates total percentages that selected response. *Large Business (GS>50kW) shown in frequencies.	Rate Class Unweighted n (Weighted in brackets) Residential n=2,722 (2,500)	Small Business n=101 (100)	Large Business (GS>50kW)* n=9
Improving resiliency to severe weather			
Spend More	53%	48%	5
Draft Plan	47%	52%	4
Improving reliability using intelligent switches			
Spend More	32%	34%	4
Draft Plan	45%	32%	4
Spend Less	23%	35%	1
Modernizing older distribution lines			
Draft Plan	65%	61%	7
Spend Less	35%	39%	2
Replacing at-risk poles			
Spend More	26%	27%	2
Draft Plan	50%	41%	6
Spend Less	24%	32%	1
Investing in electric vehicles			
Draft Plan	54%	47%	8
Spend Less	46%	53%	1
Control room enhancements			
Draft Plan	72%	63%	9
Spend Less	28%	37%	0
Meter replacement program			
Draft Plan	59%	49%	7
Spend Less	41%	51%	2
Overall Evaluation of the Plan			
Spend more	23%	27%	0
Spend according to the draft plan	53%	47%	8
Spend less	13%	19%	0

As demonstrated in the chart above, customers support the plan as presented in the survey for the most part. For this reason, CNPI has not made any changes from the project plans as drafted. Two areas where customers had divided thoughts were in improving resiliency to severe weather and investing in electric vehicles.

With respect to resiliency improvements, a relatively small majority of residential (53%) customers supported increased investments in resiliency measures along CNPI's lake front. Among small businesses the opinion was likewise split, with slightly more customers supporting the draft plan (52%). Similar to the residential group, slightly more large businesses (5 of 9) supported enhanced resiliency spending. CNPI

has *not* adjusted its Test Year budget to increase severe weather resiliency beyond the draft plan, but will consider opportunities within requested test year funding envelope to make incremental improvements in this area, including continuation/expansion of CNPI's off-ROW "dead tree" program in higher risk areas. As noted above, CNPI's continued investments in system renewal and system automation, though not targeted solely at system resiliency improvements, will continue to support enhanced ability to withstand extreme weather.

Regarding the replacement of light vehicles, the majority (54%) of residential customers supported CNPI to continue with its plan to replace certain light vehicles with alternative fuel vehicles (EV or hybrid). A relatively similar proportion of residential customers (46%) indicated CNPI should replace light vehicles with traditional fuel option vehicles. The opinion among small businesses is similarly split, however slightly more customers supported a non-alternative fuel option (53%), while large business customers overwhelmingly (8 of 9) supported the alternative fuel option.

Consistent with the majority feedback, and in line with CNPI's environmental objectives, CNPI will plan to replace the targeted light vehicles with alternative fuel vehicles. CNPI has developed its plan with consideration to the operational appropriateness of alternative fuel vehicles. For example, CNPI will not be investing in alternative fuel technology for its heavy vehicle fleet which for example are required during power outages; with certain incremental equipment "pilot projects" as the exception.

DSP Appendix I of contains the full report detailing the survey results.

In addition to the Application specific customer survey outline above, CNPI has communicated application proposals to the following groups of customers through separate means:

- CNPI reached out specifically to its embedded distributor to outline the cost allocation proposals for its embedded distributor class.

- CNPI communicated with its unmetered class customers (street lighting, sentinel lighting, and unmetered scattered load). The communications included drafted bill impacts, as well as a reminder/request for unmetered customers to notify CNPI of any changes to their unmetered connections and devices.

- CNPI communicated with its existing standby customer on several occasions regarding its planned proposals to update its Standby rate methodology.

1.7 PERFORMANCE MEASUREMENT

1.7.1 SCORECARD RESULTS AND ANALYSIS

Section 5 of CNPI's Business Plan outlines CNPI's performance for each of the scorecard measures over the last five years, explains future targets for each measure, and where applicable describes how past performance and/or future targets have affected the proposals in this Application and DSP. The Business Plan is included as Appendix 1-B. Additionally, CNPI's 2024 scorecard and Management Discussion and Analysis can be accessed at the link below:

Scorecard – Canadian Niagara Power Inc

The chart below shows the forecasted scorecard results for 2025:

Table 1- 26: Forecasted 2025 Scorecard

Performance Outcomes	Performance Category	Measure	2021	2022	2023	2024	2025 (Forecast		Industry Target
Customer Focus	Service Quality	New Residential/Small Business Services Connected on Time	91.8%	96.0%	95.8%	97.5%	100.0%		90.0%
		Scheduled Appointments Met On Time	100.0%	98.6%	100.0%	100.0%	100.0%		90.0%
	Customer Satisfaction	Telephone Calls Answered On Time	81.1%	79.2%	83.8%	80.4%	86.3%		65.0%
		First Contact Resolution	99.3%	99.8%	99.5%	99.6%	99.9%		no target
		Billing Accuracy	99.8%	99.9%	100.0%	99.9%	99.9%		98.0%
		Customer Satisfaction Survey Results	95.0%	94.0%	89.0%	92.0%	92.0%		no target
Operational Effectiveness	Safety	Level of Public Awareness	83.0%	82.0%	82.0%	85.0%	85.0%		no target
		Level of Compliance with Ontario Regulation 22/04	C	C	C	C	C		C
		Serious Electrical Incident Index- Number of General Public Incidents	-	1.00	-	2.00	-		-
		Serious Electrical Incident Index- Rate per 10, 100,	-	0.66	-	1.23	-		-
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted	2.5	1.95	2.25	1.86	2.66		5-year avg
		Average Number of Times that Power to a Customer is Interrupted	1.78	1.67	2.62	1.66	3.04		5-year avg
	Asset	Distribution System Plan Implementation Progress	Completed	Completed	Completed	Completed	Completed		no target
	Cost Control	Efficiency Assessment	4	4	4	4	4		no target
		Total Cost per Customer	$ 905	$ 968	$ 1,134	$ 1,183	$ 1,222		no target
		Total Cost per Km of Line	$ 17,810	$ 19,189	$ 21,458	$ 22,005	$ 23,290		no target
Public Policy Responsiveness	Connection of Renewable	New Micro-embedded Generation Facilities Connected On Time		100%		100%	100%		
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Lia	0.24	0.23	0.21	0.23	0.23		no target
		Leverage: Total Debt (includes short-term and long-term debt)to Equity Ratio	2.69	2.55	2.35	2.07	2.00		no target
		Profitability: Deemed Regulatory Return On Equity	8.78%	8.66%	8.66%	8.66%	8.66%		no target
		Profitability: Achieved Regulatory Return On Equity	3.47%	8.47%	7.90%	7.53%	7.29%		no target

Service Quality

Canadian Niagara Power has consistently exceeded the 90% minimum industry standard for new connections on time, with a five-year average of 95.3%. Scheduled appointments also exceeded the minimum industry standard of 90%, with a five-year average of 99.7%.

CNPI's telephone calls answered on time measure has exceeded the industry standard of 65% with an average performance of 81.1%. This metric may vary from year to year based on the number of phone calls received, and based on internal resourcing.

CNPI strives to improve its service levels by offering more self-serve options to its customers, however the increasing complexity of customer inquiries has added new challenges; for example, a greater level of customer choice for RPP customers may result in longer call times as customer service representatives support customers in understanding and making a choice of pricing plan.

CNPI's goal is to maintain or exceed the strong performance levels in the coming years.

Customer Satisfaction

First contact resolution has remained stable throughout the period, consistently in the range of 99-100% annually. CNPI measures first contact resolution on the basis of calls completed without escalation.

Billing accuracy performance has also consistently been in the 99-100% range, consistently exceeding the industry target of 98%.

Canadian Niagara Power goes beyond the customer satisfaction survey requirements by conducting a customer satisfaction survey annually instead of biennially.

CNPI employs UtilityPULSE to complete the survey annually, which contains a consistent survey questionnaire on the core aspects of service delivery, as well as occasional "new"/ad-hoc survey topics. While the ad-hoc topics are not employed in the measurement of customer satisfaction, the responses to these questions may provide CNPI with insights used for future planning. Customer Satisfaction is consistently a corporate KPI for CNPI, reinforcing alignment with customer preferences. The UtilityPULSE provides a provincial benchmark of satisfaction, and it is CNPI's goal to exceed this benchmark. As shown in Table 1-27 below, CNPI's customer satisfaction results tend to exceed the Ontario average.

Table 1- 27: Customer Satisfaction Results Compared to Industry Benchmark

Year	Ontario Benchmark	CNPI Results
2021	93%	95%
2022	92%	94%
2023	92%	89%
2024	88%	92%
2025	89%	92%

Safety

CNPI has a well-developed corporate safety program, which is further detailed in Exhibit 4. CNPI's most recent 5-year safety performance indicate consistent compliance with Ontario Regulation 22/04 and Public Awareness of Electrical Safety survey results that consistently exceed 80%. This survey is completed by a third party on behalf of CNPI every other year. The successful results can partially be attributed to CNPI's safety awareness programs in the community. During the historical period, (three) serious electrical incidents were reported by the Electrical Safety Authority. All three incidents thankfully concluded without harm and involved homeowners performing unsafe tree management work close to power lines on their property. CNPI has communicated directly with the homeowners in question and the ESA, to apply the appropriate warnings and financial fees. CNPI also maintains communications regarding safety requirements on its website and through other methods of communication, including explanations of safety precautions regarding working near powerlines. In 2026, CNPI is planning enhanced safety communications on its website

Reliability

CNPI's scorecard shows the average number of hours that power to a customer is interrupted (SAIDI) and the average number of times that power to a customer is interrupted (SAIFI). CNPI's most recent SAIDI

and SAIFI targets apply to 2022-2026, and are based on 2017-2021 performance. In 2022-2025, CNPI has performed favourably compared to the targets for SAIDI (2.76) in all years and SAIFI(2.03) in most years. 2023 and 2025 performance missed the target SAIFI, but all other years compared favourably to target.

2023 SAIFI performance was influenced by defective equipment outages, including one significant outage caused by the failure of a conductor sleeve, which involved a relatively high number of customers impacted, with four other defective equipment outages at the sub-transmission level which impacted a larger number of customers. 2025 performance was influenced by two weather events in November and December of that year, which affected a larger number of customers (but did not meet the definition of a Major Event Day). 2025 SAIFI also reflected an increase in planned outages as a result of necessary outages for CNPI's Delta-to-Wye voltage conversion work. CNPI works to minimize the impacts of planned outages, as well as communicating in advance with affected customers. CNPI notes that strong SAIDI performance in these years indicates that when outages occur, CNPI is able to restore power on a timely basis.

The scorecard measures for reliability exclude outages that are caused by loss of supply (ie: upstream in the electricity system, and outside of CNPI's control), as well as Major Events (ie: weather events that exceed the standards which the distribution is designed to sustain).

Distribution System Plan Implementation Progress

On an annual basis, CNPI reviews its progress compared to the distribution system plan in order to make an assessment of the year's accomplishments. Considerations include the completion and timing of key projects, the management of projects in a safe and environmentally sound manner, and adherence to annual and cumulative budget. Developments outside of CNPI's control are also factored in, such as the need to reprioritize projects in response to higher-than-expected customer connection requests, emerging risks identified through ongoing inspections and testing that were not apparent at the time of initial project prioritization, etc. Considering all of these factors, CNPI assesses DSP implementation each year as "Completed" or "Incomplete". The assessment is reported annually on CNPI's distribution scorecard. For the historic period, CNPI has assessed the annual DSP Implementation measure as consistently "Completed", reflecting that the planned work, as adjusted for unplanned requests and reprioritization of other projects, has generally been completed.

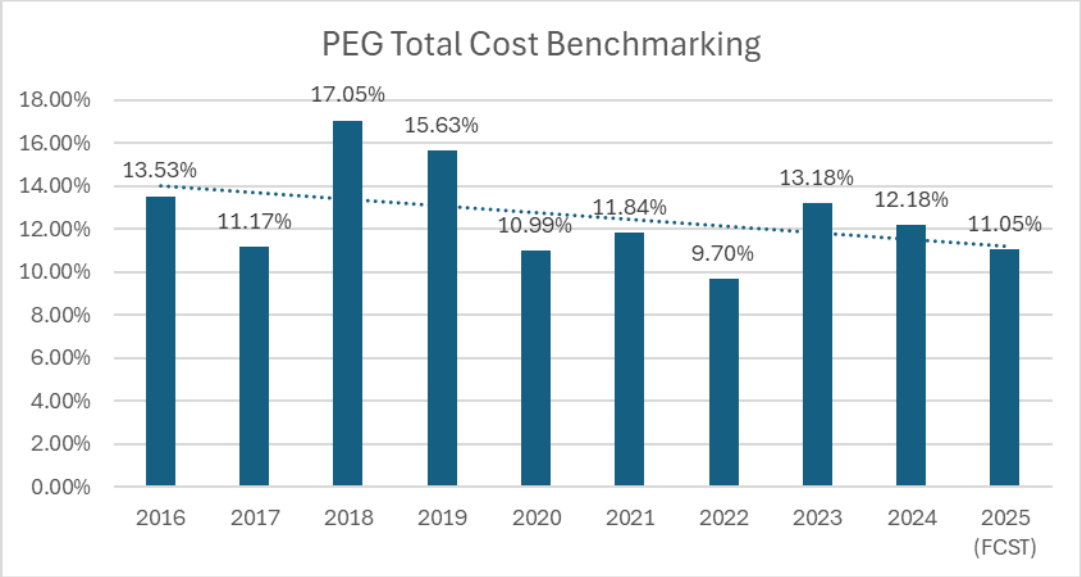
Cost Control

Pacific Economics Group (PEG) issues a total cost benchmarking and efficiency assessment annually, which assesses the performance of all Ontario LDCs. PEG also assesses a total cost for each distributor, which is also shown divided by the number of customers and km of line, to provide unit based metrics.

CNPI's cost performance, according to the OEB PEG Benchmarking model, shows an improving trend over the last decade, following investments in the recent historical periods to support customer growth, reliability improvements, and meeting growing regulatory and customer expectations. The table below shows the 10-year annual efficiency for CNPI as assessed by PEG, including an overall decreasing trend over the period. CNPI notes that the benchmarking results have been affected by the treatment of

shared ET costs up to the 2020 results, which resulted in overall poorer efficiency performance in those years.

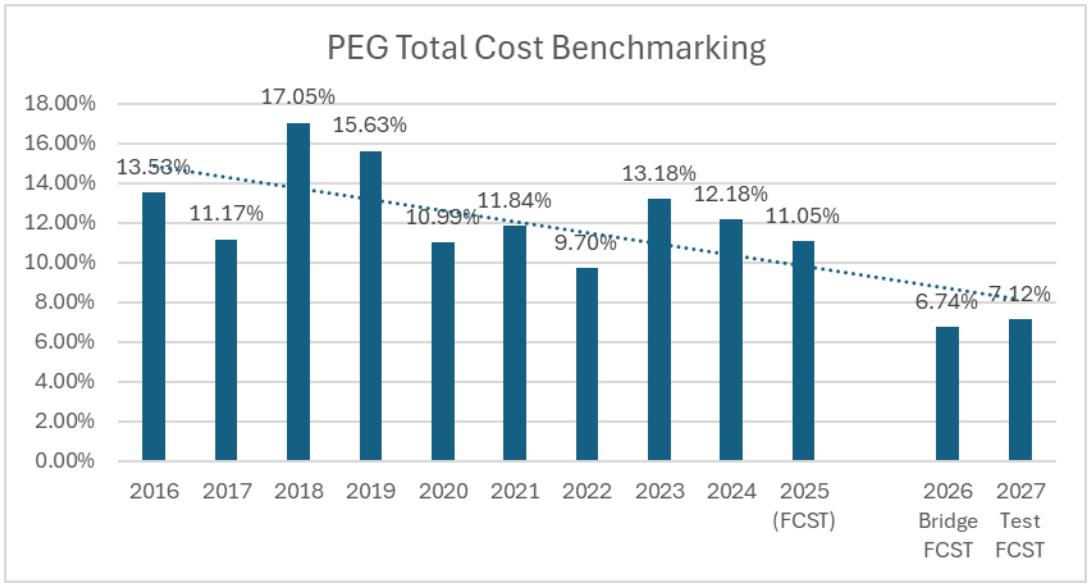
Table 1- 28: Total Cost Benchmarking Results- Historic



1.7.2 TOTAL COST BENCHMARKING

CNPI's historical and forecasted efficiency assessment for the 2016-2027 period, using the OEB's Benchmarking Forecast Model, is shown below:

Table 1- 29: Total Cost Benchmarking with Forecast



CNPI has consistently been assigned to Cohort Group 4 (associated with a 0.45% stretch factor) throughout this period.

The following items have a significant effect on CNPI's historical benchmarking results:

- Prior to 2020, CNPI's actual costs in the PEG model reflect 100% of the capital investments related to providing shared IT services to affiliates using assets owned by CNPI.

- The significant increase in customer and third-party driven investments in the 2017-2025 period resulted in capital investments in the System Access category significantly above typical levels. The PEG model captures the gross costs of these investments, ignoring the corresponding increase in CIAC which serves to offset increases in rate base and ultimately revenue requirement.

- CNPI's customers are spread among two non- contiguous service areas, located in Niagara and Gananoque regions. This characteristic means that for some functions, CNPI must incur a higher level of certain fixed expenses compared to the cost that would be required to serve the same number of customers, system load, etc. for utility with one contiguous service territory.

- CNPI's annual capital investments over the recent period have affected the total cost benchmarking assessment.

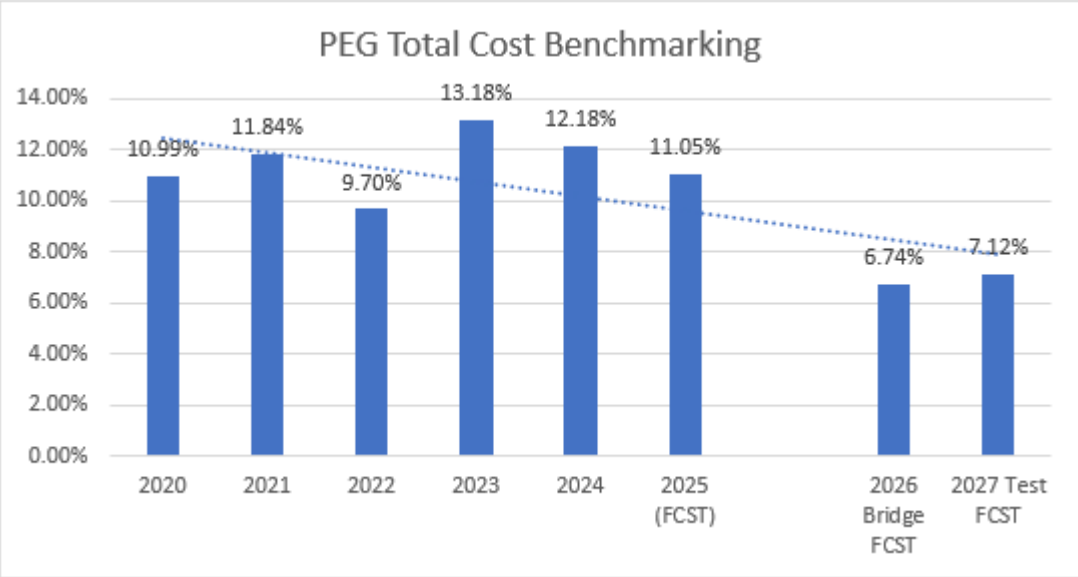
The results above show a declining trend in the most recent actual PEG assessments, 2020-2027 (ie: the years since the approach to IT services has been adjusted). CNPI has used the OEB's benchmarking model to forecast the results for 2025 based on the RRR data to be submitted in April 2026, with 2026 and 2027 forecasts based on the Bridge and Test Year figures forecasted in this Application.

CNPI notes that the benchmarking model forecasts a significant improvement in 2026 and 2027 performance; while CNPI is pursuing improvements in cost efficiency through measures throughout its business, CNPI is also aware that the Benchmarking model and Forecast model have a high sensitivity to inflation factors (or their assumptions in the forecast model) including wage growth, economy-wide inflation, and rate of return, and the outcomes of the actual benchmarking efficiency assessments may be different that those shown below as a result of the actual results for those factors. For this reason, CNPI does not have a strong level of confidence that the 2026 and 2027 results will see CNPI moving to an improved efficiency cohort (ie: from cohort 4 to the more efficient cohort 3). CNPI has input the figures for 2025 and 2026 based on the OEB-issued rate-setting parameters for those years, and kept the 2027 forecast consistent with the most recently issued figures (2026).

CNPI's total cost is influenced by the cumulative capital additions and annual OM&A. With capital additions in 2026 showing a reduced level in an effort to achieve greater adherence to the 2022-2026 DSP, the results for the Bridge Year are expected to be a strong improvement in cost performance compared to predicted cost. While improved cost efficiency performance is a target outcome for CNPI, this reduced level of annual capital additions is not expected to continue into the 2027-2031 period, as a result of the distribution system needs and forecasted customer requirements which are outlined in the Distribution System Plan, including the investments in reliability-supporting projects which will enable

CNPI to achieve its continuous improvement targets for reliability. Similarly, CNPI has undertaken and will continue to undertake cost saving initiatives in its OM&A programs (as summarized in Table 1-32 below), however increasing cost pressures and the need for OM&A spending to deliver CNPI's target outcomes will continue to challenge CNPI's ability to make achieve year-over-year OM&A cost savings.

Table 1- 30: Total Cost Benchmarking 2020-2027



1.7.3 ACTIVITY AND PROGRAM-BASED BENCHMARKING

CNPI has continued to monitor the annual updates to the Activity and Program Based Benchmarking, which compares unit costs for certain groups of USOA Accounts related to a single program

The OEB has selected ten programs to include in its review: six OM&A programs and four Capital Additions programs.

For each program, the OEB has selected a "unit" that is reported each year by each distributor, to act as a denominator to scale or normalize costs between distributors and from one year to another. The Units should generally represent a major driver of costs in the program, for example the unit for the Billing O&M program is number of customers, because items such as internal labour, postage, paper, and other billing-related costs typically increase with each incremental customer.

The most recently released OEB Unit Cost Benchmarking Report contains 2020-2024 data. CNPI has included forecasts based on 2025 actual data and 2026/2027 bridge year data.

Generally, CNPI has not made planning decisions as a result of the APB report data. CNPI monitors and reviews the annual APB results. Drivers of year-over-year changes in CNPI's own performance are typically already known through other capital and OM&A forecasting and variance analysis. CNPI's unit cost performance compared to other utilities could theoretically provide information on programs with opportunities for improvements in cost performances, however there are usually too many factors

affecting sector results to infer with confidence whether and where cost-saving improvements may be available and appropriate (without negatively impacting other cost areas, or service quality and other critical outcomes).

Consistent with the requirements outlined in Section 2.1.7 of the Filing Requirements, CNPI has provided an analysis of the year-over-year trending, including forecasted Bridge and Test Year unit costs, as well as a comparison to the five-year industry average below, with explanations focused on the following variances as outlined in the Filing Requirements:

- year-over-year or annual vs. average cost differences in excess of 20%; and
- increases compared to industry average exceeding 25%.

For this (APB) section only, CNPI has used the two criteria above to define "materiality".

Table 1-31 below summarizes the unit costs for each metric per the most recent APB report, and the forecasted 2025, Bridge and Test year amounts, highlighting the data points that meet one of the materiality criteria above.

Table 1- 31: APB Unit Costs Results and Forecast

	Historical (APB Report)					Forecast (based on Actuals)	Forecast (Based on Bridge/Test)		APB Report	APB Report
Measure	2020	2021	2022	2023	2024	2025	2026	2027	2020-2024 CNP Average	Industry Average
Billing O&M	$ 13.25	$ 12.68	$ 11.82	$ 12.19	$ 11.51	$ 12.32	$ 13.76	$ 13.74	$ 12.29	$ 27.17
Metering O&M	$ 27.05	$ 28.29	$ 27.65	$ 28.26	$ 32.36	$ 31.71	$ 29.32	$ 33.31	$ 28.72	$ 13.25
Vegetation Management O&M	$ 24.79	$ 25.66	$ 26.06	$ 27.69	$ 26.23	$ 28.32	$ 28.28	$ 28.84	$ 26.09	$ 65.23
Lines O&M	$ 1,368.87	$ 1,310.54	$ 1,419.54	$ 1,550.01	$ 1,297.30	$ 1,320.02	$ 1,174.11	$ 1,340.55	$ 1,389.25	$ 1,118.90
Stations O&M	$ 672.27	$ 527.55	$ 372.30	$ 387.88	$ 431.05	$ 861.87	$ 1,023.92	$ 1,080.85	$ 478.21	$ 1,453.19
Poles, Towers O&M	$ 8.15	$ 6.08	$ 2.55	$ 7.03	$ 5.56	$ 5.75	$ 4.97	$ 5.46	$ 5.87	$ 12.87
Stations CAPEX	$ 4,641.21	$ 200.59	$ 20,501.43	$ 11,063.83	$ 5,919.69	$ 661.85	$ 528.11	$ 8,605.43	$ 8,465.35	$ 3,171.28
Poles, Towers CAPEX	$ 4,514.64	$ 5,954.15	$ 5,306.27	$ 7,950.59	$ 8,277.58	$ 9,283.49	$ 7,546.11	$ 8,901.81	$ 6,400.64	$ 17,645.80
Line Tranformer CAPEX	$ 7,337.28	$ 9,259.33	$ 7,076.89	$ 18,877.70	$ 15,930.55	$ 8,069.65	$ 8,069.65	$ 8,069.65	$ 11,696.35	$ 14,792.93
Meters CAPEX	$ 16.14	$ 10.85	$ 8.02	$ 33.76	$ 19.62	$ 17.16	$ 11.09	$ 50.62	$ 17.68	$ 32.72

indicates data points that CNPI has adjusted from APB report
indicates a material variance explained below

Billing O&M

Year-over-Year Change:

There have not been any material increases from the previous year or from the 5-year average for 2020-2024.

Forecast Years:

Forecasted Billing O&M costs per unit for 2025-2027 are not materially different than the historic years.

Comparison to Industry:

CNPI's billing costs per unit are -55% lower than the industry average billing unit cost. While CNPI could attribute some of this difference to various CNPI initiatives (e-billing and bill stock efficiency, degree of billing automation), it is possible that differences in accounting practices between distributors may contribute to this variance. The major costs recorded in CNPI's account 5315 include postage, print and paper costs, as well as billing labour.

Metering O&M

Year-over-Year Change:

There have not been any material increases from the previous year or from the 5-year average for 2020-2024.

Forecast Years:

Forecasted Billing O&M costs per unit for 2025-2027 are not expected to be materially different than the historic years.

Comparison to Industry:

CNPI's metering O&M per customer for the historic period is $28.72, which is 117% higher than the industry average of $13.25. CNPI's relatively lower customer density could explain a portion of this difference. It is possible there are differences in the types of costs included in the Metering O&M costs that have driven this variance, for example, if there are items that some distributors classify as billing collecting or customer service costs which CNPI classifies as meter reading costs this may explain the lower-than-benchmark billing costs and higher-than-benchmark metering O&M costs.

The costs included in the metering program accounts include various third party metering, meter reading, meter disconnects, and meter operator expenses, as well as internal metering labour.

CNPI notes that the majority of distributors, 36 of 53 have higher-than average unit costs for this metric, and with a smaller majority, 30 of 53 exceeding the average unit cost by more than 25%. CNPI notes there may be some correlation between very large utilities and low unit costs in this Program[10].

CNPI has not made any specific adjustments to its planning in response to this Unit Cost Benchmarking metric. Metering O&M spending is required to support accurate meter reading and billing and the safe operation of the meter population. CNPI will continue to monitor APB and other information sources in an effort to determine what is causing a difference in Metering O&M unit costs compared to industry, and whether any action is appropriate.

Vegetation Management O&M

Year-over-Year Change:

[10] Alectra, Toronto Hydro and Hydro Ottawa are among the utilities with lower-than average cost in the Metering O&M Program.

There have not been any material increases from the previous year or from the 5-year average for 2020-2024.

Forecast Years:

Forecasted Vegetation Management O&M costs per unit for 2025-2027 are not expected to be materially different than the historic years.

Comparison to Industry:

CNPI's Vegetation Management unit costs are -60% lower than industry average, or -$39.14 per pole. These results are non-intuitive, as CNPI has a relatively lower-density, more rural service territory than average, which would typically be associated with an increase in the level of tree coverage and vegetation management costs. There is a relatively high degree of variability in unit costs between distributors. CNPI's Vegetation Management costs are primarily related to third-party tree trimming, grubbing, and brush control, as well as some minimal internal CNPI labour allocation.

Lines O&M

Year-over-Year Change:

There have not been any material increases from the previous year or from the 5-year average for 2020-2024.

Forecast Years:

Forecasted Lines O&M costs per unit for 2025-2027 are not expected to be materially different than the historic years.

Comparison to Industry:

CNPI's Lines O&M cost per circuit km of line is within 25% of the industry average.

Stations O&M

Year-over-Year Change:

For the most part, there have not been any material increases from the previous year or from the 5-year average for 2020-2024. 2020 unit costs were higher than the 5-year average by 41% driven by required work at one station (Beach Station).

Forecast Years:

CNPI is forecasting an increase in Stations O&M costs, without an increase in station MVA. 2025 unit costs are expected to be a material increase over the 2020-2024 period, driven by an unexpected oil change at one of CNPI's stations (station 19). In the 2026 and 2027 forecast years, CNPI anticipates a greater stations

O&M cost, associated with increased OT cybersecurity activities. There is no increase in the MVA associated with this activity.

Comparison to Industry:

CNPI's Station O&M is average over the historical period is -67% or -$975/MVA lower than industry average for the 2020-2024 period. CNPI forecasts that its unit costs for this metric will increase but remain below the industry average. A variety of factors affect station maintenance costs, other than the installed total MVA (including, for example, the average age and condition of the stations and station assets). Stations O&M costs typically include internal labour and external contract services performing routine and ad-hoc maintenance activities for CNPI's distribution substations.

Poles, Towers and Fixtures O&M

Year-over-Year Change:

Poles, towers and fixtures O&M has been relatively steady over the historic period, with the exception of a significant decrease in 2022. As a result of the decrease in 2022, the increase in 2023 costs (which is similar to 2020 total costs, and a lower per-unit cost than 2020), shows as a 175% increase, however in reality this is a return to relatively normal levels, as a result of reduced pole testing delays in 2022, with some catch up costs affecting 2023.

Forecast Years:

Forecasted costs are not expected to be significantly different than the historic unit costs for this metric.

Comparison to Industry:

CNPI's unit cost for Poles and Towers O&M is -54% or $6.99 lower on a per-pole basis compared to the industry average. CNPI cannot attribute this lower cost to a specific initiative or factor, but notes there are several other utilities with costs per pole in this range. In the future years, CNPI plans to continue its pole testing program in order to improve the available data regarding its pole population, to enhance its asset condition assessment and analysis capabilities.

Stations CAPEX

Year-over-Year Change:

For CNPI, station capital additions vary from year to year based on the planned and necessary station-related projects in that year. This could include relatively inexpensive replacements of small components at the station (lower cost, more frequent), larger component repairs/replacements/expansions, or the construction of an entirely new substation (highest-cost, less frequent). Aside from very large utilities, most LDCs will not have a large enough population of substations that would result in stable year-over-year spending on station capital. The unit measure in this metric is total MVA. CNPI notes that station capital spending would not be expected to have a linear correlation with station MVA, as there are many stations investments that are not associated with MVA increase. 2022 capital additions increased

materially compared to prior year and compared to CNPI's average due to the commissioning of two stations- Rosehill and Catharine Stations.

Capital Additions in 2023 were materially higher than CNPI's five-year average because of work at the Port Colborne TS Exit Feeder, EOP Substations work, and Sherkston Shores Substation Transformer. This work did not contribute any significant change in total station MVA but was necessary to address reliability and aging assets at these stations. Further details on these projects can be found in the variance analysis included in Exhibit 2 and the DSP.

Forecast Years:

This metric is expected to increase beyond 20% on a year-over-year basis in 2027, as a result of a planned project at the Gananoque Main station, which is a relatively high-priority (#5 ranked) Test Year project to address contingency risk at the Gananoque Main station to reduce the potential for long-duration, costly outages under certain scenarios. The project is outlined in the DSP, where the project narrative is included as Project 1 in DSP Attachment B. There is no increase in MVA associated with the project.

Comparison to Industry:

CNPI's station CAPEX per MVA, according to the most recent benchmarking report is 167% or approximately $11,000 higher than industry average. CNPI attributes this increase to the type of station investments for CNPI during this period, as CNPI constructed two new stations and made significant investments in several others. Other utilities affecting the industry average may not have made significant investments during this period, so their cost per unit may be based on minimal investments only. CNPI notes that it has a relatively high number of distribution substations, due in part to the distribution system challenge created by the variety of legacy voltage systems present in CNPI's service territory. Other distributors may have fewer substations (or none), and therefore less frequent investment requirements. This circumstance is relatively outside of CNPI's control, and CNPI must continue to make investments in substations, where appropriate per its asset management processes and distribution system planning objectives.

Poles, Towers CAPEX

Year-over-Year Change:

Poles and Towers CAPEX has had higher than 20% increases in 2023 compared to CNPI's 5-year average and prior year, as well as higher than 20% increase in 2024 compared to 5-year average. CNPI has experienced a significant increase in the unit price per pole experienced over the recent history, influenced by COVID-related impacts. As CNPI maintains an inventory of poles for future use, the timing of when these higher-cost poles went into service may be later than the years in which the poles were purchased, causing a lag in the reflection of higher per-unit purchase prices to capital additions. Work in 2021, 2023 and 2024 related to pole replacements, line rebuilds and voltage conversion was relatively high and this is likely what contributed the year over year trend in this measure.

Forecast Years:

CNPI expects the unit costs in the forecast years to increase, as CNPI continues its pole replacement, line rebuild and voltage conversion programs, and as the impacts of previous and further inflationary pressures materialize. As a result of its Climate Change Vulnerability Assessment, included as DSP Appendix F, CNPI may also consider increasing the size or classification of poles in areas of the system with greater climate vulnerabilities, attracting a higher per-unit material cost. CNPI does not anticipate this will have a significant impact on its overall annual cost per unit, when averaged with the impacts of other projects.

Comparison to Industry:

The unit cost assessed for CNPI for Pole CAPEX is -64% or -$11,245 lower than industry average for the same period. CNPI cannot confidently determine why its cost performance would be lower, and this performance may be driven by factors that are outside of LDCs' control. For example, in some areas of CNPI's service territory, the ground conditions necessitate rock excavation in order to install a pole. Pole installations in these areas would have a significantly higher (ex: 35%) cost to replace, all other factors equal, however this requirement does not apply to the majority of the service area.

CNPI has a number of initiatives aimed at managing its assets in a way that balances cost control and operational objectives. CNPI's proactive pole replacement program helps mitigate the risk of in-service pole failures, which are much more costly when they occur (in addition to causing outages). Additionally, when possible, CNPI coordinates pole replacement work for end-of-life poles with other planned work in the same area. This practice minimizes the installation cost per pole compared to completing a "one-off" pole replacement.

Line Transformers CAPEX

Year-over-Year Change:

CNPI's year over year and/or year vs. 5-year average cost per line transformer had material increases in 2021, 2023, and 2024. Following a review of the data in the APB report, CNPI will review its methodology for reporting number of transformers as part of the 2.1.5.8 report, as there may be a mismatch between the timing of the cost of line transformers and the year the transformer (unit) is reported. CNPI's accounting practice, consistent with the treatment of major spares in the Accounting Procedures Handbook, is to capitalize transformers when they are received. The same treatment applies to meters, but most other assets are only capitalized when they are energized.

When a transformer is installed/replaced in the field, the labour and other costs for the installation are also capitalized with the asset. Therefore the annual capital additions represent the transformers received in a particular year, together with the labour/other costs required to install transformers in that year. CNPI has historically reported the number of transformers installed in a year as part of 2.1.5.8. CNPI believes this reporting has affected transformer unit cost, particularly in 2023 and 2024, when the number of purchased transformers may have driven an increase in the additions to account 1850, but the number of transformers installed appear to be shown in the unit.

In comparing purchasing data, CNPI has noted a significant increase in the cost per unit for the same model of most transformer models. CNPI analyzed cost data from 2019-2024, which indicated a unit cost increase of approximately 50-60% during this period. These cost increases, driven by supply chain issues associated with COVID, have impacted the cost trending in recent years. CNPI expects similar pressures would have been experienced by all other Ontario distributors.

In recent years, CNPI increased its inventory of transformers given the increase in the number of units required for key projects such as Voltage Conversion and line rebuild projects, particularly in light of increases/delays in delivery times.

Forecast Years:

CNPI anticipates the market cost for transformers to continue to increase over the forecast period. Increases in unit cost may also be driven by requirements to increase the number of larger-capacity transformers for new builds/service upgrades, as a result of increasing electrification (including EV uptake).

Comparison to Industry:

CNPI has noted some discrepancies in the industry averaging for the Transformer CAPEX measure. Depending on the calculation methodology applied, the industry average can be $14,793, or $10,794 (as presented). Using either calculation, CNPI is within 25 % of the industry average cost per transformer, and using a benchmark of $14,793 (average of the "industry total" annual averages), CNPI is -21% lower than the industry average. With the possible unit data correction noted regarding the number of transformers purchased, CNPI believes its unit costs would be lower, and even more favourable to industry average. Factors including accounting practices, inventory management practices, asset management practices, and customer make up (ex: proportion of residential vs. higher-cost industrial load) could impact transformer capex unit costs.

Meters CAPEX

Due to a reporting issue, CNPI's reported meter capital additions for 2022 in the APB appear as "0 NIL". In reality, CNPI reported approximately $244,000 in meter additions in 2022, via various sub-accounts of account 1860. Only the NIL sub-account was pulled into the APB filing. CNPI confirms its FAC reporting in RRR 2.1.5.8 (total capital additions) included the correct amount, and that the correct amount of meter additions has been included in the FAC schedules in Exhibit 2.

Year-over-Year Change:

As with transformers, CNPI capitalizes meters upon receipt, which contributes to the capital additions under account 1860. Additionally, any labour and other costs to install meters on a customer's premise are capitalized in the year the meter is energized. The unit basis for Meters CAPEX is number of customers, which is relatively stable. If investments in meters for new customers were the only metering capital additions, then a customer-based metric (specifically number of *new* customers in the year) would a driver of meter capital; however metering additions also relate to the replacement of end of life meters,

as well as meter changes when a customer upgrades their service ,ie: there are many circumstances with no increase in number of customers, but capital addition is required.

The denominator for meter capex (total, cumulative number of customers) has remained relatively steady over recent years, however CNPI has purchased and installed new meters annually to accommodate customer growth, customer upgrades, and end of life meter replacement.

After correcting for the reporting issue above for 2022, the meter additions for 2023 remain higher than 2022 and higher than CNPI's 5-year average. Meter purchases in 2023 were higher due to COVID-related supply chain delays in the receipt of some meters ordered in 2022 and 2021. CNPI also made a significant investment in wholesale revenue metering equipment as part of its Port Colborne TS project that is reflected in the 2023 additions.

Forecast Years:

CNPI is planning to undertake a 10-year project to replace its population of aging smart meters, which will increase meter additions in the forecast years. Further details related to this project can be found in the DSP, particularly Project #13 under DSP Appendix B. If the APB units measure for Meter Capital remains customer related, the projected cost per customer will increase, because meter replacements will occur for most of CNP's existing customer base over the coming years. As the program will target smart meters, which are the lowest unit cost of all CNPI's meter types, the per-*meter* cost should not increase to the same extent. CNPI expects other LDCs will face similar trends, as all LDCs will need to address an aging smart meter population, and will likely face similar input costs.

Comparison to Industry:

CNPI's unit cost per customer is -46% lower or $15 lower than the average meter capital addition cost per customer. As discussed above, CNPI expects metering additions to increase over the short to medium term, both for itself and the industry, in response to the large population of smart meters installed around 2009 simultaneously approaching end of life.

The overall level of metering capital additions may also be influenced by factors such as customer population (ie: % of smart versus MIST metered customers), level of customer growth, customer density, and other factors outside a distributor's control.

1.7.4 PERFORMANCE IMPROVEMENT TARGETS

As outlined in the sections above, CNPI has a strong history of meeting and exceeding performance metrics. CNPI's customer satisfaction frequently exceeds the Ontario Average. CNPI's reliability statistics during most years have exceeded targets. Furthermore, despite increasing inflation and other challenges, CNPI's total cost efficiency assessment over recent years has been trending downwards. CNPI's safety results demonstrate strong public awareness and compliance, with incident trending which CNPI hopes to eliminate through its continued safety education and awareness programming. CNPI's safety goals are

to improve or maintain public safety awareness, to maintain its existing level of compliance, and zero public safety incidents.

CNPI's goal for customer service metrics will be to maintain the existing high level of performance.

For Customer Satisfaction results, CNPI continues to target above-average results, compared to the Ontario benchmark.

For reliability metrics, CNPI is committed to continuous improvement, consistent with the OEB's new continuous improvement assigned target as outlined in the DSP, where CNPI has proposed capital and operating programs which will support this goal.

Likewise, CNPI's target is to continuously improve its long-term total cost efficiency result, as assessed by Pacific Economics Group annually on behalf of the OEB, while meeting its other objectives related to customer outcomes, public policy responsiveness and other objectives such as cyber security.

1.8 FINANCIAL INFORMATION

1.8.1 HISTORICAL FINANCIAL STATEMENTS

CNPI's most recent audited financial statements which covers two years are included as an Attachment to this Exhibit:

- Attachment 1-F Audited Financial Statements for Year Ended 31 December 2025

1.8.2 ANNUAL REPORT

The Filing Requirements require an Applicant to file an "Annual Report and Management's Discussion and Analysis for the most recent year of the distributor and of the parent company, **as available and applicable**" [emphasis added].

Neither CNPI, nor its parent company (FortisOntario) publish an Annual Report and MD&A.

CNPI does prepare a MD&A in respect of the OEB Scorecard, which is included as Appendix A to the Business Plan[11] FortisOntario is not a licensed distributor and as such does not prepare a similar MD&A.

Reconciliation between the financial results shown in CNPI's RRR filings and CNPI's Audited Financial Statements are presented in Attachment 1-G of this Exhibit. CNPI focused on reconciling some of the key inputs into this proceeding including net assets (i.e. for FAC and rate base purposes) and income statement (i.e. variance analysis for both other revenue and OM&A, historical ROE calculations).

1.8.3 PROSPECTUS AND RECENT DEBT/SHARE ISSUANCE UPDATE

[11] CNPI's Business Plan is provided as Attachment 1-B to this Exhibit.

CNPI has not produced either a prospectus or an information circular to support third-party debt or equity offerings.

1.9 FACILITATING INNOVATION

CNPI has undertaken actions to promote innovation internal to its organization, in the pursuit of improvements in efficiency, service offerings, and other key outcomes. CNPI has also taken steps to support its customers' innovation initiatives as they relate to the use of CNPI's distribution system.

1.9.1 NON-WIRES SOLUTIONS

As outlined in the Filing Requirements, CNPI has implemented the new requirements regarding the consideration of Non-Wires Solutions (NWS)/Non-Wires Alternatives (NWA) in this Application. CNPI has developed a pre-screening flow chart to identify which of its projects may qualify for consideration of a Non-Wires Solution (please see Table DSP-39 in CNPI's DSP). For the upcoming DSP period, CNPI identified one system need which met the criteria for further analysis, the Ridgeway Reliability Improvement project. In the DSP, CNPI conducted a Benefit-Cost Analysis for this project, including two "traditional" and one NWS approach. Ultimately, the NWS approach would have been significantly more costly for similar levels of benefits, and consistent with the outcomes of the Benefit Cost Analysis, CNPI has proposed to proceed with a traditional approach[12]. CNPI is therefore not currently applying for any margin on payment or other incentives related to NWS at this time.

However, when considering project alternatives to address operational constraints such as system capacity and performance during contingencies CNPI will consider non-distribution system alternatives ("non-wires solutions") such as DER or demand response when developing possible solutions to relieve these types of issues. CNPI also continues to monitor the development of available and applied NWAs/NWS to facilitate its familiarity with the technologies, business cases in order to inform CNPI's own consideration of NWAs/NWS.

1.9.2 SUPPORT FOR CUSTOMERS' ENERGY INNOVATION

CNPI also continues to support the connection of generation, DERs and Electric Vehicles in its distribution system, in compliance with the most recent applicable connection procedures. CNPI has promptly contributed to the OEB's Centralized Capacity Information Map, to support preliminary information sharing regarding available capacity for load and generation connections in CNPI's service territory.

As outlined above, beginning in 2026, CNPI has also enrolled to participate in LDC "stream one" eDSM programming, namely to support local marketing efforts in CNPI's service territories for existing IESO eDSM programs. Through this initiative, CNPI expects to support its customer base in pursuing

[12] Please see DSP Appendix J and the project narratives for Projects 10 and 11 in DSP Appendix B

innovative investments, through conservation, demand management, generation and fuel switching programs, as applicable.

1.9.3 INNOVATION AND EFFICIENCY IMPROVEMENTS AT CNPI

OMS Improvements

CNPI's OMS has enabled CNPI to provide its customer-facing public outage map in 2024. CNPI further plans to leverage this technology in order to send interested customers a text message outage notification. As CNPI continues further with these and other improvements over the DSP period, CNPI expects to take advantage of further efficiencies and service improvements.

CNPI has also begun to utilize the OMS as its main outage database for outage reporting, tracking and analysis purposes. The increased automation provided by the OMS has reduced the amount of manual processing to develop routine and ad-hoc reporting, allowing staff to reallocate their time to higher-value work, such as analyzing outage trends. CNPI also notes an improvement in the control and accuracy of outage statistics, as the processes in the previous database were relatively manual. CNPI estimates a time savings of at least two weeks of combined person-hours per year, or an estimated value of approximately $7,000 in productivity improvement.

Self-Service Options

As outlined above, CNPI has also made innovative improvements in its customer service offerings, including making online forms available 24/7 for key customer account requests. CNPI plans to investigate further customer service form automation in the future. In recent years, CNPI has also improved its online portal, and promoted e-billing to customers. As required, CNPI has made Green Button available to its customers and has enabled smart metered customers to select among various regulated pricing plans based on their usage patterns and preferences.

Environmental Initiatives

CNPI is pursuing opportunities to apply innovative and environmentally friendly technologies in its operations. CNPI's Fort Erie Facility features incorporated environmental considerations such as energy-saving measures and water filling stations to enable a plastic bottle-free environment. The facility features operational EV charging stations. CNPI has also taken steps in a pilot project investigating the potential for electrification of further aspects of its fleet, having had alternative fuel vehicles as part of the light fleet for several years now.

Innovation Committee- Promoting a Culture of Innovation

Beginning in 2025, CNPI has participated in the newly-established FortisOntario Innovation Committee, with objectives to promote, identify and celebrate innovation in various forms throughout FortisOntario subsidiaries (including sharing of innovative ideas from one subsidiary to another). The committee meets regularly and intends to support developing ideas for innovation, as well as awarding innovation ideas through an annual "innovation awards" program.

Innovation at FortisOntario can include: process improvements (small or large), adoption or creative use of technology, cross functional collaboration, pilot or proof of concept initiatives, or application or adaption of new best practices from third parties. The goals of the program include business value (ex: customer experience, reliability, safety benefits, financial outcomes, efficiency gains), execution feasibility, and risk control (ex: cost of implementation, compliance risk impact). The committee's target is to implement the first innovation awards in 2026.

Other initiatives aimed at improved productivity, efficiency and service offerings are highlighted in the table below. Productivity has been considered to mean reducing the resources to produce a given output, using the same resources to produce an improved output, and combinations of the two. Many of the improvements below do not directly lead to immediate cost savings, however they permit CNPI to accommodate growing work loads (from customer expectations, volumes of work, changing regulatory requirements, production of higher-quality work) within existing staff complement, or with reduced dependence on external resources, and therefore still contribute to long-term cost efficiency.

Table 1- 32: List of Historic and Planned Continuous Improvement Measures

Program	Description	Impact
Changes to Bill Stock	CNPI has implemented changes to its bill and envelope stock that reduce the cost per paper bill	Estimated at $10,000 per year.
Promotion of E-Billing	Through annual campaigns to promote e-billing CNPI has almost doubled its e-billing proportions since 2021 (from 26% to 48%)	Estimated at $120,000 per year in savings compared to if e-billing remained at same rate as 2021
Distribution Automation	Distribution Automation in CNPI's system can help to avoid a sustained outage in some circumstances, and to limit the impact of sustained outages when they occur. Distribution automation measures also support a quicker restoration by allowing CNPI to identify the location of a fault more quickly.	•reduced frequency and duration of outages. •reduced number and duration of trouble calls. •mitigates the restoration efforts required during major extreme weather outages, which reduces third party mutual aid costs.

Program	Description	Impact
Elimination of Some Phone Lines	CNPI has recently undertaken a review of the existing land lines, as some staff use their "desk phones" infrequently if at all. Voluntary elimination of desk phones has been implemented in early 2026 in light of this infrequent use, and given the alternative communication methods available for affected staff (cell phones, online phone/teams, etc.).	•cost savings are expected to be over $15,000 per year.
Use of Artificial Intelligence	CNPI has begun to assess use cases for Artificial Intelligence (AI) in a variety of functions, within corporate policy safeguards for this sort of activity that focus on appropriate use and protecting confidentiality. This includes requirements for qualified staff to validate the appropriateness of any AI-developed materials. AI has been used for such functions as fast-tracking research, and/or preparing first-draft summary materials.	• improved productivity allowing staff to focus on high-value work. • improved quality of written communication (through use of AI to summarize, reword materials). •possibility for speed improvements for currently time-consuming processes.
SAP Improvement- Security Deposit Automation	CNPI developed and implemented SAP improvements to automate the review of security deposits.	•improved timeliness, accuracy, reduced compliance risk for security deposit processes. •allows for re-allocation of resources to higher-value work.
SAP Improvement- Automation of Disconnect Notices	CNPI developed and implemented SAP improvements to automate the creation of disconnect notices within CNPI's collection processes.	•improved consistency and timeliness of collections processes; •allows for re-allocation of resources to higher-value work such as directly supporting customers; •reduced opportunity for manual human errors for complicated collections process rules.

Program	Description	Impact
Work Order Automation- Use of Tablets	CNPI has implemented the use of in-field tablets to support work order automation, currently being used for Meter Change automation. CNPI is looking to expand the project to other work orders as well.	•stream-lining process for Customer Service and Metering Departments; •increased timeliness and accuracy of communications and record-keeping. •Automated synch to SAP. •Elimination of some administrative steps, allowing for a refocusing of resources to higher-value work.
"Dead Tree " Removal Program	CNPI has implemented and plans to expand a program for the removal of "dead trees" that are outside of its Right-of-Way but still pose a significant reliability risk. The program is focused on trees at higher risk locations (ex: near assets which serve a higher amount of customers). CNPI must work with home-owners to receive permission to complete this work. The dead trees are more likely to fall over onto distribution assets during bad weather, causing increased outage risk.	•Expected reduction in unplanned outages; •Reduction in trouble calls caused by dead trees. •Improved system resilience to extreme weather events, with associated reduced outages and reduced restoration costs.
Locates Scope Review	CNPI worked with its locates provider to focus the scope of third party locate work, particularly through increased use of "office clears" - in areas where CNPI has no underground assets.	• increased locates timeliness and performance within OEB and Ontario OneCall standards; •CNPI was able to mitigate third-party cost increases facing 80% unit cost increases in 2023, this is estimated at upwards of $150,000, all other factors equal
Proactive Asset Replacment	CNPI's programs for end-of-life asset replacement are designed to avoid in-field asset failures.	• avoid larger-scale unplanned outages due to asset failure. •reduced trouble calls. •reduced outage risk during bad weather conditions, and extreme weather (ex: resilience impact).
Implementation of Wildlife Guards	Beginning in 2019/2020, CNPI updated its standards to include wildlife guards for	•relatively low-cost solution •mitigate the risk of unplanned outages and associated restoration

Program	Description	Impact
	all transformers and reclosers	costs •environmental benefits.
Impact of Shared Services	Shared services among a number of CNPI's functions allows CNPI and its affiliates to achieve cost savings compared to a standalone utility model.	•sharing of fixed costs, benefits of economies of scale in several functions; •availability of higher-quality services and solutions (ex: Tier 1 CIS/ERP; in-house legal support, etc.) that would not normally be achievable for standalone utilities of this size. •sharing of best practices and other forms of collaboration among affiliates supports enhanced efficiency gains. •improved ability to mitigate the impacts of unexpected turnover (ex: increased pool of affiliate subject matter expertise available to support).
Improvements from Voltage Conversion Programs	CNPI has made investments into its voltage conversion programs over the most recent and previous DSP periods.	•Improvements to public and worker safety; •Reduced reliability risk and improved resiliency associated with relatively newer assets; •Improvements in loss factor which directly impacts customers' bills. Improved loss factor will save the typical residential customer about $1.30 per year. • Improved capability to support load growth; improved ability to support system automation improvements. • End of Life asset replacement has been coordinated with voltage conversion work to improve the cost efficiency of EOL replacements versus ad-hoc single asset replacements.

Program	Description	Impact
Smart Meter Replacement Program	CNPI plans to structure its smart meter replacement program over a 10-year period to optimize the use of resources for this program.	•lower the per-unit cost for replacement as a result of pacing. •proactive replacement approach supports cost-effective replacements and limits risk. •CNPI's long-term goal is to create a chronologically diverse meter population that promotes cost-effectiveness and cost stability for both capital and O&M metering costs.
Summer Student/Co-op Placements	CNPI frequently hires summer and/or co-op students in various departments.	• Supports longer-term workforce continuity through increasing interest and experience in trades and other utility-specific job functions. •Students contribute temporary incremental resources particularly during peak workload seasons (ie: summer construction) and/or vacation periods. •Students make productive contributions, usually at relatively lower rates of compensation.

1

1.10 OTHER RELEVANT INFORMATION

1.10.1 DISTRIBUTOR CONSOLIDATION

CNPI has not recently undertaken any merger, acquisition or other consolidations. There are no relevant rebasing deferrals, etc. to consider in this Application.

CNPI actively collaborates with other utilities in order to achieve more cost-efficient and productive customer outcomes, including with FortisOntario affiliates. Under the FortisOntario shared corporate services model, CNPI and other affiliates (Algoma Power and Cornwall Electric) purchase the following shared services from Canadian Niagara Power:

- Billing
- IT Services including Billing/ERP System (SAP)
- Finance and Accounting
- Legal
- Regulatory
- Executive and Governance
- Human Resources
- Health, Safety and Environment
- Engineering/Planning.

One of the benefits of this sharing mechanism is the provision of these services at lower costs than would normally available to CNPI on a stand alone basis. For example, a stand alone utility may have a 2-3 FTE Regulatory Affairs department, however in FortisOntario a department with this same level of FTEs is shared among all affiliates, and the costs are allocated and shared accordingly, resulting in a lower FTE allocation (CNPI has been allocated approximately 1 Regulatory FTE).

A further benefit of this form of collaboration is the availability of more productive and powerful tools, as well as greater flexibility of resources. Through the use of the shared SAP[13] system, CNPI is able to access a more integrated and automated ERP/CIS system than would normally be affordable to a utility of approximately 30,000 customers. CNPI has access to in-house legal counsel and internal auditing functions, which would not normally be available to a utility of CNPI's size. Implementation of policy initiatives and other one-time projects are completed with "internal" resources that are more knowledgeable about CNPI and its customers, business practices and other specifics. CNPI is able to complete these objectives through the use of a larger pool of available resources, mitigating timeline and cost risks. Examples of recent projects that have benefitted from collaboration include:

- Implementation of the Green Button Initiative;

[13] SAP and related services are also shared with other LDCs.

- Completion of aspects of this Application (ex: Customer Engagement);
- Implementation of CyberSecurity policy and measures;
- Investigation and implementation of environmental initiatives.

In addition to the direct services provided listed above, FortisOntario LDCs collaborate frequently to share best practices, lessons learned, procedures, etc.

In addition to collaboration with affiliates, CNPI also actively participates in industry groups, such as the Electricity Distributor Association (EDA) and Utility Standards Forum (USF). CNPI has adopted many USF engineering standards. In addition to saving time and costs for the development of standalone engineering standards, this also allows CNPI to achieve a greater level of consistency with other Ontario utilities, which can be beneficial in emergency response/mutual aid scenarios.

Lastly, CNPI has benefitted from the purchase of services from specialized sector service providers, many of which are affiliates of other Ontario LDCs, which perform similar services for other LDCs. Through the use of these specialized firms, CNPI is able to deliver services that are more cost-efficient and specially tailored to its customers. Examples of these services include:

- 24/7 outage call answering;
- Certain billing, bill print and bill presentment services;
- Green Button implementation;
- Services related to obtaining, processing and presenting interval meter data;
- MDMR Sync operations; and
- Utility business process consulting.

CNPI confirms there are no ACM/ICMs from previous applications to address in this Application, and that this is not the first rebasing following a consolidation.

1.10.2 APPLICANT'S DISTRIBUTION LICENCE

CNPI operates under OEB Electricity Distribution Licence ED-2002-0572. A copy of this licence is attached as Attachment 1-H to this Exhibit.

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

ATTACHMENT 1-A:
CUSTOMER SUMMARY

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

About Canadian Niagara Power

Canadian Niagara Power provides local distribution service to the Fort Erie, Port Colborne and Gananoque areas, In Gananoque, Canadian Niagara Power also operated under the brand "Eastern Ontario Power".

Canadian Niagara Power delivers electricity over more than 1,600km of distribution lines to approximately 31,000 customers.

Canadian Niagara Power has a relatively low customer density (number of customers per square-kilometer) relative to other distribution companies in Ontario. Canadian Niagara Power's combined service areas cover 357 square kilometers, approximately 80% of which is rural.

About the Application

Like most other Ontario distributors, Canadian Niagara Power applies to the OEB every year to approve rates for the following year. These applications are on a five-year cycle, with a detailed "Cost of Service" review in Year 1, followed by adjustments in years 2-5 that are tied to, but lower than, inflation. This application is a Cost of Service Application. Much of the application relates to reviewing Canadian Niagara Power's costs and setting its base distribution rates.

The application is only for distribution rates, which is one component of your bill. Other components of your bill include costs for transmission lines or electricity generation plants, which are not part of this application. For the average residential customer, only approximately 28% of the bill goes to Canadian Niagara Power. Costs related to transmission are approved by the Ontario Energy Board (OEB) in similar applications by electricity transmitters. Some generation costs are also approved by the OEB, while other costs are a product of either the competitive wholesale market, or long-term power purchase contracts. Canadian Niagara Power passes through these costs without any markup or profit margin.

The pass-through transmission rates that Canadian Niagara Power charges to its customers are reviewed and approved by the OEB each year. For low-volume customers, the OEB also approves Time of Use and Tiered electricity rates (for generation costs) on a province-wide basis. Since Canadian Niagara Power's revenue from these pass-through rates is typically different than its actual costs, rate applications also include requests for "rate riders" which true-up past differences. These rate riders can be either charges or credits.

Customer Engagement and Performance Metrics

Canadian Niagara Power has a broad customer and stakeholder engagement program that includes: customer satisfaction surveys, community outreach/stakeholder sessions, a customer engagement program and other supporting engagement activities such as outage communication via social media.

Canadian Niagara Power also conducted an online customer survey specific to this application, which requested feedback from customers on programs and spending levels. Over 9% of Canadian Niagara Power's customers completed the survey.

Canadian Niagara Power has considered feedback from all of the above activities with a goal of meeting the needs and preferences of our customers.

The OEB expects utilities to measure their performance across a number of categories: Customer Focus, Operational Effectiveness, Public Policy Responsiveness, and Financial Performance. Every year, the OEB publishes a scorecard that compares Canadian Niagara Power's performance against targets and trends over the past five years, which can be accessed on Canadian Niagara Power's website. The following OEB website has additional information on utility performance:

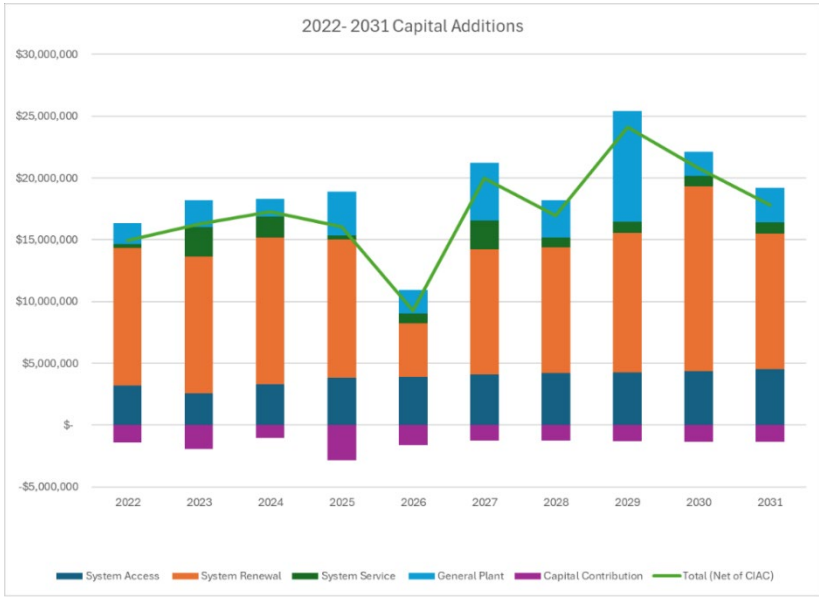
https://www.oeb.ca/utility performance-and-monitoring

Canadian Niagara Power's Goals

Canadian Niagara Power operates according to seven core values: Respect for People; Inclusion and Diversity, Safety and the Environment; Financial Success; Customer Service; Productivity; and Community Involvement. Based on a combination of these values, customer preferences and OEB expectations (discussed above), Canadian Niagara Power identified several strategic objectives for its Five-Year Plan, which are discussed in Canadian Niagara Power's 2027 Business Plan (Appendix 1B of Exhibit 1 of the application).

Summary of Canadian Niagara Power's 5-Year Plan

Canadian Niagara Power prepared a 2027-2031 Distribution System Plan that outlines its strategy and proposed spending levels for capital investments, and the ongoing operation and maintenance of its system. The following chart summarizes Canadian Niagara Power's actual (2022-2025) and planned (2026-2031) capital investments:



Other Proposals and Requests

Canadian Niagara Power has a standby class, where a customer pays to have capacity available, but not used. Canadian Niagara Power has proposed a new methodology and charges for its Standby Rate, which can be found in Exhibit 8 of the application. Canadian Niagara Power is also proposing changes to the definitions of its Standby and General Service 50 to 4,999kW to better describe the applicability of the classes.

Rate Setting and Rate Relief

Canadian Niagara Power's forecasted 2027 costs of approximately $30 million includes operating costs, cost for capital investments that are spread over the life of the assets, the cost of debt and equity to support capital investments, and taxes.

These total costs are divided between groups of customers (residential, commercial, industrial, street lighting, sentinel lights, embedded distributor, and unmetered load), and rates are calculated based on forecasted 2027 load and customer counts. Revenue from the embedded distributor customer in 2027 is forecasted to be more than the costs assigned to them. Distribution revenues are proposed to be adjusted to keep these revenues within the limits of OEB policy.

Rate relief programs like the Ontario Electricity Rebate (OER) and the Ontario Electricity Support Program (OESP) are not affected by this application.

Bill Impacts

For the distribution portion of the bill, Canadian Niagara Power has forecasted increases of $6.65 for the typical residential customer(750 kWh per month) and $13.61 for a typical small commercial customer (2000 kWh per month). These adjustments are the result of CNPI's proposed rates and changes to true-ups for distribution-related costs.

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

ATTACHMENT 1-B:
CNPI BUSINESS PLAN (WITH APPENDICES)

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

ATTACHMENT 1-B:
CNPI BUSINESS PLAN (WITH APPENDICES)

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1 EXECUTIVE SUMMARY

Canadian Niagara Power Inc. ("CNPI") has developed this business plan to address the expectations of the OEB's "Handbook for Utility Rate Applications", issued October 13, 2016. It outlines how key challenges associated with CNPI's service areas, CNPI's core values, and the preferences of CNPI's customers have all been integrated into its cost of service application (the "Application") and Distribution System Plan ("DSP") in a manner that is consistent with the outcomes of the OEB's Renewed Regulatory Framework ("RRF"). This business plan also summarizes CNPI's historical, target and forecasted performance with respect to performance metrics to ensure that CNPI delivers on its strategic objectives.

CNPI has established core values that are integrated into its planning process and daily activities, as well as objectives and principles that are integral to its asset management and system planning processes. Section 2 of this document outlines these values and principles, and summarizes how they are aligned with the objectives of the RRF. Based on these values and principles, as well as the identified preferences of CNPI's customers, strategic objectives are identified that drive projects and programs in the 2027-2031 period.

An overview of CNPI and its ownership structure, service area, unique aspects and key challenges is provided in Section 3 of this business plan.

Section 4 focuses on the four categories of RRF outcomes, and discusses how these have informed the Application and DSP, with a particular focus on customer engagement activities specific to the application and the customer preferences identified through those activities.

Section 5 of this document summarizes performance metrics that have been considered during the planning process and that will be used to ensure that CNPI delivers on its plans.

2 GUIDING PRINCIPLES AND STRATEGIC OBJECTIVES

2.1 VALUES AND PRINCIPLES

CNPI has established seven core values that all employees should strive to promote and comply with each working day:

Respect for People

Treat others as you would have others treat you. Honesty, integrity and ethics are never compromised.

Diversity, Equity and Inclusion

Create a welcoming environment that encourages and promotes diversity, cross-culture working experiences and strong relationships with our Indigenous communities and partners. Demonstrate leadership and foster a workplace culture where all employees feel empowered to bring their authentic selves to the workplace, and do their best work.

Safety and the Environment

Demonstrate a personal, unrelenting commitment to safety and environmental excellence. Protect yourself, your fellow employees, the public, and the environment.

Financial Success

Produce solid earnings, with dividends that meet the expectations of CNPI shareholders. Grow shareholder value through prudent equity investments and business partnerships. Ensure that debt obligations are always met in a timely manner and to the satisfaction of our creditors.

Customer Service/Engagement

Everyone has customers. Determine your customers' needs by listening. When you can meet these needs, do so. When you cannot, tell them that you cannot, or tell them who can. When in doubt about how to treat a customer, do what you believe is right. When serving customers, be pleasant, courteous and accurate; smile, act professionally and enjoy yourself. Attitudes are contagious.

Productivity

Effective teamwork combined with employee innovation produces productivity gains. Employees are encouraged to pursue opportunities to implement new ideas and methods that enhance overall individual and team performance. Remember…if you have a better way to do something – just do it.

Community Involvement

Each of us has an obligation to support the communities that support us. This means time as much as money. Success is measured by the reaction of community leaders and the opinions expressed by community residents.

Asset Management Objectives

In addition to the core values above, the fundamental objective of CNPI's Asset Management Program ("AMP") is to prudently and efficiently manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement of all distribution assets in a sustainable manner that maximizes safety and customer reliability, while optimizing asset lifecycle costs.

Using the AMP, Area Planning Studies ("APS") and other performance analysis as inputs, CNPI's overall system planning and capital expenditure planning process ensures that CNPI continues to provide the safe, reliable, and efficient distribution of electricity to its customers.

There are three key principles that are integral to CNPI's distribution system planning process:

1) Meet the needs and expectations of its customers, as identified through regular customer engagement;
2) Provide safe, reliable, and high-quality service to all of the customers of CNPI; and
3) Satisfy the first two principles in a sustainable manner, with a focus on long-term value and performance outcomes.

Finally, CNPI is guided by the four categories of outcomes under the OEB's RRF, namely customer focus, operational effectiveness, public policy responsiveness, and financial performance. Additional information on how each of the RRF outcomes has influenced the Application and DSP is provided in Section 4.

Table 1 below summarizes how CNPI's core values, asset management objectives and system planning principles identified above, relate to each other and to the RRF performance outcomes established by the OEB.

Table 1: Performance Outcome Alignment with Planning Objectives and Core Values

RRFE Performance Outcome	CNPI Planning Objectives/Principles	CNPI Core Values
Customer Focus	Meet the needs and expectations of its customers, as identified through regular customer engagement; Provide safe, reliable, and high-quality service; Minimize long-term costs to be borne by ratepayers;	Customer Service Respect for People Inclusion and Diversity Community Involvement Safety and the Environment
Operational Effectiveness	*Prudently and efficiently* manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement of all distribution assets in a sustainable manner	Customer Service Inclusion and Diversity Productivity
Public Policy Responsiveness	Principles are derived from safety considerations; *acts, regulations, codes and guidelines*	Safety and the Environment
Financial Performance	*Prudently and efficiently* manage the planning and engineering, design, addition, inspection and maintenance, replacement, and retirement *of all distribution assets in a sustainable manner*	Inclusion and Diversity Productivity Financial Success

2.2 STRATEGIC OBJECTIVES

Based on the values and principles identified in Section 2.1, and the preferences of CNPI's customers as identified through customer engagement, the following objectives are the primary driver of projects and programs identified in the 2027-2031 DSP:

With a commitment to continued public and worker safety, environmental stewardship, and cost efficiency:

- Invest to **improve reliability** compared to historic levels, including considering opportunities for improved system resilience against climate vulnerabilities.
- Invest to **meet growing customer base** and increasing load in areas of the system.
- Maintain strong **customer experience** performance through investments in key **software systems**. Pursue initiatives to enhance the customer experience.
- Continue and enhance CNPI's risk-based approach to replacement of **aging assets**.
- **Leverage technology** to improve the management and visibility of distributed assets.

- Promote **employee engagement** to support a safe, productive workplace.

2.3 STRATEGIC INITIATIVES

The following projects and programs in the 2027-2031 DSP are planned in consideration of meeting the objectives identified above:

Investments to Improve Reliability and Resilience

Consistent with the OEB's recent updates to the reliability performance targets, CNPI is targeting continuous improvement in its reliability performance over the forecast period. CNPI has been assigned an annual improvement of 0.5%.

CNPI expects the improvements to materialize from the following key sources:

- Operating and maintenance programs such as vegetation management, cyclical asset preventative maintenance, and a wildlife protection program.
- Historic and continuing delta conversion projects will enable the application of advanced protection and control functions.
- Continuation of the deficiency program for the replacement of aging and defective distribution assets.
- Over the past several years, CNPI has constructed three new substations (Rosehill DS, Catharine DS, and Station 16), retrofitted a power transformer at Sherkston DS, and rebuilt the feeder egress in coordination with Hydro One's new Port Colborne TS construction. These investments have optimized system configuration, increased contingency backup among substations and feeders, and enhanced overall system reliability. Looking ahead to the forecast period, CNPI plans to construct one new substation at Crystal Beach/Ridgeway and to enhance the EOP Main Substation.
- CNPI is in the process of procuring and installing reclosers and SCADA-controlled automated switches to further modernize and automate the distribution system. These upgrades will improve outage detection, isolation, and restoration capabilities, resulting in improved system reliability.
- CNPI will continue to rebuild its 27.6 kV feeders and strengthen its 34.5 kV feeders. These upgrades will enhance contingency supply to downstream substations operating at lower voltage levels and will positively impact overall system reliability and outage performance.
- CNPI is improving the automation of the second power transformer at the Gananoque Main Substation. This enhancement will reduce switching time between the two transformers and improve system reliability under contingency conditions.

In terms of improvements of the distribution system's resilience against climate vulnerabilities, CNPI undertook a vulnerability assessment with the support of a third party, which is included as DSP Appendix F.

The Vulnerability Assessment identified adaptation measures, ranging from enhancements to equipment and standards used in distribution system construction, to enhanced vegetation management and asset monitoring, to various planning and preparation measures.

CNPI is not proposing any material stand-alone programs, but has undertaken or plans to undertake activities in line with the adaptation strategies, as better detailed in Section 5.3.6 of the DSP.

As it relates to design standard and design-criteria-related items CNPI is assessing opportunities to apply measures such as stronger-class poles, shorter ruling spans, increased conductor and cable sizes, on an incremental basis, in areas that present the highest climate-related risks. Incremental costs associated with these measures are not expected to be material.

CNPI has also taken measures to improve data collection and analytical capabilities related to asset management.

Incremental vegetation management to mitigate off-right-of-way risks has also been introduced and is planned to be expanded.

Additionally, CNPI is in the process of reviewing its Business Continuity Plan and associated procedures.

Investments to meet Growing Customer Base/Increased Load

CNPI is committed to expanding and reinforcing its distribution system in order to meet the needs of its customers with respect to requests for new services and service upgrades. CNPI is committed meeting evolving public policy related to economic development, housing expansion, and expansion of broadband internet service to currently underserved areas. CNPI continues to consult with third parties to develop it plans for System Access investments, as further outlined in DSP section 5.2.2, including municipal authorities, local developers, telecommunications companies, regional planning partners, and current and potential end-use customers. For its System Access forecasts, CNPI has reflected known/confirmed future developments, and allotments for further forecasted growth in its five-year plan. For System Access, CNPI does not have control over the magnitude and pacing of investments (as CNPI is generally obligated to invest to provide a connection, upgrade, or joint use access to a requesting customer).

With respect to planning for longer-term growth to meet system capacity and reliability needs, CNPI has employed multiple growth scenarios as part of the Area Planning Study in its Distribution System Plan.

These growth forecasts consider baseline, and accelerated scenarios, that include assumptions regarding growth from electric vehicles and other forms of electrification and/or economic development. The impacts of these system tests and other analyses (ex: asset condition assessments) have influenced many of CNPI's proposed investments, for example the Ridgeway Station/Line Configuration Projects 9 and 10 which are partially driven by capacity growth increasing risk on the existing Station 19).

Maintain and Enhance Customer Experience

CNPI has established a strong history meeting customer expectation, having consistently performed above standard in all Scorecard customer-focused metrics, and a strong record of exceeding provincial levels of customer satisfaction in most historic years. Throughout the historic period, CNPI has also implemented initiatives in response to identified customer preferences, notably a customer-facing outage map introduced in 2024 to allow customers easy access to outage information including number of customers affected, and (where provided) estimated restoration times. CNPI is pursuing an initiative for automated outage text message notifications.

CNPI has established a committee for Accelerating the Customer Experience ("ACE"), together with other FortisOntario Subsidiaries. Initiatives for 2026 involve:

1) Improve customer notification mechanisms.

2) Website review and standardization.

3) Education regarding Conservation, Rates and Energy Efficiency.

The above mentioned measures (including outage maps and outage notification) have been identified customer preferences through customer surveys and other forms of engagement. In addition to the measures outlined above, CNPI plans to continue to investigate improvement opportunities from the following sources: collaboration with FortisOntario and Fortis subsidiaries to share best practices that support customer outcomes and/or cost efficiencies; expansion of digital self-service options where cost effective, continued outreach to customers through surveys and other forms of engagement, and initiatives to support vulnerable and/or hard-to-reach customers through increasing awareness of customer assistance programs through accessible and inclusive communication channels.

In order to support its current levels of customer experience and the continuity of other critical business, CNPI has identified a need to upgrade its existing key Customer Information System (CIS) and Enterprise Resource Planning (ERP) SAP software. The investment is planned to be in service in 2029, prior to the expiration of extended vendor support for the existing platform. CNPI has assessed various options to address the potential of the platform going out of support, and concluded that a "brownfield" system upgrade is the best option to mitigate risks to CNPI's ability to deliver key outcomes for customers and other stakeholders. Further information is available in DSP section 5.4.1, DSP Appendix K, and Material Information Form # 25 (DSP Appendix B).

Replacement of Aging Assets

CNPI conducts regular inspection and testing of distribution system assets. The results of an asset condition assessment of the major assets in CNPI's distribution system are summarized in Section 5.3.2 of the DSP.

CNPI conducts preventative maintenance on its assets, and for most asset types, CNPI conducts condition-based end-of-life proactive replacements (with the exception of distribution transformers, conductors, and underground assets where a run-to-failure approach is significantly more cost-effective). Proactive replacements, where applicable, allow CNPI to avoid in-field asset failure, which is typically associated with significantly higher costs to replace assets, and significantly longer outages (whereas proactive replacements can be completed with no outage in some cases, or a controlled, planned, and previously communicated shorter outage, in other cases).

As part of the investments in its "System Renewal" capital investment category, CNPI has planned for the replacement of poor-condition assets. To the extent possible, for cost efficiency purposes, CNPI has developed projects that incorporate both asset end of life considerations and other performance outcomes related to safety, reliability and power quality, for example voltage conversion and line rebuild programs.

CNPI also expects to improve its asset condition data health over the coming years, through additional data collected through existing substation maintenance, pole testing, and line inspection programs. Additionally, CNPI is developing asset management portals and performance dashboards to enhance data intelligence and analytical capabilities. These tools are expected to enable more targeted asset renewal planning and improved prioritization.

Leverage Modern Technology to Improve System Management and Visibility

Tested and reliable distribution modernization/automation technologies have evolved over recent decades which allow distributors to operate their systems with greater control, efficiency, and permit improvements in reliability. These technologies may also enable further future use cases, such as expanded ability to monitor and control distributed energy resources (DERs), and potentially operate as a Distribution System Operator (DSO). CNPI continues to monitor opportunities to implement these technologies in a risk-based cost-effective manner, having already developed its experience with system automation over prior Distribution System Plans.

CNPI's 2027-2031 plan involves focused investments in SCADA-controlled reclosers at key locations in Niagara and Gananoque. The installation of these devices is integral to CNPI's reliability improvement plans, as the devices (among other benefits), allow CNPI to avoid sustained outages that would otherwise occur, or shorten/limit the impact of sustained outages compared to what they otherwise would be. The installation of the devices is also expected to have an impact on system resiliency, as distribution automation can mitigate outages during large-scale weather events, reducing reparation costs and outage durations. CNPI has also planned for the sustaining replacement of end-of-life protective and remote-controlled devices and upgrades to the existing SCADA communication and Protection and Control functions. These projects are further outlined in CNPI's DSP, particularly the descriptions for Project #2.

Additionally, CNPI plans to invest in the modernization of its existing Control Room in Fort Erie, with investments in facilities, software, and hardware that will support a conversion to a digital "Live Wall" from the current paper-based wall map used for switching and dispatching functions. The investments will improve CNPI's ability to coordinate regular distribution operations and maintenance work with increased timeliness, safety and precision, and will also enhance these same factors during storm restoration and other outage management activities (including those conducted during severe/extreme weather events). Added benefits from the control room investments involve improved visibility and ability to control DERs, as well as enabling future Control Room collaboration/backup with other FortisOntario subsidiaries, which would improve CNPI's ability to mitigate business continuity risk in extreme weather scenarios, as well as improving service coverage and/or cost efficiency of control room functions.

CNPI continues to monitor the development of Non-Wires Solutions (NWS) to traditional "pole and wire" solutions to distribution system issues, consistent with OEB policy in this area. In this Application, CNPI has identified one project with a potential Non-Wires Alternative solution (Ridgeway Area Improvement Project), however following a preliminary assessment and a more robust cost-benefit analysis regarding a potential Battery Energy Storage System (BESS) NWS, CNPI has determined that a traditional solution remains the most cost-effective and beneficial solution in this case. CNPI will continue to monitor developments in the applications and cost levels for various NWS, and consider their potential, as appropriate to address distribution system issues.

Employee Engagement

CNPI implemented an Employee Engagement Initiative aimed at fostering a collaborative and inclusive workplace culture. Employee Engagement measures the involvement and enthusiasm of employees in their work and workplace and higher levels of engagement contribute to increased productivity, efficiencies, and overall safety, which improve the level of service provided to customers. This program is designed to strengthen communication, enhance employee satisfaction, and promote organizational alignment with strategic objectives. Activities under this initiative include structured feedback mechanisms, recognition programs, and team-building sessions, all of which contribute to improved morale and operational efficiency. These efforts support CNPI's long-term commitment to workforce stability and productivity, which are essential for delivering reliable service to customers.

More broadly, CNPI has implemented various employee initiatives to promote general engagement, including programs to support employee health and wellness, training for new supervisors, and Diversity Equity and Inclusion initiatives.

In recent years, CNPI has a significantly increased level of turnover in its workforce as a result of retirements and resignations. Simultaneously CNPI has observed greater challenges recruiting well-qualified candidates for key roles. This trend has resulted in productivity/subject matter expertise losses and cost increases (recruitment costs, third party support costs to address internal resource gaps).

CNPI continues to target its overall compensation package in such a way that will allow it to compete for qualified candidates, including the wages/salaries, Short Term Incentive (for eligible positions) and a change in the pension plan offered, for some employee groups. CNPI also plans to increase the Human Resources staffing levels to mitigate this developing trend.

3 UTILITY OVERVIEW

3.1 OVERVIEW OF THE SERVICE AREAS

Location and Geography

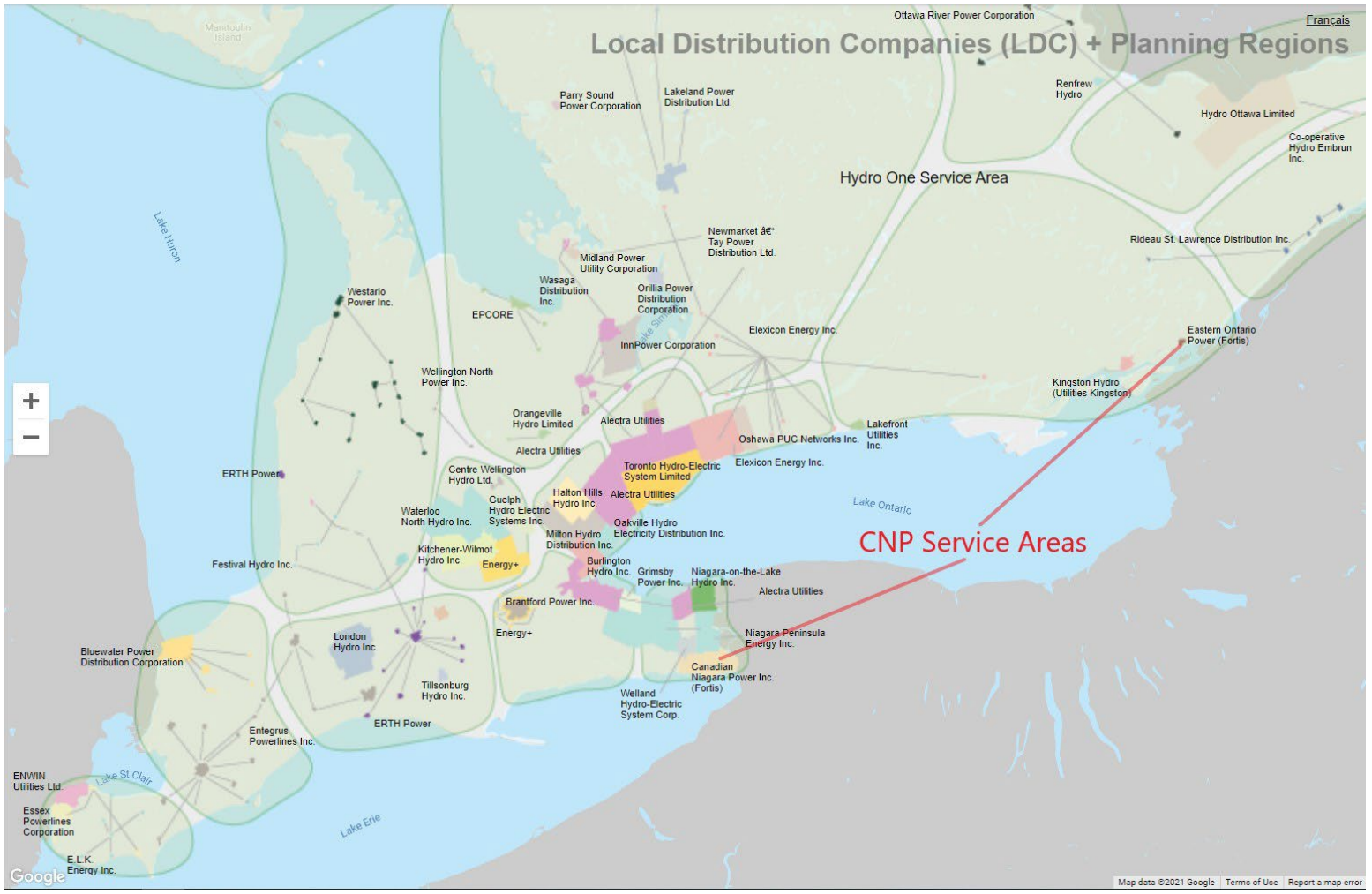
CNPI is an amalgamation of three former distinct LDCs:

- Canadian Niagara Power, serving the Town of Fort Erie
- Port Colborne Hydro, serving the City of Port Colborne
- Eastern Ontario Power, serving the Town of Gananoque and some surrounding area

Figures 2-4 show the extent of CNPI's Fort Erie and Port Colborne service areas (along the northeast shoreline of Lake Erie), and CNPI's Gananoque service area (operating as Eastern Ontario Power, northeast of Lake Ontario, along the St. Lawrence River).

Each of the three former LDCs that now comprise CNPI (CNPI, Port Colborne Hydro and Granite Power Corporation) were independently owned and operated for decades prior to operation and ownership changes involving CNPI in the 2001-2011 period. As a result, through a series of different planning decisions, operating philosophies, and construction standards, the three systems have distinct supply points and different primary system voltages, as detailed in Section 3.5.

Figure 1: CNPI Service Areas (Southern Ontario Context)



Map Data © Google; LDC + Planning Region Overlay © IESO

Figure 2: Fort Erie (Red) and Port Colborne (Green) Service Areas

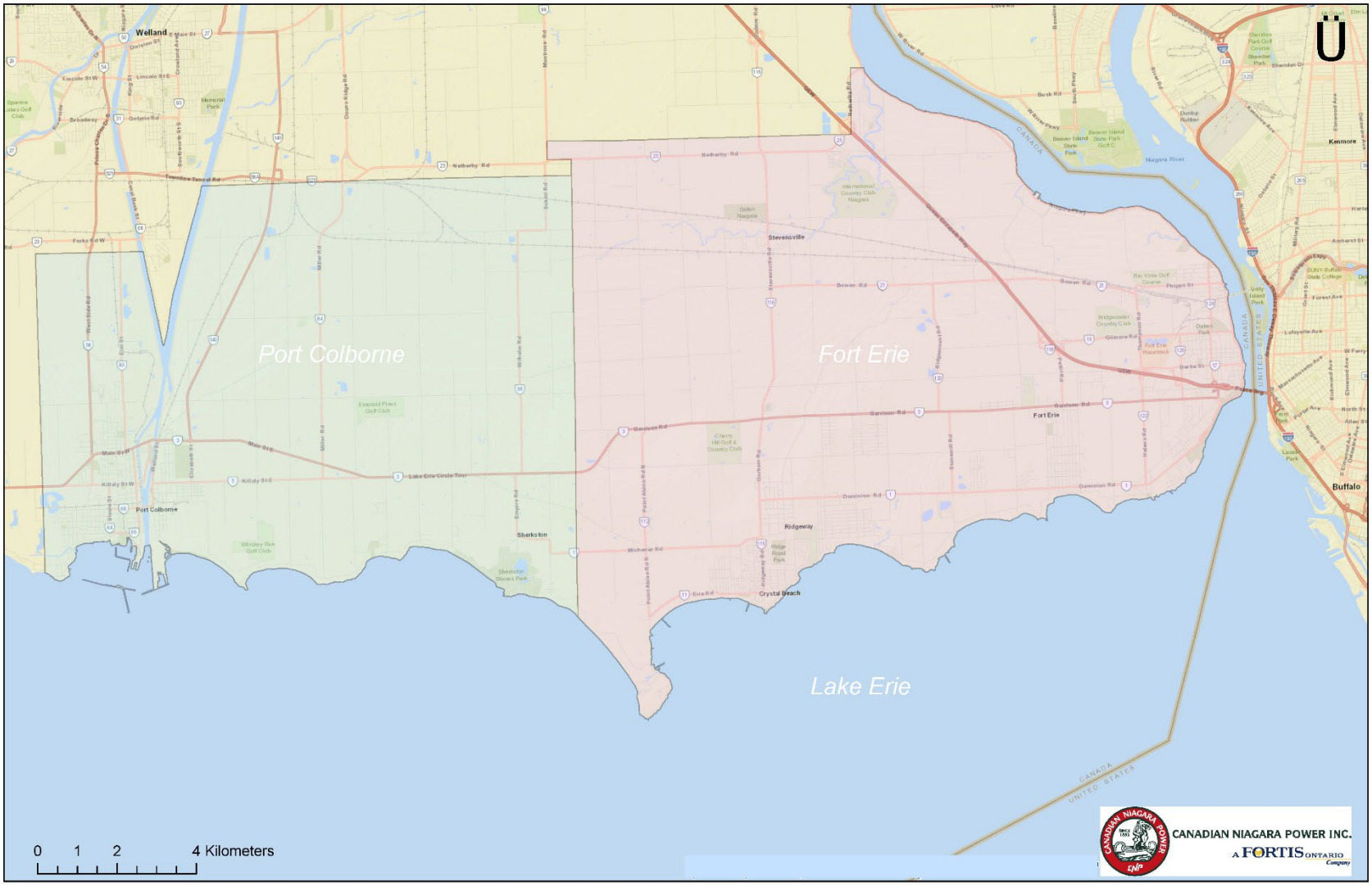
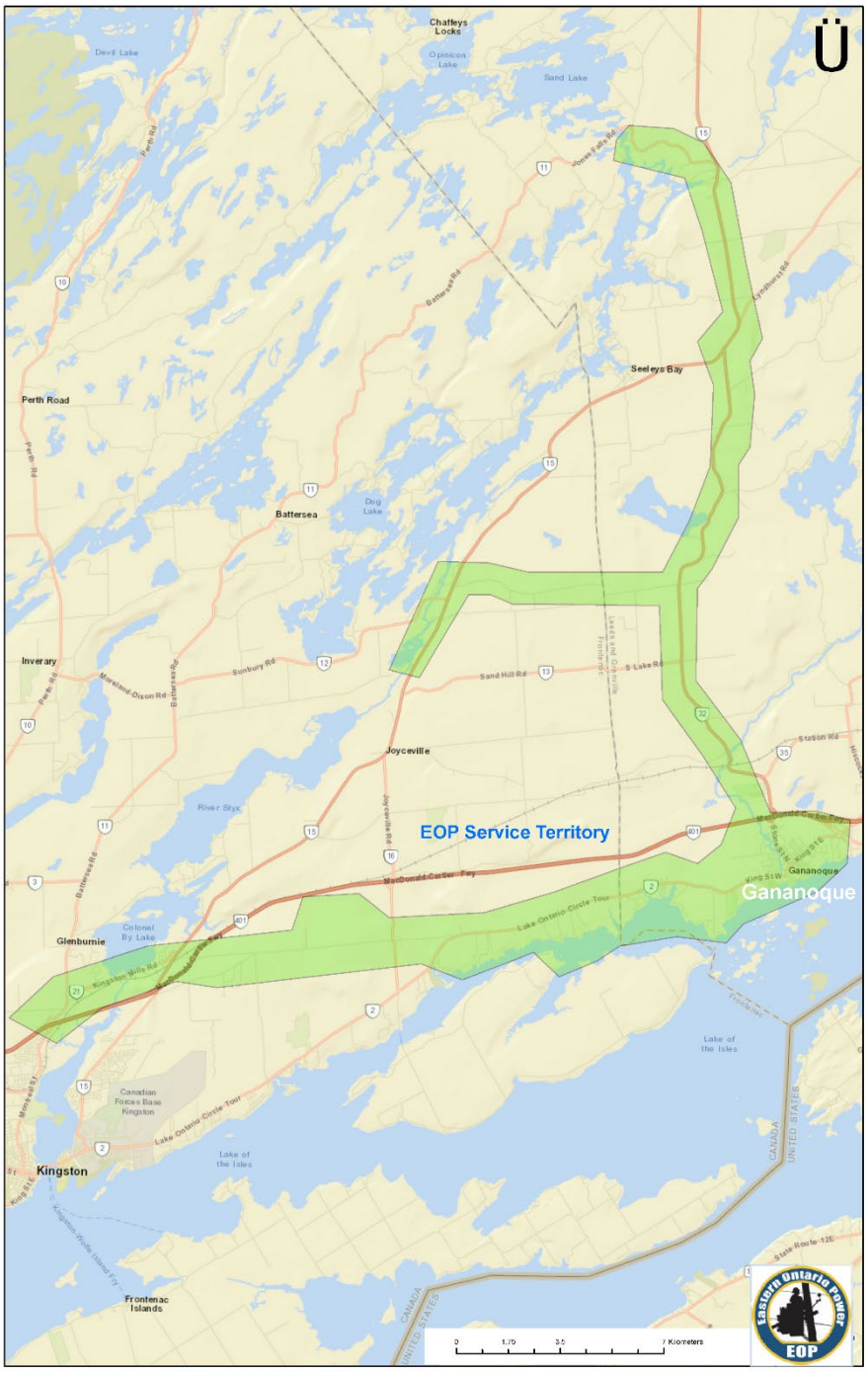


Figure 3: Gananoque Service Area (Green)



Employment and Industry

Major industries in CNPI's service area include refining/manufacturing/fabricating (industrial, metals, chemical and food products, among others), tourism/service/hospitality, agriculture, as well as other supporting industries. CNPI's service area has seen a relative stability in the post-COVID commercial and industrial load and customer base, with load (particularly for larger customers), with a gradual increase in residential customers and associated energy consumption.

Over 90% of CNPI's customers are residential. Among these customers is a mix of customers employed by organizations in CNPI's service areas, and customers residing in CNPI's service areas but commuting to other municipalities for work. An aging population also means that CNPI's residential class includes a large base of retirees. As of the 2016 census, the median ages in CNPI's service areas ranged from 50.4 to 52 years, compared to 41.6 years for Ontario as a whole. Commercial and Industrial customers currently comprise less than 10% of CNPI's total customer base, with only 0.7% of all customers having a demand greater than 50 kW.

Climate

The climate in CNPI's service area is humid continental, which is characterized by large variations in seasonal temperatures including cold winters and warm, humid summers. The location of CNPI's service areas along the shores of Lake Erie and Lake Ontario often results in lake-effect winds and precipitation more severe than areas further inland, which presents a significant challenge with respect to reliability improvement.

3.2 UTILITY OWNERSHIP

CNPI is a wholly-owned subsidiary of FortisOntario Inc. ("FortisOntario"), which is headquartered in Fort Erie, Ontario. FortisOntario also owns Algoma Power Inc. and Cornwall Street Railway Light and Power Company Limited (both licensed distributors), and a 5 MW natural gas cogeneration district heating plant located in Cornwall, Ontario (a licensed generator). FortisOntario is the Ontario-based subsidiary of Fortis Inc. ("Fortis"), which is the largest investor- owned gas and electric distribution utility in Canada. FortisOntario subsidiary Wataynikaneyap Power PM Inc. acts as project manager for the Wataynikaneyap Power transmission project in Northwestern Ontario. FortisOntario holds a ten percent interest in each of three other licensed distributors: Westario Power Inc., Rideau St. Lawrence Holdings Inc., and Grimsby Power Inc.

Fortis Inc. is a well-diversified leader in the North American regulated electric and gas utility industry, with 2025 revenue of $12 billion and total assets of $75 billion as at December 31, 2025. Its utilities account serve more than 3.5 million electricity and gas customers across Canada and in the United States and the Caribbean.

3.3 UTILITY DESCRIPTION

CNPI serves approximately 27,700 customers in Port Colborne and Fort Erie. CNPI serves an additional approximately 3,600 customers in the portion of its service area in and around Gananoque, operating as Eastern Ontario Power in the Gananoque area.

CNPI's combined service areas cover 357 square kilometres, approximately 80% of which is rural. CNPI's distribution system is comprised of over 1,600 km of primarily overhead distribution lines, and supplies a combined summer-peaking demand of approximately 110 MW.

3.4 RATE HARMONIZATION

CNPI achieved full harmonization of its monthly service charges and distribution volumetric rates for its three service territories (Fort Erie, Gananoque and Port Colborne) as a result of the Board's decision in CNPI's 2016 incentive rate-setting mechanism (IRM) Application (EB-2015-0058). Rate riders were subsequently harmonized in CNPI's 2017 cost of service application (EB-2016-0061).

3.5 KEY CHALLENGES

The following key challenges, which are discussed in greater detail in Section 5.2.1 of CNPI's 2027-2031 DSP, have been factored into the strategic objectives and strategic initiatives identified in Section 2 of this Business Plan.

Growth/ Growth Forecasting

While growth over the historic period has been moderate, CNPI has faced an increased challenge with growth and growth forecasting form multiple factors. Localized growth in certain areas of the distribution system has progressed faster than others. Primarily residential-load growth has impacted the Ridgeway and Crystal Beach areas. In Port Colborne, CNPI is aware of potential developments in commercial/industrial load, however there are limited committed projects, and the presence and attractiveness of direct transmission connections creates uncertainty in CNPI's distribution load forecasting. The provincial outlook for increased electricity demand indicates significant long-term increases due to electrification, industrial development and other factors, however it is uncertain to what extent this load growth will occur in the test year, and to what extent the impacts (for example EV adoption) will affect CNPI's service territories.

System Voltage Levels

CNPI's system continues to feature multiple voltage levels, though CNPI has made significant progress in the recent historic period through its voltage conversion programs to convert 4.8 kV delta to 8.3 kV wye configuration. In addition, CNPI operates extensive 2.4/4.16 kV distribution systems in its Port Colborne, Stevensville (part of Fort Erie), and Gananoque service areas. These voltage levels are among the lowest still in common use in Ontario and result in higher distribution system losses and capacity constraints under certain contingency conditions. Where feasible, standardizing system voltage through voltage conversion can reduce or defer the need for substation capacity expansions, improve overall system performance, and better position the distribution system to accommodate future load growth.

Further, the historical selection of different distribution voltage levels in Fort Erie (4.8 kV and 34.5 kV) and Port Colborne (4.16 kV and 27.6 kV) makes it impractical to standardize system voltages and provide interconnections between these adjacent service areas.

Low Density

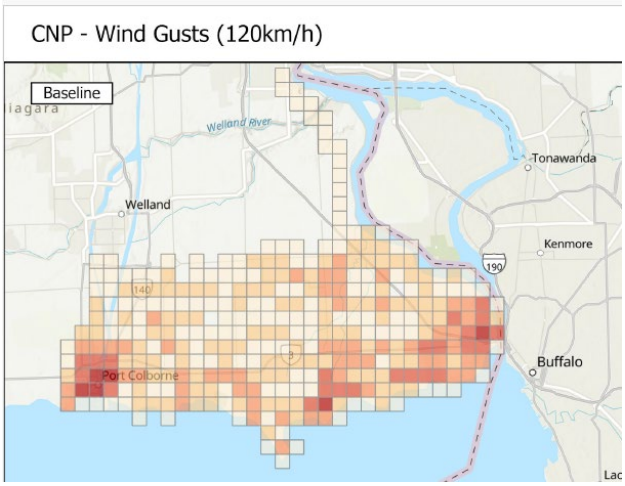
In terms of customer density (e.g. customers per km of line and customers per square km of service area), CNPI ranks in the lowest quartile among LDCs in Ontario. From a reliability perspective, the rural portions of CNPI's service area are generally served by longer distribution feeders, which are exposed to a higher number of trees per km than in urban/suburban settings. The distance between substations and the number of radial line segments limits load transfer and restoration options during outages. Voltage conversion programs that are in progress further limit CNPI's contingency options, since substations or feeders that might otherwise provide an alternate supply to a particular area operate at different voltage levels for a period of time. Ratio banks deployed during voltage conversion efforts are also generally designed without redundancy and are less reliable overall compared to traditional substations.

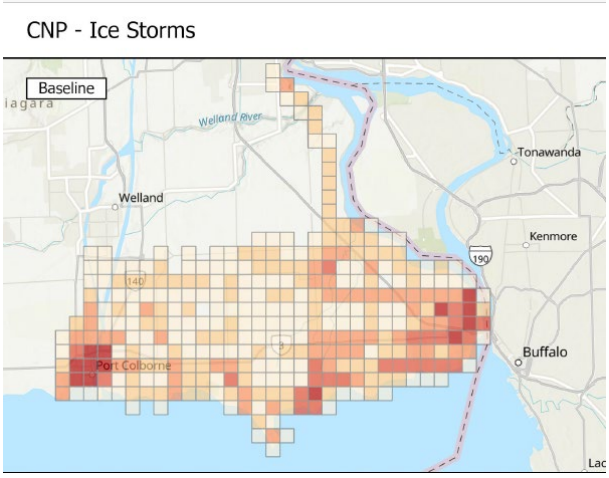
The relatively lower density in CNPI's service area is also a driver of higher per-customer costs, for example because longer lines and more poles may be necessary to serve the same number of customers compared to a similar higher-density utility.

Storm Damage

CNPI has experienced an increasing frequency of severe storms causing widespread outages and severe damage to its distribution system. A summary of CNPI's Major Event Day ("MED") classifications and the resulting effect on CNPI's reliability statistics is provided in Section 5.2.3.0 of CNPI's DSP. One of these MEDs relates to a larger scale significant severe weather event in December 2022 which would have met the OEB's newly defined "High-Impact, Low-Frequency" definition.

CNPI has completed a Climate Change Vulnerability Assessment, which is included as DSP Appendix F. The vulnerability assessment confirms higher risks associated with the areas surrounding the Lake Eerie shores in CNPI's Niagara service area, for example please see the two risk maps below:





System Modernization

In light of the challenges to reliability caused by CNPI's low-density, heavily forested, mostly-rural service areas, CNPI's system currently lacks sufficient automated switching devices to optimally mitigate contingency risks, improve system performance, and meet reliability requirements.

CNPI has implemented an ongoing grid modernization strategy that includes OMS-SCADA-GIS integration, enhanced LOV/FLISR capabilities, and the use of smart meter outage data. CNPI's APS identifies several initiatives, including the installation of SCADA-controlled reclosers at critical tie points to enable switching automation and support faster fault isolation and service restoration, as well as control room modernization to improve operational efficiency, communication, and accuracy.

4 OUTCOMES OF THE RENEWED REGULATORY FRAMEWORK

On October 18, 2012, the OEB issued its "Report of the Board: A Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach." The report set out a comprehensive framework economic regulation of the Ontario distribution sector (the Renewed Regulatory Framework, or "RRF"), which emphasizes the importance of performance outcomes in four key categories:

- Customer Focus
- Operational Effectiveness
- Public Policy Responsiveness
- Financial Performance

The sections below describe how CNPI continues to engage with its customers in order to better understand their needs, expectations and preferences, and how CNPI's core values, customer preferences, and the RRF performance outcomes are integrated and prioritized in its planning activities.

4.1 CUSTOMER FOCUS

Customer and stakeholder engagement has long been a component of CNPI's planning process. CNPI employs a variety of education and engagement initiatives that include customer satisfaction surveys, community outreach/stakeholder sessions, and other supporting engagement activities.

CNPI strives to continuously enhance its engagement activities, as well as to seek feedback to understand which engagement and communication channels are considered to be the most effective by its customers.

4.1.1 CUSTOMER ENGAGEMENT

CNPI continues to employe a customer satisfaction survey through a third party provider, UtilityPULSE. The survey is conducted annually, which is more frequent than the requirement for the purpose of OEB scorecard reporting. The survey contains a standard set of questions, which allows CNPI to assess its own customer satisfaction performance trending over time, as well as its performance compared to the Ontario provincial average results. In addition, CNPI may add supplemental questions focusing on particular areas of interest each year.

CNPI also engages with its customers through various other methods. Day-to-day contact with customers, customer/public seminars focused on topics such as safety and large customer concerns, and other touchpoints all inform CNPI's understanding of customer need and preferences.

In addition to the annual customer satisfaction survey, CNPI has conducted an application-specific engagement related to the proposals in this Application. CNPI worked with Innovative Research Group to develop a customer engagement online workbook to inform customers of its plans for the upcoming 2027-2031 distribution system plan, and seek feedback for key programs. For seven projects, customers were presented with a description of the project and its intended impacts to their distribution service as well

as estimated bill impacts. Customers were presented with alternatives to the draft plan for each project, which would potentially increase or decrease both service outcomes and the bill impacts.

4.1.2 IDENTIFICATION OF CUSTOMER NEEDS AND PREFERENCES

Through the various surveys and customer touch points, CNPI has identified the following general customer preferences:

- Customers value reliability;
- Customers value a lower bill; and
- Customers' expectations with respect to communications about their service are evolving.
- The interactions between the items above are complex and dependent on the specifics of the initiatives being proposed. For example, with communications initiatives, customers have responded positively when presented solely with the potential for an improved service offering, however have responded negatively when asked whether they are willing to pay a modest bill increase (ex: "a few cents per month") to obtain the service.

Through its various interactions, CNPI is also aware that preferences vary from customer to customer, and may also be different from one customer classification to another. For many CNPI initiatives, particularly those related to distribution system investments, it is not possible to tailor investments to benefit only those customer groups or customer classes which value them.

For these reasons, CNPI selected the seven projects to present in the application-specific consultation, to obtain customer feedback specific to the planned service offering and bill impacts for each project.

In general, customers supported CNPI's proposals for each of the seven projects as-proposed, with many customers also supporting a "spend more" to enhance service offerings for the projects. For some projects there was a lower level of consensus than others, including the replacement of light fleet vehicles with "alternative fuel vehicles" (where a modest majority of residential customers, 54%, supported CNPI's draft plan, and a modest majority of the small business customers, 53% preferred that CNPI replace the vehicles with traditional fuel-vehicles). In this case, CNPI reviewed the customer feedback, but chose to maintain its existing plan focused on alternative-fuel vehicles. This plan is supportive of CNPI's environmental stewardship goals, it is still consistent with the majority customer preference, and based on the summary of customer concerns with this program (indicating some customers are concerned with the reliability of AFVs), CNPI believes its approach addresses customers' concerns. Another project with lower consensus is the notion of accelerating local asset replacements and vegetation management in areas where severe weather risk is highest. A modest majority of residential customers (53%) supported a "spend more" option, while a modest majority of small business customers (52%) supported a "draft plan" option. CNPI has reviewed this feedback and believes it has proposed programs which will improve resilience to severe weather, including some additional programming related to vegetation management. Additionally in future years CNPI will look for opportunities for low-cost incremental improvements in high-weather-risk areas that improve resilience.

Further details regarding the customer engagement results and impacts to DSP can be found in section 5.2.2 of the DSP, and DSP Appendix I.

4.2 OPERATIONAL EFFECTIVENESS

With respect to the RRF outcome of operational effectiveness, distributors are expected to achieve continuous improvement in productivity and cost performance, while delivering on safety, reliability and quality objectives.

With respect to safety, CNPI's results have been consistently compliant, with relatively stable public safety scores. The recorded electrical incidents in 2022 and 2024, have not resulted in any harm and relate to a member of the public refusing to follow CNPI's and the ESA's requirements regarding safe tree trimming around power lines on the customer's property.

CNPI has also consistently met its system reliability targets over the 2021-2025 period, with the exception of frequency of outages in 2023 and 2025. Reliability is generally improving over the historical period, and CNPI's targets for the 2027-2031 period include an element of continuous annual improvement consistent with OEB targets assigned to CNPI. A discussion of the reliability trending is included in DSP section 5.2.3 as well as DSP Appendix C.

For customer-focused deliverables including timeliness of connections, billing accuracy, phone call answering and customer satisfaction, CNPI has had strong stable performance consistently in excess of OEB targets.

CNPI's cost performance, according to the OEB PEG Benchmarking model, shows an improving trend over the last decade, following investments in the recent historical periods to support customer growth, reliability improvements, and meeting growing regulatory and customer expectations.

4.3 PUBLIC POLICY RESPONSIVENESS

Distributors are expected to deliver on obligations mandated by government and regulators.

CNPI has met its obligations for the connection of generation to the distribution system. Additionally, over the historic period, CNPI has implemented regulatory policy changes and initiatives including the Green Button initiative, implementation of new rate plan options (ex: Ultra Low Time-of-Use, new EV Charging transmission rates, etc.). CNPI has actively worked with telecommunications entities, including those involved in designated broadband projects. CNPI has also implemented updates to its DER and load connection processes, including changes to the economic evaluation calculations for residential developments. CNPI has also amended its LEAP funding to expand funding availability so that no eligible LEAP applicant would be denied due to lack of funding. As of 2026, CNPI has begun participating in "Stream 1" eDSM program marketing to support the expansion of CNPI's customers' awareness of IESO eDSM programs. CNPI has also enhanced its outage communication tools, practices and procedures in line with OEB changes related to outage management and communication.

In this Application, CNPI has addressed new policy requirements including the evaluation of Non-Wires Solutions as alternatives to traditional distribution program investments. Additionally, in parallel with the OEB's development of its Vulnerability Assessment and System Hardening initiative, CNPI separately undertook a Climate Change Vulnerability Assessment to identify climate hazards and risks in its service territory, as well as adaptation strategies.

CNPI is also aware of recent changes to the *OEB Act* which have added an OEB objective related to economic development. CNPI remains active in its discussions with existing and potential new commercial and industrial customers, working together with the customers, regional planning authorities, and municipal governments to support these customers in their new services and/or expansions through clear and timely communication.

4.4 FINANCIAL PERFORMANCE

Under the RRF, distributors are expected to achieve improvements in efficiency that are sustainable, while maintaining financial viability and earning a fair return. Historical financial results are discussed in Section 5.7 of this Business Plan.

5 PERFORMANCE METRICS AND TARGETS

On March 5, 2014, the OEB issued its "Report of the Board – Performance Measurement for Electricity Distributors: A Scorecard Approach". The resulting OEB Scorecard contains a set of performance measures and standards to assess distributor performance against the four categories of RRF outcomes identified in Section 4.

The sections that follow address CNPI's performance in relation to each of the OEB Scorecard performance measures over the last five years. Targets for future performance are also discussed, with an emphasis on specific performance measures identified as important to customers and performance measures that have significantly influenced the development of CNPI's 2027-2031 DSP.

Prior to discussing individual OEB Scorecard performance measures, additional context is provided in relation to the OEB's LDC benchmarking efforts in consideration of CNPI's circumstances, as well as CNPI's capital investment plans and operational costs that underpin a number of cost control metrics and financial ratios presented later in this section.

5.1 OEB BENCHMARKING

During the hearing stage of EB-2016-0061, CNPI identified that from a cost benchmarking perspective, changes in accounting methodology relating to shared IT assets had negatively affected its OEB total cost benchmarking results, as a result of the PEG model not including any of the Other Revenue series of accounts.

Starting in 2020, CNPI changed its accounting methodology to record the revenue received from these services as an offset to OM&A, as opposed to other revenue in Account 4375. This approach, consistent with a similar accounting change made by Algoma Power Inc. in its last cost of service application, results in the total costs of the shared IT services being more appropriately reflected in each company's total cost benchmarking results.

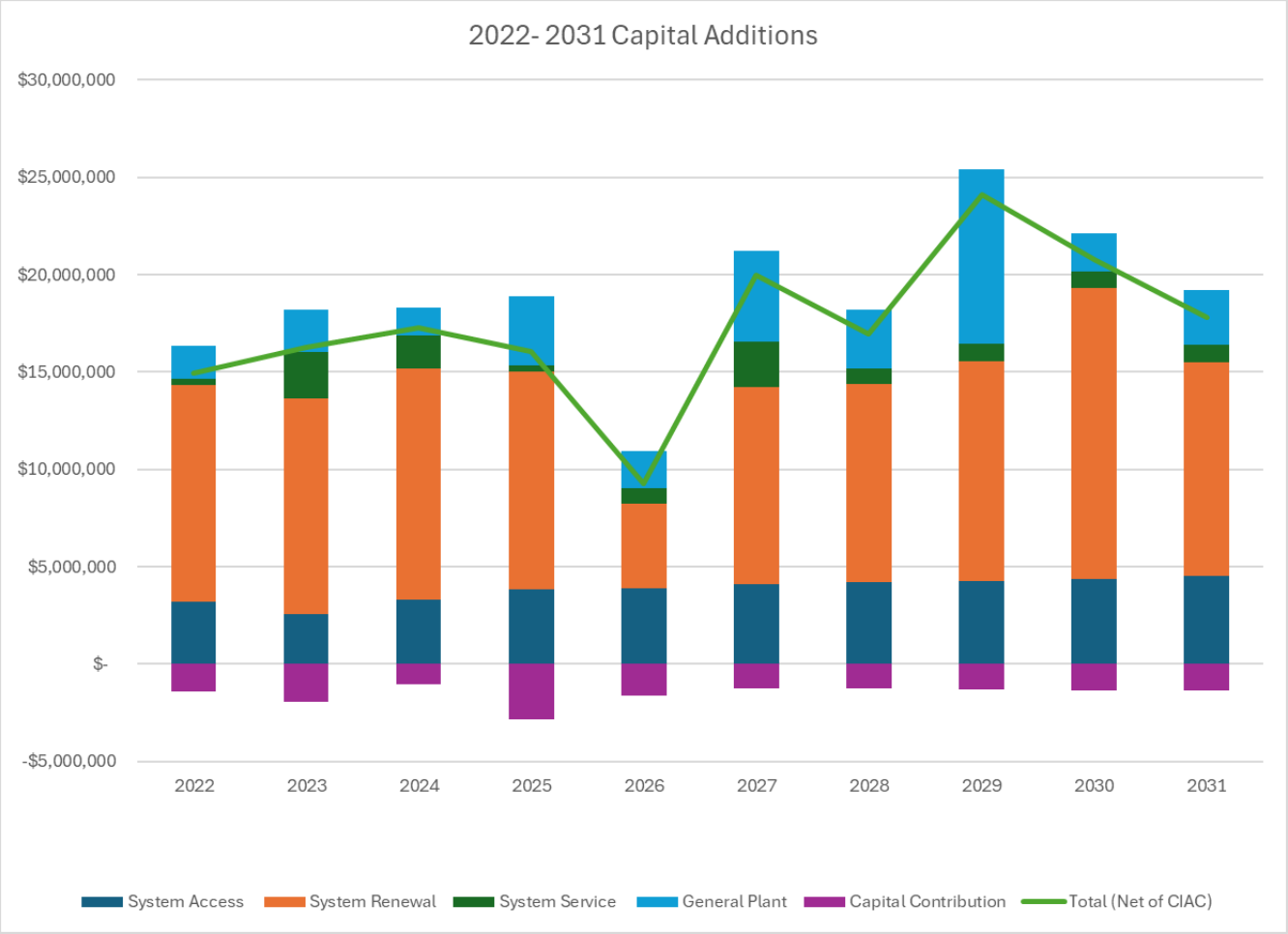
CNPI also notes that the total cost benchmarking model considers gross asset costs, without consideration of Contributions in Aid of Construction (CIAC) that serve to offset the rate impact from investments that are driven by customer connections and third parties. While this issue is common to all LDCs, the impact on benchmarking costs will depend on the quantum of these System Access investments and the amount of CIAC not included in the PEG cost benchmarking model.

The above issues, combined with the discussion of System Access investments in the following section provide important context for fluctuations in CNPI's cost benchmarking results in Section 5.5.2.2.

5.2 CAPITAL INVESTMENTS

The following figure summarizes CNPI's historical actual capital investments, as well as forecasted investments in the 2026 Bridge Year, and the 2027-2031 period covered by its current DSP:

Figure 4: Historical and Forecast Capital Expenditures



CNPI's historical capital investments saw a continuation of increased System Access investments in the post- COVID era, to meet customer and third-party needs. The investments were driven by subdivision and service upgrades, combined with some joint-use and road relation. CNPI's forecast investments in this category are comparable for the 2027-2031 period, however there remains an element of uncertainty related to these investments which are customer driven and therefore primarily outside of CNPI's control.

CNPI's System Renewal investments to replace end of life assets include an accelerated focus on voltage conversion programs in the 2022-2025. The accelerated pace of voltage conversion was initiated to further mitigate safety risk associated with the 4.8 kV delta system, keep voltage conversion efforts aligned with line and substation asset end of life replacement requirements, and to mitigate contingency risk as identified through planning studies. CNPI experienced timing and cost implications as a result of COVID-19 impacts, including restrictions affecting the pace of construction work, as well as higher-than expected input prices as a result of global supply chain and other impacts. Additions in 2022/2023 are also impacted by spending related to storm damage, primarily one severe storm occurring in late 2022, which saw continued damage repairs and replacements into 2023.

System Service investments to improve system reliability and performance peaked in 2023, as a result of additions related to the new substation in Stevensville. Investments in System Service line rebuilds and voltage conversion occurred throughout the historic period, at lower levels than the same programs under the System Renewal category. CNPI has made additions related to distribution automation in 2024, with planned further investments in 2026.

General Plant investments in assets that are not part of the distribution system (e.g. fleet and equipment, land and facilities, IT) are relatively consistent year-over-year, with larger investments occurring in 2025, as a result of large vehicle purchases, and some facilities spending to mitigate security and business risk. Forecasted spending in the 2027-2031 period is forecasted to peak in 2029 as a result of a significant software system upgrade that is necessary to maintain continuity of key business practices and protect cyber security. 2027 investments in General Plant will include investments at CNPI's Fort Erie garage, necessary to enable continued prompt outage response, as well as investments to modernize CNPI's control room.

CNPI has accelerated historical capital investments as compared to the plan presented in its 2022-2026 DSP as in response to asset condition, increases in pricing for necessary projects, and the continued focus on delta to wye voltage conversion. Timing of the completion of some larger projects has also contributed to increases compared to the plan for 2022-2026. Detailed explanations for changes in strategy, pacing and prioritization over the 2022-2026 period are provided in Section 5.4.1 of the current DSP.

CNPI's target with respect to capital investments in the 2027-2031 period is to complete all of the projects and program-based replacements identified in its DSP. CNPI will however maintain flexibility to reprioritize projects and/or adjust replacement rates based on updates to the inputs to its asset management process.

5.3 OPERATION, MAINTENANCE AND ADMINISTRATION (OM&A) COSTS

The following table summarizes CNPI's historical and forecasted OM&A costs for the 2017-2022 period:

Table 2: Historical and Forecast OM&A Costs

	2022 Board Approved	2022 Actuals	2023 Actuals	2024 Actuals	2025 Actuals	2026 Bridge Year	2027 Test Year
Operations	$ 1,911,789	$ 2,009,458	$ 2,109,545	$ 2,194,331	$ 2,322,507	$ 2,410,236	$ 2,570,922
Maintenance	$ 2,056,623	$ 2,239,433	$ 2,766,105	$ 2,376,646	$ 2,452,663	$ 2,227,905	$ 2,481,211
Billing and Collecting	$ 1,736,564	$ 1,542,005	$ 1,752,600	$ 1,756,504	$ 1,911,880	$ 1,859,907	$ 1,870,476
Community Relations	$ 78,761	$ 129,992	$ 61,474	$ 81,964	$ 150,083	$ 93,991	$ 92,089
Administrative and General	$ 3,815,430	$ 3,863,564	$ 4,207,796	$ 4,838,510	$ 4,874,497	$ 4,858,057	$ 5,368,575
Total	**$ 9,599,168**	**$ 9,784,453**	**$ 10,897,520**	**$ 11,247,955**	**$ 11,711,630**	**$ 11,450,096**	**$ 12,383,274**
%Change (year over year)		1.9%	11.4%	3.2%	4.1%	-2.2%	8.1%

The most significant drivers of year over year changes in OM&A costs include:

- Labour costs relating to annual variations in FTE count and average compensation rates, as more fully analyzed in OEB Appendix 2-K. These represent the costs required for CNPI to recruit and

retain the expertise required to safely and efficiently expand, operate and maintain the distribution system, respond to customer requests and preferences as well as providing timely and accurate bills, and the various functions which support these key activities.

- Increases in third party Enterprise Technology costs, Telecommunications Costs and Cyber Security, which support CNPI's ability to protect privacy and operational technology security, to support and enhance service delivery and customer outcomes, and to efficiently operate the distribution system.

- Increases in LEAP funding, in order to provide as much funding as necessary to accommodate the level of qualified applicants, in compliance with OEB expectations.

- Increase in regulatory expenses as a result of increased policy activity and filing requirements, to support CNPI's continued public policy responsiveness and compliance.

The above summary is included to provide context on the major drivers and adjustment that affect CNPI's various cost performance metrics in the following sections of this business plan. A comprehensive OM&A cost driver analysis is provided in Exhibit 4 of the Application.

CNPI's target for the forecast period is to balance inflationary OM&A cost increases with productivity and efficiency improvements, consistent with the price-cap adjustment factors inherent in the OEB's IRM rate-setting framework.

5.4 SCORECARD METRICS – CUSTOMER FOCUS

The OEB Scorecard contains six performance metrics related to the RRF outcome of Customer Focus, divided into categories of Service Quality and Customer Satisfaction.

5.4.1 SERVICE QUALITY

CNPI's historical performance has consistently exceeded OEB targets in all three Service Quality metrics, as summarized in the following charts. CNPI's future target is to maintain performance that meets or exceeds OEB targets and is consistent with historical performance levels.

Figure 5: Services Connected On Time

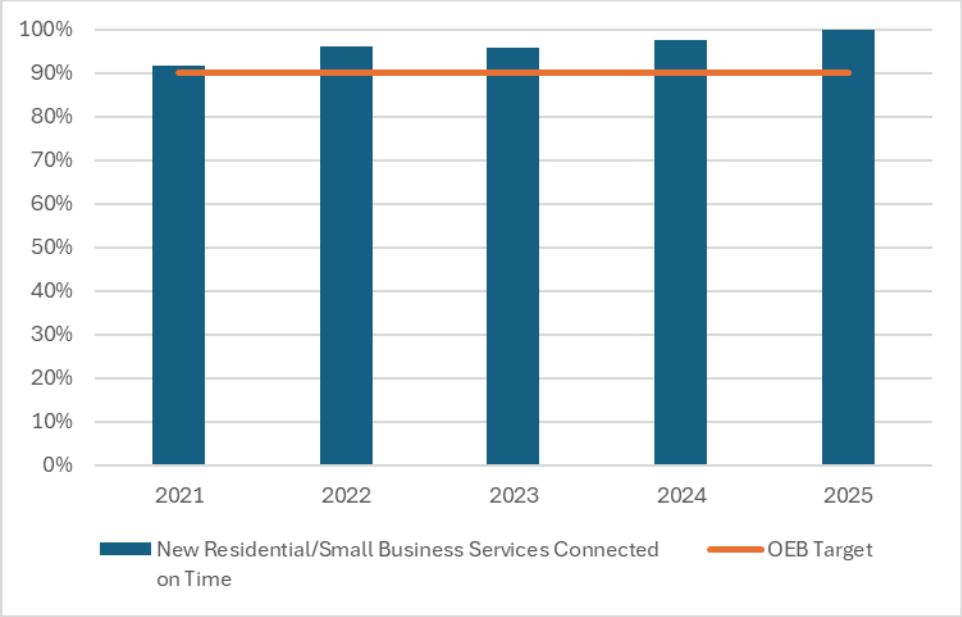


Figure 6: Appointments Met On Time

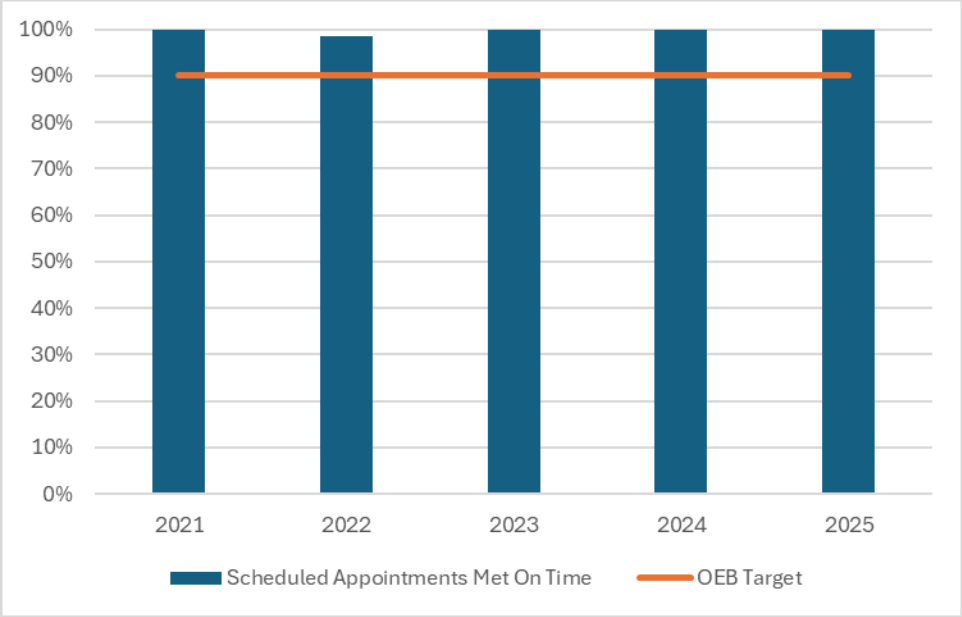
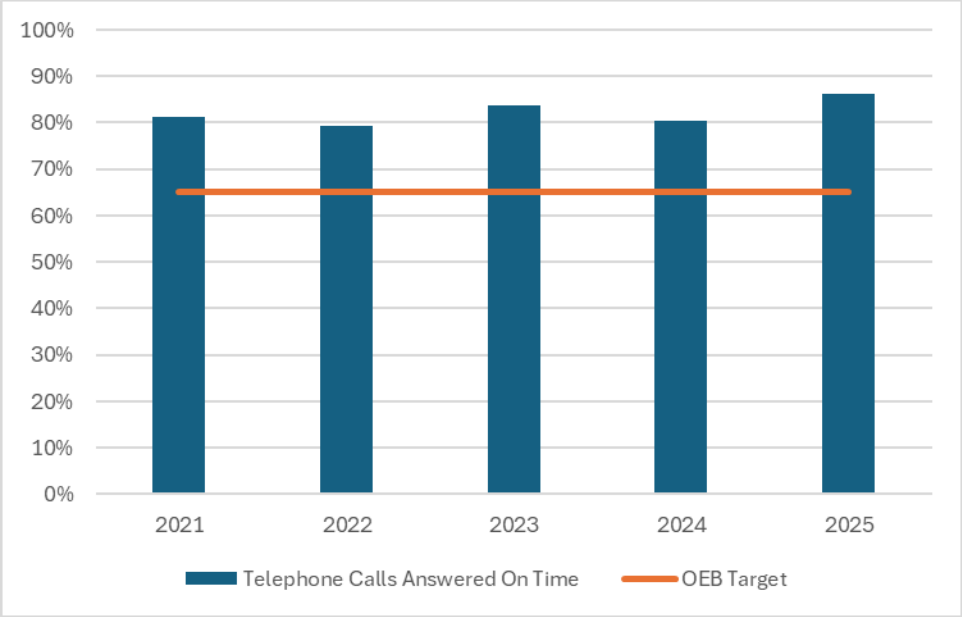


Figure 7: Calls Answered On Time

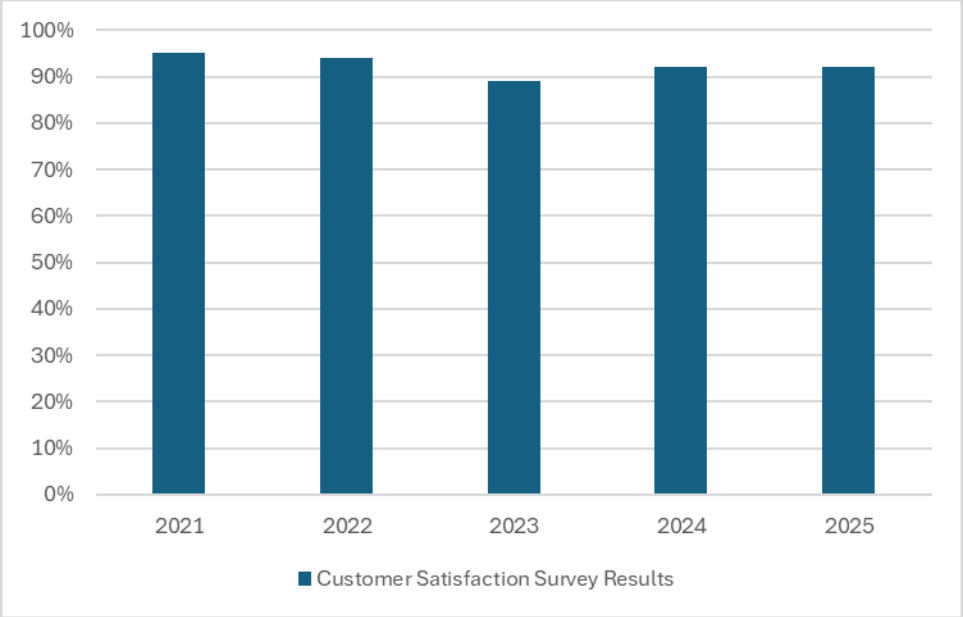


5.4.2 CUSTOMER SATISFACTION

CNPI conducts annual customer satisfaction surveys to better understand and meet the needs of its customers. While the OEB has not set specific targets for customer satisfaction scores, the results in Figure 9 below indicate both a stable trend in CNPI's overall customer satisfaction score and consistently high scores in recent years. Downward trending in 2023 results was attributed to two factors: growing province-wide affordability concerns caused by post-COVID inflationary pressures; as well as a significant severe weather event in late 2022 which caused extended outages in CNPI's service territory.

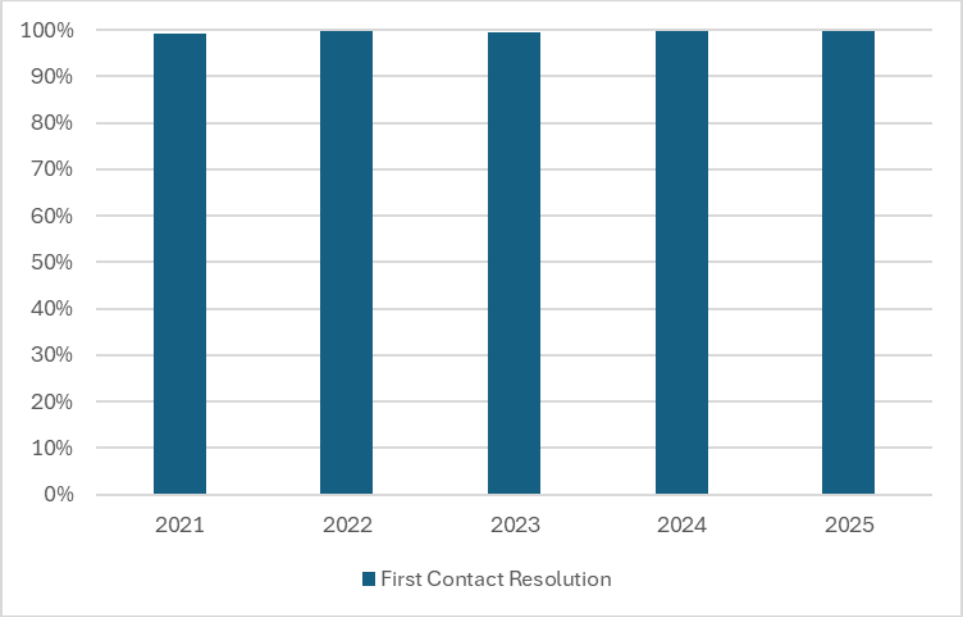
In 2025, CNPI initiated additional customer engagement activities related to its 2027 cost of service application (as described in Section 4.2), in order to educate customers about CNPI's plans, and request feedback on specific projects, for CNPI to consider in the development of its final DSP proposals.

Figure 8: Customer Satisfaction Scores



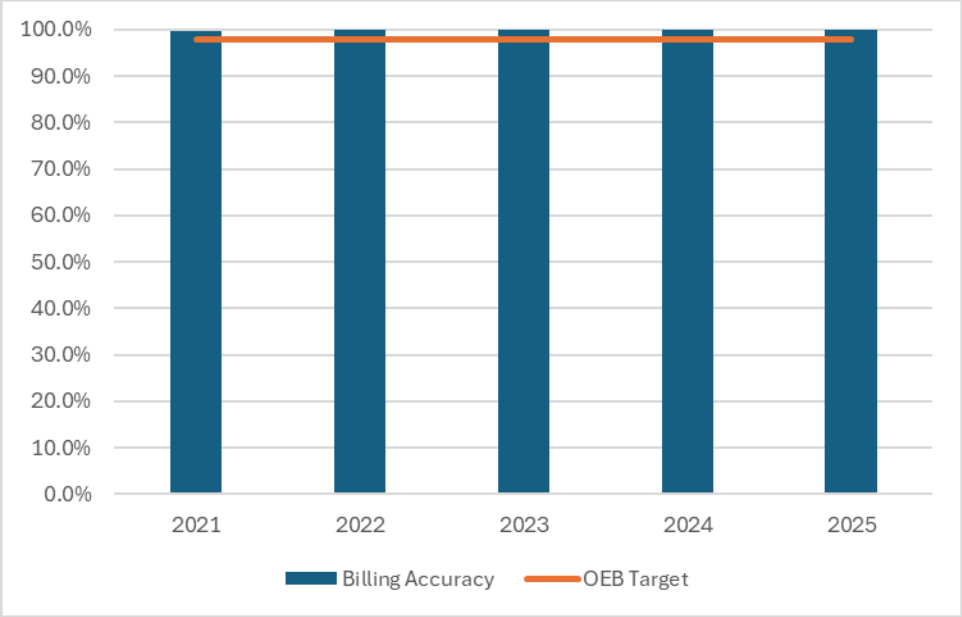
First Contact Resolution is a measure of the percentage of inbound calls that are resolved by the first point of contact (i.e. not escalated to a supervisor or more senior staff member). Less than 1% of calls have historically required escalation, and CNPI expects to continue this level of performance.

Figure 9: First Contact Resolution



The OEB target for Billing Accuracy is 98%. CNPI has consistently exceeded this target, and intends to continue this performance level in future years.

Figure 10: Billing Accuracy



5.5 SCORECARD METRICS – OPERATIONAL EFFECTIVENESS

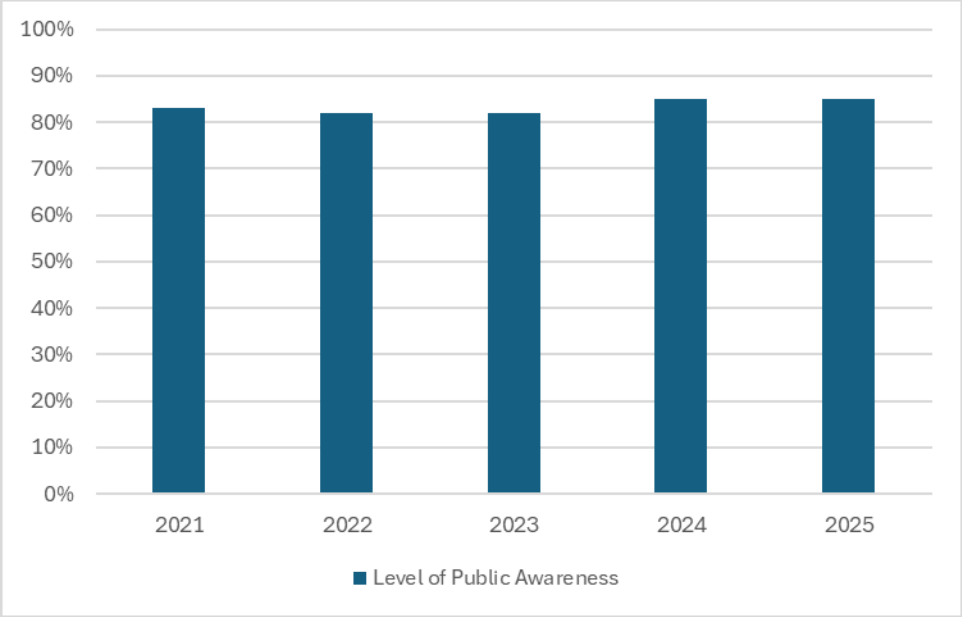
The OEB Scorecard contains ten performance metrics related to the RRF outcome of Operational Effectiveness, divided into categories of Safety, System Reliability, Asset Management and Cost Control.

5.5.1 SAFETY

An unrelenting commitment to safety is entrenched in CNPI's core values and a focus on both worker and public safety will always be included among CNPI's strategic objectives.

UtilityPULSE is engaged to complete bi-annual surveys in relation to "Public Awareness of Electrical Safety". On completion of these surveys, UtilityPULSE generates a "Public Safety Awareness Index Score" for CNPI and other LDC's. CNPI's scores from recent surveys have been relatively stable, ranging between 83% to 85%. CNPI plans to continue to deliver and improve on its public outreach initiatives related to safety, with a goal on improving its Public Safety Awareness Index Score with each survey.

Figure 11: Safety – Level of Public Awareness



Over the 2021-2025 period, CNPI has consistently achieved full compliance with Ontario Regulation 22/04, and has had three electrical incident involving the public, all of which ended without any harm, but involved a customer undertaking tree trimming activities against guidance from CNPI and the Electrical Safety Authority. CNPI's target is to continue to achieve full compliance and to have zero serious safety incidents.

5.5.2 SYSTEM RELIABILITY

The OEB Scorecard includes SAIDI and SAIFI performance metrics that measure the average number of hours and the average number of times that power to a CNPI customer is interrupted. Scorecard results are adjusted to focus on outages that are within the LDC's control by removing outages associated with Loss of Supply ("LoS"), and Major Event Days ("MED"). CNPI's target is to achieve adjusted reliability results in any given year that consistently improve upon its 2020-2024 average, consistent with the reliability benchmarking goals released by the OEB in 2025.

In CNPI's experience, while customers are more understanding of outages during major storm events, all outages, regardless of cause or responsibility, ultimately affect customers' perceptions of the reliability of CNPI's system. CNPI therefore regularly reviews SAIDI and SAIFI results and trending for all outages and adjusted values.

The following figures summarize CNPI's historical reliability performance, for all outages, adjusted to remove LoS, and adjusted to remove both LoS and MED (i.e. outages under CNPI's control, consistent with the OEB scorecard). During the historic period, planned outages have at times affected reliability performance, in particular the frequency (SAIFI, average number of outages), due to programs such as voltage conversion. The outages are necessary to conduct replacement projects that will avoid

unplanned outages which are typically much more impactful and costly to address. Additionally, CNPI takes measures to limit the impact of planned outages, as well as communicating in advance with affected customers to mitigate inconvenience.

Figure 12: SAIDI Trend

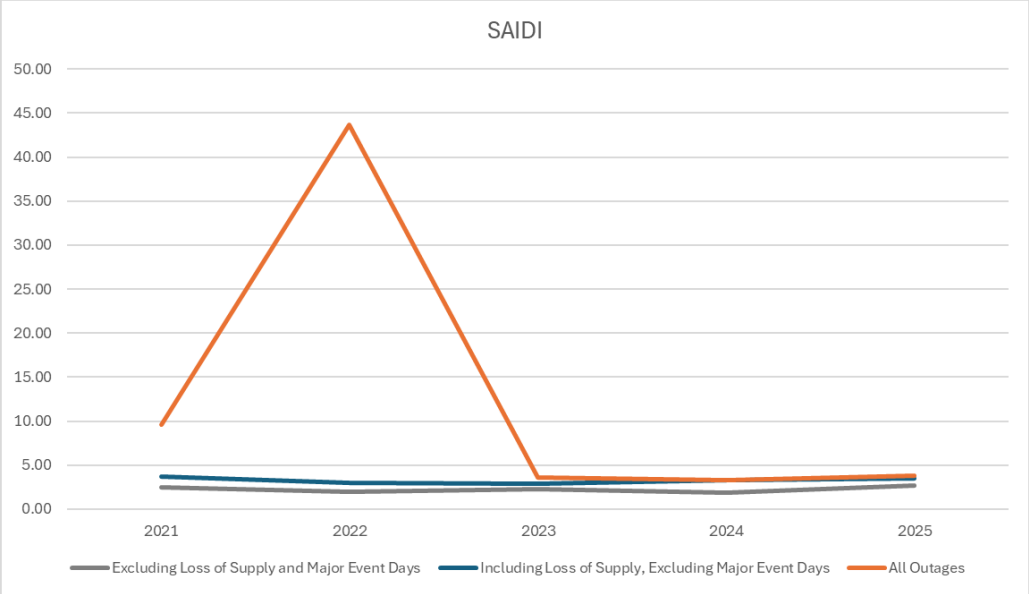


Figure 13: SAIDI Trend- Excluding Major Events

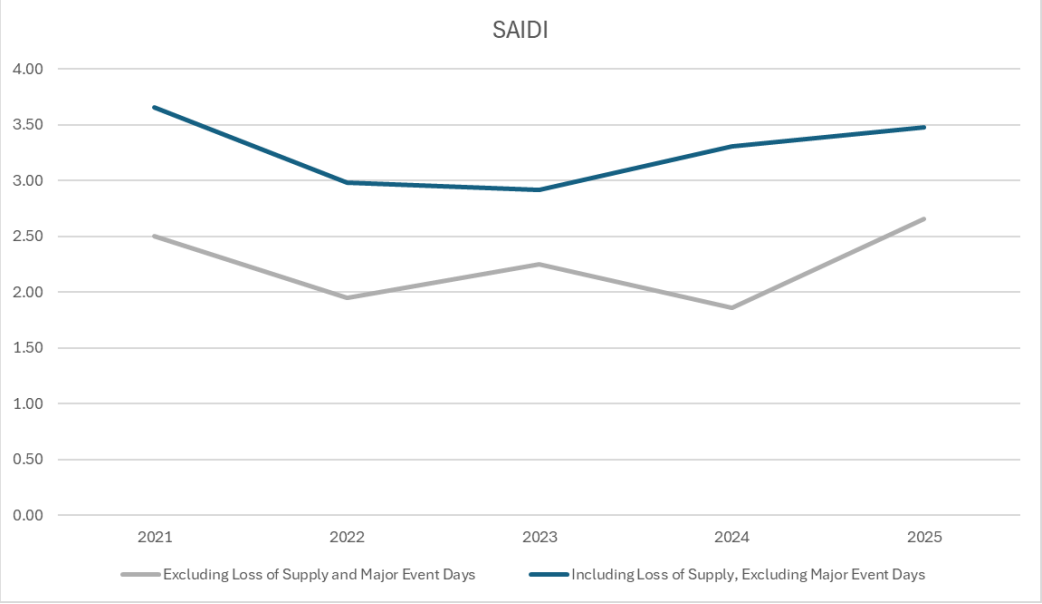
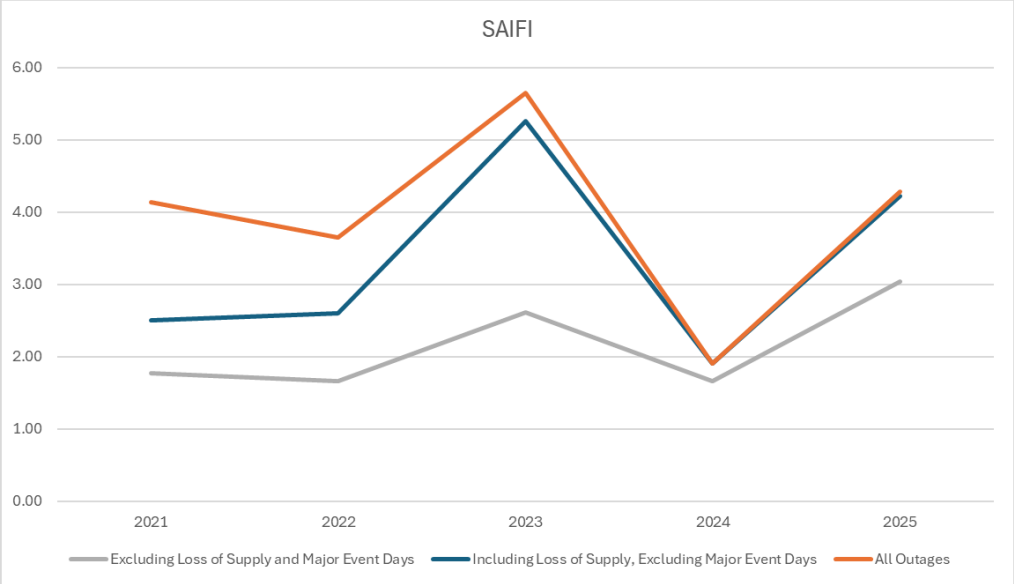


Figure 14: SAIFI Trend



5.5.2.1 ASSET MANAGEMENT

The OEB scorecard contains a statement to describe the extent of an LDC's implementation progress with respect to its DSP. For the historical DSP period (2022-2025), CNPI indicated "Complete" for all years.

On an annual basis, CNPI makes a qualitative assessment of DSP completion, considering project scope and spending, and adjustments for unexpected developments (ex: higher than forecasted requests for new connections). The assessment of "complete" in the historic years indicates that the planned work, as adjusted for unplanned requests and reprioritization of certain capital projects, has generally been completed.

An accelerated pace for voltage conversion efforts, higher-than forecasted system access investments, and deferrals/reductions of some projects for to address growing input costs are discussed in Section 5.4 of the DSP.

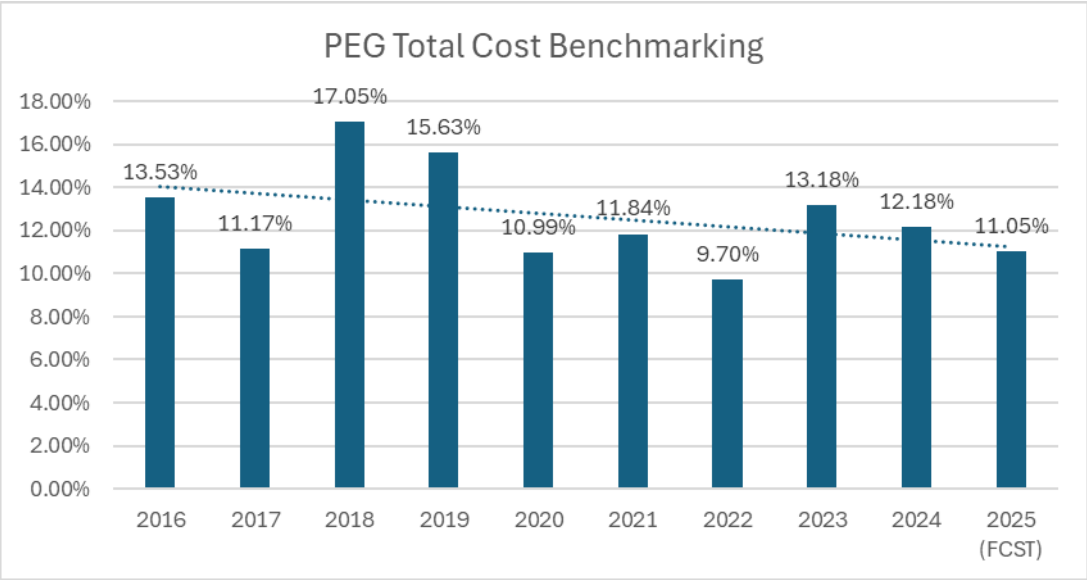
5.5.2.2 COST CONTROL

Cost control performance metrics included in the OEB Scorecard are driven by the output of the OEB's total cost benchmarking framework, particularly the Total Cost Benchmarking model compiled and updated by Pacific Economics Group (the "PEG Model"). CNPI's historical challenges with the PEG Model are summarized in Section 5.1. As a result of these issues, CNPI has focused on trending and cost drivers in its analysis of historical results and setting of future targets.

The PEG Model calculates each LDC's "Actual Total Cost" by adding the majority of OM&A accounts from the LDC's trial balance, and determining a proxy for capital costs based on historical and current capital additions, an asset price index, an economic depreciation rate, and a rate of return. The PEG Model also

calculates a "Predicted Total Cost" for each LDC, using a standard formula that considers business conditions such as number of customers, load, km of line, etc. The percentage difference between actual and predicted cost is the PEG Model measure of cost performance, where lower percentage results indicate greater efficiency. The following chart shows CNPI's cost performance, according to the PEG model:

Figure 15: Total Cost Benchmarking – Efficiency Assessment



Further to the discussion in Section 5.1, two issues have a significant effect on CNPI's historical benchmarking results:

- Prior to 2020, CNPI's actual costs in the PEG model reflect 100% of the capital investments related to providing shared IT services to affiliates using assets owned by CNPI.

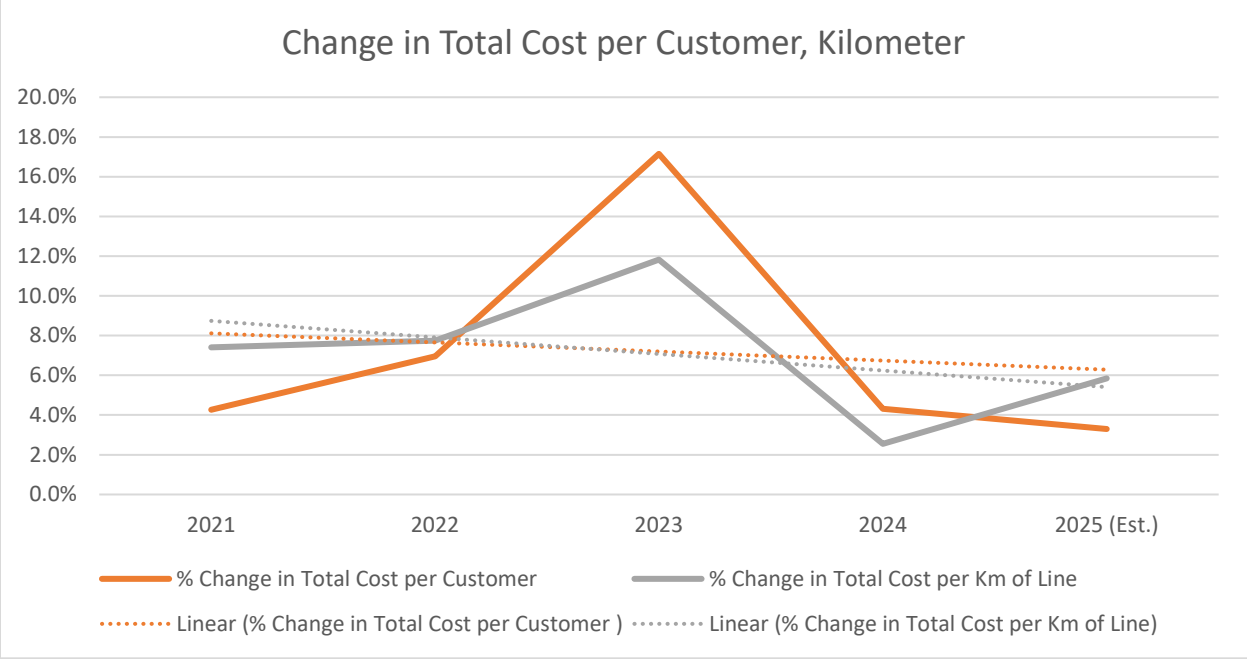
- The significant increase in customer and third-party driven investments in the 2017-2019 period resulted in capital investments in the System Access category significantly above typical levels. The PEG model captures the gross costs of these investments, ignoring the corresponding increase in CIAC which serves to offset increases in rate base and ultimately revenue requirement.

The results above show a declining trend from 2018-2022 and CNPI anticipates that this trend will continue into the 2022-2026 forecast period as a result of a moderate declining trend in capital investment levels.

The OEB Scorecard also includes metrics related to total cost per customer and total cost per km of line, as summarized in Table 2.[1] Section 2.3.2 of CNPI's current DSP discusses CNPI's performance with respect to a number of additional OEB cost metrics not included on the scorecard.

Table 3: Scorecard Cost Control Metrics

	2021	2022	2023	2024	2025 (Est.)
Efficiency Assessment	4	4	4	4	4
Total Cost per Customer	$ 905	$ 968	$ 1,134	$ 1,183	$ 1,222
Total Cost per Km of Line	$ 17,810	$ 19,189	$ 21,458	$ 22,005	$ 23,290



5.6 SCORECARD METRICS – PUBLIC POLICY RESPONSIVENESS

The OEB Scorecard currently contains one metric related to the RRF outcome of Public Policy Responsiveness the Connection of Renewable Generation.

CNPI has consistently met or exceeded OEB targets related to connecting renewable generation on time.

In addition to the scorecard measure, please see the discussion in section 4.3 above regarding other CNPI initiatives during the historic period which demonstrate a commitment to public policy responsiveness.

[1] "Total cost" in this table is based on PEG model calculations.

5.7 FINANCIAL PERFORMANCE

5.7.1 SCORECARD METRICS – FINANCIAL PERFORMANCE

The following table summarizes CNPI's Scorecard financial ratios for the 2021-2025 period:

Table 4: Scorecard Financial Ratios

	2021	2022	2023	2024	2025
Liquidity: Current Ratio (Current Assets/Current Liabilities)	0.24	0.23	0.21	0.23	0.23
Leverage: Total Debt (includes short-term and long-term debt)to Equity Ratio	2.69	2.55	2.35	2.07	2.00
Profitability: Deemed Regulatory Return On Equity	8.78%	8.66%	8.66%	8.66%	8.66%
Profitability: Achieved Regulatory Return On Equity	3.47%	8.47%	7.90%	7.53%	7.29%

CNPI's future target is to achieve its deemed return on equity while maintaining liquidity and leverage ratios that are relatively consistent with historical levels. CNPI notes that the OEB scorecard results focus on CNPI's segmented distribution business, whereas CNPI manages financial metrics such as liquidity and leverage on a consolidated basis with its transmission and distribution divisions. CNPI's audited financial statements, provided as appendices in Exhibit 1 of the Application, provide information on CNPI's consolidated financial position.

5.7.2 REVENUE REQUIREMENT / REVENUE DEFICIENCY

The following table presents CNPI's Revenue Requirement trend from the 2022 Board Approved to 2027 Test Year:

Table 5: Revenue Requirement Trend

Revenue Requirement Component	2022 Board Appr	2022 Actual	2023 Actual	2024 Actual	2025 Actual	2026 Bridge	2027 Test
OM&A Expenses (Incl LEAP)	9,599,168	9,784,453	10,897,520	11,247,955	11,711,630	11,450,096	12,383,274
Amortization/Depreciation	5,577,375	5,252,704	5,268,232	5,449,191	5,866,296	6,275,873	6,819,285
Property Taxes	105,100	108,513	113,284	121,125	133,361	123,548	143,019
Income Taxes (Grossed Up)	442,125	543,477	113,751	233,706	223,116	431,359	484,384
Regulated Return on Rate Base:							
Deemed Interest	2,967,107	2,864,591	3,079,198	3,338,755	3,575,328	3,714,909	4,337,837
Return on Deemed Equity	4,494,100	4,338,825	4,663,878	5,057,012	5,415,335	5,626,750	6,195,653
Service Revenue Requirement	**23,184,975**	**22,892,562**	**24,135,863**	**25,447,744**	**26,925,066**	**27,622,536**	**30,363,451**
Revenue Offsets	-1,341,251	-1,239,780	-1,740,524	-1,647,298	-1,720,635	-1,347,001	-1,349,599
Base Revenue Requirement (Excl Transformer Ownership Allowance)	**21,843,724**	**21,652,783**	**22,395,339**	**23,800,446**	**25,204,431**	**26,275,535**	**29,013,852**

CNPI's 2027 cost of service application is intended to set rates that will recover the 2027 base revenue requirement identified in Table 4 above. Table 5 below illustrates that revenues at current rates are insufficient to recover this revenue requirement, resulting in a net revenue deficiency of $3,499,599, confirming the need for CNPI to proceed with its scheduled cost of service application.

Table 6: Calculation of Revenue Deficiency

Line No.	Particulars	Initial Application	
		At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$3,499,599
2	Distribution Revenue	$25,514,253	$25,514,253
3	Other Operating Revenue Offsets - net	$1,349,599	$1,349,599
4	Total Revenue	$26,863,852	$30,363,451
5	Operating Expenses	$19,345,577	$19,345,577
6	Deemed Interest Expense	$4,337,837	$4,337,837
8	Total Cost and Expenses	$23,683,414	$23,683,414
9	Utility Income Before Income Taxes	$3,180,437	$6,680,037
10	Tax Adjustments to Accounting Income per 2013 PILs model	($4,852,173)	($4,852,173)
11	Taxable Income	($1,671,735)	$1,827,864
12	Income Tax Rate	26.50%	26.50%
13	Income Tax on Taxable Income	($443,010)	$484,384
14	Income Tax Credits	$ -	$ -
15	Utility Net Income	$3,623,447	$6,195,653
16	Utility Rate Base	$170,023,406	$170,023,406
17	Deemed Equity Portion of Rate Base	$68,009,362	$68,009,362
18	Income/(Equity Portion of Rate Base)	5.33%	9.11%
19	Target Return - Equity on Rate Base	9.11%	9.11%
20	Deficiency/Sufficiency in Return on Equity	-3.78%	0.00%
21	Indicated Rate of Return	4.68%	6.20%
22	Requested Rate of Return on Rate Base	6.20%	6.20%
23	Deficiency/Sufficiency in Rate of Return	-1.51%	0.00%
24	Target Return on Equity	$6,195,653	$6,195,653
25	Revenue Deficiency/(Sufficiency)	$2,572,206	$ -
26	Gross Revenue Deficiency/(Sufficiency)	$3,499,599 (1)	

CANADIAN NIAGARA POWER INC.
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BP APPENDIX- A:
Cost of Service Survey Report

INNOVATIVE RESEARCH GROUP

Online Survey
2027 Rate Application Engagement Report

CANADIAN NIAGARA POWER INC.
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This report and all of the information and data contained within it may not be released, shared or otherwise disclosed to any other party, without the prior, written consent of Canadian Niagara Power Inc.

March 2026

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INNOVATIVE RESEARCH GROUP

Canadian Niagara Power Inc. 2027 Rate Application Customer Engagement

Innovative Research Group Inc. (INNOVATIVE) was engaged by Canadian Niagara Power Inc. to assist in meeting its customer engagement commitments under the Renewed Regulatory Framework for Electricity Distributors and Chapter 5 Filing Requirements. The information contained within this report is the result of a series of customer engagements.

Setting the Context

Canadian Niagara Power is in the process of finalizing its 2027-2031 Investment Plan. This report covers the results of a series of customer "workbook" surveys that were used to gather customer preferences on program expenditures in the upcoming five-year period. This "workbook" survey was deployed to all customers with an email address, as well as promoted through a generic link on Canadian Niagara Power's website and social media platforms.

Interpreting the Results

Residential and small business responses were weighted by region and electricity usage to ensure the responses were representative of the broader customer base. INNOVATIVE is confident that the residential and small business online workbook results contained within this report are representative of Canadian Niagara Power's actual customer base.

Large business responses have not been weighted. Results for these customer classes have been expressed as frequencies due to smaller sample size.

Customer Segmentation

In addition to segmenting customers based on where they reside or operate in Canadian Niagara Power's service territory, it is important to be able to identify factors that may influence customer preferences and distinguish between what is within, and what is outside of Canadian Niagara Power's influence or control.

Segmentation has been used throughout the residential and small business sections of this report to look beyond the topline numbers to analyze the results for key segments:

1. **Region:** Using customer data provided by Canadian Niagara Power, we split customers into three regions for analysis; Fort Erie, Port Colborne and Gananoque.

2. **Consumption Quartiles**: For residential and small business customers, results are also shown by consumption quartiles, or otherwise, how much electricity the customer consumes in an average month (in KWh). This is used to ensure that no one customer consumption profile is over or underrepresented in the survey results.

3. **Vulnerable Consumers**: For residential customers, using a combination of household size and combined household income, the report identifies customers who would be eligible for financial assistance programs. The methodology used to calculate this segmentation is based on the OEB's *Ontario Electricity Support Program (OESP)* criteria.

4. **Bill Impact on Finances**: Segmentation that INNOVATIVE refers to as "Bill Impact on Finances" is provided. This segment is determined based on the extent to which customers agree with the following statement:

    a) Residential: *The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.*

    b) Small Business*: The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.*

Understanding Segmentation

Segmentation is an effective way of looking past the topline numbers and dig deeper into the needs and preferences of the customer segments above. For instance, while it is valuable to know that, overall, 79% of residential customers are satisfied with Canadian Niagara Power, it is also important to understand whether satisfaction differs based on region or based on perceptions that may be outside of the utility's influence or control. Segmentation allows readers of this report to quickly look past the topline numbers and understand how various segments of customers feel about various issues.

Sample Validation

Customer Engagement Survey

Sample Validation

To ensure that customers reached by email are representative of the broader population of Canadian Niagara Power's customers, we use Canadian Niagara Power's complete customer lists to compare known sample variables between those with an email address and the full population of customers.

This allows us to identify any systematic differences between those with an email on file and the full population of customers on known variables that may impact outcomes. All samples that are weighted include quotas by region and consumption quartile to ensure representativeness.

Overall Customer Email Coverage

The table below summarizes the email coverage of each rate class.

Rate Class	Total Records (Meters)	Unique customers*	Customers with an email	Email coverage (out of customers)
Residential	28,172 meters	25,456	16,817	**66.1%**
Small Business (GS<50)	2,471 meters	1,454	1,124	**77.3%**
Commercial & Industrial (GS>50)	240 meters	133	132	**99.2%**

*Unique *customers* from the complete list of Canadian Niagara Power's records (individual meters) are identified by cross-referencing available contact information to identify customers with multiple meters. Customers are assigned to their highest-order rate class in the following order (Commercial & Industrial, Small Business (GS<50kW), Residential). For customers with multiple records within the same rate class, the record with the highest average monthly consumption is used for the purpose of assigning sample variables.

Sample Validation

Email Sample vs. Total Customer Accounts

Legend: Difference*
More than -10%
-10% to -4%
-4% to +4%
+4% to +10%
More than +10%

Sample Validation

The information on this page and the one following compares the sample of each rate class with email addresses to the total customer accounts of that rate class across two known variables – distributions of (1) region and (2) average monthly consumption. This analysis is conducted only among rate classes without complete or near complete email coverage.

(1) Regional Distribution by Rate Class

Communities are grouped into three unique regions within Canadian Power Niagara Power's service territory.

Across rate classes, the distributions of region between the full population and email sample are similar (+- 4%). Any regional differences are accounted for in the survey results by setting quotas based on region to ensure the survey results are representative of the Canadian Niagara Power customer base.

Rate Class	Region	Share of full population	Share of email sample	Difference
Residential	Fort Erie	58%	60%	**+2%**
	Port Colborne	31%	30%	**-1%**
	Gananoque	11%	11%	**-1%**
Small Business (GS<50)	Fort Erie	50%	51%	**+1%**
	Port Colborne	34%	34%	**0%**
	Gananoque	16%	14%	**-1%**

Sample Validation

Email Sample vs. Total Customer Accounts Cont'd

(2) Distribution of Consumption Quartile by Rate Class

Across rate classes, the distributions of consumption quartile between the full population and email sample are similar (+- 4%). For small business customers, average monthly consumption (kWh) is higher in the email sample than in the full population.

This difference is accounted for in the survey results by setting quotas based on consumption quartile to ensure the survey results are representative of the Canadian Niagara Power customer base.

Legend: Difference*
More than -10%
-10% to -4%
-4% to +4%
+4% to +10%
More than +10%

Rate Class	Consumption Quartile	Share of full population	Share of email sample	Difference
Residential	First	25%	25%	**0%**
	Second	25%	24%	**-1%**
	Third	25%	25%	**0%**
	Fourth	25%	26%	**+1%**
	Average Monthly Consumption (kWh)	704.78	723.96	**+3%**
Small Business (GS<50)	First	25%	23%	**-2%**
	Second	25%	24%	**-1%**
	Third	25%	26%	**-1%**
	Fourth	25%	27%	**+2%**
	Average Monthly Consumption (kWh)	2,389.01	2,637.17	**+10%**

Summary Results

Investment Trade-Offs

(%) indicates total percentages that selected response. *Large Business (GS>50kW) shown in frequencies.	Rate Class Unweighted n (Weighted in brackets)		
	Residential n=2,722 (2,500)	**Small Business** n=101 (100)	**Large Business (GS>50kW)*** n=9
Improving resiliency to severe weather			
Spend More	53%	48%	5
Draft Plan	47%	52%	4
Improving reliability using intelligent switches			
Spend More	32%	34%	4
Draft Plan	45%	32%	4
Spend Less	23%	35%	1
Modernizing older distribution lines			
Draft Plan	65%	61%	7
Spend Less	35%	39%	2
Replacing at-risk poles			
Spend More	26%	27%	2
Draft Plan	50%	41%	6
Spend Less	24%	32%	1
Investing in electric vehicles			
Draft Plan	54%	47%	8
Spend Less	46%	53%	1
Control room enhancements			
Draft Plan	72%	63%	9
Spend Less	28%	37%	0
Meter replacement program			
Draft Plan	59%	49%	7
Spend Less	41%	51%	2
Overall Evaluation of the Plan			
Spend more	23%	27%	0
Spend according to the draft plan	53%	47%	8
Spend less	13%	19%	0

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Residential Customers

Online Survey Results



Canadian Niagara Power Inc.
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May 19, 2026
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Field Dates

The **Residential Online Survey** was sent to all Canadian Niagara Power Inc. residential customers with an available email address. Customers had an opportunity to complete the survey between **February 11th and March 12th, 2026**.

Each customer received a unique URL that could be linked back to their average monthly consumption, region and rate class.

In total, the residential survey was sent to **16,821** customers from *customer.service@cnpower.com*. Three reminder emails were sent on a rolling basis over the survey field window to those who had not yet completed the survey.

Residential Online Survey Completes

A total of **2,722** (unweighted) Canadian Niagara Power Inc. residential customers completed the online survey.

Sample Weighting

The residential online survey sample was weighted down to n=2,500 proportionately by consumption quartile, and region in order to be representative of the broader Canadian Niagara Power Inc. customer base.

The table below summarizes the unweighted and weighted (in brackets) sample breakdown by consumption quartile and region. Totals may not correspond with cell values, as some customers are missing region or consumption quartile information. Weights are calculated based on all available information for a given customer.

Region	Consumption Quartiles				Total
	First	Second	Third	Fourth	
Fort Erie	447 (382)	445 (367)	413 (359)	427 (351)	1,732 (1,460)
Port Colborne	179 (187)	213 (199)	195 (198)	207 (193)	794 (777)
Gananoque	45 (60)	30 (44)	50 (73)	71 (87)	196 (264)
Total	671 (630)	688 (610)	658 (630)	705 (630)	2,722 (2,500)

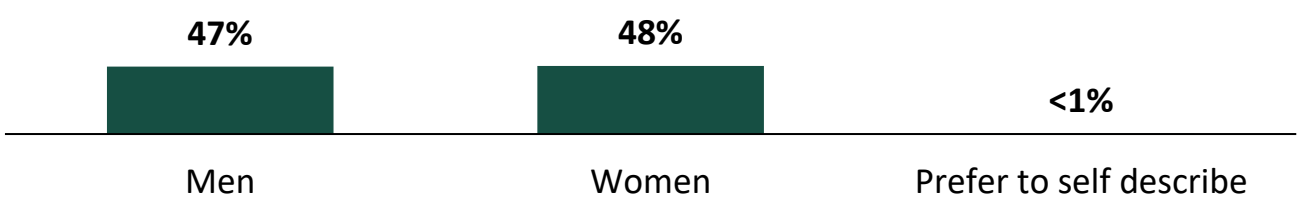
Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Demographic Breakdown

Canadian Niagara Power Inc.
EB-2026-0029
Exhibit I
Tab 2
Schedule 1
May 19, 2026
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Residential

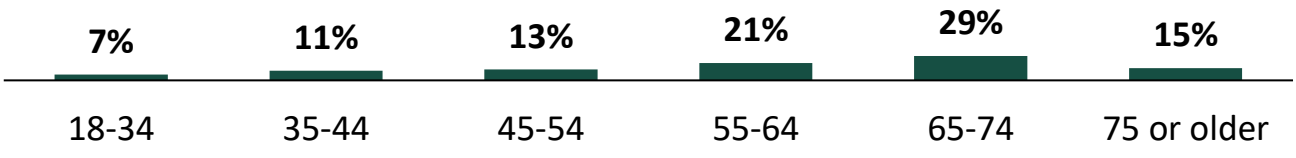
Q Gender



"Prefer not to say" (5%) not shown.

n=2,500

Q Age

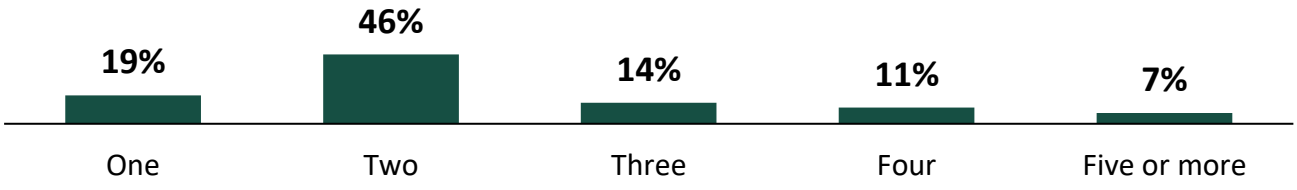


"Prefer not to say" (4%) not shown.

n=2,500

Demographic Breakdown
Continued

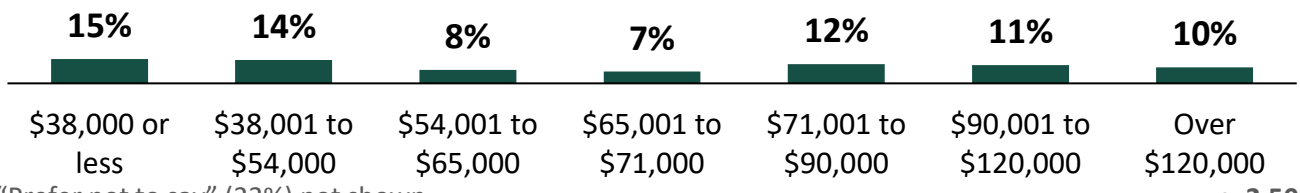
Q Household Size



"Prefer not to say" (3%) not shown.

n=2,500

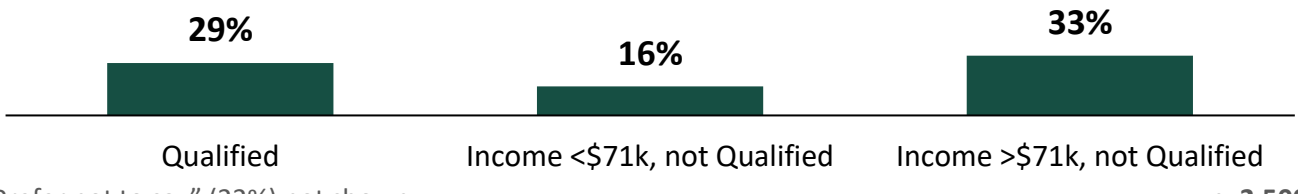
Q After Tax Household Income



"Prefer not to say" (22%) not shown.

n=2,500

Q LEAP/OESP Qualification (based on household size and income)



"Prefer not to say" (22%) not shown.

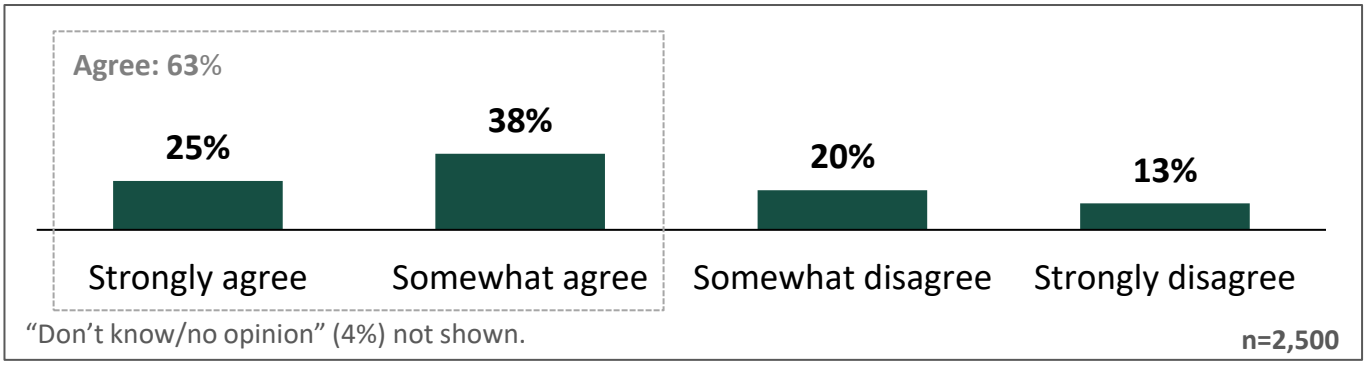
n=2,500

Environmental Controls

Canadian Niagara Power Inc.
EB-2026-0029
Exhibit 1
May 19, 2026
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To what extent do you agree or disagree with the following statements?

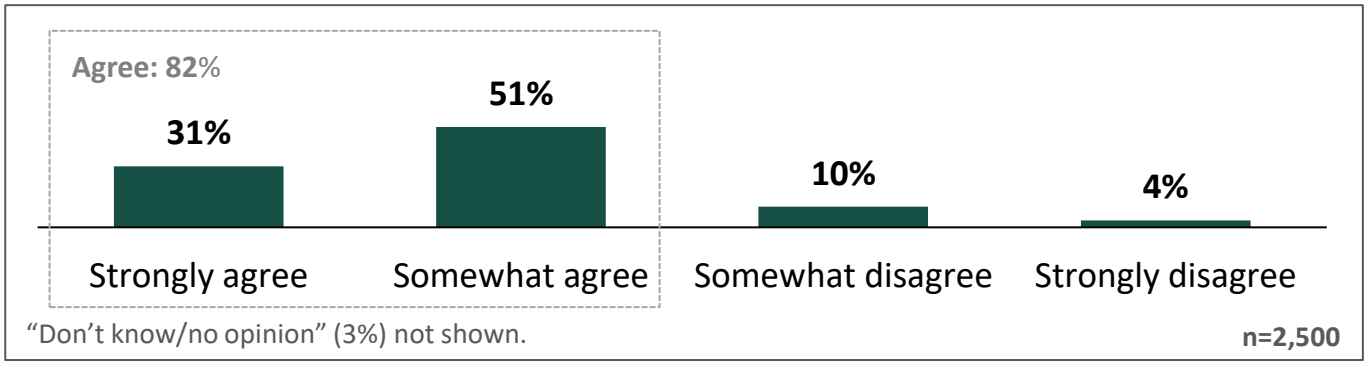
Q The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.



"Don't know/no opinion" (4%) not shown.

n=2,500

Q Consumers are well served by the electricity system in Ontario.



"Don't know/no opinion" (3%) not shown.

n=2,500

Canadian Niagara Power Customer Engagement Survey

Welcome to Canadian Niagara Power's customer engagement survey!

Canadian Niagara Power is looking for your input on choices that will impact the services you receive and the rates you pay.

- **Canadian Niagara Power is looking for your input on its draft investment plan** for the years 2027-2031 to ensure it is making spending decisions that matter to you, the customer.
- **You don't need to be an electricity expert to complete this survey**. It focuses on basic choices and provides the background information you need to answer the questions.
- This survey will take approximately 15 minutes to complete and can be done so at your convenience. Once you begin, your progress will be saved, and you can return to the customer engagement at any time. While the survey can be completed on a smaller mobile device, you may want to consider switching to a tablet or laptop so that it's easier for you to read.

Those who complete the survey will be eligible to enter a draw to win one (1) of three (3) $500 cash prizes.

All individual responses will be kept confidential.
Innovative Research Group (www.innovativeresearch.ca), an independent research company, has been hired by Canadian Niagara Power to gather your feedback while protecting your confidentiality. Your individual answers will not be shared with Canadian Niagara Power in any identifiable way.

INNOVATIVE RESEARCH GROUP

WORKBOOK PAGE

Canadian Niagara Power Customer Engagement Survey

What is this survey about?

Canadian Niagara Power Inc. (CNPI) provides electricity distribution services to approximately 27,500 customers in **Port Colborne** and **Fort Erie**, and an additional 3,600 customers in and around **Gananoque**, where it operates under the name **Eastern Ontario Power**.

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Eastern Ontario Power
A FORTIS ONTARIO Company

Typically, every five years, local distributors like Canadian Niagara Power are required to file an application with the Ontario Energy Board (OEB) to set rates. In this process, Canadian Niagara Power's rate application will be examined in detail, and they must demonstrate that customer needs and priorities were factored into this process.

Today, Canadian Niagara Power wants your feedback on:

1. What you feel they should be prioritizing over the next five years.
2. Specific investment decisions they need to make related to responding to the impacts of severe weather, modernizing the distribution system, and other critical infrastructure.

This feedback, along with other input, will be used to help Canadian Niagara Power refine and finalize their draft investment plan.

But first, we need to ensure that we are all on the same page regarding Canadian Niagara Power's role in the broader electricity system, how much of your bill goes to Canadian Niagara Power, and where that money goes.

WORKBOOK PAGE

Familiarity & Experience

Canadian Niagara Power's role in Ontario's electricity system

Canadian Niagara Power Customer Engagement Survey

What is Canadian Niagara Power's role in the electricity system?

Ontario's electricity system is made up of three key components: generation, transmission and distribution.

Generation

Where electricity comes from

Ontario gets its electricity from a mix of energy sources. About half comes from nuclear power. The remainder comes from a mix of hydroelectric, natural gas, wind, and solar. Ontario Power Generation, a government-owned company, generates almost half of Ontario's electricity.



Transmission

How electricity travels across Ontario

Once electricity is generated, it must be transported to communities across the province. This happens by way of high voltage transmission lines that serve as highways for electricity. Most of this system is owned and operated by Hydro One.



Local Distribution

How electricity is delivered to you

Canadian Niagara Power is responsible for the local distribution system, which takes electricity from transmission lines and brings it to your community.

Canadian Niagara Power builds and maintains critical equipment, delivers electricity, reads meters, answers customer calls, responds during outages, and clears trees and brush from power lines.

Canadian Niagara Power does not generate electricity or set electricity prices.



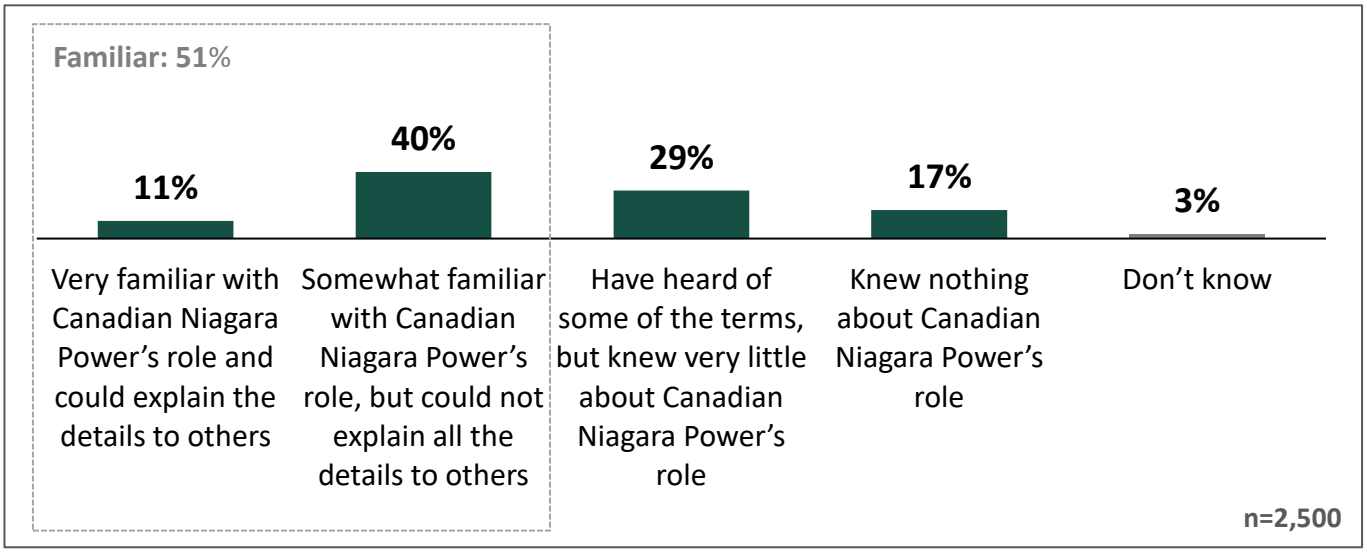
WORKBOOK PAGE

Familiarity & Experience

Canadian Niagara Power's role in Ontario's electricity system

Canadian Niagara Power Inc.
EB-2026-0029
Residential
May 19, 2026
Page 247 of 365

Q Before this survey, how familiar would you say you were with Canadian Niagara Power and the role it plays in Ontario's electricity system?



	Region			Consumption Quartiles			
	Fort Erie	Port Colborne	Gananoque	Low	Medium-Low	Medium-High	High
Very familiar	11%	11%	6%	11%	9%	10%	13%
Somewhat familiar	42%	40%	31%	37%	43%	39%	42%
Knew very little	28%	30%	34%	27%	30%	30%	29%
Knew nothing	16%	17%	26%	21%	16%	18%	14%
Don't know	3%	3%	3%	4%	2%	3%	2%
Familiar (Very + Somewhat)	**53%**	**51%**	**37%**	**48%**	**52%**	**49%**	**54%**

Familiarity & Experience

Canadian Niagara Power's role in Ontario's electricity system

Canadian Niagara Power Inc.
EB-2026-0029
Residential
May 19, 2026
Page 18 of 168
Exhibit

Q Before this survey, how familiar would you say you were with Canadian Niagara Power and the role it plays in Ontario's electricity system?

		LEAP/OESP Qualification			Bill Impact	
	Overall	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
Very familiar	11%	10%	8%	12%	11%	10%
Somewhat familiar	40%	40%	40%	41%	40%	40%
Knew very little	29%	25%	32%	29%	29%	30%
Knew nothing	17%	20%	17%	16%	17%	17%
Don't know	3%	4%	3%	2%	3%	4%
Familiar (Very + Somewhat)	**51%**	**51%**	**48%**	**53%**	**51%**	**50%**

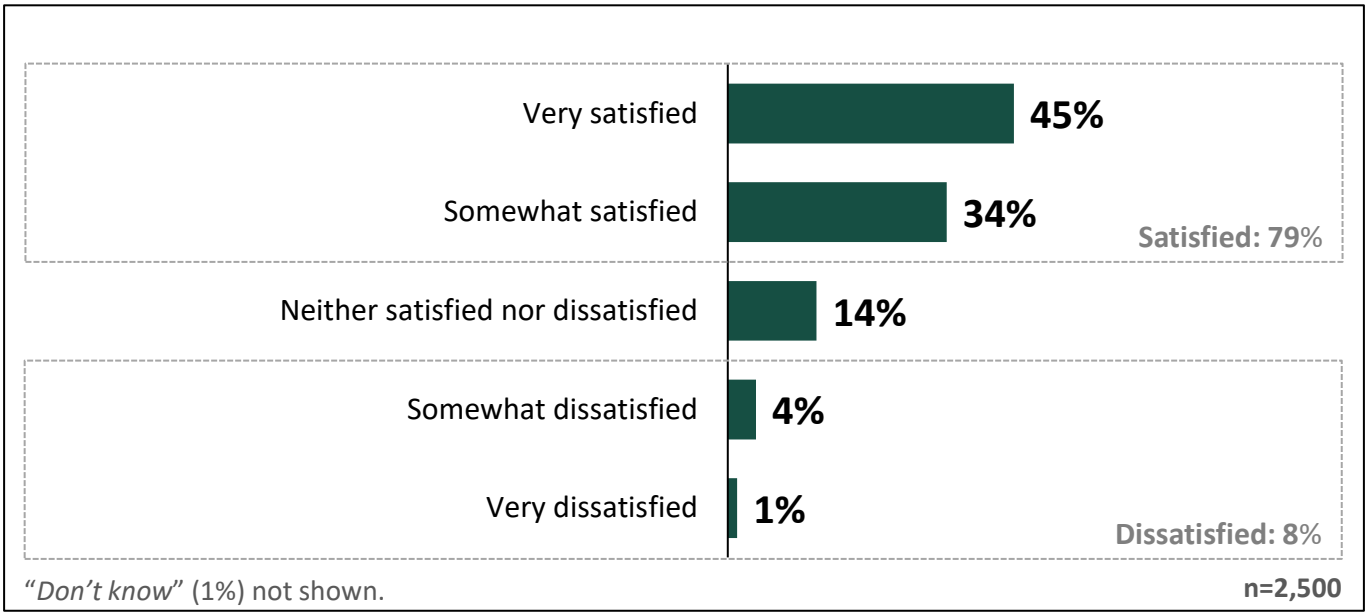
Familiarity & Experience

Overall satisfaction with Canadian Niagara Power's service

Canadian Niagara Power Inc.
EB-2026-0029
May 19, 2026
Exhibit I.1.1
Attachment 1 of 35

Residential

Q Overall, how satisfied or dissatisfied are you with the service you receive from Canadian Niagara Power?



"*Don't know*" (1%) not shown.

n=2,500

	Region			Consumption Quartiles			
	Fort Erie	Port Colborne	Gananoque	Low	Medium-Low	Medium-High	High
Very satisfied	45%	46%	40%	47%	50%	43%	40%
Somewhat satisfied	35%	35%	32%	33%	34%	33%	38%
Neither	13%	14%	17%	15%	11%	17%	13%
Somewhat dissatisfied	5%	3%	7%	4%	3%	5%	5%
Very dissatisfied	1%	1%	2%	1%	1%	1%	3%
Don't know	<1%	1%	2%	1%	1%	<1%	1%
Satisfied (Very + Somewhat)	**80%**	**81%**	**72%**	**80%**	**84%**	**76%**	**78%**
Dissatisfied (Very + Somewhat)	**6%**	**5%**	**9%**	**5%**	**4%**	**7%**	**8%**

Familiarity & Experience

Overall satisfaction with Canadian Niagara Power's service

Canadian Niagara Power Inc.
EB-2026-0029
May 19, 2026
Exhibit I
Tab 1 Schedule 3
Page 1 of 1

Residential

Q Overall, how satisfied or dissatisfied are you with the service you receive from Canadian Niagara Power?

		LEAP/OESP Qualification			Bill Impact	
	Overall	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
Very satisfied	45%	49%	47%	43%	40%	54%
Somewhat satisfied	34%	30%	35%	37%	37%	30%
Neither	14%	15%	13%	14%	16%	10%
Somewhat dissatisfied	4%	5%	4%	4%	5%	4%
Very dissatisfied	1%	1%	1%	2%	2%	1%
Don't know	1%	1%	<1%	<1%	<1%	1%
Satisfied (Very + Somewhat)	**79%**	**78%**	**82%**	**81%**	**77%**	**84%**
Dissatisfied (Very + Somewhat)	**6%**	**6%**	**5%**	**5%**	**7%**	**5%**

Familiarity & Experience

How Canadian Niagara Power can improve services

Q Is there anything in particular you would like Canadian Niagara Power to do to improve its services to you? (Optional)

Responses	%
Lower rates/decrease bills	9.4%
Improve reliability/reduce outages	8.1%
Satisfied with services/no issues	5.6%
Improve line maintenance/vegetation management	2.4%
Grid modernization/infrastructure investment	2.3%
Improve communication during outages	1.8%
Financial strain on vulnerable customers (e.g. seniors, fixed income)	1.0%
Improve outage restoration speed	0.9%
Billing improvements (e.g. timing, payment options, bill format)	0.7%
Lower delivery charges	0.5%
Improve customer service (e.g. access/responsiveness)	0.5%
Energy alternatives/renewable energy options	0.4%
Improve website/online service	0.4%
Provide incentives/rebates or support programs	0.3%
Improve general communication with customers	0.2%
More transparency around costs (e.g. understanding charges)	0.2%
More information/visibility into electricity usage	0.2%
Increase system capacity/address growth	0.1%
Other	0.7%
No comment/None/Don’t know	64.4%

Note: Only responses > 0.1% shown.

Familiarity & Experience

Portion of the electricity bill paid to Canadian Niagara Power

WORKBOOK PAGE

Canadian Niagara Power Customer Engagement Survey

How much of my electricity bill goes to Canadian Niagara Power?

Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board (OEB), the provincial energy regulator.

While **Canadian Niagara Power** is responsible for collecting payment for the entire electricity bill, only a portion goes to Canadian Niagara Power for distribution delivery. As of January 1st, 2026, for a typical residential customer, about 28% of the bill, or $46.08, goes to Canadian Niagara Power per month.

The rest of your bill payment is passed onto provincial transmission companies, power generation companies, the government and regulatory agencies.

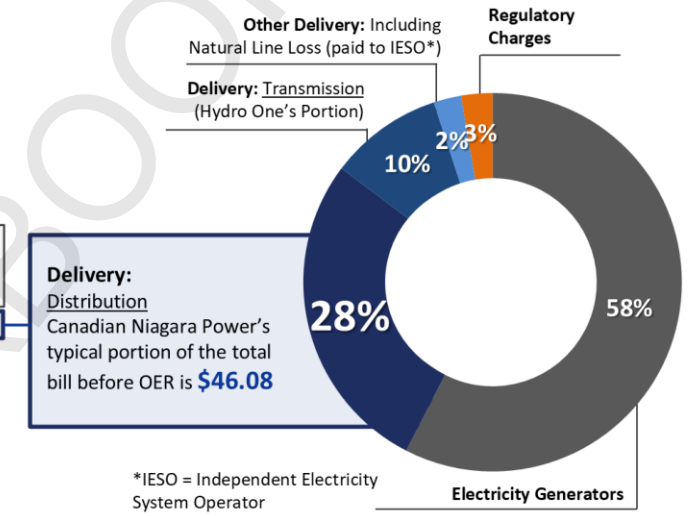
Sample CNPI Monthly Bill
(based on consumption of 750 kWh as of Jan. 1, 2026)

Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
On-Peak (highest price) @ 20.3 c/kWh	27.41
Mid-Peak (mid price) @ 15.7 c/kWh	21.20
Off-Peak (lowest price) @ 9.8 c/kWh	47.04
Delivery	66.11
Regulatory Charges	4.43
Total Electricity Charges	$166.19
HST	21.60
Ontario Electricity Rebate	(-$39.05)
Total Amount	$148.74

Delivery:
Distribution
Canadian Niagara Power's typical portion of the total bill before OER is **$46.08**



The pie chart above is based on a total bill of $166.19, which excludes the Ontario Electricity Rebate and HST. The chart may not total 100% due to rounding.

The sample bill above uses an average consumption level of 750kWh per month, however your usage may vary above or below this assumed level. These types of variations would mostly impact your electricity (On, Mid and Off-Peak) charges.

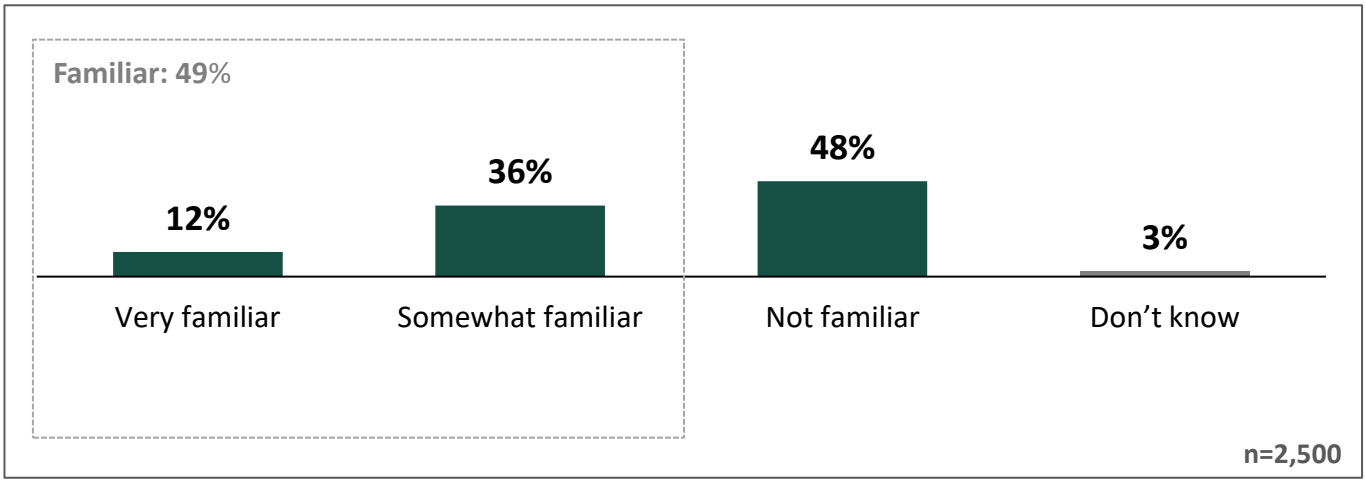
Familiarity & Experience

Portion of the electricity bill paid to Canadian Niagara Power

Canadian Niagara Power Inc.
EB-2026-0028
Exhibit I
May 19, 2026
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Residential

Q Before this survey, how familiar were you with the amount of your electricity bill that went to Canadian Niagara Power?



	Region			Consumption Quartiles			
	Fort Erie	Port Colborne	Gananoque	Low	Medium-Low	Medium-High	High
Very familiar	13%	13%	9%	10%	12%	14%	14%
Somewhat familiar	38%	36%	28%	35%	35%	37%	38%
Not familiar	47%	48%	59%	53%	50%	45%	46%
Don't know	3%	3%	4%	2%	3%	4%	2%
Familiar (Very + Somewhat)	**51%**	**49%**	**37%**	**45%**	**46%**	**51%**	**52%**

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Very familiar	12%	9%	15%	14%	10%
Somewhat familiar	37%	37%	37%	38%	34%
Not familiar	48%	50%	46%	46%	52%
Don't know	3%	3%	2%	2%	4%
Familiar (Very + Somewhat)	**49%**	**47%**	**52%**	**51%**	**44%**

Summary of Investment Plan

How Canadian Niagara Power plans

Canadian Niagara Power Customer Engagement Survey

How does Canadian Niagara Power Plan?

Every five years, **Canadian Niagara Power** develops comprehensive plans that outline both short-term and long-term system needs.

These plans are informed by:

- Internal **engineering and technical experts**
- **Customer feedback** from surveys like this one
- **Mandatory legal and regulatory requirements**, including connecting customers, moving equipment, and installing and maintaining customer meters
- **Internal and external pressures** on the distribution system

What are the biggest pressures on the distribution system?

Canadian Niagara Power is facing a number of challenges that are putting pressure on the system, requiring more resources, new solutions and growing costs to manage. These challenges include:



The increasing frequency and severity of weather events

- In both 2020 and 2022, many customers experienced prolonged power outages due to several severe storms, including heavy snowfall and freezing rain.



Increasing demand for electricity and customer requests to connect to the grid

- According to the Independent Electricity System Operator (IESO), Ontario's independent electricity planning expert, electricity demand in Ontario is forecasted to increase by 75 per cent by 2050.



Rising costs related to inflation, supply chain disruptions, and tariffs

- Like with many businesses, the cost of electrical distribution equipment has increased considerably since 2020. Canadian Niagara Power must find ways to manage these cost pressures.

Canadian Niagara Power has prepared its 2027-2031 draft plan to address these existing and emerging challenges and continue to deliver safe and reliable electricity.

WORKBOOK PAGE

Summary of Investment Plan

Objectives that Canadian Niagara Power is focused on

Canadian Niagara Power Customer Engagement Survey

What is Canadian Niagara Power's 2027-2031 plan focused on?

Canadian Niagara Power has developed a draft plan for 2027-2031 that is focused on **6 primary objectives**, including:

1. **Managing rising costs to limit potential rate increases.**
2. **Making investments in infrastructure that are at higher risk of failure.**
3. **Reducing the number and length of power outages compared to historic levels.**
4. **Improving system resilience against severe weather events, such as ice storms and windstorms.**
5. **Meeting the needs of a growing customer base and increased electricity usage.**
6. **Making investments in technology that provide direct benefits to both customers and the grid.**

WORKBOOK PAGE

Summary of Investment Plan

Objectives that Canadian Niagara Power is focused on

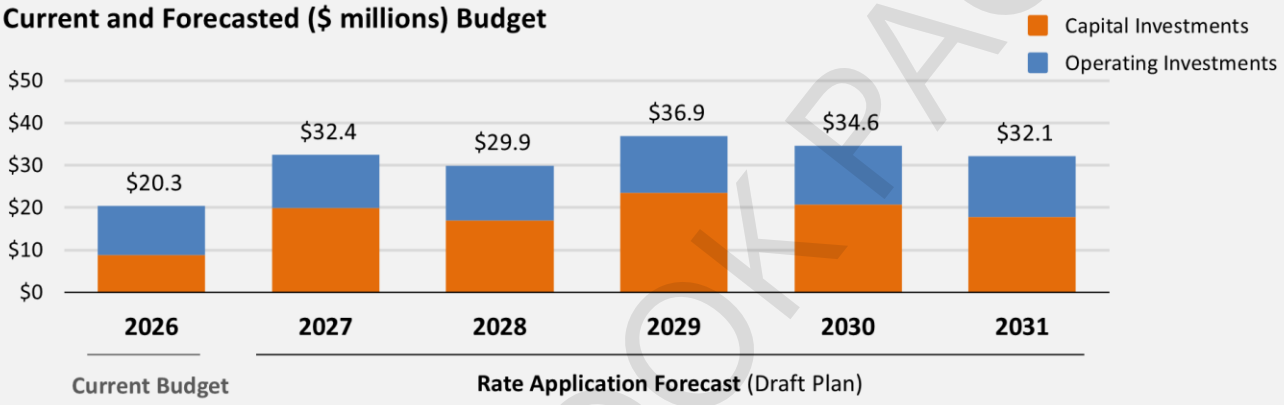
Canadian Niagara Power Customer Engagement Survey

How much will Canadian Niagara Power's draft plan cost?

Canadian Niagara Power has calculated the cost of their draft plan to target the outcomes outlined on the previous page. The costs of this plan are spread among Canadian Niagara Power's more than 31,000 residential and business customers.

The draft plan would result in an overall funding requirement of approximately **$166 million** for 2027-2031. This includes both **capital investments** which include buying and constructing physical infrastructure such as poles, wires, transformers, facilities, trucks, and computers and **operational investments** which include maintenance, testing, and operation of the equipment, vegetation management, as well as the staff needed to manage the grid and serve customers daily.

Current and Forecasted ($ millions) Budget

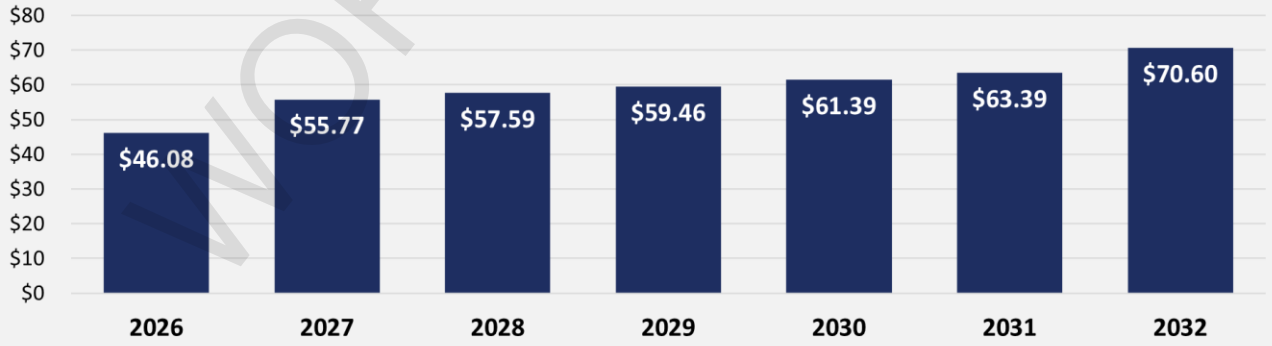


How will this plan impact customer bills?

For a typical residential customer, the distribution portion of their **monthly** bill is estimated to increase from $55.77 in 2027 to $70.60 by the end of 2032 – **an increase of $14.83 on the monthly bill.**

The impact of capital investments made during the 2027-2031 period will largely impact customers' rates starting in 2032, as shown below.

Distribution Portion of Monthly Bill



Note:

- Canadian Niagara Power's capital plan until 2026 was previously approved by the Ontario Energy Board. 2027 rates largely reflect investments made in the current rate period.
- These estimated rate increases and forecasted budgets are preliminary and are subject to change based on customer feedback, regulatory approval, and other factors. Canadian Niagara Power's operating budget forecasts are based on inflationary adjustments.
- 2033-2036 bill impacts are expected to be in line with inflation.

WORKBOOK PAGE

Summary of Investment Plan

Canadian Niagara Power's investment breakdown

Residential

WORKBOOK PAGE

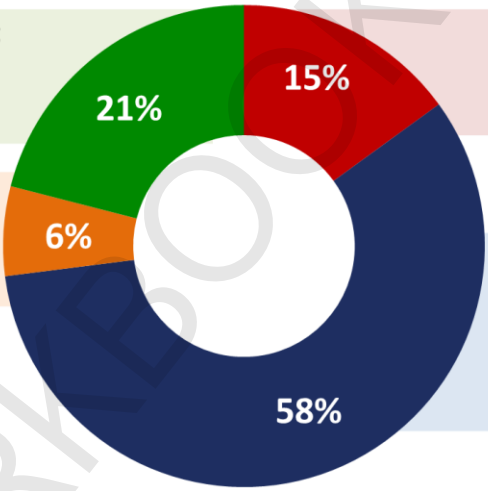
Canadian Niagara Power Customer Engagement Survey

Where is the money being invested?

73% of the forecasted rate increase in 2032 is being driven by the proposed capital investments over the next 5-year plan. The remaining 27% of the forecasted rate increase in 2032 is being driven by proposed operating investments.

Below is a breakdown of the biggest **capital investments** drivers contributing to Canadian Niagara Power's proposed investment plan.

Investments in supporting infrastructure, including specialized vehicles, service centre, and IT to support customer service.



Mandatory investments to connect new customers or to comply with legislated programs.

Investments in reliability and system capacity improvements, including enhanced grid automation.

Investments in replacing assets like lines, poles, meters and station equipment that is in poor condition, at end of life, or assets which require upgrades to today's standards.

Many of the investments contributing to the overall forecasted rate increase will be explored in more detail in the subsequent pages.

Summary of Investment Plan

How Canadian Niagara Power's distribution system performs

Canadian Niagara Power Customer Engagement Survey

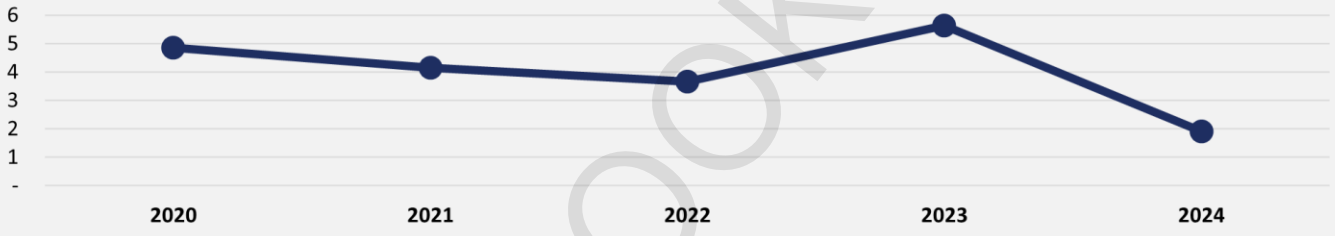
How does Canadian Niagara Power's distribution system perform?

Canadian Niagara Power's combined service territory spans 357 square kilometres, of which, roughly 80% is classified as rural. Serving a largely rural customer-base presents unique challenges, including locating and restoring power outages.

Canadian Niagara Power tracks both the **average number of power outages** per customer and **the average duration customers are without power** per year.

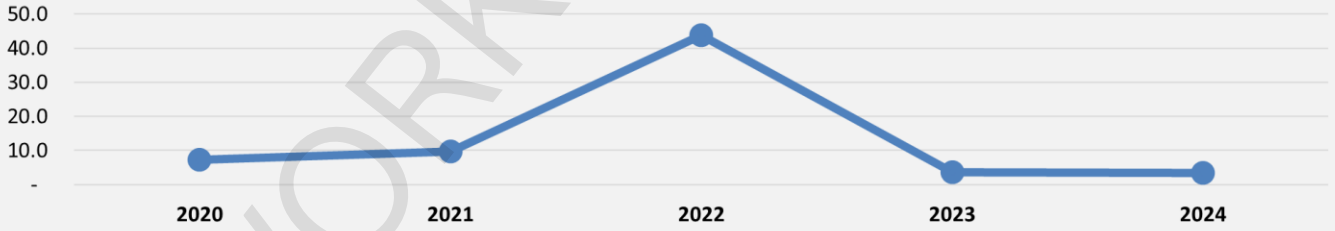
On average, between 2020 and 2024, the typical Canadian Niagara Power customer has been without power 4 times per year.

Number of Outages (Average Outages Per Customer)



When it comes to the total time spend without electricity per year over the same period, the typical Canadian Niagara Power customer has been without power for 13.5 hours each year on average.

Duration of Outages (Average Hours Per Customer)



It's important to keep in mind that these are system averages, and that your actual experience may be different. Notably, the system experienced prolonged outages in 2022 due to the December 2022 severe ice storm.

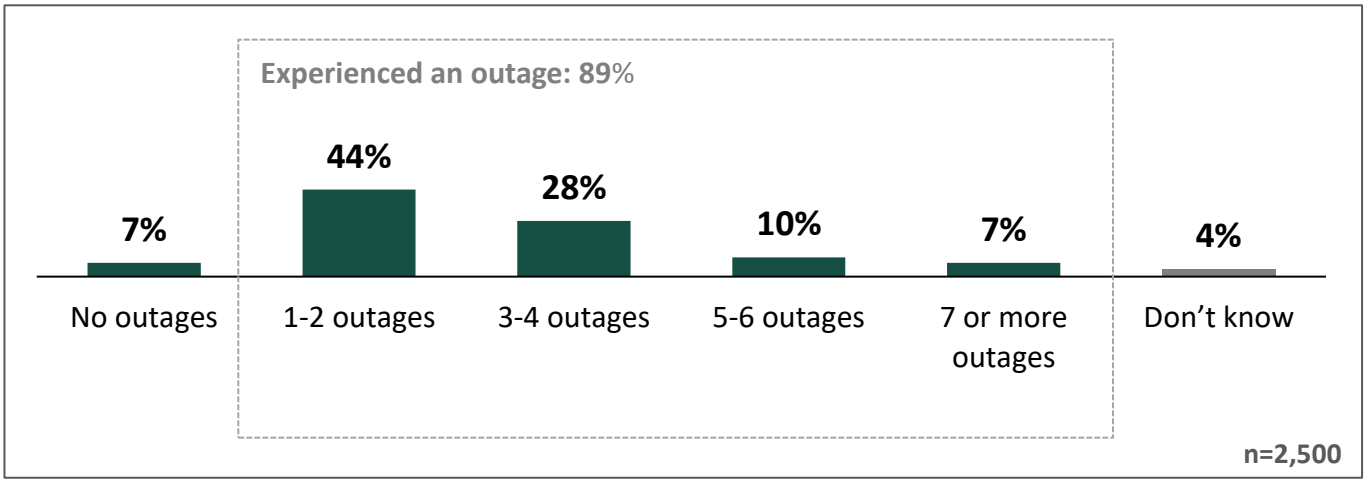
WORKBOOK PAGE

Summary of Investment Plan

How Canadian Niagara Power's distribution system performs

Exhibit 1
Canadian Niagara Power Inc.
EB-2026-0029
Residential
May 19, 2026
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Q Have you experienced any power outages as a Canadian Niagara Power customer in the past 12 months which lasted longer than one minute?



	Region			Consumption Quartiles			
	Fort Erie	Port Colborne	Gananoque	Low	Medium-Low	Medium-High	High
No outages	8%	7%	3%	12%	6%	5%	5%
1-2 outages	45%	51%	22%	46%	48%	42%	42%
3-4 outages	28%	26%	37%	24%	29%	31%	30%
5-6 outages	9%	8%	21%	8%	10%	11%	10%
7 or more outages	7%	6%	13%	5%	5%	8%	9%
Don't know	4%	3%	4%	6%	2%	3%	4%
Experienced an outage (At least 1 outage)	**88%**	**91%**	**93%**	**82%**	**92%**	**92%**	**91%**

Summary of Investment Plan

How Canadian Niagara Power's distribution system performs

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Residential

Q Have you experienced any power outages as a Canadian Niagara Power customer in the past 12 months which lasted longer than one minute?

		LEAP/OESP Qualification			Bill Impact	
	Overall	**Qualified**	**<$71k Not Qualified**	**>$71k Not Qualified**	**Major Impact**	**No Major Impact**
No outages	7%	8%	8%	6%	7%	6%
1-2 outages	44%	49%	43%	42%	44%	44%
3-4 outages	28%	25%	31%	29%	27%	30%
5-6 outages	10%	8%	10%	12%	11%	8%
7 or more outages	7%	6%	5%	9%	7%	6%
Don't know	4%	3%	3%	2%	3%	5%
Experienced an outage (At least 1 outage)	**89%**	**89%**	**89%**	**91%**	**89%**	**89%**

Summary of Investment Plan

Top contributors to outages

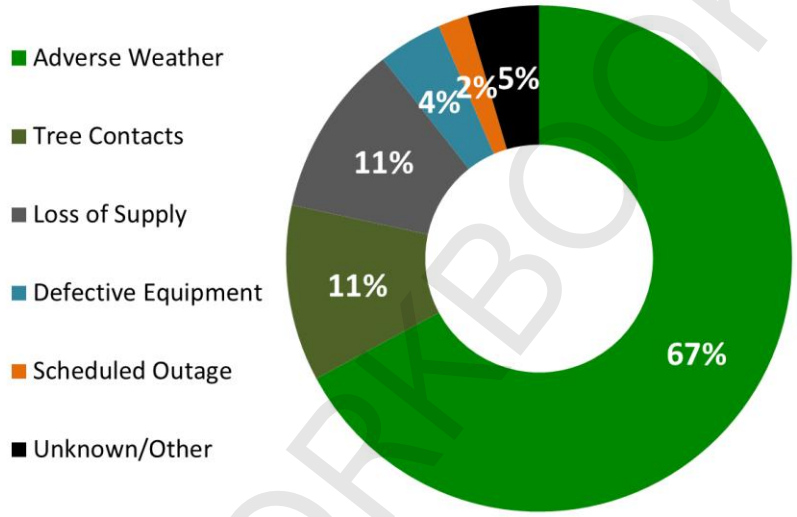
Canadian Niagara Power Customer Engagement Survey

What are the top contributors of outages?

Since 2020, 89% of the hours customers have been without power can be traced back to three causes – **adverse weather** (67%), **tree contacts** (11%), and **loss of supply** from the transmission system (11%) operated by Hydro One.

While transmission system failures are largely out of the control of Canadian Niagara Power, there are investments that can be made to attempt to reduce the impacts of tree contacts, defective equipment, and even adverse weather.

Customer Outage Duration (Hours) by Cause 2020-2024





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Summary of Investment Plan

Choices Canadian Niagara Power want feedback on

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Canadian Niagara Power Customer Engagement Survey

What choices does Canadian Niagara Power want my feedback on?

The remainder of this survey asks for your input on the total cost of the draft investment plan plus **7 key choices** within the plan that Canadian Niagara Power is looking for feedback on.

Canadian Niagara Power will need to demonstrate to the OEB both what they heard from customers, as well as how they reflected your feedback in its plans.

Between 2027-2031, many of the investments that Canadian Niagara Power will make are mandatory – whether to connect new customers or perform other mandatory and legislated work. Canadian Niagara Power must also make the necessary investments in infrastructure to ensure the system operates in a safe and reliable manner.

Canadian Niagara Power will seek your feedback on projects where there is a degree of optionality – whether in scope or pacing of investment that can have a direct impact on the services you receive.

How do I make choices?

- Each choice has a summary of options that Canadian Niagara Power is considering. In many cases, that includes options that would see Canadian Niagara Power ***spend less*** or ***spend more*** than what is currently being proposed in the draft plan.
- For each option, Canadian Niagara Power has estimated the impact it would have on customer bills compared to the draft plan. These impacts are approximate.
- Following each question, you will also have an opportunity to provide additional feedback if you choose to.
- Once you have finished giving feedback on these key choices, you will have an opportunity to review and change your responses until you feel you have found the right balance between the level of investment and cost.

WORKBOOK PAGE

Investment Trade-Offs

Improving resiliency to severe weather

Residential

Canadian Niagara Power Customer Engagement Survey

Choice 1: Improving resiliency to severe weather

Since 2020, adverse weather has accounted for the majority of power outages that customers experience.

In recent years, Canadian Niagara Power has begun replacing and repairing equipment, making it more resilient to the impacts of severe weather events, such as ice storms and windstorms.



There are certain parts of Canadian Niagara Power's service territory that are more susceptible to the increased frequency of severe weather events. For instance, in 2022, a severe ice storm left thousands without power along the lakefront in Fort Erie and Port Colborne.

In its current draft plan, Canadian Niagara Power is continuing to prioritize investments in equipment based on safety, reliability and asset condition considerations. Priority is not currently given to areas that are at higher risk of severe weather.

However, Canadian Niagara Power could spend more to proactively replace poles and wires and increase the frequency of cleaning trees and brush in areas at higher risk of severe weather. These investments could potentially minimize the impacts of severe weather, including both the risk of outages and costly emergency repairs.

Which of the following options do you prefer?

Option	Rate Impact	Investment Details + Outcome(s)
Spend More	$0.11 more per month by 2032	• Invest in additional tree and brush clearing and pole/wire replacement in high-risk areas • Reduce the risk of weather-related outages in areas more prone to severe weather events
Draft Plan	Within proposed rate increase	• Defer investments to improve resiliency to severe weather events, maintaining the current risk of weather-related outages in at-risk areas

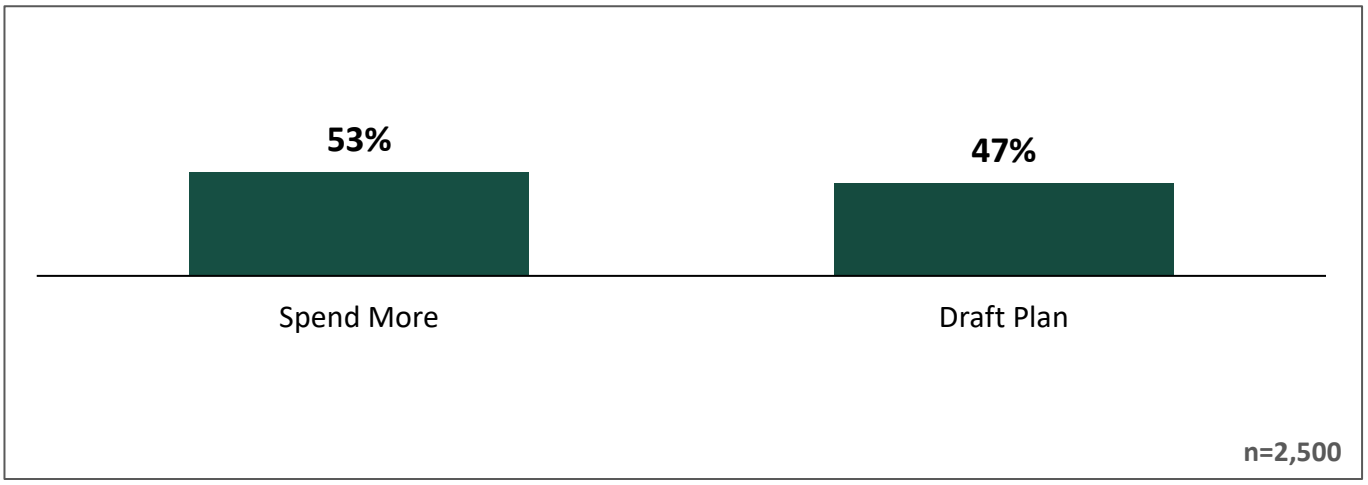
WORKBOOK PAGE

Investment Trade-Offs

Improving resiliency to severe weather

Residential

Q Which of the following options do you prefer?



	Region			Consumption Quartiles			
	Fort Erie	Port Colborne	Gananoque	Low	Medium-Low	Medium-High	High
Spend More	53%	51%	58%	52%	55%	54%	50%
Draft Plan	47%	49%	42%	48%	45%	46%	50%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Spend More	48%	51%	58%	46%	65%
Draft Plan	52%	49%	42%	54%	35%

INNOVATIVE RESEARCH GROUP

Investment Trade-Offs

Improving resiliency to severe weather

Residential

Q Additional Feedback (Optional)

Responses	%
Better preventative maintenance/proactive planning	2.1%
Against increases/costs are too expensive	1.6%
Burying lines underground	1.3%
Willing to pay more for improved resiliency	1.3%
Seek operational efficiencies/alternative funding/customers shouldn't pay	1.1%
Concern about increasing frequency/severity of weather events	0.8%
Improve line maintenance/vegetation management	0.6%
Invest now to prevent future outages/costs	0.6%
Support the draft plan/rate increase as reasonable	0.6%
High-risk area funding and prioritization	0.5%
Financial strain on vulnerable customers (e.g. seniors, fixed income)	0.4%
Concerns about corporate spending/resource allocation	0.4%
Household resiliency/backup solutions	0.4%
Request for alternative option/choices	0.3%
Need for transparency/clear communication/information	0.2%
Other	0.5%
No comment/None/Don’t know	87.3%

Note: Only responses > 0.1% shown.

Investment Trade-Offs

Improving reliability using intelligent switches

Canadian Niagara Power Customer Engagement Survey

Choice 2: Improving reliability using intelligent switches

Technology has changed the way that Canadian Niagara Power can manage and monitor the distribution system.



Automated switches can help Canadian Niagara Power remotely monitor and trace power outages and re-route electricity from a control room rather than sending a repair crew to patrol the lines.

When an outage occurs in an area without this automated technology, it can take crews between 4 and 8 hours to locate the issue, fix it, and restore power. Currently, Canadian Niagara Power has deployed 9 automated switches in various parts of its service territory. A network of automated switches can significantly improve restoration times when an outage occurs.

In its current draft plan, Canadian Niagara Power is proposing to install 21 new automated switches. The location of these switches would be determined based on either benefitting the greatest number of customers or more sensitive customers like hospitals and fire stations.

That said, depending on customer feedback, Canadian Niagara Power could install more or fewer automated switches. The more switches that are installed, the more the system will benefit from improved restoration times.

Which of the following options do you prefer?

Option	Rate Impact	Investment Details + Outcome(s)
Spend More	$0.11 more per month by 2032	• Install **26 automated switches** by 2031 • Further improve outage restoration times relative to the current draft plan
Draft Plan	Within proposed rate increase	• Install **21 automated switches** by 2031 • Improve outage restoration times relative to today
Spend Less	$0.23 less per month by 2032	• Install **10 automated switches** by 2031 • Limit the benefits of improved restoration times relative to the current draft plan

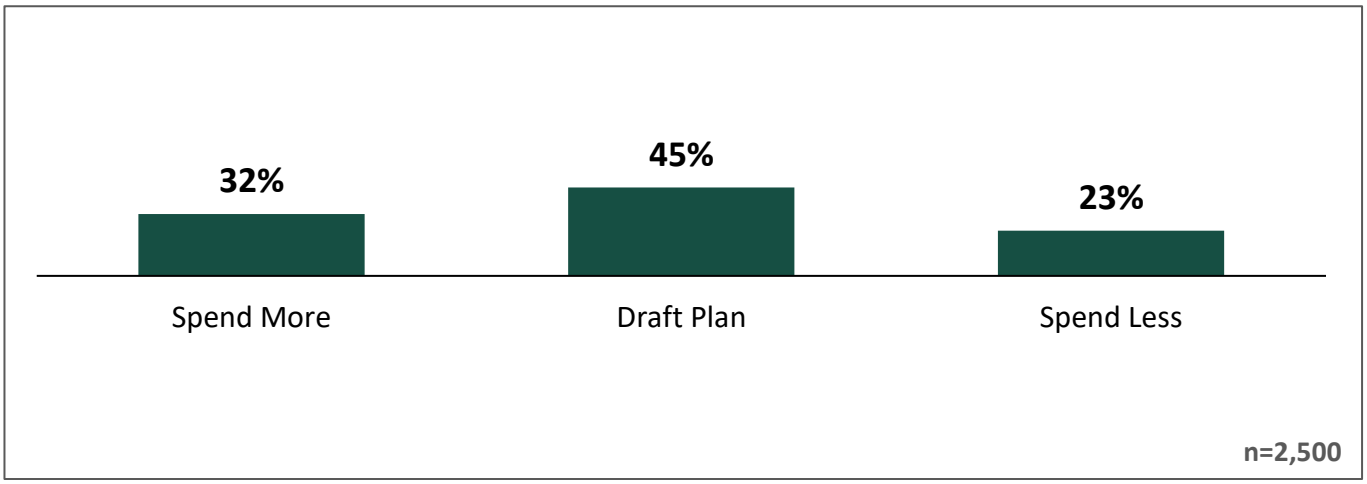
WORKBOOK PAGE

Investment Trade-Offs

Improving reliability using intelligent switches

Residential

Q Which of the following options do you prefer?



	Region			Consumption Quartiles			
	Fort Erie	Port Colborne	Gananoque	Low	Medium-Low	Medium-High	High
Spend More	31%	29%	42%	32%	33%	31%	31%
Draft Plan	46%	46%	41%	43%	45%	46%	46%
Spend Less	23%	25%	17%	24%	22%	23%	23%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Spend More	28%	32%	38%	25%	43%
Draft Plan	45%	47%	43%	46%	43%
Spend Less	27%	22%	19%	29%	14%

Investment Trade-Offs

Improving reliability using intelligent switches

Residential

Q Additional Feedback (Optional)

Responses	%
Willing to pay more for improved reliability	1.6%
Against increases/costs are too expensive	1.1%
Support the draft plan/rate increase as reasonable	0.9%
Need for transparency/clear communication/information	0.8%
Seek operational efficiencies/alternative funding/customers shouldn't pay	0.4%
Concerns with automated switches/limitations	0.4%
Better preventative maintenance/proactive planning	0.2%
Invest now to prevent future outages/costs	0.2%
Household resiliency/backup solutions	0.2%
High-risk area funding and prioritization	0.2%
Financial strain on vulnerable customers (e.g. seniors, fixed income)	0.2%
Concerns about corporate spending/resource allocation	0.2%
Support for automation/technology modernization	0.1%
Other	0.4%
No comment/None/Don't know	93.1%

Note: Only responses > 0.1% shown.

Investment Trade-Offs

Modernizing older distribution lines

Residential

Exhibit 1

Canadian Niagara Power Customer Engagement Survey

Choice 3: Modernizing older distribution lines

Parts of Canadian Niagara Power's service territory have historically been served by older lines that have much less capacity than modern ones. Meaning that as demand for electricity increases, these lines can struggle to distribute the constant flow of electricity that customers expect.

Over the past decade, Canadian Niagara Power has modernized many of these lines, however, some pockets of the service territory are still served by these older lines. In areas where these lines have been replaced, there have been reliability improvements.

In its current draft plan, Canadian Niagara Power is proposing to complete a large remaining line modernization project in the Point Abino area. However, Canadian Niagara Power could consider delaying some of these efforts beyond 2031. This would reduce costs in the short-term but would require Canadian Niagara Power to complete this project in two phases, resulting in increased disruption, reduced ability to accommodate increased load, and could result in higher costs beyond 2031.



Which of the following options do you prefer?

Option	Rate Impact	Investment Details + Outcome(s)
Draft Plan	Within proposed rate increase	• Complete full conversion by 2031 • Improve localized reliability and increased capacity in the Point Abino area
Spend Less	$0.35 less per month by 2032	• Undertake conversion in two phases, targeting completion beyond 2031 • Delayed reliability improvements due to prolonged project cycle

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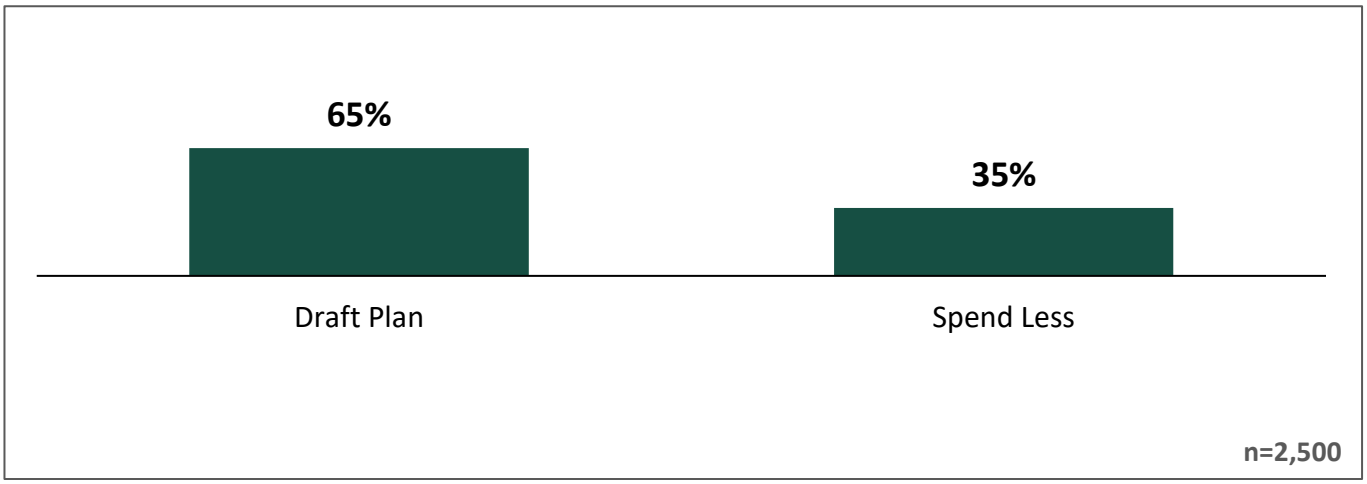
Investment Trade-Offs

Modernizing older distribution lines

Residential

Erratum

Q Which of the following options do you prefer?



	Region			Consumption Quartiles			
	Fort Erie	Port Colborne	Gananoque	Low	Medium-Low	Medium-High	High
Draft Plan	64%	66%	69%	66%	63%	65%	67%
Spend Less	36%	34%	31%	34%	37%	35%	33%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Draft Plan	63%	66%	67%	59%	75%
Spend Less	37%	34%	33%	41%	25%

Investment Trade-Offs

Modernizing older distribution lines

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Q Additional Feedback (Optional)

Responses	%
Invest now to prevent future outages/costs	0.7%
Against increases/costs are too expensive	0.7%
Customers who benefit/are affected should pay	0.6%
Support the draft plan/rate increase as reasonable	0.4%
Seek operational efficiencies/alternative funding/customers shouldn't pay	0.4%
Need for transparency/clear communication/information	0.4%
Concerns about geographic equity in prioritization	0.4%
Burying lines underground	0.3%
Willing to pay more for improved reliability	0.3%
Financial strain on vulnerable customers (e.g. seniors, fixed income)	0.2%
Better preventative maintenance/proactive planning	0.2%
Improve line maintenance/vegetation management	0.1%
Current reliability viewed as sufficient/upgrades unnecessary	0.1%
Other/No comment/None/Don’t know	95.2%

Note: Only responses > 0.1% shown. Other is <0.1%, combined with No comment/None/Don’t know.

Investment Trade-Offs

Replacing at-risk poles

Canadian Niagara Power Customer Engagement Survey

Choice 4: Replacing at-risk poles

Canadian Niagara Power operates and maintains approximately 1,700 km of distribution line that is supported by over 22,000 poles.

Each year, Canadian Niagara Power identifies and prioritizes which poles should be replaced based on their condition, age, and the consequences of their potential failure.

Recently, Canadian Niagara Power has replaced, on average, approximately 115 at-risk poles per year. A recent assessment showed that 940 poles are at higher risk of failure, which, while rare, could result in significant interruptions and outages.

In its current draft plan, Canadian Niagara Power is proposing to replace approximately 115 at-risk poles each year. There is also an option to do more or less. When less is done, it increases the chances of more outages and more costly reactive repairs but also pushes some of the associated costs further down the road. When more is done, it can result in some minor improvements to reliability and get ahead of the curve at an additional cost.



Which of the following options do you prefer?

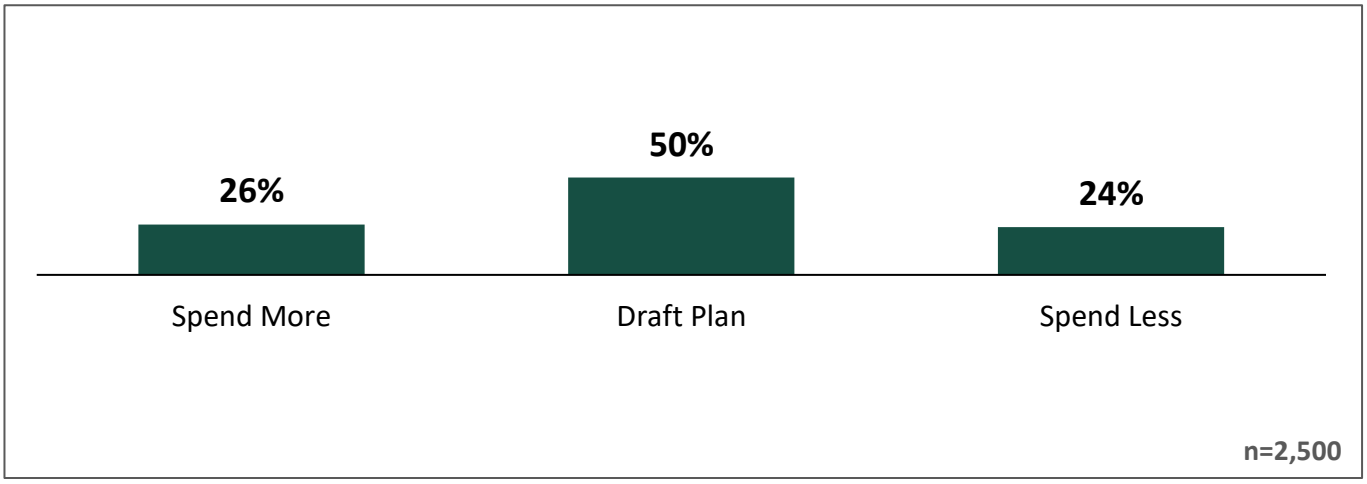
Option	Rate Impact	Investment Details + Outcome(s)
Spend More	$0.14 more per month by 2032	• Replace approximately 127 at-risk poles each year • Further reduce the risk of pole failure relative to the current draft plan
Draft Plan	Within proposed rate increase	• Replace approximately 115 at-risk poles each year • Reduce the risk of pole failure relative to today
Spend Less	$0.14 less per month by 2032	• Replace approximately 104 at-risk poles each year • Increased risk of pole failure relative to the current draft plan

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Investment Trade-Offs

Replacing at-risk poles

Q Which of the following options do you prefer?



	Region			Consumption Quartiles			
	Fort Erie	Port Colborne	Gananoque	Low	Medium-Low	Medium-High	High
Spend More	26%	23%	33%	28%	26%	25%	24%
Draft Plan	50%	51%	48%	47%	50%	52%	51%
Spend Less	24%	26%	20%	25%	25%	23%	25%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Spend More	22%	30%	29%	20%	35%
Draft Plan	49%	49%	50%	50%	50%
Spend Less	29%	21%	21%	30%	15%

Investment Trade-Offs

Replacing at-risk poles

Residential

Q Additional Feedback (Optional)

Responses	%
Burying lines underground	1.1%
Invest now to prevent future outages/costs	0.5%
Better proactive planning/replacement strategies	0.5%
Against increases/costs are too expensive	0.4%
Need for transparency/clear communication/information	0.4%
Willing to pay more for improved reliability	0.3%
Seek operational efficiencies/alternative funding/customers shouldn't pay	0.3%
Replace wood poles with stronger/more durable materials	0.3%
Concerns about past management and maintenance	0.2%
Support for phased/gradual approach	0.2%
Financial strain on vulnerable customers (e.g. seniors, fixed income)	0.1%
Support the draft plan/rate increase as reasonable	0.1%
Improve line maintenance/vegetation management	0.1%
Customers who benefit/are affected should pay	0.1%
Concerns about corporate spending/resource allocation	0.1%
Other	0.2%
No comment/None/Don’t know	95.2%

Note: Only responses > 0.1% shown.

Investment Trade-Offs

Investing in electric vehicles

Canadian Niagara Power Customer Engagement Survey

Choice 5: Investing in electric vehicles

Canadian Niagara Power operates a fleet of vehicles to build and maintain a safe and reliable electricity system.



As with other equipment, Canadian Niagara Power has vehicle replacement criteria that weighs whether it is more cost effective to repair a vehicle, rather than replace it.

Light vehicles are everyday vehicles used for transportation and support, including trucks, SUVs and cars. **Heavy vehicles** are large, specialized vehicles used for construction, maintenance, or emergency repair work on the electrical grid.

Over the five years of the upcoming plan, Canadian Niagara Power has identified 8 out of approximately 24 light vehicles requiring replacement that could be replaced with electric or hybrid models.

In its current draft plan, Canadian Niagara Power is planning to replace these light vehicles with electric or hybrid models. While these vehicles would both reduce emissions and lower ongoing operating costs, the vehicles are more expensive than traditional gasoline options.

Which of the following options do you prefer?

Option	Rate Impact	Investment Details + Outcome(s)
Draft Plan	Within proposed rate increase	• Replace 8 light vehicles with electric or hybrid models • Reduce overall cost of operating vehicles and emissions
Spend Less	$0.07 less per month by 2032	• Replace 8 light vehicles with traditional gasoline options • Reduce upfront costs, but increased operating costs in the future

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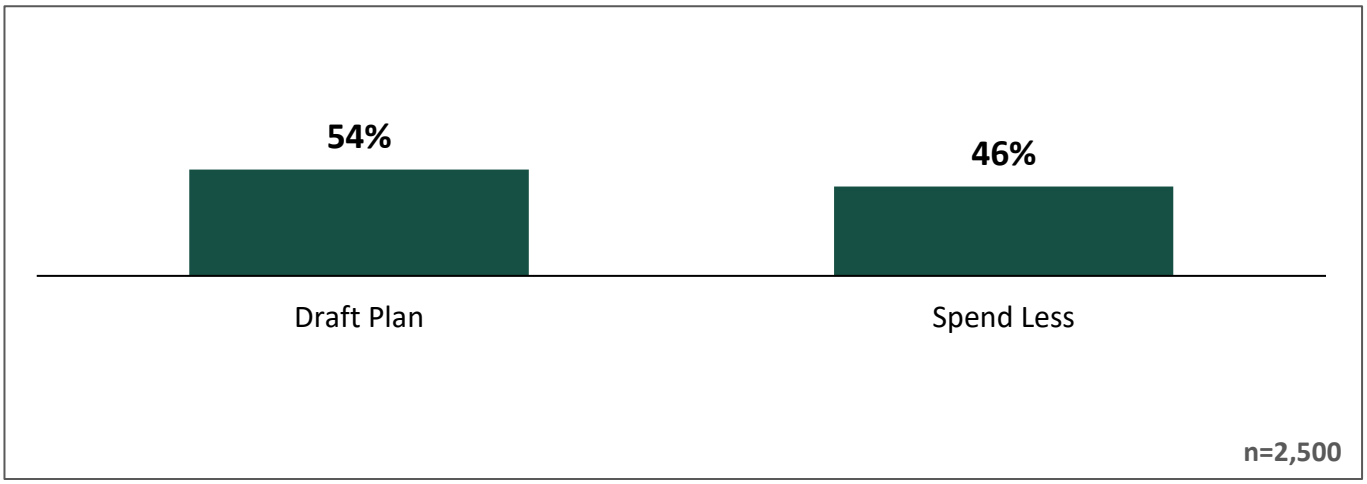
Investment Trade-Offs

Investing in electric vehicles

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Q Which of the following options do you prefer?



	Region			Consumption Quartiles			
	Fort Erie	Port Colborne	Gananoque	Low	Medium-Low	Medium-High	High
Draft Plan	54%	53%	60%	55%	53%	54%	55%
Spend Less	46%	47%	40%	45%	47%	46%	45%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Draft Plan	53%	59%	58%	50%	62%
Spend Less	47%	41%	42%	50%	38%

Investment Trade-Offs

Investing in electric vehicles

Residential

Q Additional Feedback (Optional)

Responses	%
Fleet performance and emergency readiness	0.9%
Long-term cost of acquisition and maintenance	0.8%
Preference for hybrid vehicles	0.8%
Concerns about reliability in cold weather	0.8%
Preference for gasoline/diesel vehicles	0.4%
Need for transparency/clear communication/information	0.4%
Support the draft plan/rate increase as reasonable	0.4%
EV charging and grid capacity constraints/limitation	0.3%
Seek operational efficiencies/alternative funding/customers shouldn't pay	0.3%
Concerns about corporate spending/resource allocation	0.3%
Positive environmental impact/emission reductions	0.2%
Against increases/costs are too expensive	0.2%
Adoption timing and operational feasibility	0.1%
Government support and funding opportunities	0.1%
Local/domestic vehicle sourcing	0.1%
Skepticism about environmental benefits	0.1%
Other	0.3%
No comment/None/Don’t know	93.4%

Note: Only responses > 0.1% shown.

Investment Trade-Offs

Control room enhancements

Canadian Niagara Power Customer Engagement Survey

Choice 6: Control room enhancements

Canadian Niagara Power's control room serves as a central facility to monitor, manage, and control the distribution grid. When an outage occurs, the control room plays an important role in locating the issue, and in some instances, remotely restoring power where intelligent switches have been installed.



Canadian Niagara Power's existing control room was established approximately 20 years ago, and since that time, there have been advancements in control room technology. Canadian Niagara Power's current control room relies primarily on the use of paper maps to display the status of the system. The paper maps are updated with pins and manual mark-ups.

Among other enhancements, in its current draft plan, Canadian Niagara Power is proposing to make upgrades to its control room to move from paper maps to a digital, real-time control room, which is in line with current best practices in the industry.

These control room enhancements would enable faster and more accurate system monitoring and control, improve the accuracy of online outage maps, and eliminate manual mapping updates. These enhancements would be particularly impactful during large outage events, such as severe weather, to support more rapid outage restoration efforts.

Which of the following options do you prefer?

Option	Rate Impact	Investment Details + Outcome(s)
Draft Plan	Within proposed rate increase	• Enhance Canadian Niagara Power's control room, including installing digital screens for system mapping • Improve system monitoring efficiency and outage restoration efforts
Spend Less	$0.29 less per month by 2032	• Continue with current control room technology, including paper mapping system

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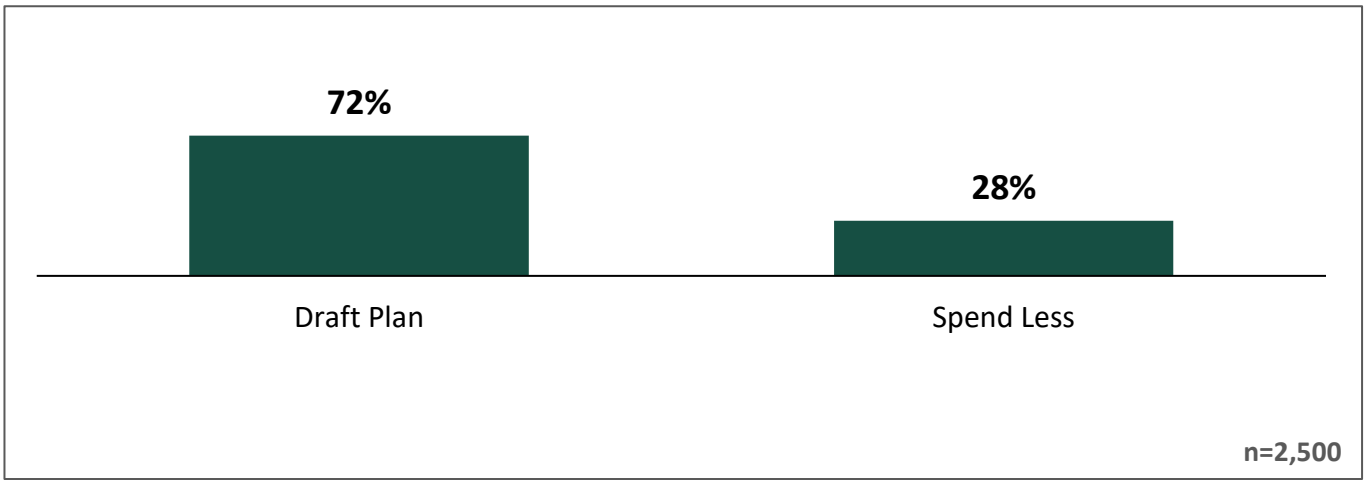
Investment Trade-Offs

Control room enhancements

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Q Which of the following options do you prefer?



	Region			Consumption Quartiles			
	Fort Erie	Port Colborne	Gananoque	Low	Medium-Low	Medium-High	High
Draft Plan	72%	70%	76%	72%	71%	72%	72%
Spend Less	28%	30%	24%	28%	29%	28%	28%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Draft Plan	67%	73%	76%	65%	83%
Spend Less	33%	27%	24%	35%	17%

Investment Trade-Offs

Control room enhancements

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Q Additional Feedback (Optional)

Responses	%
Technology upgrades and maintenance planning	1.8%
System reliability and risk mitigation/utilize combined system	1.2%
Support the draft plan/rate increase as reasonable	0.4%
Concerns about corporate spending/resource allocation	0.3%
Need for transparency/clear communication/information	0.3%
Against increases/costs are too expensive	0.3%
Seek operational efficiencies/alternative funding/customers shouldn't pay	0.2%
Outage safety and system resilience	0.2%
Address existing operational challenges first	0.1%
Emerging technology and AI integration	0.1%
Support for phased/gradual approach	0.1%
Other	0.1%
No comment/None/Don’t know	95.0%

Note: Only responses > 0.1% shown.

Investment Trade-Offs

Meter replacement program

Residential

Canadian Niagara Power Customer Engagement Survey

Choice 7: Meter replacement program

Electricity meters are a critical component of the infrastructure needed to measure electricity consumption and bill customers accurately. Meters are a physical piece of equipment that are typically located on the side of houses and buildings.



Most of Canadian Niagara Power's meters were installed in 2009 and will soon need to be replaced as the technology becomes outdated and unsupported.

Canadian Niagara Power has identified roughly 26,000 out of over 31,000 meters for replacement.

In its current draft plan, Canadian Niagara Power plans to replace these roughly 26,000 meters over a 10-year period starting in 2027. Under this plan, the cost of this meter replacement program would be spread evenly across both this upcoming rate period (2027-2031) and the next (2032-2036).

However, to further reduce costs, Canadian Niagara Power has an option to spread this replacement program over an even longer period. While this would reduce costs in the short term, it would result in higher costs in the future, and the potential for emergency meter replacements if aging meters fail.

Which of the following options do you prefer?

Option	Rate Impact	Investment Details + Outcome(s)
Draft Plan	Within proposed rate increase	• Replace roughly 26,000 meters at an even pace over a 10-year period
Spend Less	$0.30 less per month by 2032	• Replace roughly 26,000 meters at a slower pace now, but more during 2032-2036, delaying some of the rate impact • Increased risk of meter failure and emergency replacement relative to draft plan

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Investment Trade-Offs

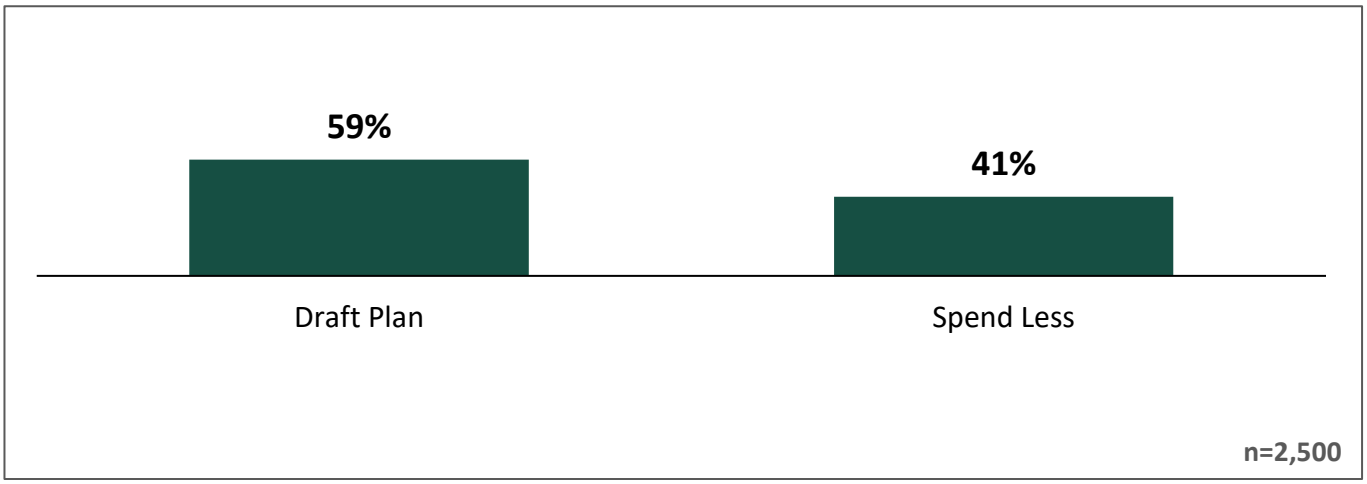
Meter replacement program

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Q Which of the following options do you prefer?



	Region			Consumption Quartiles			
	Fort Erie	Port Colborne	Gananoque	Low	Medium-Low	Medium-High	High
Draft Plan	58%	60%	65%	59%	57%	63%	58%
Spend Less	42%	40%	35%	41%	43%	37%	42%

	LEAP/OESP Qualification			Bill Impact	
	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Draft Plan	56%	59%	63%	53%	70%
Spend Less	44%	41%	37%	47%	30%

Investment Trade-Offs

Meter replacement program

Residential

Q Additional Feedback (Optional)

Responses	%
Support the draft plan/rate increase as reasonable	0.5%
Prioritized replacement based on meter vulnerability	0.4%
Smart meter concerns/issues (e.g. health, safety, privacy, etc.)	0.4%
Meter reliability and performance	0.4%
Seek operational efficiencies/alternative funding/customers shouldn't pay	0.4%
Need for transparency/clear communication/information	0.3%
Technological modernization	0.3%
Against increases/costs are too expensive	0.3%
Skepticism about replacement program	0.3%
Support for phased/gradual approach	0.2%
Concerns about past management and maintenance	0.2%
System efficiency and lifecycle management	0.1%
Concerns about corporate spending/resource allocation	0.1%
Other	0.1%
No comment/None/Don’t know	96.0%

Note: Only responses > 0.1% shown.

Investment Trade-Offs

Finalizing Choices

Residential

WORKBOOK PAGE

Canadian Niagara Power Customer Engagement Survey

What is the impact of my choices?

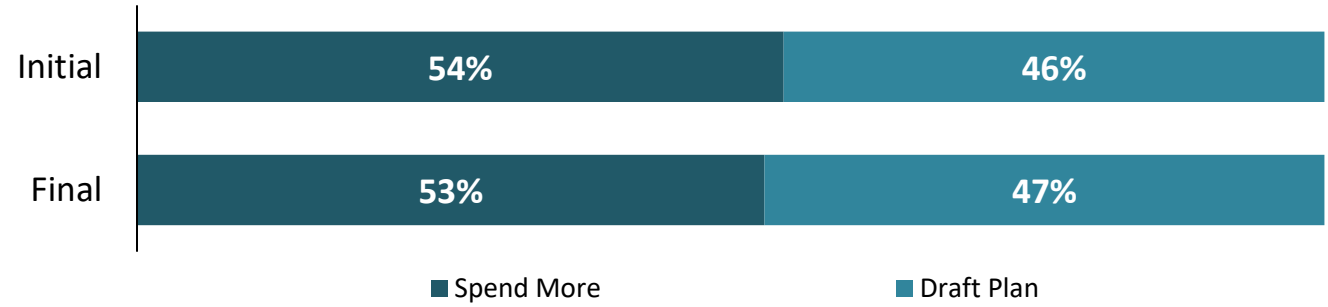
Throughout this survey, you have been asked about **7 key choices**. Below is a summary of your choices.

At the bottom of this page, you will find the total rate impact of your choices. You can change your responses if you desire, and the estimated impact on your monthly bill will be recalculated.

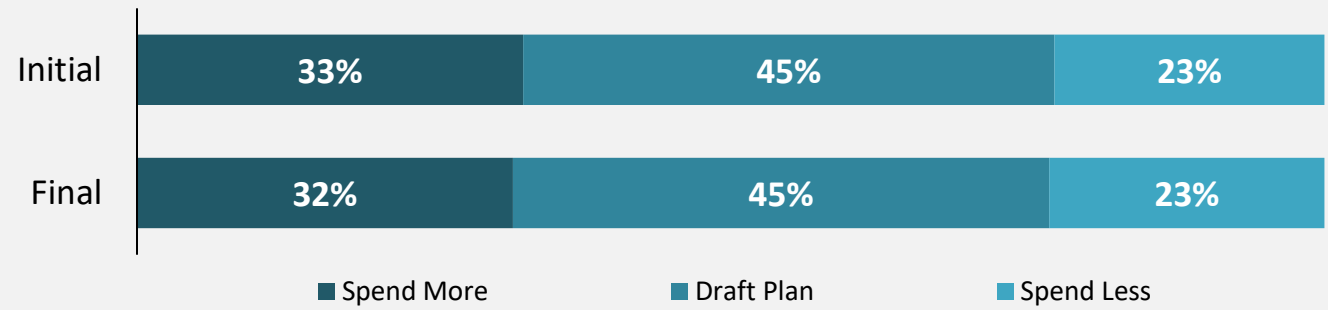
Investment Trade-Offs

Finalizing Choices

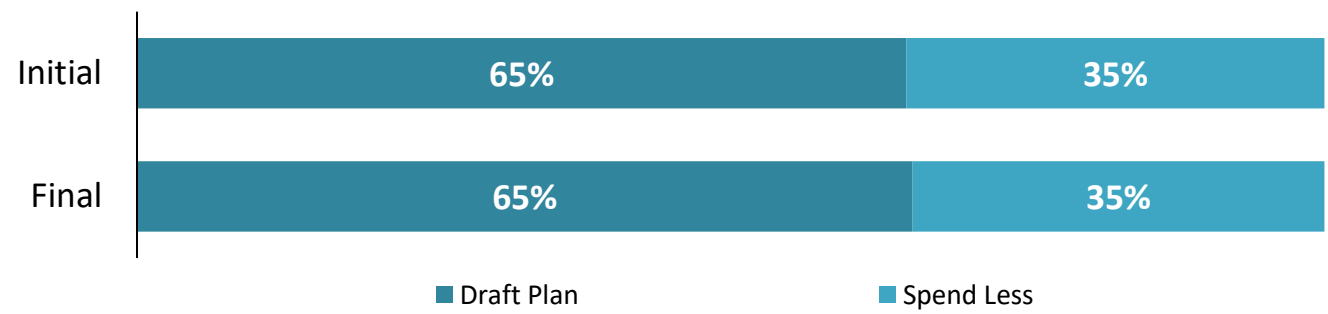
Choice 1: Improving resiliency to severe weather



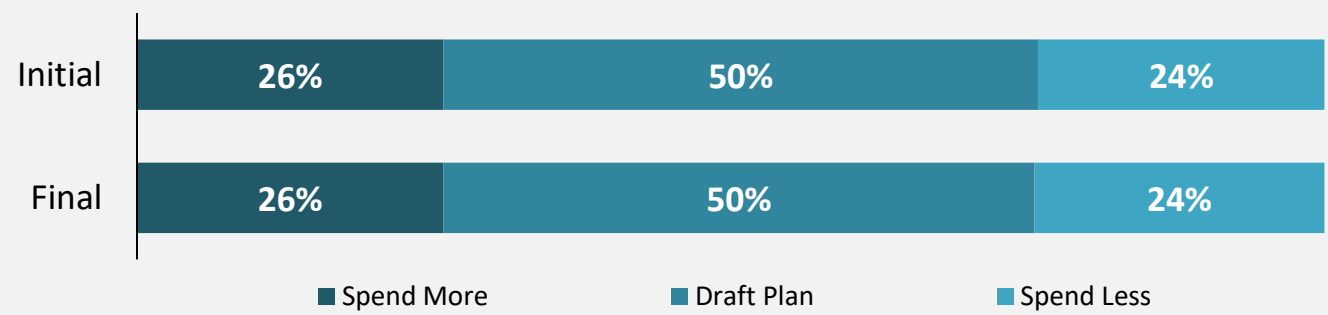
Choice 2: Improving reliability using intelligent switches



Choice 3: Modernizing older distribution lines



Choice 4: Replacing at-risk poles



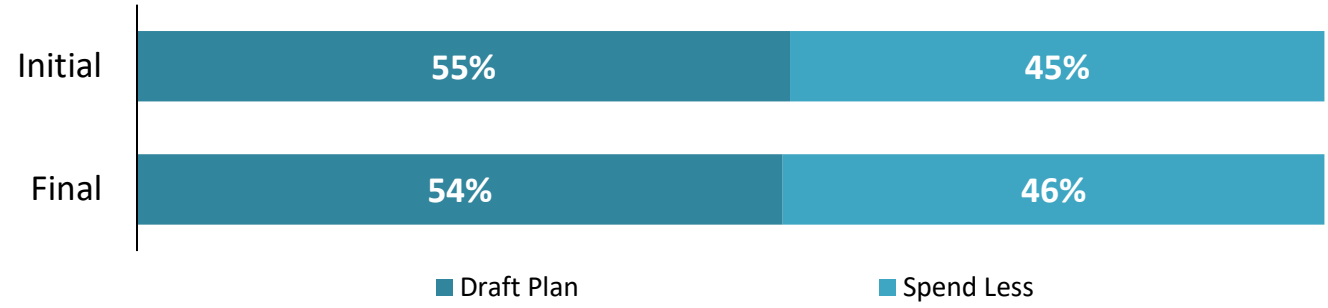
Investment Trade-Offs

Finalizing Choices

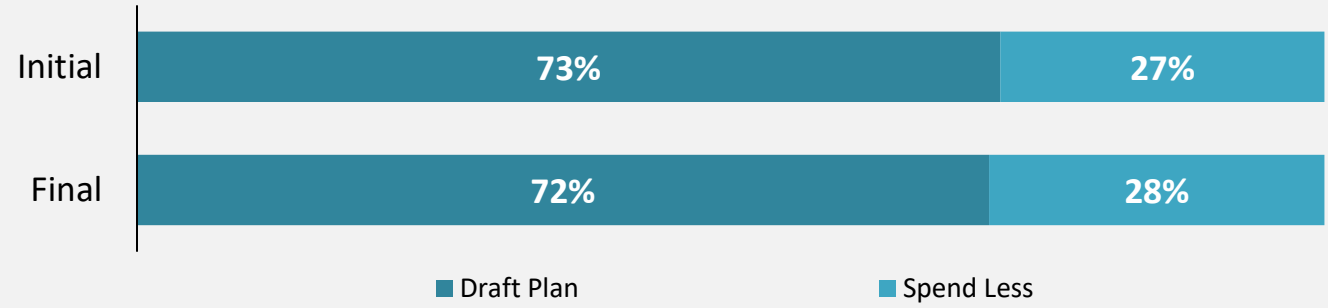
Canadian Niagara Power Inc.
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Residential

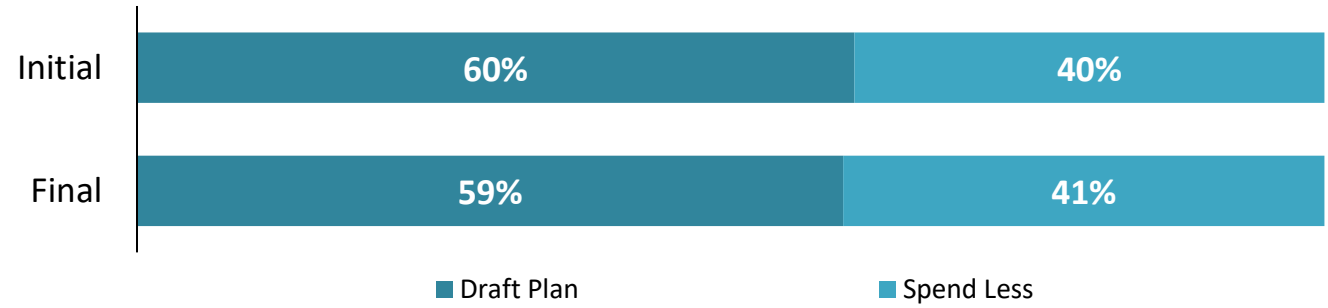
Choice 5: Investing in electric vehicles



Choice 6: Control room enhancements



Choice 7: Meter replacement program



Investment Trade-Offs

Overall evaluation of the draft plan

Residential

Exhibit

Canadian Niagara Power Customer Engagement Survey

Evaluating Canadian Niagara Power's 2027-2031 draft plan

Canadian Niagara Power has calculated an overall cost for their draft plan. While the plan may change based on feedback from the earlier questions in this survey, Canadian Niagara Power would like to know how you feel about the overall draft plan.

For a typical residential customer, the distribution portion of their **monthly** bill is estimated to increase from $55.77 in 2027 to $70.60 by the end of 2032 – **an increase of $14.83 on the monthly bill.**

WORKBOOK PAGE

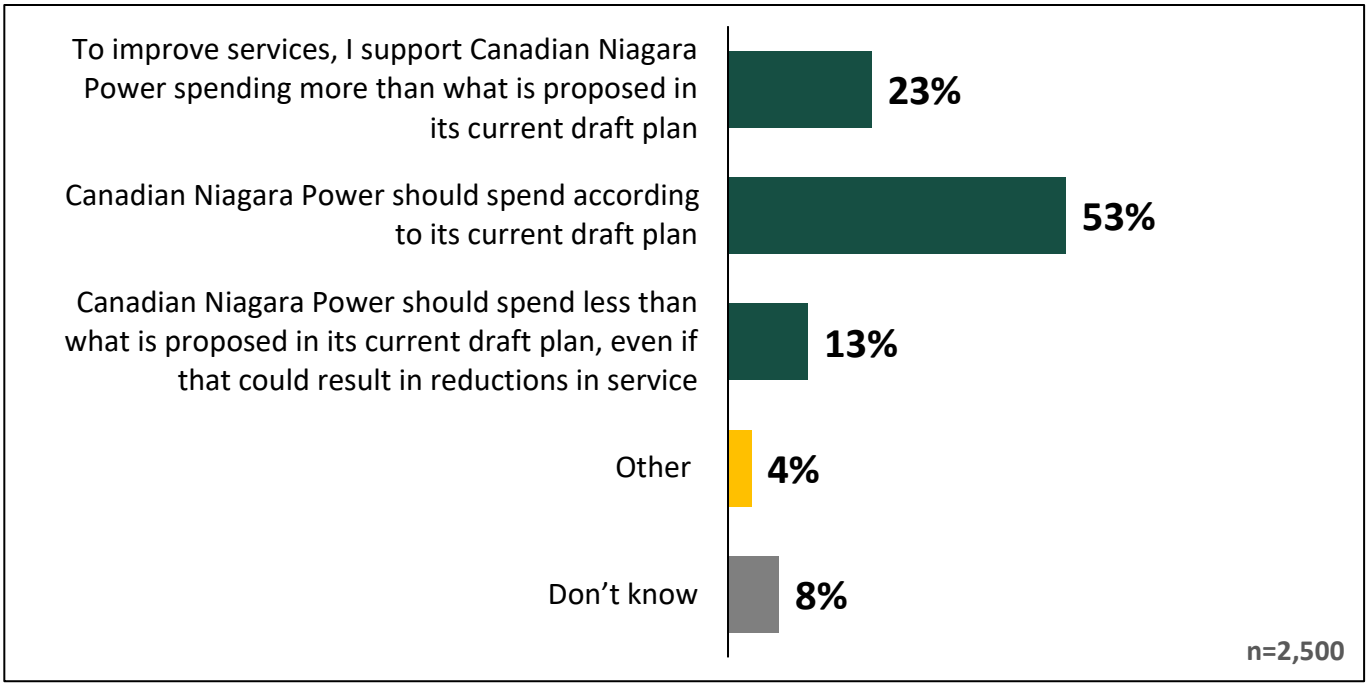
Investment Trade-Offs

Overall evaluation of the draft plan

Canadian Niagara Power Inc.
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Residential

Q Considering what you have learned about Canadian Niagara Power's 2027-2031 draft plan, which of the following best represents your point of view?



	Region			Consumption Quartiles			
	Fort Erie	Port Colborne	Gananoque	Low	Medium-Low	Medium-High	High
Spend More	22%	21%	30%	22%	23%	24%	22%
Draft Plan	55%	53%	43%	54%	55%	50%	55%
Spend Less	13%	12%	12%	13%	12%	13%	13%
Other	4%	4%	4%	3%	3%	4%	5%
Don't know	7%	10%	10%	8%	8%	10%	6%

Investment Trade-Offs

Overall evaluation of the draft plan

Canadian Niagara Power Inc.
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Residential

Q Considering what you have learned about Canadian Niagara Power's 2027-2031 draft plan, which of the following best represents your point of view?

		LEAP/OESP Qualification			Bill Impact	
	Overall	Qualified	<$71k Not Qualified	>$71k Not Qualified	Major Impact	No Major Impact
Spend More	23%	17%	22%	31%	16%	34%
Draft Plan	53%	55%	54%	52%	55%	50%
Spend Less	13%	13%	13%	12%	16%	7%
Other	4%	3%	4%	3%	4%	3%
Don't know	8%	12%	7%	3%	9%	6%

Investment Trade-Offs

Final comments on the draft plan

Residential

Q Do you have any final comments regarding Canadian Niagara Power's draft plan for 2027-2031 and the proposed rate increase? (Optional)

Responses	%
Lower rates/rates are too high	1.3%
Seek operational efficiencies/alternative funding/customers shouldn't pay	1.3%
Support the increase/investments are necessary	1.2%
Invest now to prevent future outages/costs	1.1%
System reliability/outage reduction	1.0%
Concerns around cost of living/inflation	0.9%
Financial strain on vulnerable customers (e.g. seniors, fixed income)	0.9%
Positive comment about CNPI/service	0.7%
Concerns about corporate spending/resource allocation	0.5%
Distrust in the survey/inevitable rate increases	0.5%
Support for environmental/renewable energy initiatives	0.5%
Better preventative maintenance/proactive planning	0.4%
Support for phased/gradual approach	0.4%
Be transparent/communicate about rate increases/investments	0.3%
Survey/engagement experience feedback - positive	0.3%
Concerns about past management and maintenance	0.3%
Criticism of CNPI profit-driven approach	0.2%
Survey/engagement experience feedback - negative	0.2%
Improve line maintenance/vegetation management	0.2%
Fair cost allocation/user-pays for system impacts/upgrades	0.1%
Maintain current service levels/prioritize areas of higher need	0.1%
Other	0.4%
No comment/None/Don't know	87.2%

Note: Only responses > 0.1% shown.

INNOVATIVE RESEARCH GROUP

Residential Customers

Survey Diagnostics

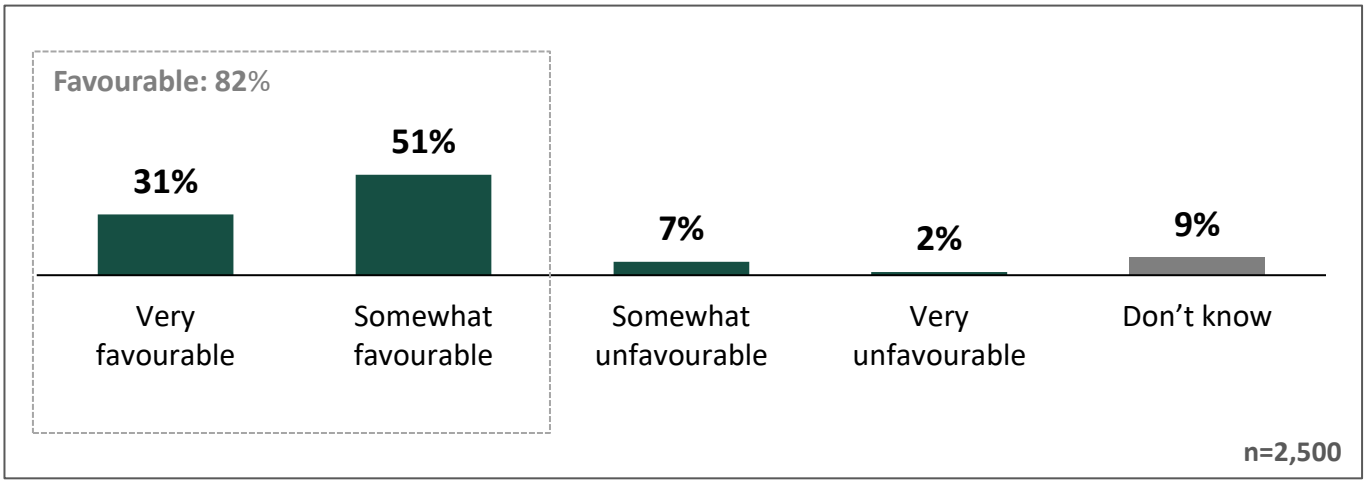


Survey Diagnostics

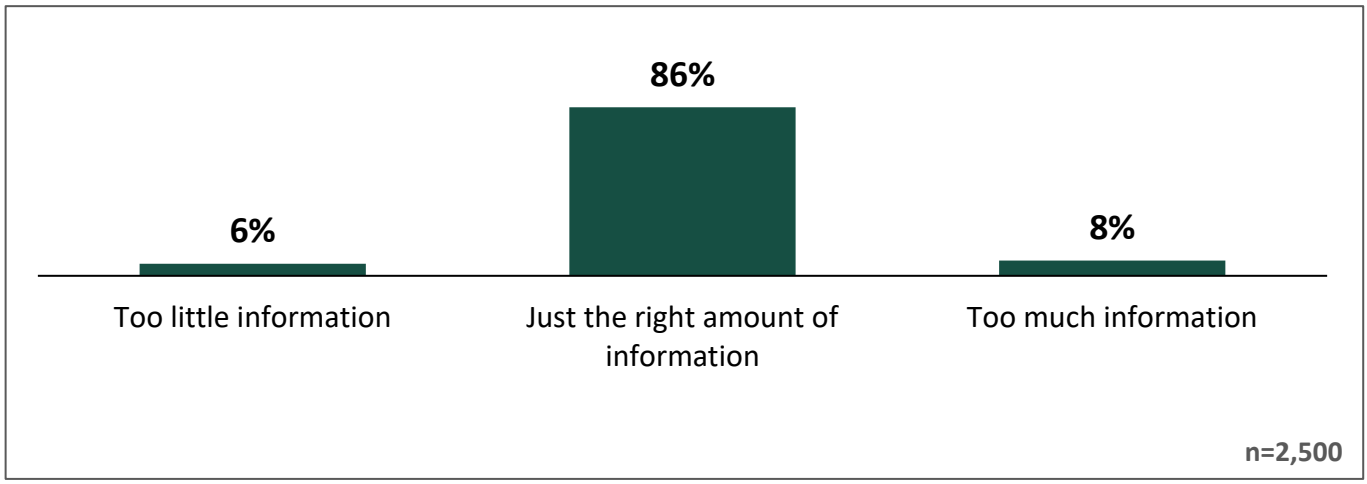
Favourability and amount of information

Canadian Niagara Power values your feedback. In order to do better in the future, they want to hear about your experience with this survey.

Q Overall, did you have a favourable or unfavourable impression of the customer engagement you just completed?



Q In this customer engagement, do you feel that Canadian Niagara Power provided too much information, not enough, or just the right amount?



Survey Diagnostics

Other information not included

Residential

Q Was there any content missing that you would have liked to have seen included in this customer engagement? (Optional)

Responses	%
More detailed information on the investments/infrastructure	1.1%
Transparency on internal operations (e.g. finances, salaries, etc.)	1.0%
Information on renewable energy and alternative energy sources	0.8%
More information/communication about rate increases	0.7%
Reducing customer costs/affordability measures	0.6%
Survey/engagement experience feedback - negative	0.5%
Seek operational efficiencies/alternative funding/customers shouldn't pay	0.4%
Location-specific infrastructure and risk information	0.4%
Staffing, wages, and human resource details	0.4%
Survey/engagement experience feedback - positive	0.3%
Better explanation/transparency on bills	0.3%
Helping seniors/fixed-income individuals	0.3%
Requests for historical data/information (e.g. spending, impact, cost)	0.3%
Tips on reducing electricity usage	0.2%
Distrust in the engagement/rate increases are inevitable	0.2%
Forecasts for energy demand and infrastructure needs	0.2%
Information on emerging technologies/impact on the grid	0.2%
Better outage communication/information	0.1%
Critiques of legibility and user experience	0.1%
Comparison to other utilities/benchmarking (e.g. rates, services, costs)	0.1%
Impact on the environment/wildlife	0.1%
Other	0.9%
No comment/None/Don’t know	90.0%

Note: Only responses > 0.1% shown.

Survey Diagnostics

Outstanding questions

Q Is there anything that you would still like answered? (Optional)

Responses	%
Reducing customer costs/affordability measures	0.8%
Better explanation/transparency on bills	0.6%
Transparency on internal operations (e.g. finances, salaries, etc.)	0.5%
More detailed information on the investments/infrastructure	0.3%
Renewable and alternative energy options (e.g. solar, wind, battery storage)	0.3%
More information/communication about rate increases	0.3%
Improve customer service/communication (general/outage)	0.3%
System reliability/infrastructure resilience	0.2%
Energy efficiency/cost-saving programs	0.2%
Survey/engagement experience feedback - negative	0.2%
Infrastructure planning and execution oversight	0.2%
Positive comment about CNPI/service	0.2%
Survey/engagement experience feedback - positive	0.2%
Fair distribution of costs and billing equity	0.2%
Advanced meter infrastructure and usage analytics	0.2%
Helping seniors/fixed-income individuals	0.1%
Distrust in the engagement/rate increases are inevitable	0.1%
Government involvement/subsidies	0.1%
Improve line maintenance/vegetation management	0.1%
Comparison to other utilities/benchmarking (e.g. rates, services, costs)	0.1%
Other	1.2%
No comment/None/Don't know	93.8%

Note: Only responses > 0.1% shown.

INNOVATIVE RESEARCH GROUP

Small Business Customers

Online Survey Results



Field Dates

The **Small Business Online Survey** was sent to all Canadian Niagara Power Inc. small business customers with an available email address. Customers had an opportunity to complete the survey between **February 11th and March 12th, 2026**.

Each customer received a unique URL that could be linked back to their average monthly consumption, region and rate class.

In total, the small business survey was sent to **1,124** customers from *customer.service@cnpower.com*. Three reminder emails were sent on a rolling basis over the survey field window to those who had not yet completed the survey.

Small Business Online Survey Completes

A total of **101** (unweighted) Canadian Niagara Power Inc. small business customers completed the online survey.

Sample Weighting

The small business online survey sample was weighted down to n=100 proportionately by consumption quartile, and region in order to be representative of the broader Canadian Niagara Power Inc. customer base.

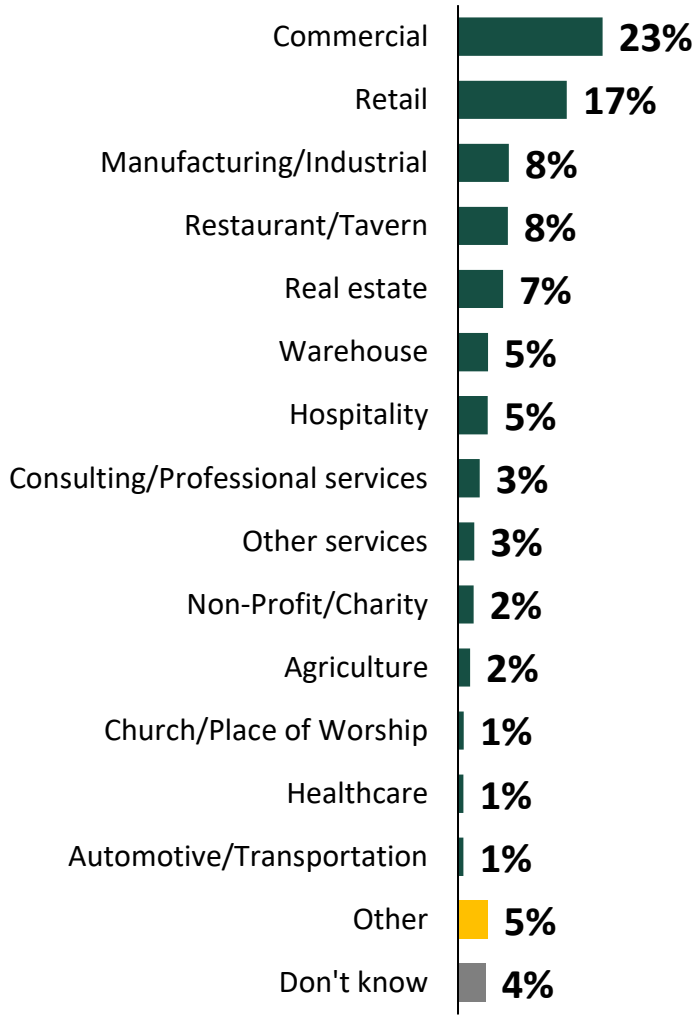
The table below summarizes the unweighted and weighted (in brackets) sample breakdown by consumption quartile and region. Totals may not correspond with cell values, as some customers are missing region or consumption quartile information. Weights are calculated based on all available information for a given customer.

Region	Collapsed Consumption Quartiles		Total
	Low-Medium (First + Second)	Medium-High (Third + Fourth)	
Fort Erie	24 (25)	23 (25)	47 (50)
Port Colborne	23 (17)	16 (17)	39 (34)
Gananoque	7 (8)	8 (8)	15 (16)
Total	54 (50)	47 (50)	101 (100)

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Firmographics Breakdown

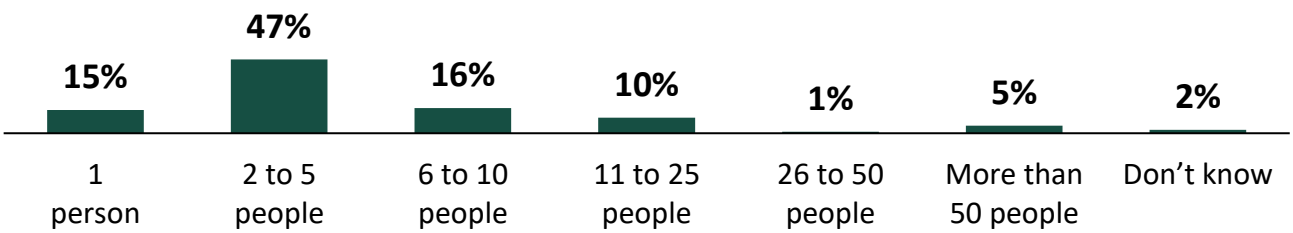
Q Business Sector



"Prefer not to say" (6%) not shown.

n=100

Q Business Size



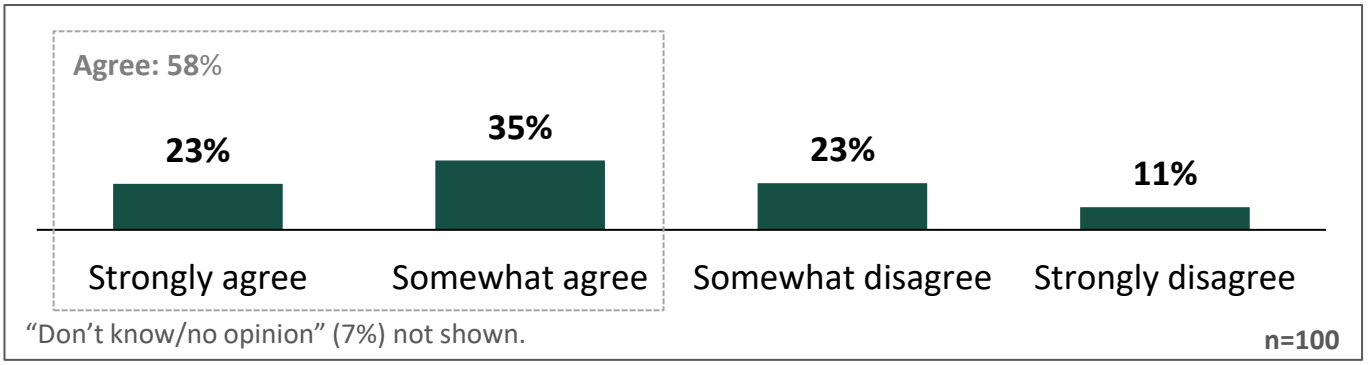
"Prefer not to say" (5%) not shown.

n=100

Environmental Controls

To what extent do you agree or disagree with the following statements?

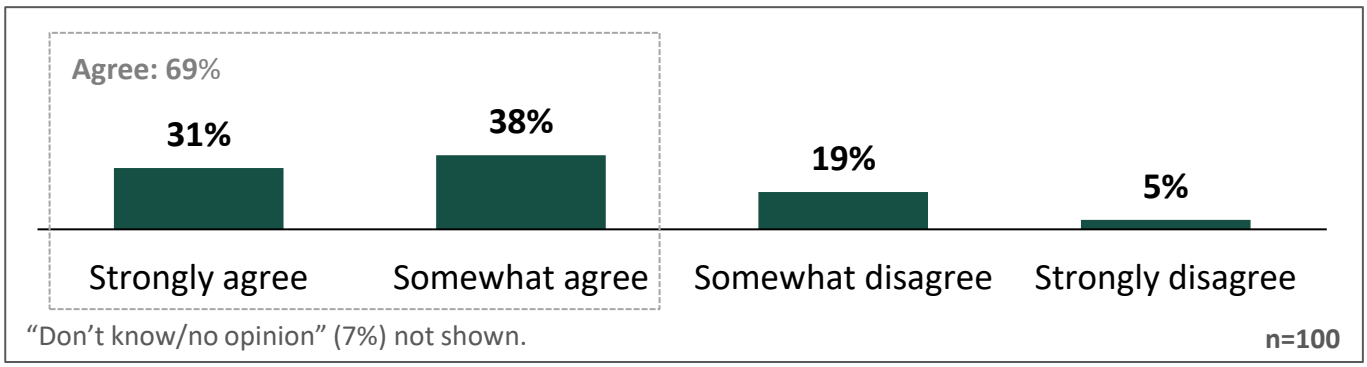
Q The cost of my organization's electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.



"Don't know/no opinion" (7%) not shown.

n=100

Q Consumers are well served by the electricity system in Ontario.



"Don't know/no opinion" (7%) not shown.

n=100

Canadian Niagara Power Customer Engagement Survey

Welcome to Canadian Niagara Power's customer engagement survey!

Canadian Niagara Power is looking for your input on choices that will impact the services you receive and the rates you pay.

- **Canadian Niagara Power is looking for your input on its draft investment plan** for the years 2027-2031 to ensure it is making spending decisions that matter to you, the customer.
- **You don't need to be an electricity expert to complete this survey**. It focuses on basic choices and provides the background information you need to answer the questions.
- This survey will take approximately 15 minutes to complete and can be done so at your convenience. Once you begin, your progress will be saved, and you can return to the customer engagement at any time. While the survey can be completed on a smaller mobile device, you may want to consider switching to a tablet or laptop so that it's easier for you to read.

Those who complete the survey will be eligible to enter a draw to win one (1) of three (3) $500 cash prizes.

All individual responses will be kept confidential.
Innovative Research Group (www.innovativeresearch.ca), an independent research company, has been hired by Canadian Niagara Power to gather your feedback while protecting your confidentiality. Your individual answers will not be shared with Canadian Niagara Power in any identifiable way.

INNOVATIVE RESEARCH GROUP

WORKBOOK PAGE

Canadian Niagara Power Customer Engagement Survey
What is this survey about?

Canadian Niagara Power Inc. (CNPI) provides electricity distribution services to approximately 27,500 customers in **Port Colborne** and **Fort Erie**, and an additional 3,600 customers in and around **Gananoque**, where it operates under the name **Eastern Ontario Power**.

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

Eastern Ontario Power
A FORTIS ONTARIO Company

Typically, every five years, local distributors like Canadian Niagara Power are required to file an application with the Ontario Energy Board (OEB) to set rates. In this process, Canadian Niagara Power's rate application will be examined in detail, and they must demonstrate that customer needs and priorities were factored into this process.

Today, Canadian Niagara Power wants your feedback on:

1. What you feel they should be prioritizing over the next five years.
2. Specific investment decisions they need to make related to responding to the impacts of severe weather, modernizing the distribution system, and other critical infrastructure.

This feedback, along with other input, will be used to help Canadian Niagara Power refine and finalize their draft investment plan.

But first, we need to ensure that we are all on the same page regarding Canadian Niagara Power's role in the broader electricity system, how much of your bill goes to Canadian Niagara Power, and where that money goes.

WORKBOOK PAGE

Familiarity & Experience

Canadian Niagara Power's role in Ontario's electricity system

Canadian Niagara Power Customer Engagement Survey

What is Canadian Niagara Power's role in the electricity system?

Ontario's electricity system is made up of three key components: generation, transmission and distribution.

Generation

Where electricity comes from

Ontario gets its electricity from a mix of energy sources. About half comes from nuclear power. The remainder comes from a mix of hydroelectric, natural gas, wind, and solar. Ontario Power Generation, a government-owned company, generates almost half of Ontario's electricity.

Transmission

How electricity travels across Ontario

Once electricity is generated, it must be transported to communities across the province. This happens by way of high voltage transmission lines that serve as highways for electricity. Most of this system is owned and operated by Hydro One.



Local Distribution

How electricity is delivered to you

Canadian Niagara Power is responsible for the local distribution system, which takes electricity from transmission lines and brings it to your community.

Canadian Niagara Power builds and maintains critical equipment, delivers electricity, reads meters, answers customer calls, responds during outages, and clears trees and brush from power lines.

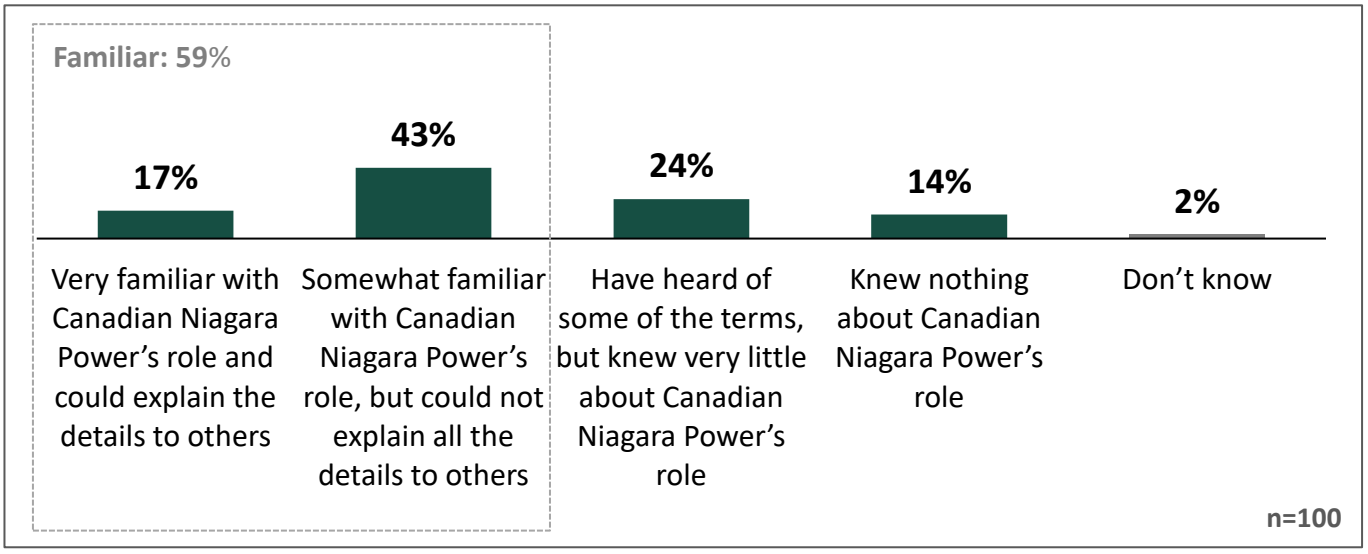
Canadian Niagara Power does not generate electricity or set electricity prices.

WORKBOOK PAGE

Familiarity & Experience

Canadian Niagara Power's role in Ontario's electricity system

Q Before this survey, how familiar would you say you were with Canadian Niagara Power and the role it plays in Ontario's electricity system?



	Collapsed Consumption Quartiles		Bill Impact	
	Low-Medium	Medium-High	Major Impact	No Major Impact
Very familiar	17%	16%	19%	14%
Somewhat familiar	42%	43%	32%	58%
Knew very little	26%	22%	27%	19%
Knew nothing	13%	16%	22%	4%
Don't know	2%	3%	--	6%
Familiar (Very + Somewhat)	**59%**	**60%**	**51%**	**71%**

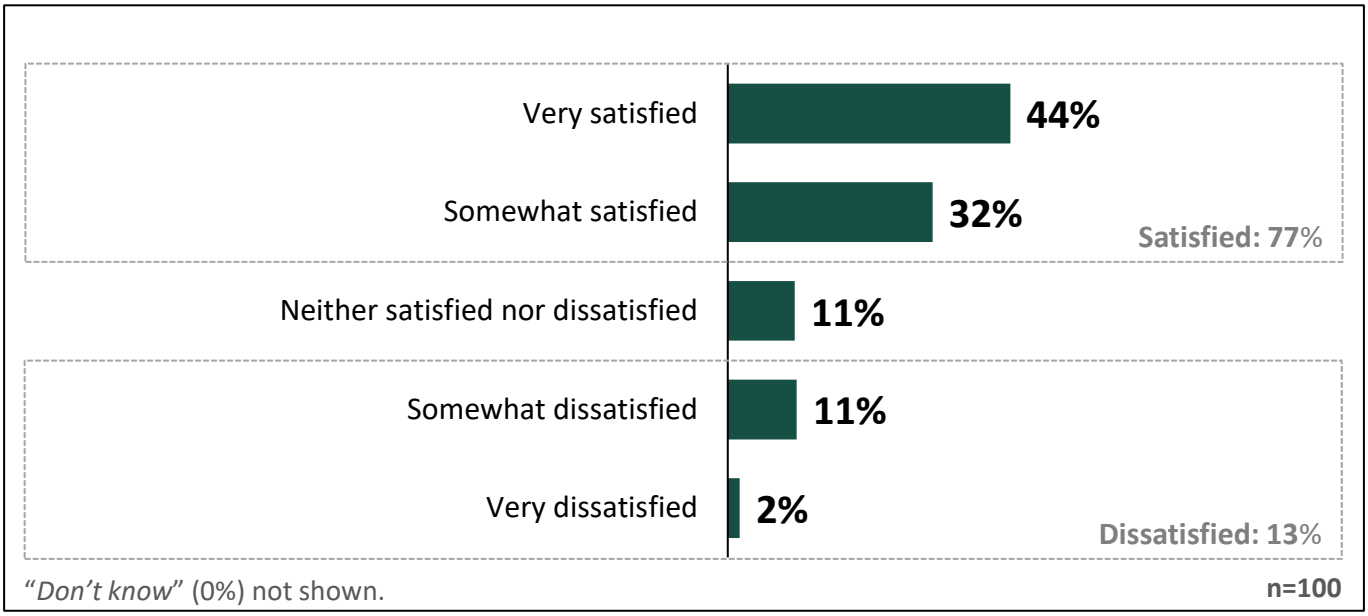
Familiarity & Experience

Overall satisfaction with Canadian Niagara Power's service

Canadian Niagara Power Inc.
EB-2026-0026
May 19, 2026
Exhibit I
Tab 1 Schedule 3
Page 1 of 3

Small Business

Q Overall, how satisfied or dissatisfied are you with the service your organization receives from Canadian Niagara Power?



"*Don't know*" (0%) not shown.

n=100

	Collapsed Consumption Quartiles		Bill Impact	
	Low-Medium	**Medium-High**	**Major Impact**	**No Major Impact**
Very satisfied	44%	45%	37%	55%
Somewhat satisfied	29%	35%	34%	30%
Neither	13%	9%	13%	6%
Somewhat dissatisfied	13%	9%	14%	6%
Very dissatisfied	1%	2%	1%	3%
Don't know	--	--	--	--
Satisfied (Very + Somewhat)	**73%**	**80%**	**71%**	**85%**
Dissatisfied (Very + Somewhat)	**14%**	**11%**	**16%**	**9%**

Familiarity & Experience

How Canadian Niagara Power can improve services

Q Is there anything in particular you would like Canadian Niagara Power to do to improve its services to you? (Optional)

Responses	%
Improve reliability/reduce outages	8.3%
Lower rates/decrease bills	7.2%
Satisfied with services/no issues	5.2%
Improve communication during outages	3.2%
Grid modernization/infrastructure investment	2.2%
Provide incentives/rebates or support programs	1.1%
Lower delivery charges	1.0%
Improve customer service (e.g. access/responsiveness)	1.0%
Billing improvements (e.g. timing, payment options, bill format)	0.9%
Improve outage restoration speed	0.8%
Other	1.8%
No comment/None/Don't know	67.2%

Note: Only responses > 0.1% shown.

Familiarity & Experience

Portion of the electricity bill paid to Canadian Niagara Power

WORKBOOK PAGE

Canadian Niagara Power Customer Engagement Survey

How much of my electricity bill goes to Canadian Niagara Power?

Every item and charge on your bill is mandated by the provincial government or regulated by the Ontario Energy Board (OEB), the provincial energy regulator.

While **Canadian Niagara Power** is responsible for collecting payment for the entire electricity bill, only a portion goes to Canadian Niagara Power for distribution delivery. As of January 1st, 2026, for a typical small business customer, about 25% of the bill, or $101.83, goes to Canadian Niagara Power per month.

The rest of your bill payment is passed onto provincial transmission companies, power generation companies, the government and regulatory agencies.

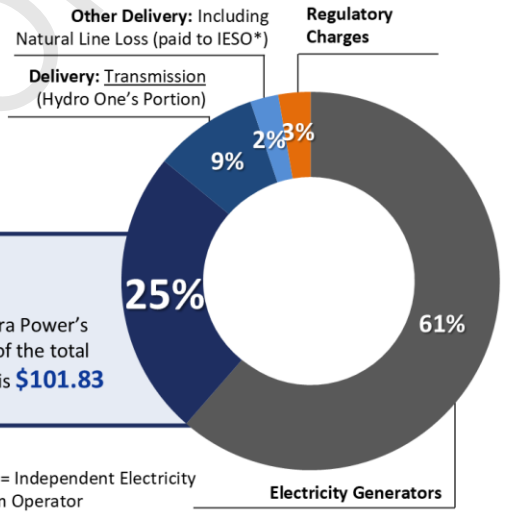
Sample CNPI Monthly Bill
(based on consumption of 2,000 kWh as of Jan. 1, 2026)

Account Number:
0000000000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
On-Peak (highest price) @ 20.3 c/kWh	73.08
Mid-Peak (mid price) @ 15.7 c/kWh	56.52
Off-Peak (lowest price) @ 9.8 c/kWh	125.44
Delivery	148.85
Regulatory Charges	11.41
Total Electricity Charges	$415.30
HST	53.99
Ontario Electricity Rebate	(-$97.60)
Total Amount	$371.69

Delivery:
Distribution
Canadian Niagara Power's typical portion of the total bill before OER is **$101.83**



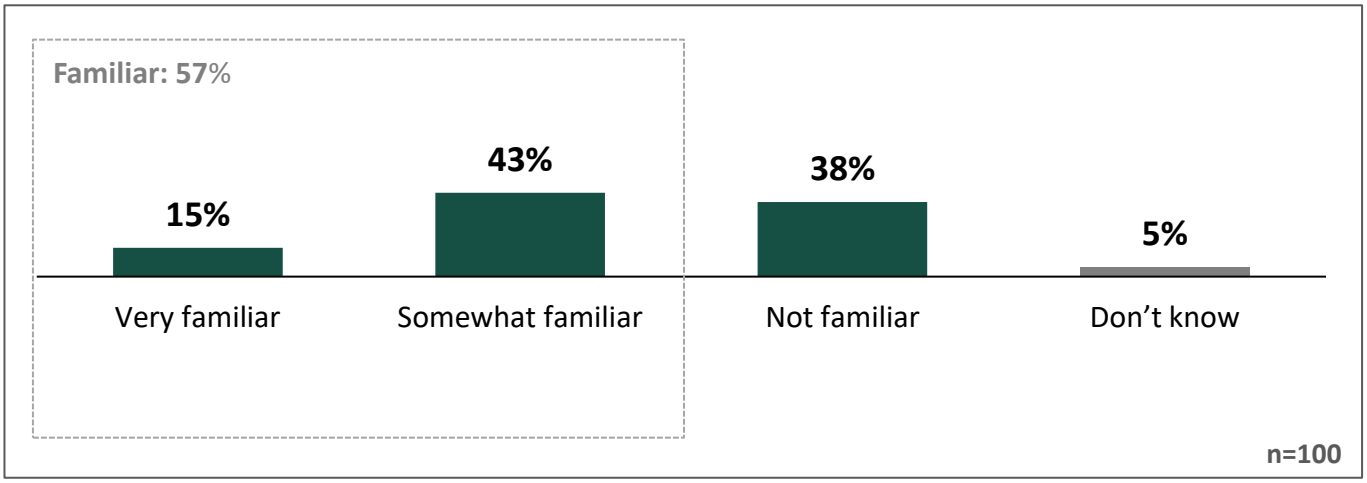
The pie chart above is based on a total bill of $415.30, which excludes the Ontario Electricity Rebate and HST. The chart may not total 100% due to rounding.

The sample bill above uses an average consumption level of 2,000 kWh per month, however your usage may vary above or below this assumed level. These types of variations would mostly impact your electricity (On, Mid and Off-Peak) charges.

Familiarity & Experience

Portion of the electricity bill paid to Canadian Niagara Power

Q Before this survey, how familiar were you with the amount of your organization's electricity bill that went to Canadian Niagara Power?



	Collapsed Consumption Quartiles		Bill Impact	
	Low-Medium	Medium-High	Major Impact	No Major Impact
Very familiar	13%	16%	20%	7%
Somewhat familiar	41%	44%	30%	60%
Not familiar	41%	35%	47%	25%
Don't know	5%	4%	3%	8%
Familiar (Very + Somewhat)	**54%**	**60%**	**50%**	**67%**

Summary of Investment Plan

How Canadian Niagara Power plans

Canadian Niagara Power Customer Engagement Survey

How does Canadian Niagara Power Plan?

Every five years, **Canadian Niagara Power** develops comprehensive plans that outline both short-term and long-term system needs.

These plans are informed by:

- Internal **engineering and technical experts**
- **Customer feedback** from surveys like this one
- **Mandatory legal and regulatory requirements**, including connecting customers, moving equipment, and installing and maintaining customer meters
- **Internal and external pressures** on the distribution system

What are the biggest pressures on the distribution system?

Canadian Niagara Power is facing a number of challenges that are putting pressure on the system, requiring more resources, new solutions and growing costs to manage. These challenges include:



The increasing frequency and severity of weather events

- In both 2020 and 2022, many customers experienced prolonged power outages due to several severe storms, including heavy snowfall and freezing rain.



Increasing demand for electricity and customer requests to connect to the grid

- According to the Independent Electricity System Operator (IESO), Ontario's independent electricity planning expert, electricity demand in Ontario is forecasted to increase by 75 per cent by 2050.



Rising costs related to inflation, supply chain disruptions, and tariffs

- Like with many businesses, the cost of electrical distribution equipment has increased considerably since 2020. Canadian Niagara Power must find ways to manage these cost pressures.

Canadian Niagara Power has prepared its 2027-2031 draft plan to address these existing and emerging challenges and continue to deliver safe and reliable electricity.

WORKBOOK PAGE

Summary of Investment Plan

Objectives that Canadian Niagara Power is focused on

Canadian Niagara Power Customer Engagement Survey

What is Canadian Niagara Power's 2027-2031 plan focused on?

Canadian Niagara Power has developed a draft plan for 2027-2031 that is focused on **6 primary objectives**, including:

1. **Managing rising costs to limit potential rate increases.**
2. **Making investments in infrastructure that are at higher risk of failure.**
3. **Reducing the number and length of power outages compared to historic levels.**
4. **Improving system resilience against severe weather events, such as ice storms and windstorms.**
5. **Meeting the needs of a growing customer base and increased electricity usage.**
6. **Making investments in technology that provide direct benefits to both customers and the grid.**

WORKBOOK PAGE

Summary of Investment Plan

Objectives that Canadian Niagara Power is focused on

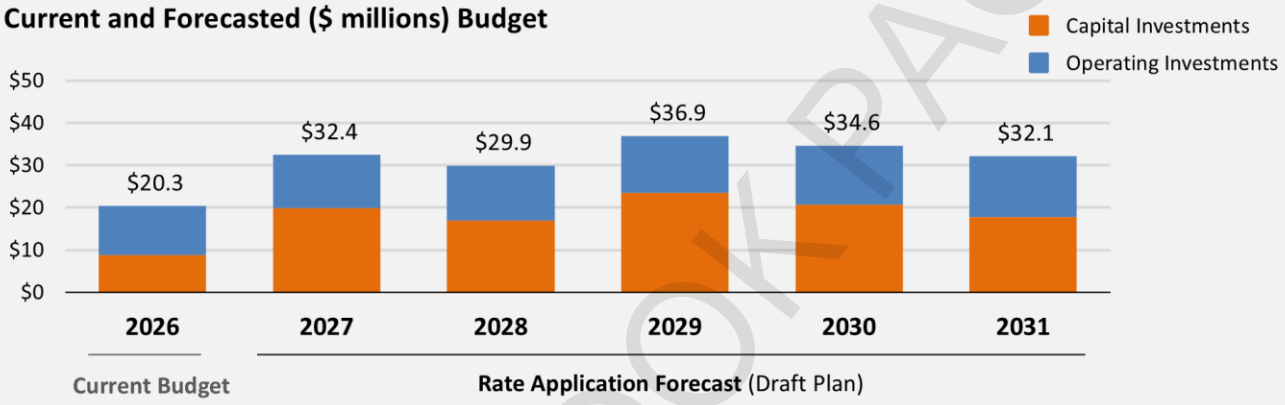
Canadian Niagara Power Customer Engagement Survey

How much will Canadian Niagara Power's draft plan cost?

Canadian Niagara Power has calculated the cost of their draft plan to target the outcomes outlined on the previous page. The costs of this plan are spread among Canadian Niagara Power's more than 31,000 residential and business customers.

The draft plan would result in an overall funding requirement of approximately **$166 million** for 2027-2031. This includes both **capital investments** which include buying and constructing physical infrastructure such as poles, wires, transformers, facilities, trucks, and computers and **operational investments** which include maintenance, testing, and operation of the equipment, vegetation management, as well as the staff needed to manage the grid and serve customers daily.

Current and Forecasted ($ millions) Budget

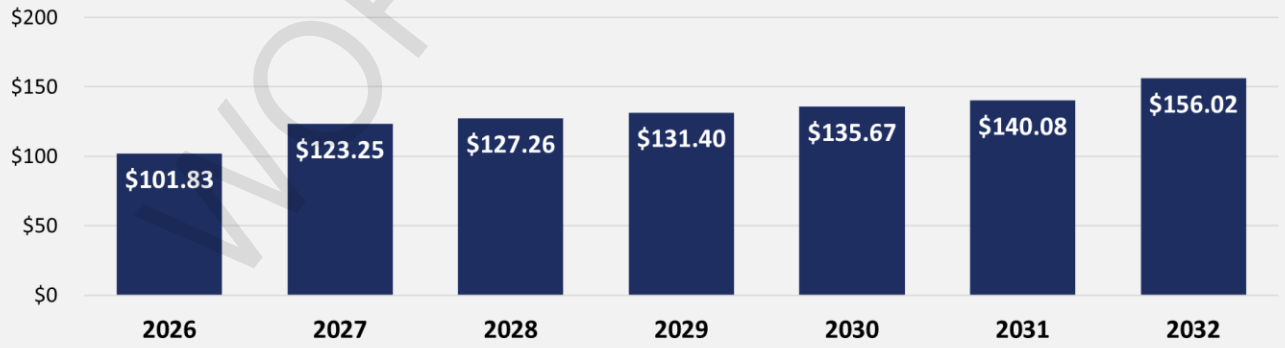


How will this plan impact customer bills?

For a typical small business customer, the distribution portion of their **monthly** bill is estimated to increase from $123.25 in 2027 to $156.02 by the end of 2032 – **an increase of $32.77 on the monthly bill.**

The impact of capital investments made during the 2027-2031 period will largely impact customers' rates starting in 2032, as shown below.

Distribution Portion of Monthly Bill



Note:

- Canadian Niagara Power's capital plan until 2026 was previously approved by the Ontario Energy Board. 2027 rates largely reflect investments made in the current rate period.
- These estimated rate increases and forecasted budgets are preliminary and are subject to change based on customer feedback, regulatory approval, and other factors. Canadian Niagara Power's operating budget forecasts are based on inflationary adjustments.
- 2033-2036 bill impacts are expected to be in line with inflation.

WORKBOOK PAGE

Summary of Investment Plan

Canadian Niagara Power's investment breakdown

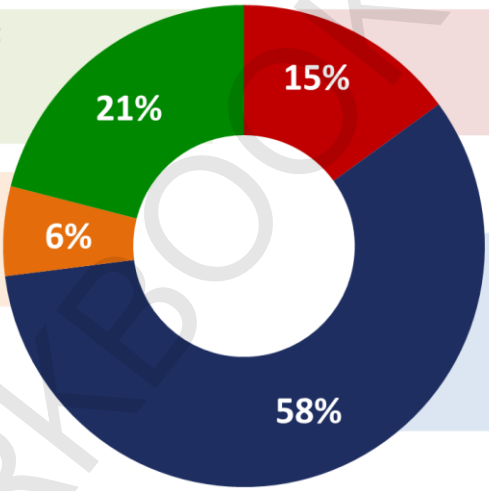
Canadian Niagara Power Customer Engagement Survey

Where is the money being invested?

73% of the forecasted rate increase in 2032 is being driven by the proposed capital investments over the next 5-year plan. The remaining 27% of the forecasted rate increase in 2032 is being driven by proposed operating investments.

Below is a breakdown of the biggest **capital investments** drivers contributing to Canadian Niagara Power's proposed investment plan.

Investments in supporting infrastructure, including specialized vehicles, service centre, and IT to support customer service.



Mandatory investments to connect new customers or to comply with legislated programs.

Investments in reliability and system capacity improvements, including enhanced grid automation.

Investments in replacing assets like lines, poles, meters and station equipment that is in poor condition, at end of life, or assets which require upgrades to today's standards.

Many of the investments contributing to the overall forecasted rate increase will be explored in more detail in the subsequent pages.

WORKBOOK PAGE

Summary of Investment Plan

How Canadian Niagara Power's distribution system performs

Canadian Niagara Power Customer Engagement Survey

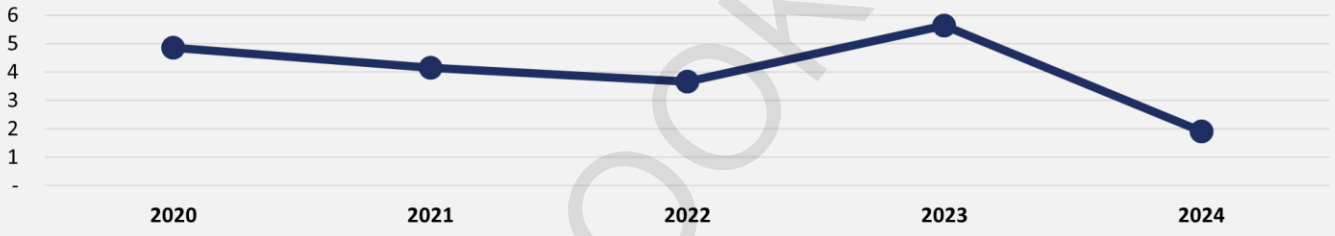
How does Canadian Niagara Power's distribution system perform?

Canadian Niagara Power's combined service territory spans 357 square kilometres, of which, roughly 80% is classified as rural. Serving a largely rural customer-base presents unique challenges, including locating and restoring power outages.

Canadian Niagara Power tracks both the **average number of power outages** per customer and **the average duration customers are without power** per year.

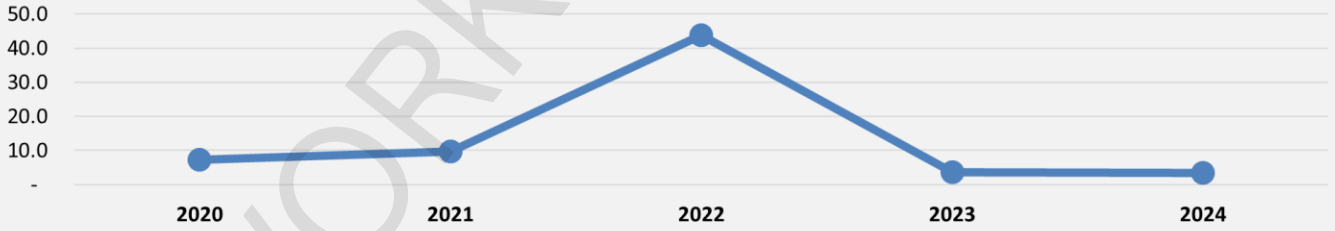
On average, between 2020 and 2024, the typical Canadian Niagara Power customer has been without power 4 times per year.

Number of Outages (Average Outages Per Customer)



When it comes to the total time spend without electricity per year over the same period, the typical Canadian Niagara Power customer has been without power for 13.5 hours each year on average.

Duration of Outages (Average Hours Per Customer)



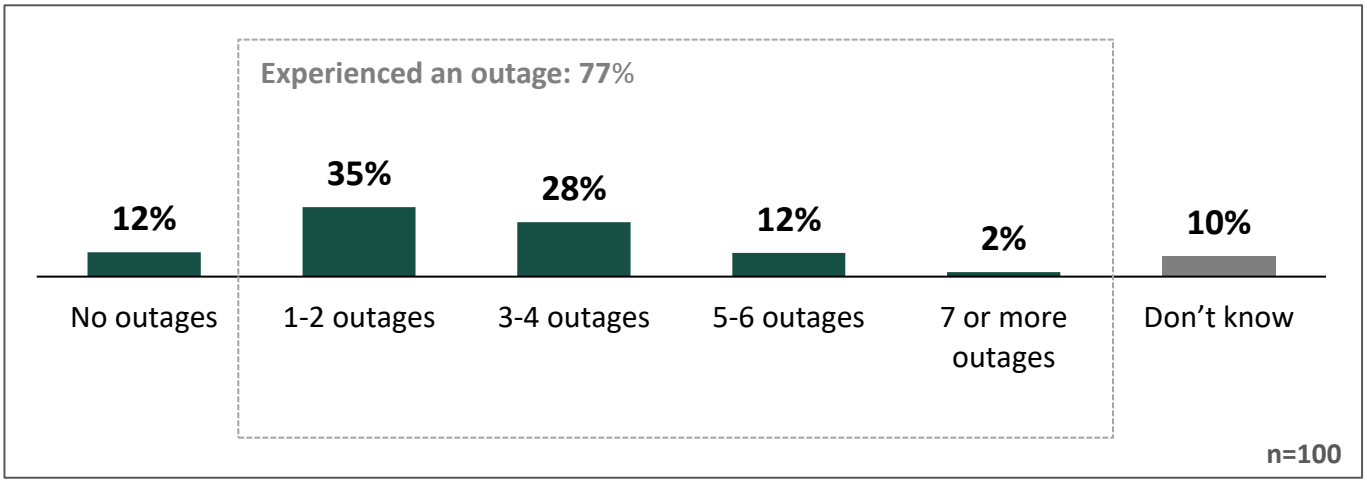
It's important to keep in mind that these are system averages, and that your actual experience may be different. Notably, the system experienced prolonged outages in 2022 due to the December 2022 severe ice storm.

WORKBOOK PAGE

Summary of Investment Plan

How Canadian Niagara Power's distribution system performs

Q Has your organization experienced any power outages as a Canadian Niagara Power customer in the past 12 months which lasted longer than one minute?



	Collapsed Consumption Quartiles		Bill Impact	
	Low-Medium	Medium-High	Major Impact	No Major Impact
No outages	12%	13%	12%	13%
1-2 outages	31%	40%	27%	46%
3-4 outages	31%	24%	35%	18%
5-6 outages	14%	10%	13%	10%
7 or more outages	--	5%	2%	3%
Don't know	13%	8%	11%	10%
Experienced an outage (At least 1 outage)	**75%**	**79%**	**77%**	**77%**

Summary of Investment Plan

Top contributors to outages

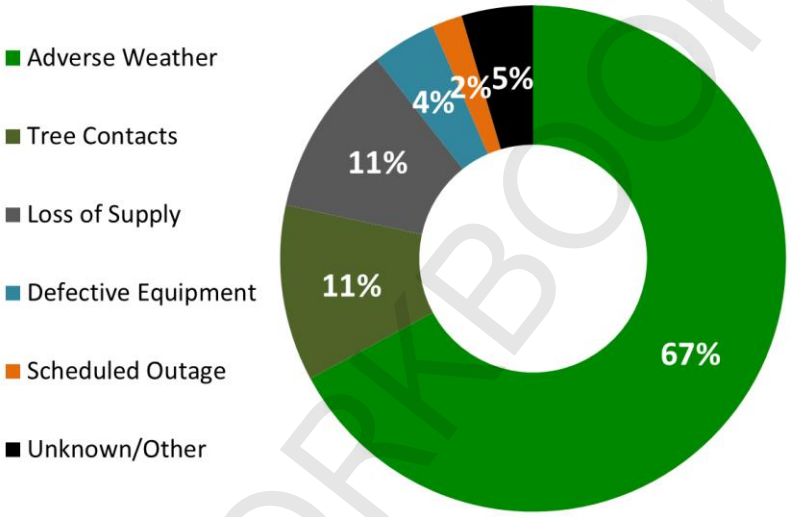
Canadian Niagara Power Customer Engagement Survey

What are the top contributors of outages?

Since 2020, 89% of the hours customers have been without power can be traced back to three causes – **adverse weather** (67%), **tree contacts** (11%), and **loss of supply** from the transmission system (11%) operated by Hydro One.

While transmission system failures are largely out of the control of Canadian Niagara Power, there are investments that can be made to attempt to reduce the impacts of tree contacts, defective equipment, and even adverse weather.

Customer Outage Duration (Hours) by Cause 2020-2024





WORKBOOK PAGE

Summary of Investment Plan

Choices Canadian Niagara Power want feedback on

Canadian Niagara Power Customer Engagement Survey

What choices does Canadian Niagara Power want my feedback on?

The remainder of this survey asks for your input on the total cost of the draft investment plan plus **7 key choices** within the plan that Canadian Niagara Power is looking for feedback on.

Canadian Niagara Power will need to demonstrate to the OEB both what they heard from customers, as well as how they reflected your feedback in its plans.

Between 2027-2031, many of the investments that Canadian Niagara Power will make are mandatory – whether to connect new customers or perform other mandatory and legislated work. Canadian Niagara Power must also make the necessary investments in infrastructure to ensure the system operates in a safe and reliable manner.

Canadian Niagara Power will seek your feedback on projects where there is a degree of optionality – whether in scope or pacing of investment that can have a direct impact on the services you receive.

How do I make choices?

- Each choice has a summary of options that Canadian Niagara Power is considering. In many cases, that includes options that would see Canadian Niagara Power ***spend less*** or ***spend more*** than what is currently being proposed in the draft plan.
- For each option, Canadian Niagara Power has estimated the impact it would have on customer bills compared to the draft plan. These impacts are approximate.
- Following each question, you will also have an opportunity to provide additional feedback if you choose to.
- Once you have finished giving feedback on these key choices, you will have an opportunity to review and change your responses until you feel you have found the right balance between the level of investment and cost.

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Investment Trade-Offs

Improving resiliency to severe weather

Canadian Niagara Power Customer Engagement Survey

Choice 1: Improving resiliency to severe weather

Since 2020, adverse weather has accounted for the majority of power outages that customers experience.

In recent years, Canadian Niagara Power has begun replacing and repairing equipment, making it more resilient to the impacts of severe weather events, such as ice storms and windstorms.



There are certain parts of Canadian Niagara Power's service territory that are more susceptible to the increased frequency of severe weather events. For instance, in 2022, a severe ice storm left thousands without power along the lakefront in Fort Erie and Port Colborne.

In its current draft plan, Canadian Niagara Power is continuing to prioritize investments in equipment based on safety, reliability and asset condition considerations. Priority is not currently given to areas that are at higher risk of severe weather.

However, Canadian Niagara Power could spend more to proactively replace poles and wires and increase the frequency of cleaning trees and brush in areas at higher risk of severe weather. These investments could potentially minimize the impacts of severe weather, including both the risk of outages and costly emergency repairs.

Which of the following options do you prefer?

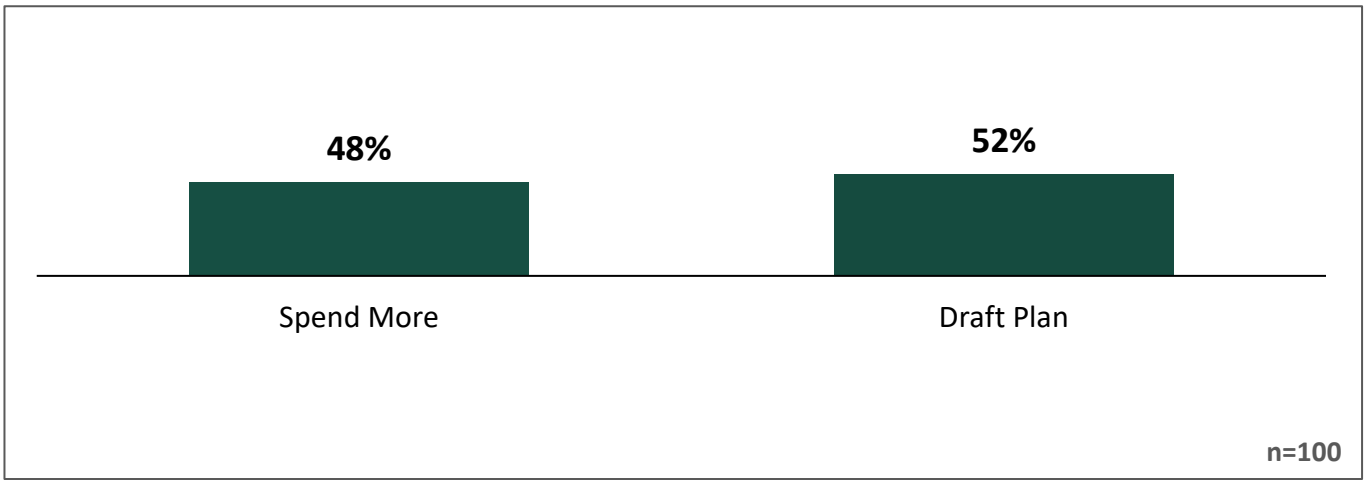
Option	Rate Impact	Investment Details + Outcome(s)
Spend More	$0.24 more per month by 2032	• Invest in additional tree and brush clearing and pole/wire replacement in high-risk areas • Reduce the risk of weather-related outages in areas more prone to severe weather events
Draft Plan	Within proposed rate increase	• Defer investments to improve resiliency to severe weather events, maintaining the current risk of weather-related outages in at-risk areas

WORKBOOK PAGE

Investment Trade-Offs

Improving resiliency to severe weather

Q Which of the following options do you prefer?



	Collapsed Consumption Quartiles		Bill Impact	
	Low-Medium	Medium-High	Major Impact	No Major Impact
Spend More	48%	48%	44%	54%
Draft Plan	52%	52%	56%	46%

Q Additional Feedback (Optional)

Responses	%
Burying lines underground	3.1%
Seek operational efficiencies/alternative funding/customers shouldn't pay	2.7%
Against increases/costs are too expensive	2.3%
Concern about increasing frequency/severity of weather events	1.3%
Better preventative maintenance/proactive planning	0.9%
Willing to pay more for improved resiliency	0.7%
No comment/None/Don't know	88.9%

Note: Only responses > 0.1% shown.

Investment Trade-Offs

Improving reliability using intelligent switches

Canadian Niagara Power Customer Engagement Survey

Choice 2: Improving reliability using intelligent switches

Technology has changed the way that Canadian Niagara Power can manage and monitor the distribution system.



Automated switches can help Canadian Niagara Power remotely monitor and trace power outages and re-route electricity from a control room rather than sending a repair crew to patrol the lines.

When an outage occurs in an area without this automated technology, it can take crews between 4 and 8 hours to locate the issue, fix it, and restore power. Currently, Canadian Niagara Power has deployed 9 automated switches in various parts of its service territory. A network of automated switches can significantly improve restoration times when an outage occurs.

In its current draft plan, Canadian Niagara Power is proposing to install 21 new automated switches. The location of these switches would be determined based on either benefitting the greatest number of customers or more sensitive customers like hospitals and fire stations.

That said, depending on customer feedback, Canadian Niagara Power could install more or fewer automated switches. The more switches that are installed, the more the system will benefit from improved restoration times.

Which of the following options do you prefer?

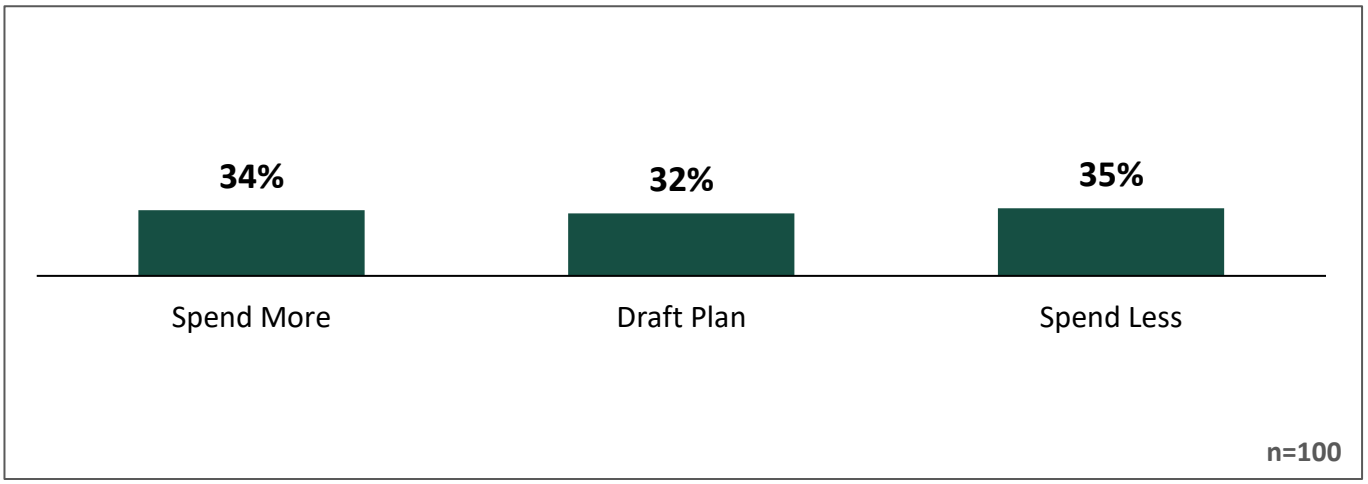
Option	Rate Impact	Investment Details + Outcome(s)
Spend More	$0.23 more per month by 2032	• Install **26 automated switches** by 2031 • Further improve outage restoration times relative to the current draft plan
Draft Plan	Within proposed rate increase	• Install **21 automated switches** by 2031 • Improve outage restoration times relative to today
Spend Less	$0.51 less per month by 2032	• Install **10 automated switches** by 2031 • Limit the benefits of improved restoration times relative to the current draft plan

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Investment Trade-Offs

Improving reliability using intelligent switches

Q Which of the following options do you prefer?



	Collapsed Consumption Quartiles		Bill Impact	
	Low-Medium	Medium-High	Major Impact	No Major Impact
Spend More	34%	33%	30%	39%
Draft Plan	28%	36%	28%	37%
Spend Less	38%	31%	42%	24%

Q Additional Feedback (Optional)

Responses	%
Support the draft plan/rate increase as reasonable	1.8%
Willing to pay more for improved reliability	1.7%
Concerns with automated switches/limitations	1.1%
Household resiliency/backup solutions	1.0%
Seek operational efficiencies/alternative funding/customers shouldn't pay	0.7%
No comment/None/Don't know	93.7%

Note: Only responses > 0.1% shown.

Investment Trade-Offs

Modernizing older distribution lines

Exhibit 1

Canadian Niagara Power Customer Engagement Survey

Choice 3: Modernizing older distribution lines

Parts of Canadian Niagara Power's service territory have historically been served by older lines that have much less capacity than modern ones. Meaning that as demand for electricity increases, these lines can struggle to distribute the constant flow of electricity that customers expect.

Over the past decade, Canadian Niagara Power has modernized many of these lines, however, some pockets of the service territory are still served by these older lines. In areas where these lines have been replaced, there have been reliability improvements.

In its current draft plan, Canadian Niagara Power is proposing to complete a large remaining line modernization project in the Point Abino area. However, Canadian Niagara Power could consider delaying some of these efforts beyond 2031. This would reduce costs in the short-term but would require Canadian Niagara Power to complete this project in two phases, resulting in increased disruption, reduced ability to accommodate increased load, and could result in higher costs beyond 2031.



Which of the following options do you prefer?

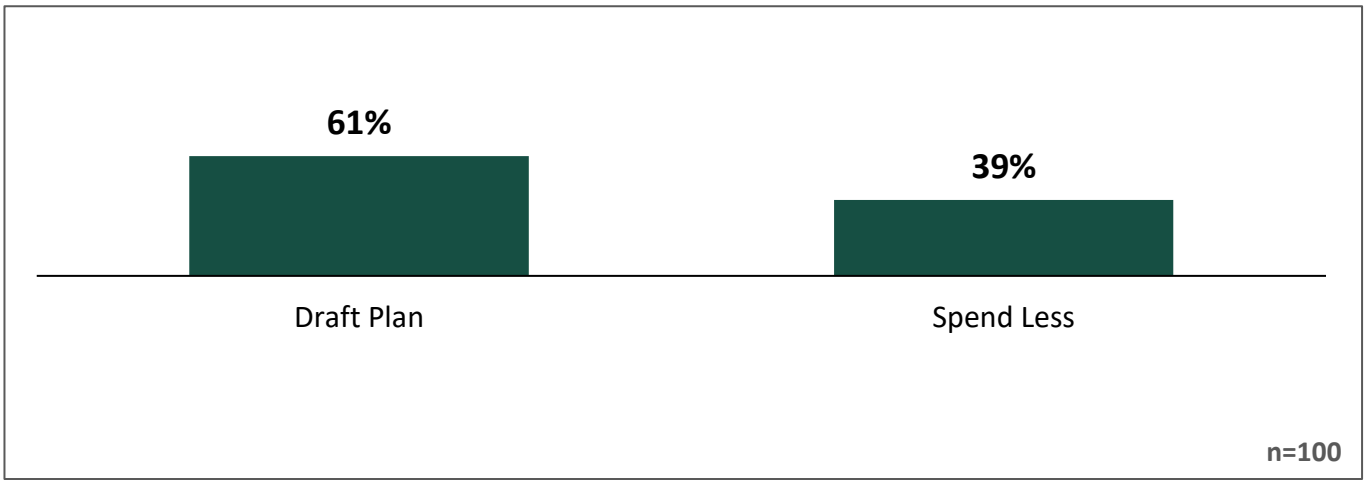
Option	Rate Impact	Investment Details + Outcome(s)
Draft Plan	Within proposed rate increase	• Complete full conversion by 2031 • Improve localized reliability and increased capacity in the Point Abino area
Spend Less	$0.77 less per month by 2032	• Undertake conversion in two phases, targeting completion beyond 2031 • Delayed reliability improvements due to prolonged project cycle

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Investment Trade-Offs

Modernizing older distribution lines

Q Which of the following options do you prefer?



	Collapsed Consumption Quartiles		Bill Impact	
	Low-Medium	Medium-High	Major Impact	No Major Impact
Draft Plan	55%	67%	54%	72%
Spend Less	45%	33%	46%	28%

Q Additional Feedback (Optional)

Responses	%
Against increases/costs are too expensive	1.8%
Better preventative maintenance/proactive planning	1.1%
Invest now to prevent future outages/costs	0.7%
No comment/None/Don't know	96.4%

Note: Only responses > 0.1% shown.

Investment Trade-Offs

Replacing at-risk poles

Canadian Niagara Power Customer Engagement Survey

Choice 4: Replacing at-risk poles

Canadian Niagara Power operates and maintains approximately 1,700 km of distribution line that is supported by over 22,000 poles.

Each year, Canadian Niagara Power identifies and prioritizes which poles should be replaced based on their condition, age, and the consequences of their potential failure.

Recently, Canadian Niagara Power has replaced, on average, approximately 115 at-risk poles per year. A recent assessment showed that 940 poles are at higher risk of failure, which, while rare, could result in significant interruptions and outages.

In its current draft plan, Canadian Niagara Power is proposing to replace approximately 115 at-risk poles each year. There is also an option to do more or less. When less is done, it increases the chances of more outages and more costly reactive repairs but also pushes some of the associated costs further down the road. When more is done, it can result in some minor improvements to reliability and get ahead of the curve at an additional cost.



Which of the following options do you prefer?

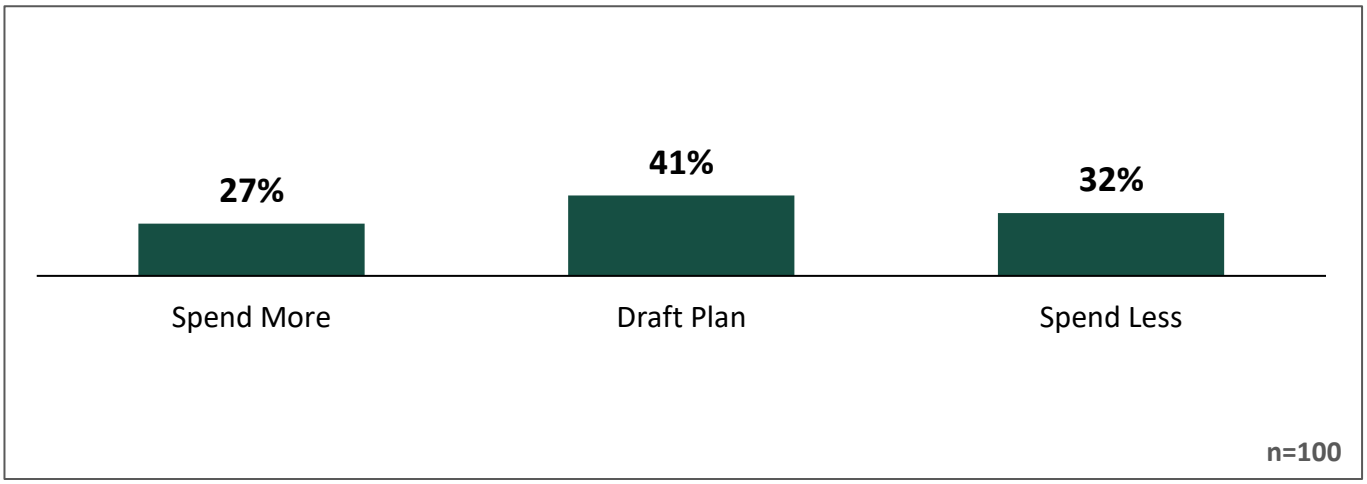
Option	Rate Impact	Investment Details + Outcome(s)
Spend More	$0.30 more per month by 2032	• Replace approximately 127 at-risk poles each year • Further reduce the risk of pole failure relative to the current draft plan
Draft Plan	Within proposed rate increase	• Replace approximately 115 at-risk poles each year • Reduce the risk of pole failure relative to today
Spend Less	$0.30 less per month by 2032	• Replace approximately 104 at-risk poles each year • Increased risk of pole failure relative to the current draft plan

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Investment Trade-Offs

Replacing at-risk poles

Q Which of the following options do you prefer?



	Collapsed Consumption Quartiles		Bill Impact	
	Low-Medium	Medium-High	Major Impact	No Major Impact
Spend More	29%	24%	21%	34%
Draft Plan	31%	51%	41%	42%
Spend Less	40%	25%	38%	24%

Q Additional Feedback (Optional)

Responses	%
Against increases/costs are too expensive	2.9%
Seek operational efficiencies/alternative funding/customers shouldn't pay	1.8%
Burying lines underground	1.6%
Better proactive planning/replacement strategies	1.1%
No comment/None/Don't know	92.7%

Note: Only responses > 0.1% shown.

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Canadian Niagara Power Customer Engagement Survey

Choice 5: Investing in electric vehicles

Canadian Niagara Power operates a fleet of vehicles to build and maintain a safe and reliable electricity system.



As with other equipment, Canadian Niagara Power has vehicle replacement criteria that weighs whether it is more cost effective to repair a vehicle, rather than replace it.

Light vehicles are everyday vehicles used for transportation and support, including trucks, SUVs and cars. **Heavy vehicles** are large, specialized vehicles used for construction, maintenance, or emergency repair work on the electrical grid.

Over the five years of the upcoming plan, Canadian Niagara Power has identified 8 out of approximately 24 light vehicles requiring replacement that could be replaced with electric or hybrid models.

In its current draft plan, Canadian Niagara Power is planning to replace these light vehicles with electric or hybrid models. While these vehicles would both reduce emissions and lower ongoing operating costs, the vehicles are more expensive than traditional gasoline options.

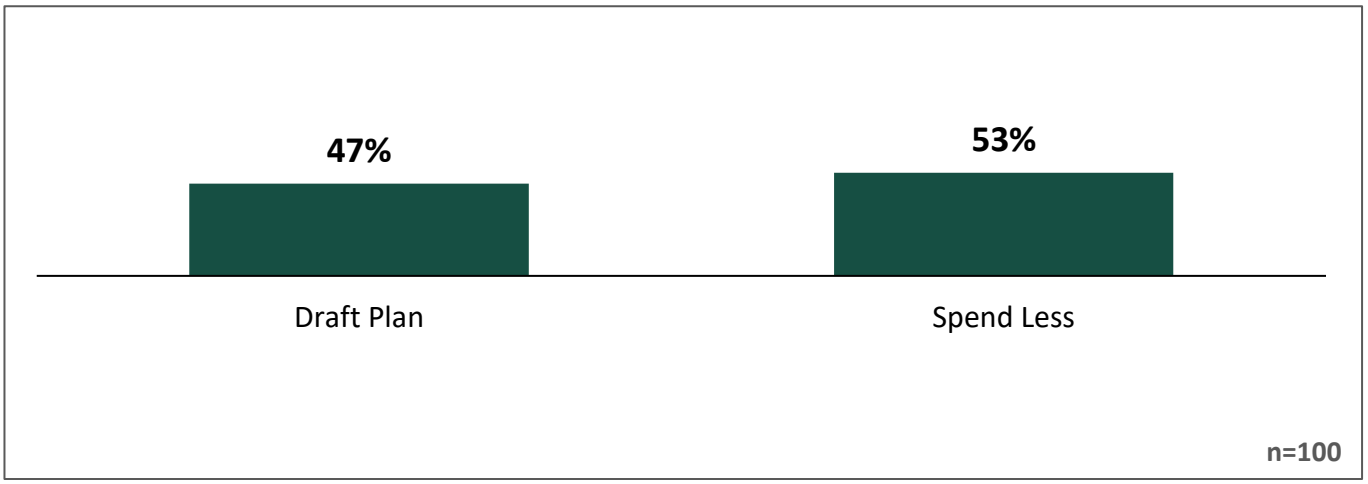
Which of the following options do you prefer?

Option	Rate Impact	Investment Details + Outcome(s)
Draft Plan	Within proposed rate increase	• Replace 8 light vehicles with electric or hybrid models • Reduce overall cost of operating vehicles and emissions
Spend Less	$0.16 less per month by 2032	• Replace 8 light vehicles with traditional gasoline options • Reduce upfront costs, but increased operating costs in the future

Investment Trade-Offs

Investing in electric vehicles

Q Which of the following options do you prefer?



	Collapsed Consumption Quartiles		Bill Impact	
	Low-Medium	Medium-High	Major Impact	No Major Impact
Draft Plan	47%	48%	39%	59%
Spend Less	53%	52%	61%	41%

Q Additional Feedback (Optional)

Responses	%
Seek operational efficiencies/alternative funding/customers shouldn't pay	1.5%
Concerns about reliability in cold weather	1.1%
Preference for gasoline/diesel vehicles	1.1%
Fleet performance and emergency readiness	1.1%
Concerns about corporate spending/resource allocation	0.9%
Long-term cost of acquisition and maintenance	0.8%
No comment/None/Don't know	93.7%

Note: Only responses > 0.1% shown.

Investment Trade-Offs

Control room enhancements

Canadian Niagara Power Customer Engagement Survey

Choice 6: Control room enhancements

Canadian Niagara Power's control room serves as a central facility to monitor, manage, and control the distribution grid. When an outage occurs, the control room plays an important role in locating the issue, and in some instances, remotely restoring power where intelligent switches have been installed.



Canadian Niagara Power's existing control room was established approximately 20 years ago, and since that time, there have been advancements in control room technology. Canadian Niagara Power's current control room relies primarily on the use of paper maps to display the status of the system. The paper maps are updated with pins and manual mark-ups.

Among other enhancements, in its current draft plan, Canadian Niagara Power is proposing to make upgrades to its control room to move from paper maps to a digital, real-time control room, which is in line with current best practices in the industry.

These control room enhancements would enable faster and more accurate system monitoring and control, improve the accuracy of online outage maps, and eliminate manual mapping updates. These enhancements would be particularly impactful during large outage events, such as severe weather, to support more rapid outage restoration efforts.

Which of the following options do you prefer?

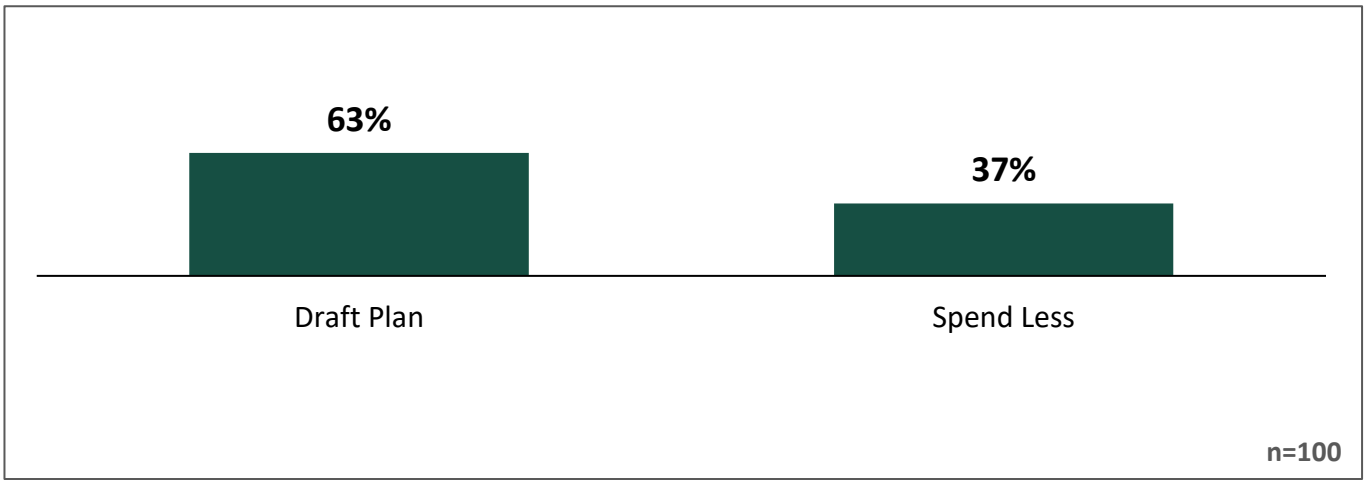
Option	Rate Impact	Investment Details + Outcome(s)
Draft Plan	Within proposed rate increase	• Enhance Canadian Niagara Power's control room, including installing digital screens for system mapping • Improve system monitoring efficiency and outage restoration efforts
Spend Less	$0.64 less per month by 2032	• Continue with current control room technology, including paper mapping system

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Investment Trade-Offs

Control room enhancements

Q Which of the following options do you prefer?



	Collapsed Consumption Quartiles		Bill Impact	
	Low-Medium	Medium-High	Major Impact	No Major Impact
Draft Plan	57%	69%	54%	75%
Spend Less	43%	31%	46%	25%

Q Additional Feedback (Optional)

Responses	%
System reliability and risk mitigation/utilize combined system	2.1%
Technology upgrades and maintenance planning	1.9%
Concerns about corporate spending/resource allocation	1.7%
Address existing operational challenges first	1.1%
Seek operational efficiencies/alternative funding/customers shouldn't pay	0.7%
No comment/None/Don’t know	92.6%

Note: Only responses > 0.1% shown.

Investment Trade-Offs

Meter replacement program

Canadian Niagara Power Customer Engagement Survey

Choice 7: Meter replacement program

Electricity meters are a critical component of the infrastructure needed to measure electricity consumption and bill customers accurately. Meters are a physical piece of equipment that are typically located on the side of houses and buildings.



Most of Canadian Niagara Power's meters were installed in 2009 and will soon need to be replaced as the technology becomes outdated and unsupported.

Canadian Niagara Power has identified roughly 26,000 out of over 31,000 meters for replacement.

In its current draft plan, Canadian Niagara Power plans to replace these roughly 26,000 meters over a 10-year period starting in 2027. Under this plan, the cost of this meter replacement program would be spread evenly across both this upcoming rate period (2027-2031) and the next (2032-2036).

However, to further reduce costs, Canadian Niagara Power has an option to spread this replacement program over an even longer period. While this would reduce costs in the short term, it would result in higher costs in the future, and the potential for emergency meter replacements if aging meters fail.

Which of the following options do you prefer?

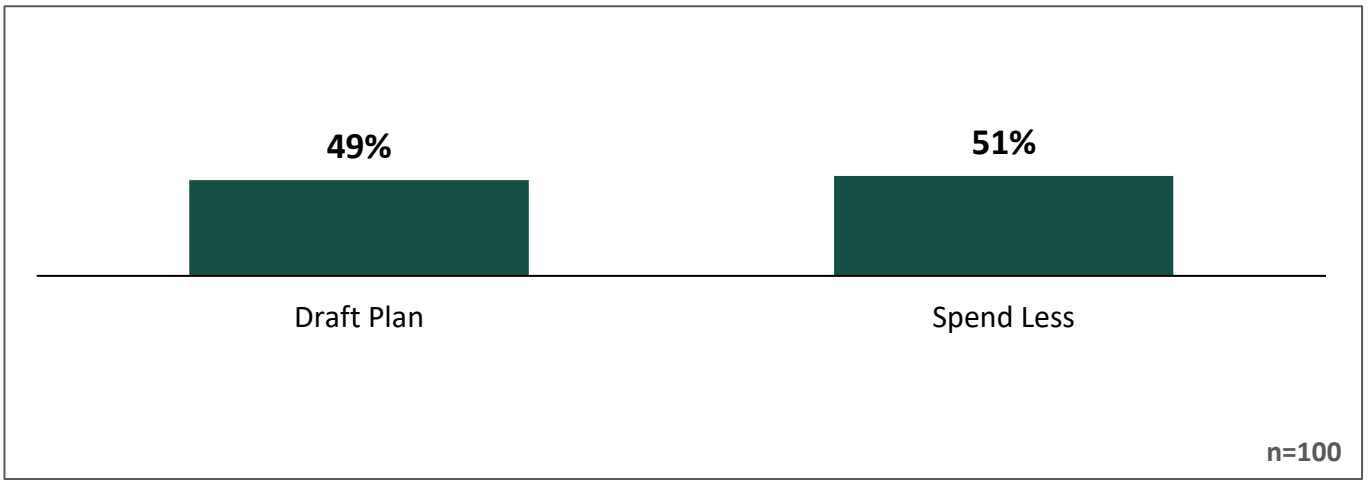
Option	Rate Impact	Investment Details + Outcome(s)
Draft Plan	Within proposed rate increase	• Replace roughly 26,000 meters at an even pace over a 10-year period
Spend Less	$0.66 less per month by 2032	• Replace roughly 26,000 meters at a slower pace now, but more during 2032-2036, delaying some of the rate impact • Increased risk of meter failure and emergency replacement relative to draft plan

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Investment Trade-Offs

Meter replacement program

Q Which of the following options do you prefer?



	Collapsed Consumption Quartiles		Bill Impact	
	Low-Medium	Medium-High	Major Impact	No Major Impact
Draft Plan	49%	49%	41%	59%
Spend Less	51%	51%	59%	41%

Q Additional Feedback (Optional)

Responses	%
Smart meter concerns/issues (e.g. health, safety, privacy, etc.)	2.5%
Seek operational efficiencies/alternative funding/customers shouldn't pay	1.7%
Need for transparency/clear communication/information	0.9%
Against increases/costs are too expensive	0.9%
Meter reliability and performance	0.9%
Support for phased/gradual approach	0.7%
No comment/None/Don't know	92.5%

Note: Only responses > 0.1% shown.

Investment Trade-Offs

Finalizing Choices

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Canadian Niagara Power Customer Engagement Survey

What is the impact of my choices?

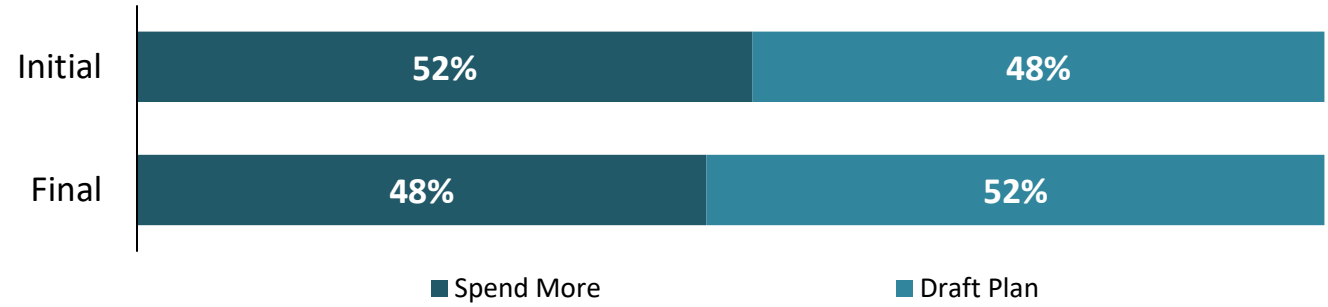
Throughout this survey, you have been asked about **7 key choices**. Below is a summary of your choices.

At the bottom of this page, you will find the total rate impact of your choices. You can change your responses if you desire, and the estimated impact on your monthly bill will be recalculated.

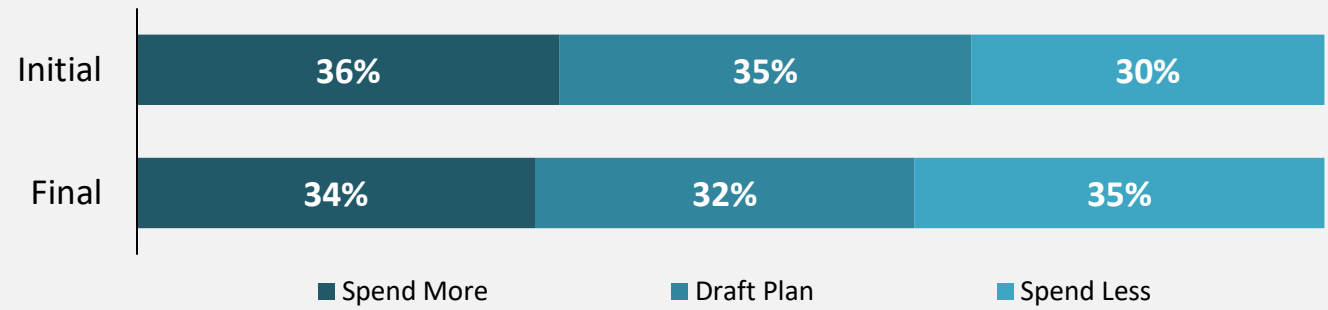
Investment Trade-Offs

Finalizing Choices

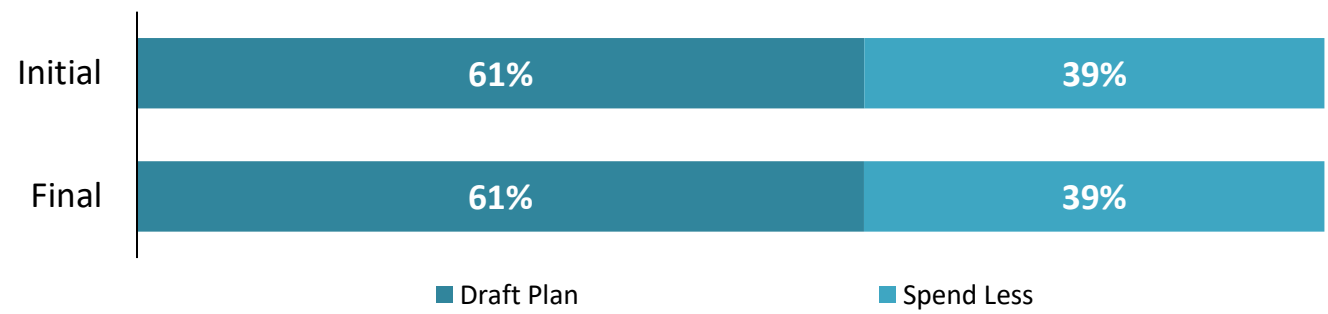
Choice 1: Improving resiliency to severe weather



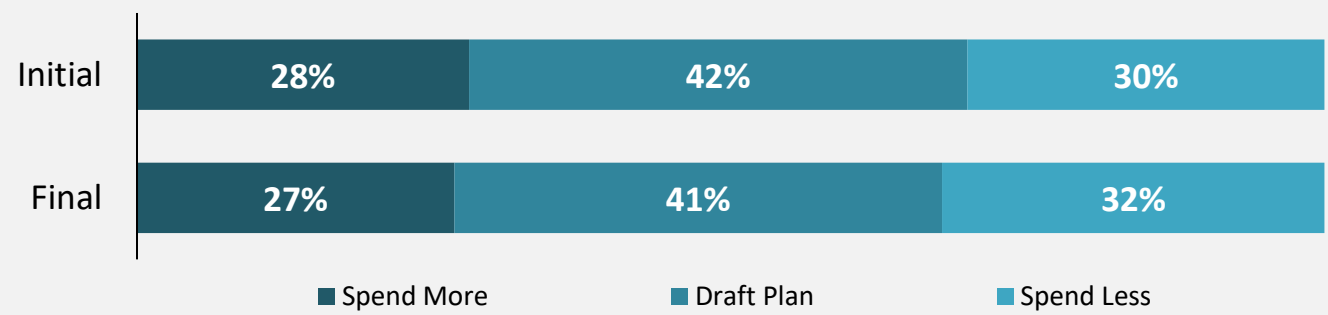
Choice 2: Improving reliability using intelligent switches



Choice 3: Modernizing older distribution lines



Choice 4: Replacing at-risk poles



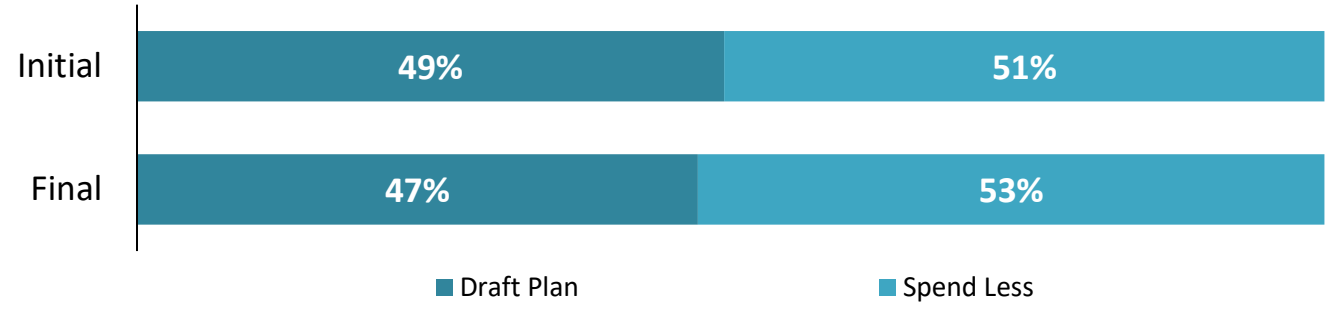
Investment Trade-Offs

Finalizing Choices

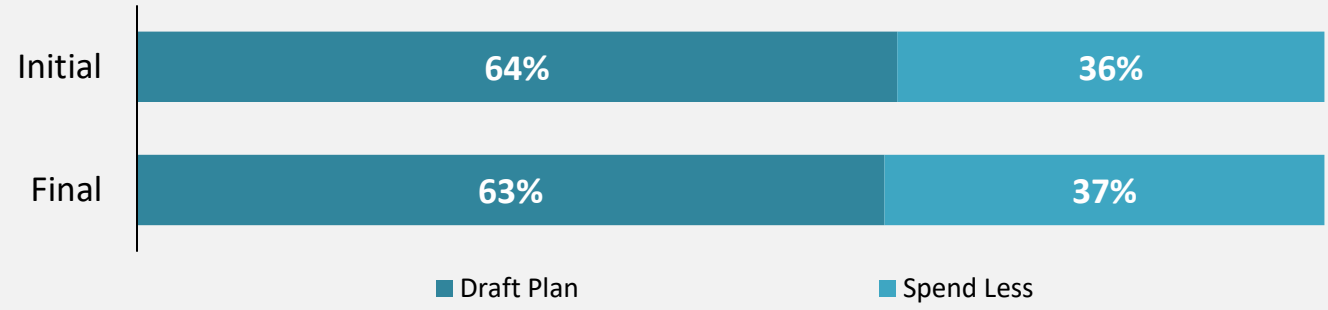
Canadian Niagara Power Inc.
EB-2026-0010
Exhibit
May 19, 2026
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Small Business

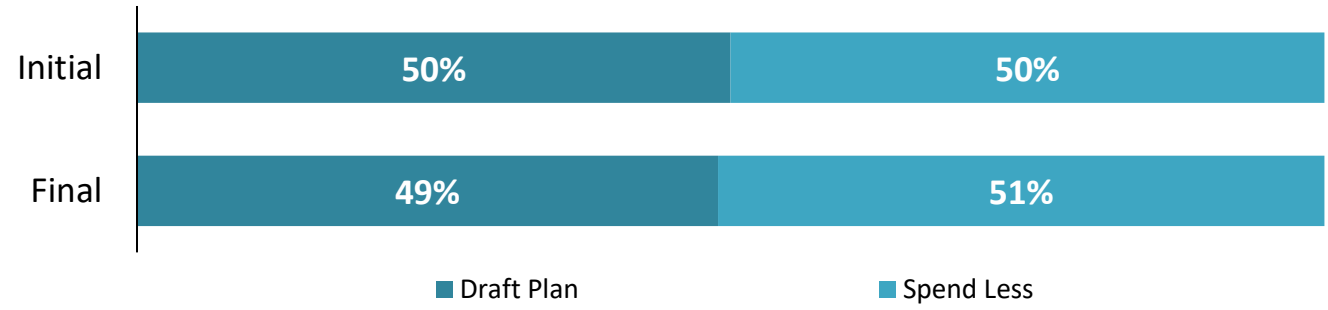
Choice 5: Investing in electric vehicles



Choice 6: Control room enhancements



Choice 7: Meter replacement program



Investment Trade-Offs

Overall evaluation of the draft plan

Small Business

Exhibit

Canadian Niagara Power Customer Engagement Survey

Evaluating Canadian Niagara Power's 2027-2031 draft plan

Canadian Niagara Power has calculated an overall cost for their draft plan. While the plan may change based on feedback from the earlier questions in this survey, Canadian Niagara Power would like to know how you feel about the overall draft plan.

For a typical small business customer, the distribution portion of their **monthly** bill is estimated to increase from $123.25 in 2027 to $156.02 by the end of 2032 – **an increase of $32.77 on the monthly bill.**

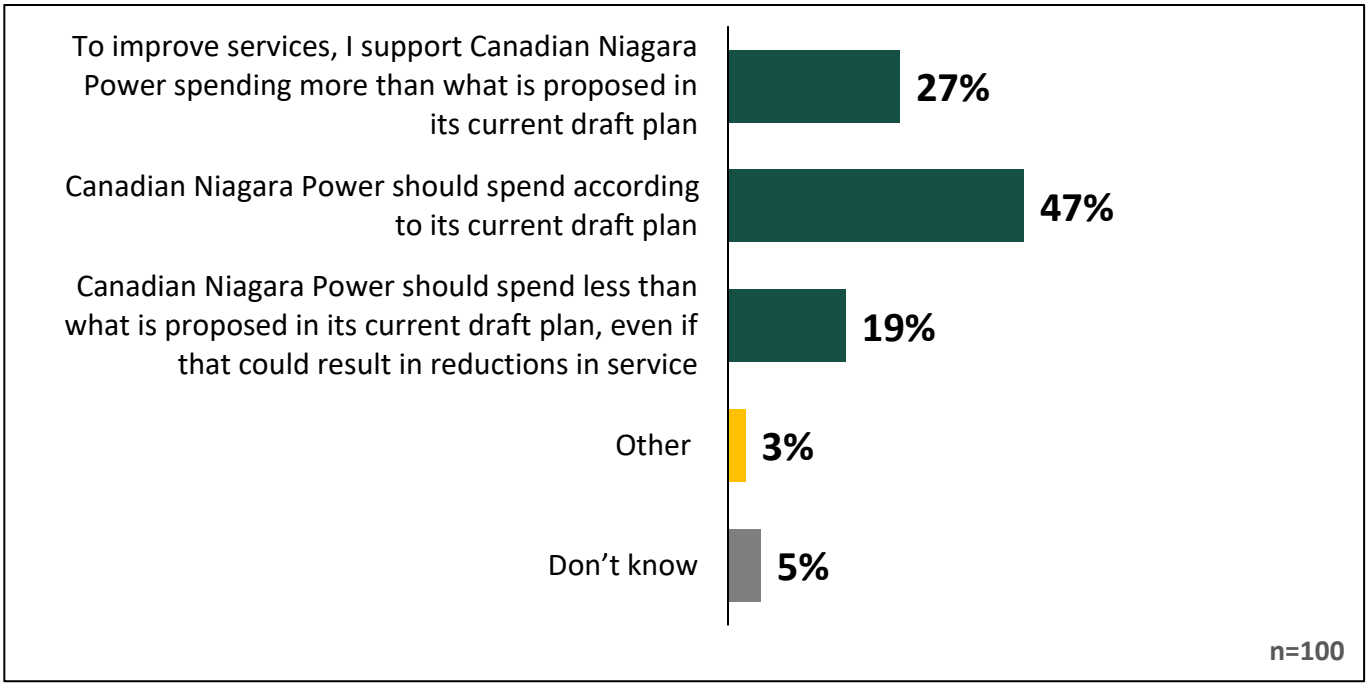
WORKBOOK PAGE

Investment Trade-Offs

Overall evaluation of the draft plan

Small Business

Q Considering what you have learned about Canadian Niagara Power's 2027-2031 draft plan, which of the following best represents your point of view?



	Collapsed Consumption Quartiles		Bill Impact	
	Low-Medium	Medium-High	Major Impact	No Major Impact
Spend More	27%	27%	23%	33%
Draft Plan	44%	49%	45%	49%
Spend Less	23%	14%	25%	10%
Other	--	5%	3%	2%
Don't know	6%	4%	4%	6%

Investment Trade-Offs

Final comments on the draft plan

Exhibit

Q Do you have any final comments regarding Canadian Niagara Power's draft plan for 2027-2031 and the proposed rate increase? (Optional)

Responses	%
Seek operational efficiencies/alternative funding/customers shouldn't pay	3.5%
Concerns around cost of living/inflation	2.1%
Distrust in the survey/inevitable rate increases	1.8%
Survey/engagement experience feedback - positive	1.6%
Better preventative maintenance/proactive planning	1.1%
Positive comment about CNPI/service	1.1%
System reliability/outage reduction	1.0%
Support for phased/gradual approach	0.9%
Support for environmental/renewable energy initiatives	0.9%
Lower rates/rates are too high	0.9%
Be transparent/communicate about rate increases/investments	0.8%
Financial strain on vulnerable customers (e.g. seniors, fixed income)	0.7%
Support the increase/investments are necessary	0.7%
No comment/None/Don't know	82.9%

Note: Only responses > 0.1% shown.

INNOVATIVE RESEARCH GROUP

Small Business Customers

Survey Diagnostics

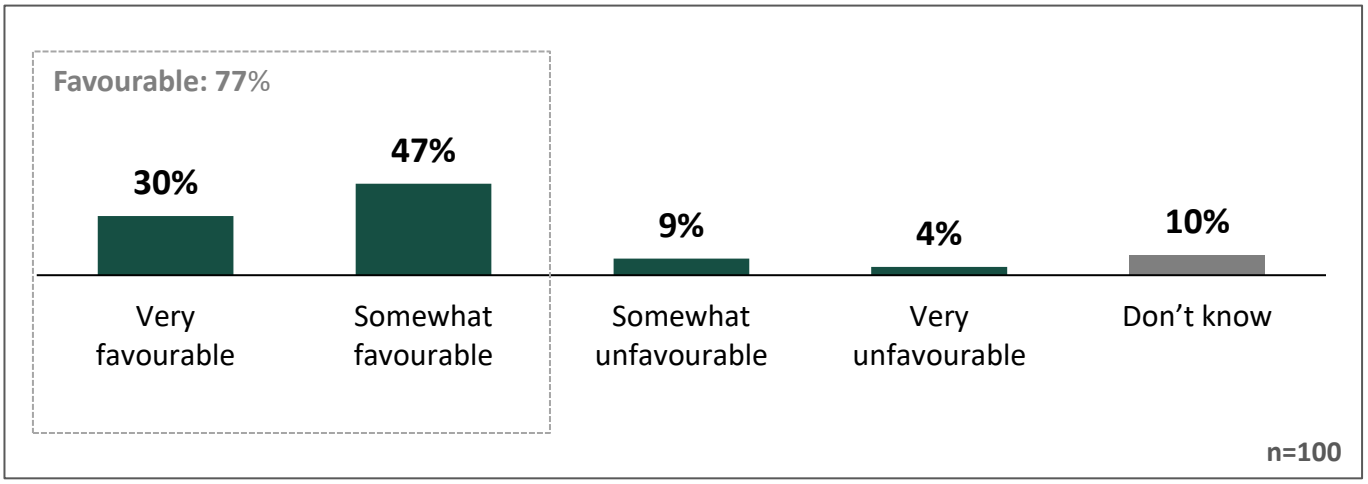


Survey Diagnostics

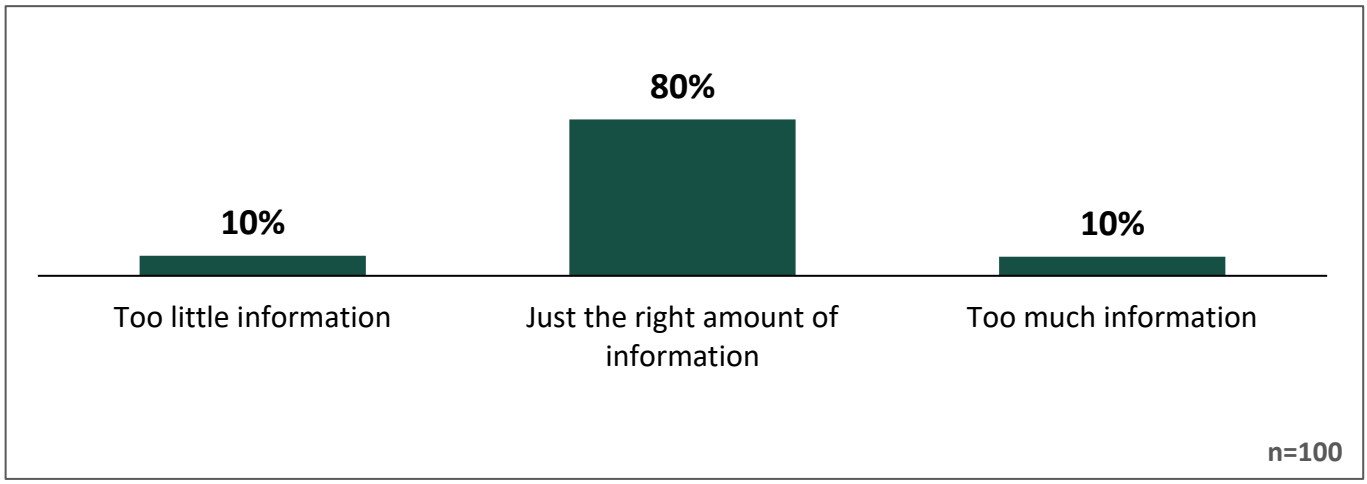
Favourability and amount of information

Canadian Niagara Power values your feedback. In order to do better in the future, they want to hear about your experience with this survey.

Q Overall, did you have a favourable or unfavourable impression of the customer engagement you just completed?



Q In this customer engagement, do you feel that Canadian Niagara Power provided too much information, not enough, or just the right amount?



Survey Diagnostics

Other information not included

Q Was there any content missing that you would have liked to have seen included in this customer engagement? (Optional)

Responses	%
Seek operational efficiencies/alternative funding/customers shouldn't pay	2.8%
Transparency on internal operations (e.g. finances, salaries, etc.)	1.9%
Reducing customer costs/affordability measures	1.6%
Survey/engagement experience feedback - negative	1.4%
Requests for historical data/information (e.g. spending, impact, cost)	1.3%
Better explanation/transparency on bills	1.1%
Distrust in the engagement/rate increases are inevitable	1.1%
More information/communication about rate increases	1.0%
Information on emerging technologies/impact on the grid	1.0%
Comparison to other utilities/benchmarking (e.g. rates, services, costs)	0.7%
Other	1.1%
No comment/None/Don’t know	85.1%

Note: Only responses > 0.1% shown.

Survey Diagnostics

Outstanding questions

Q Is there anything that you would still like answered? (Optional)

Responses	%
More detailed information on the investments/infrastructure	3.1%
Reducing customer costs/affordability measures	2.3%
Survey/engagement experience feedback - negative	1.6%
Renewable and alternative energy options (e.g. solar, wind, battery storage)	1.1%
More information/communication about rate increases	1.0%
Advanced meter infrastructure and usage analytics	1.0%
Transparency on internal operations (e.g. finances, salaries, etc.)	0.9%
Energy efficiency/cost-saving programs	0.9%
No comment/None/Don't know	88.0%

Note: Only responses > 0.1% shown.

INNOVATIVE RESEARCH GROUP

Large Business (GS>50kW) Customers

Online Survey Results



Canadian Niagara Power Inc.
EB-2026-0029
Exhibit I
Tab 1
Schedule 1
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Field Dates

The **Large Business (GS>50kW) Online Survey** was sent to all Canadian Niagara Power Inc. large business (GS>50kW) customers with an available email address. Customers had an opportunity to complete the survey between **February 11th and March 12th, 2026**.

Each customer received a unique URL that could be linked back to their average monthly consumption, region and rate class.

In total, the commercial and industrial survey was sent to **132** customers from *customer.service@cnpower.com*. Three reminder emails were sent on a rolling basis over the survey field window to those who had not yet completed the survey.

Large Business (GS>50kW) Online Survey Completes

A total of **9** (unweighted) Canadian Niagara Power Inc. large business (GS>50kW) customers completed the online survey.

Note: *Graphs and tables may not always total 100% due to rounding values rather than any error in data. Sums are added before rounding numbers. Caution interpreting results with small n-sizes.*

Firmographics

Large Business Customers Results Summary

Exhibit 1
Canadian Niagara Power Inc.
EB-2026-0029
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Question	Response	Large Business [n=9]
The sector in which your business operates	Commercial	1
	Manufacturing/Industrial	4
	Data Centre	0
	Hospitality	1
	Restaurant/Tavern	0
	Retail	1
	Warehouse	0
	Real estate	0
	Other	2
	Prefer not to say	0
Number of people who work at your organization	1 person	0
	2 to 5 people	0
	6 to 10 people	2
	11 to 25 people	1
	26 to 50 people	2
	More than 50 people	4
	Don’t know	0
	Prefer not to say	0

Familiarity & Experience

Large Business Customers Results Summary

Exhibit 1
Canadian Niagara Power Inc.
EB-2026-0029
March 13, 2026
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Question	Response	Large Business [n=9]
Before this survey, how familiar would you say you were with Canadian Niagara Power and the role it plays in Ontario's electricity system?	Very familiar	2
	Somewhat familiar	4
	Have heard of some terms	2
	Knew nothing	0
	Don't know	1
Overall, how satisfied or dissatisfied are you with the service your organization receives from Canadian Niagara Power?	Very satisfied	4
	Somewhat satisfied	3
	Neither satisfied nor dissatisfied	2
	Somewhat dissatisfied	0
	Very dissatisfied	0
	Don't know	0
Before this survey, how familiar were you with the amount of your organization's electricity bill that went to Canadian Niagara Power?	Very familiar	0
	Somewhat familiar	2
	Not familiar	7
	Don't know	0
Have you experienced any power outages in the past 12 months which lasted longer than one minute? If so, approximately how many of these power outages did you experience?	No outages	2
	1-2 outages	5
	3-4 outages	1
	5-6 outages	0
	7 or more outages	0
	Don't know	1

Investment Trade-Offs

Large Business Customers Results Summary

Large Business (GS>50kW)

Question	Response	Large Business [n=9]
Improving resiliency to severe weather: Which of the following options do you prefer?	Spend More	5
	Draft Plan	4
Improving reliability using intelligent switches: Which of the following options do you prefer?	Spend More	4
	Draft Plan	4
	Spend Less	1
Modernizing older distribution lines: Which of the following options do you prefer?	Draft Plan	7
	Spend Less	2
Replacing at-risk poles: Which of the following options do you prefer?	Spend More	2
	Draft Plan	6
	Spend Less	1
Investing in electric vehicles: Which of the following options do you prefer?	Draft Plan	8
	Spend Less	1
Control room enhancements : Which of the following options do you prefer?	Draft Plan	9
	Spend Less	0
Meter replacement program: Which of the following options do you prefer?	Draft Plan	7
	Spend Less	2

Investment Trade-Offs

Large Business Customers Results Summary

Canadian Niagara Power Inc.
EB-2026-0029
Exhibit 1
Tab 1 Sch 7
Page 240 of 355

Question	Response	Large Business [n=9]
Considering what you have learned about Canadian Niagara Power's 2027-2031 draft plan, which of the following best represents your point of view?	Spend More	0
	Draft Plan	8
	Spend Less	0
	Other	0
	Draft Plan	1

Environmental Controls

Large Business Customers Results Summary

Exhibit 1
Canadian Niagara Power Inc.
EB-2026-0029
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Large Business (GS>50kW)

Question	Response	Large Business [n=9]
The cost of my organization's electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.	Strongly agree	3
	Somewhat agree	4
	Somewhat disagree	2
	Strongly disagree	0
	Don't know/No opinion	0
Customers are well served by the electricity system in Ontario.	Strongly agree	3
	Somewhat agree	5
	Somewhat disagree	1
	Strongly disagree	0
	Don't know/No opinion	0

Building Understanding.

Acknowledgement

This report has been prepared by Innovative Research Group Inc. (INNOVATIVE) for Canadian Niagara Power Inc. The conclusions drawn and opinions expressed are those of the authors.

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CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

BP APPENDIX- B:
CNPI 2024 Scorecard and MD&A

Scorecard - Canadian Niagara Power Inc.

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		94.91%	91.76%	96.03%	95.80%	97.51%	up	90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	98.61%	100.00%	100.00%	flat	90.00%	
		Telephone Calls Answered On Time		79.79%	81.11%	79.20%	83.84%	80.44%	up	65.00%	
	Customer Satisfaction	First Contact Resolution		99.92%	99.30%	99.77%	99.54%	99.63%			
		Billing Accuracy		99.95%	99.83%	99.93%	99.95%	99.85%	down	98.00%	
		Customer Satisfaction Survey Results		92%	95%	94%	89%	92%			
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		83.00%	83.00%	82.00%	82.00%	85.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	flat		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	1	0	2	up		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.655	0.000	1.232	up		0.227
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		2.73	2.50	1.95	2.25	1.86	down		2.76
		Average Number of Times that Power to a Customer is Interrupted [2]		2.19	1.78	1.67	2.62	1.66	down		2.03
	Asset Management	Distribution System Plan Implementation Progress		Completed	Completed	Completed	Completed	Completed			
	Cost Control	Efficiency Assessment		4	4	4	4	4			
		Total Cost per Customer [3]		$868	$905	$968	$1,134	$1,183			
		Total Cost per Km of Line [3]		$16,581	$17,810	$19,189	$21,458	$22,005			
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%		100.00%	flat	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.34	0.24	0.23	0.21	0.23			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		2.80	2.69	2.55	2.35	2.07			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.78%	8.78%	8.66%	8.66%	8.66%			
			Achieved	5.00%	3.47%	8.47%	7.90%	7.53%			

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

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2024 Scorecard MD&A:

Scorecard - Performance Measure Descriptions

Scorecard MD&A - General Overview

In 2024, CNPI continued to meet or exceed the majority of its performance targets.

In 2025, CNPI expects to continue to improve its overall scorecard performance results as compared to previous years. These performance improvements are expected as a result of enhanced system reliability due to CNPI's investment in its distribution system and continued responsiveness to customer feedback

Service Quality

- **New Residential/Small Business Services Connected on Time**

In 2024, CNPI connected 97.5% of the 362 new eligible low-voltage residential and small business customers within the Ontario Energy Board's prescribed five-day timeline. Since 2011, CNPI has consistently exceeded the Ontario Energy Board's performance standard of 90%.

- **Scheduled Appointments Met On Time**

CNPI continues to exceed the Ontario Energy Board standard of meeting customers as requested within the prescribed timelines set out by the Ontario Energy Board. In 2024, CNPI met all its 42 appointments within the OEB-prescribed timeline. Performance in this measure was 100%.

- **Telephone Calls Answered On Time**

In 2024, customer service representatives answered 80.4% of CNPI's 27,721 calls within 30 seconds. This exceeds the Ontario Energy Board's mandated 65% target. CNPI continues to offer and promote various communication channels including customer self-serve portal; webchat function within the website; and social media postings.

Customer Satisfaction

- **First Contact Resolution**

CNPI measured First Contact Resolution by tracking the number of escalated calls as a percentage of total calls taken by the customer contact center. In 2024, 0.37% of calls were escalated, resulting in a first contact resolution of 99.63%.

- **Billing Accuracy**

For 2024, CNPI issued 374,789 invoices, of which 99.85% were considered accurate. This is above the industry target of 98%.

- **Customer Satisfaction Survey Results**

CNPI conducts its customer satisfaction surveys through a third-party survey provider, UtilityPULSE, consistent with many other LDCs in the province. Phone numbers were randomly selected so that 85 per cent of the interviews were conducted with residential customers and 15 per cent with general service customers. CNPI's 2024 satisfaction score is 92%. The Ontario benchmark assessed by UtilityPULSE is 88%.

The survey provides useful information to better meet the needs of CNPI's customers and is incorporated into CNPI's distribution system plan, capital planning and overall company objectives. Credibility and trust ratings have shown notable improvement, boosting sector confidence. As a result, overall customer satisfaction has increased by 3% from 89% in 2023.

CNPI officially launched its outage map live to our customers via social media, website posting and email blast on December 2, 2024 . This graphic representation provides near real-time updates of outage status in the service territory and speaks directly to what customers have been requesting. CNPI continues to make investments in its system which aim to maintain or improve reliability, which are further outlined in the section "System Reliability" below.

- **Public Safety**

  - **Component A – Public Awareness of Electrical Safety**

The Electrical Safety Authority has developed a survey on public awareness of electrical safety. The Electrical Safety Authority is responsible for developing the survey methodology and questions. The design and scoring are standardized across the province and set by the Electrical Safety Authority. In 2024, CNPI engaged UtilityPulse to complete the survey in relation to "Public Awareness of Electrical Safety". On completion of this survey, UtilityPulse generated a "Public Safety Awareness Index Score" for CNPI. CNPI's score of 85% suggests that members of the public are generally well-informed about the safety hazards associated with electrical distribution systems, but also that further education and engagement would be beneficial. This survey on "Public Awareness of Electrical Safety" is completed on a two-year cycle and will be completed again by CNPI in 2026.

  - **Component B – Compliance with Ontario Regulation 22/04**

This component includes the results of an Annual Audit, Declaration of Compliance, Due Diligence Inspections, Public Safety Concerns and Compliance Investigations. All the elements are evaluated as a whole and determine the status of compliance (Non-Compliant, Needs Improvement, or Compliant).

CNPI's status, as assessed by the ESA is Compliant.

  - **Component C – Serious Electrical Incident Index**

"Serious electrical incidents", as defined by Regulation 22/04, make up Component C. The metric details the number of and rate of "serious electrical incidents" occurring on a distributor's assets and is normalized per 10, 100 or 1,000 km of line (10km for total lines under 100km, 1000km for total lines over 1000km, and 100km for all the others).

Based on results provided by ESA, CNPI had two incidents in 2024. Both incidents thankfully concluded without public or employee harm, but were caused by a member of the public undertaking inappropriate tree cutting activities near powerlines on their property. CNPI's website (Safety Section) outlines public safety requirements for homeowners and others when completing home improvements and other work around their property.

- **Average Number of Hours that Power to a Customer is Interrupted**

The average number of hours that power to a customer is interrupted, which are adjusted for Loss of Supply and Major Event Days, shows a decreasing (improving) trend. The 2024 result of 1.86 compares favourably to CNPI's target of 2.76.

The largest source of customer hours of interruptions in 2024 were tree contacts and adverse weather.

CNPI continues to implement measures to help reduce the number and duration of outages. CNPI continues to install smart devices (fault indicators and remote control reclosers) to help identify the location of the damage faster and reduce patrol time. Additionally, CNPI installed isolation devices, switching devices, fault location and isolation and service restoration (FLISR) to restore a portion of the customers to other feeders. These measures reduce the impact of weather events and other outages to levels that are lower than they otherwise would have been. CNPI continues to complete is annual vegetation management processes, which addresses one third of the distribution system per year (ie: whole system is covered on a three year cycle).

- **Average Number of Times that Power to a Customer is Interrupted**

The average number of times that power to a customer was interrupted in 2024 was 1.66 times, indicating that the average customer experienced 1-2 outages in 2024, excluding major events and loss of supply. This number of outages represents a decrease over recent performance and compared to CNPI's target of 2.03 outages per customer.

CNPI has deployed several initiatives aimed at reducing the number of electrical service interruptions such as the vegetation management program, cyclical asset preventative maintenance programs and a wildlife protection program.

The most significant causes of customer outages(excluding major events and loss of supply) in 2024 were adverse weather and tree contacts.

CNPI reviews outage statistics on a monthly basis to identify areas of poor distribution system performance. This process indicates any trends in poor performance and identifies opportunities to improve reliability. CNPI also completes asset condition assessments to identify assets that present a risk of impacting system reliability. CNPI uses reliability indicators and asset condition assessment data as key drivers into the system planning process.

CNPI has undertaken multiple ongoing programs expected to mitigate system reliability risks:

- An annual cycle program for tree trimming. In some years the tree trimming program expands beyond the basic standard in order to protect reliability.
- CNPI has made progress on its Delta Conversion project;

- CNPI has continued its deficiency program for the replacement of aging and defective distribution assets;
- CNPI has built and/or rebuilt 2 stations or substations in the past several years, which enhances reliability.
- CNPI is in the process of purchasing and installing smart switches for its distribution system that will improve reliability.
- CNPI will continue to rebuild the 27.6 kV feeders which impacts the system improvement for outages etc.
- CNPI is improving automation of its second transformer at the Gananoque Main Substation which will improve reliability in a contingency situation.

Asset Management

- **Distribution System Plan Implementation Progress**

CNPI completed most planned projects in accordance with its Distribution System Plan, with emphasis on continuing voltage conversion in Fort Erie and Gananoque systems, and substation rebuild work in Gananoque to improve the safety and reliability of distribution systems. CNPI has also continued to invest in system expansions to accommodate requests for new services, due to new subdivision development above historical levels. All maintenance activity as defined in the Distribution Asset Management Plan was completed in 2024.

Cost Control

- **Efficiency Assessment**

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC on behalf of the Ontario Energy Board to produce a single efficiency ranking. The electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs. The statistical model developed by Pacific Economics Group to predict a distributor's costs relies on a data set that includes all distributors in Ontario.

For 2024, CNPI's efficiency assessment of Group 4 indicates that actual costs are within 10%- 25% of the costs predicted by the statistical model. CNPI's total costs are reflective of its continued re-investment in its distribution system and improving efficiency in recent years.

- **Total Cost per Customer**

The statistical model developed by Pacific Economics Group (PEG) produces total capital and operating costs for each distributor that are used to compare distributors. This amount is then divided by the total number of customers that CNPI serves to determine Total Cost per Customer. The cost performance result for 2024 is $1,183 per customer, which is a 4% increase over 2023. The 4% year-over-year change in total cost per customer is driven by a 5% increase in the total cost assessed by PEG, offset by modest customer growth of 2%.

CNPI's operating costs increased by 3.6% compared to the prior year. The PEG-assessed Capital Cost increased 6%, though the Gross Capital Additions for the year only increased by 1%. Capital Additions in 2024 were relatively consistent with the prior year, and included investments in voltage conversion, replacement of aging assets, and customer-driven projects.

Over the 2020 to 2024 period covered by the scorecard, CNPI faced inflationary cost increases, as well as cost increases associated with investments in asset replacement, system improvement, and vegetation management necessary to maintain the efficient and reliable operation of the distribution system. In contrast, CNPI's customer count increased by only 4.0% over the entire five-year period, with a result that cost increases are not offset by customer growth.

- **Total Cost per Km of Line**

This measure uses the same total cost that is used in the Cost per Customer calculation above. The total cost is divided by the total kilometers of line that CNPI operates to serve its customers. CNPI's 2024 result is $22,005 per km of line, a 2.7% increase over 2023.

Connection of Renewable Generation

- **New Micro-embedded Generation Facilities Connected On Time**

CNPI had 19 new micro-embedded generation facilities that were connected to the distribution system within 5 business days. CNPI met 100% of this target.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

The Scorecard reports the current ratio for CNPI's segmented distribution business as 0.23 for 2024 (2023 - 0.21). CNPI however manages liquidity on a consolidated basis that includes both its transmission and distribution divisions. On this basis, the 2024 current ratio based on CNPI's audited financial statements, adjusted to exclude due to related parties, is 1.35 (2023 - 0.95), which has increased from prior year. Going forward, the liquidity ratio is expected to be maintained at a level greater than 1.00, indicating that CNPI can pay its short-term debts and financial obligations.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**

The Ontario Energy Board uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5. The Scorecard reports the total debt to equity ratio for CNPI's segmented

distribution business as 2.07 for 2024 (2023 - 2.35). CNPI however manages its capital structure on a consolidated basis that includes both its transmission and distribution divisions. On this basis, the 2024 debt to equity ratio based on CNPI's audited financial statements, adjusted to include due to related parties, is 1.64 (2023 - 1.59). The leverage ratio is expected to be maintained at a level near the 1.5 deemed capital mix noted above.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**

CNPI's 2024 distribution rates were approved by the Ontario Energy Board as part of its 4th Generation Incentive Rate-Setting application. CNPI's last Cost of Service application was for rates effective January 1, 2022 and this included an expected (deemed) regulatory return on equity of 8.66%. The Ontario Energy Board allows a distributor to earn within +/- 3% of the expected return on equity. Outside of this range, the OEB may require a review of the distributor's over-/under- earning.

- **Profitability: Regulatory Return on Equity – Achieved**

CNPI's return achieved in 2024 is 7.53% (2023 - 7.90%), which is within the +/- 3% range allowed by the Ontario Energy Board. CNPI's achieved returns are lower in 2024 as compared to 2023 due to a $0.1 million (3.46%) increase in adjusted regulated net income and a $11.5 million (8.62%) increase in rate base which resulted from system access capital work, continued execution of the voltage conversion project along with other line rebuild projects, transformer purchases, substation project work and investment in computer hardware and software, which was offset by amortization expenses.

Note to Readers of 2024 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgement on the reporting date of the performance scorecard, and could be markedly different in the future.

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

ATTACHMENT 1-C:
COMPLETED 2027 CHECKLIST

2027 Cost of Service Checklist

Exhibit 1

LDC Name

EB-2026-0029

Date: May 19, 2026

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is
GENERAL REQUIREMENTS		
Ch1, p4	If third-party documentation is filed and the documentation has been labelled as "confidential" (e.g., in the header or footer of the document), and if the distributor is not seeking confidential treatment, confirmation provided that the documentation does not contain confidential information as defined in the Practice Direction on Confidential Filings, and the distributor is providing it for the public record	1.3.4, cover letter
Ch1, p4	Confidential Information - Practice Direction has been followed	1.3.4
Ch1, p5	Certification by a senior officer that the application and any evidence filed in support of the application does not include any personal information unless it is filed in accordance with Rule 9A of the OEB's Rules (and the Practice Direction Confidential Filings, as applicable)	Attachment 1-D
Ch1, p5	Certification by a senior officer that the evidence filed is accurate, consistent and complete to the best of their knowledge	Attachment 1-D
Ch1, p5	Certification by senior officer that the distributor has appropriate processes and internal controls for the preparation, review, verification and oversight of deferral and variance account balances being disposed	Attachment 1-D
Ch1, p6	A letter from the governing body (e.g., Board of Directors) certifying that it is aware of and approves the submission of the application	Attachment 1-D
Ch1, p6	Where generative artificial intelligence (AI) is used to generate content in a filing in a proceeding, distributor must: - disclose generative AI was used to generate content in a filing; and - confirm that the accuracy of the filing generated by AI has been verified by the party or rep. without the assistance of generative AI Disclosure made either: in the certification of evidence section of application, at the beginning of the document created by generative AI, or in the cover letter to a multi-document package	Attachment 1-D
2	COS checklist filed and statement identifying all deviations from Filing Requirements	Attachment 1-C
2	Chapter 2 appendices in live Excel format; PDF and Excel copy of current tariff sheet	App 2 filed in excel Tariff is Att 1-E
3	If distributor updates/amends an OEB model, reference made in corresponding exhibit re: what was updated/amended	1.3.7- all listed here.
3	Regulated entity shown separately from parent company or any other affiliates	1.3.10
3	If applicable, if cost of service filed earlier than scheduled, justify why an early rebasing is required by demonstrating why and how distributor cannot adequately manage resources and financial needs during IRM period	1.3.7 (N/A)
4	If applicable, late applications filed after the commencement of the rate year for which the application is intended to set rates is converted to the following rate year	1.3.7 (N/A)
4-5	All of the following exhibits filed: Application Overview and Administrative Documents, Rate Base and Capital (including DSP), Customer and Load Forecast, Operating Expenses, Cost of Capital and Capital Structure, Revenue Requirement and Revenue Deficiency/Sufficiency, Cost Allocation, Rate Design, Deferral and Variance Accounts	Confirmed.
5	General requirements applicable throughout application: -written evidence included before data schedules -avg. of opening and closing fiscal year balances used for items in rate base (unless alternative method justified) -debt + equity = total rate base -data for test year, bridge year, three most recent historicals (or as many needed to provide actuals back to last OEB-approved), most recent OEB-approved test	Confirmed.
5	Documents include page numbers and are provided in text searchable and bookmarked PDF format	Confirmed.
6	Links within Excel models are broken and models named so that they can be identified (e.g. RRWF instead of Attachment A)	Confirmed.
6	Materiality threshold: Explanation with supporting evidence for material amounts pertaining to CAPEX, capital variances, rate base variances, OM&A, and DVAs; additional details below the threshold if helpful to the OEB	Confirmed. Materiality threshold in 1.2.9.

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Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is
EXHIBIT 1 - APPLICATION OVERVIEW AND ADMINISTRATIVE DOCUMENTS		
Table of Contents		
7	Table of Contents listing major sections and subsections of the application	Included at the start of each exhibit and
Application Summary and Business Plan		
7	Distributor with less than 30k customers: Business or Strategic Plan. If no Business or Strategic plan: key planning assumptions, description of material factors (internal and external) that may affect the operation of the utility and major goals of the distributor in the test year and remaining years of the five-year term Distributor with 30k or more customers: Business Plan underpinning application - can be augmented by plain language summary of distributor's goals that informed the application if this is not otherwise in the Business Plan. Also provide Strategic Plan, if available	S 1.1, Attachment 1-B
7	Brief, plain language summary of the application which includes the main requests with section references and rationale behind each request. Must include: Revenue requirement (service revenue requirement requested for test year, increase/decrease ($ and %) from most recent approved, main drivers of revenue requirement changes from last OEB-approved	1.2.1
7	Load forecast summary (load and customer growth (% change in kWh, kW and change in customer #s from last OEB-approved))	1.2.2
7-8	Rate base and DSP (major drivers of DSP and cost trends, rate base requested, change in rate base from last OEB-approved ($ and %), CAPEX for test year, change in CAPEX from last OEB-approved ($ and %)	1.2.3
8	OM&A requested for test and change from last OEB-approved ($ and %), drivers and cost trends	1.2.4
8	Cost of capital (table showing proposed capital structure and parameters resulting in WACC, statement confirming use of OEB's cost of capital parameters, summary and rational of deviations from OEB methodology)	1.2.5
8	Cost allocation and rate design (proposed new customer classes and/or customer definition changes, new proposed charges, significant changes proposed to rev. cost ratios and fixed/variable split, mitigation plans)	1.2.6
8	DVAs (total disposition ($) including split between customer classes and between RPP and non-RPP (if applicable), disposition period(s), new DVAs and requested	1.2.7
8-9	Bill Impacts ($ and %) for residential customer at 750kWh, and typical customers for all other classes (based on commodity rates on TOU with regulatory charges held constant; bill impacts to be used for Notice (Sub-total A) for residential customer at 750kWh and GS<50 at 2000kWh as well as a typical consumer for a distributor's service area for all customer classes, and bill impacts based on alternative consumption profiles and customer groups as appropriate	1.2.8 (Table 1-16)
Administration		
9	Primary contact information (name, address, phone, email)	1.3.1
9	Identification of legal (or other) representation	1.3.1
9	Applicant's internet address for viewing of application and any social media accounts, with addresses, used by the applicant to communicate with customers	1.3.2
9	Statement identifying where notice should be published and why	1.3.3
9	Form of hearing requested and why	1.3.6
9	Requested effective date	1.3.4
9	Statement identifying and describing any changes to methodologies used vs previous applications	1.3.8
9	Identification of OEB directions from any previous OEB Decisions and/or Orders, including commitments made as part of approved settlements. Indication of how these are being addressed in the current application	1.3.9
9	Reference to Conditions of Service - provide reference to website and confirm version is current; identify if there are changes to Conditions of Service (a) since last CoS application and/or (b) as a result of the current application. Confirmation that there are no rates and charges linked in the Conditions of Service that are not in the distributor's Tariff of Rates and Charges must be provided	1.4.4
10	Description of the corporate and utility organizational structure showing the main units and executive and senior management positions within the organization; corporate entities relationship chart, showing the extent to which the parent company is represented on the distributor company's Board of Directors; description of the reporting relationships between distributor and management of the parent company. Also include any planned changes in corporate or operational structure, including any changes in legal organization and control	1.3.10
10	List of approvals requested (and relevant section of legislation). All approvals including accounting orders, new rate classes, revised specific service charges or retail service charges which the distributor is seeking, must be documented. Appendix 2-A **may** be used to list requested approvals	1.3.4

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Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is
Small Distributor Process Eligibility (between 5k and 30k customers)		
10	If applicable, if a very small distributor wishes to opt out of using the one-day Issues Meeting, the distributor should make that known in its application	1.3.12
11	If applicable, a small distributor seeking to use the Small Distributor Process must make that known in its application	1.3.12
Distribution System Overview		
11	Description of Service Area - general description and map showing where distributor operates and communities served	1.4
Customer Engagement		
11	Provide information regarding its customer engagement activities, activities that occur on an on-going basis, and specific activities pertaining to application. **May** use Appendix 2-AC to assist in listing customer engagement activities	1.6
11-12	Ongoing Customer Engagement - Describe methods used to communicate and engage with each customer class regularly, summarize pertinent feedback received through regular customer communications, and explain how feedback informs operations and rate application, where applicable	1.6.2-1.6.4
12	Application-Specific Customer Engagement - Explain customer engagement process specific to application (tailor customer engagement activities to distributor's circumstances and the proposals in application). Demonstrate how customer needs and priorities were factored into the decision-making process	1.6.5
12	Customer engagement with customers who would be affected by proposals related to new rate classes, changes in to existing rate classes and change in charges such as RSCs, Specific Service Charges, standby rates, and unmetered-load customers	1.6.5
12	All responses to matters raised in letters of comment filed on public record	1.3.11
Performance Measurement		1.7.1
13	Link to most recent scorecard	
13	Identification of performance improvement targets	1.7.4
13	OEB approved benchmarking model for the test year showing efficiency assessment, discussion on how the results obtained from the OEB approved forecasting model and Activity and Program-based Benchmarking (APB) have informed the distributor's business plan and application	1.7.2 and 1.7.3
13	Distributors **may** provide table showing respective OEB-approved IRM increases for each of the last historical years from last rebasing, and assigned cohort as per the OEB approved model	1.7.2
13-14	Activity and Performance-based Benchmarking (APB) results - at least provide the following unit cost variance analysis: - Year-over-year Historical Actuals (for most recent APB results) - Forecast Bridge Year vs Historical Actuals, to extent possible - Test Year vs Historical Actuals, to extent possible - An explanation of significant change (greater than 20% from previous year or five-year average) - A plan to drive down unit costs if five-year average is 25% greater than industry five-year average	1.7.3
14	Explain variances in cost performance, whether changes in unit costs are within distributor's control, and discuss relevant actions planned or underway. Discuss econometric results to extent possible	1.7.3
Facilitating Innovation		
14-15	Distributors are encouraged to include a description of the ways their approach to innovation has shaped the application. Could include explanations of approach to innovation or keeping up with innovation in their business more generally; of specific projects or technologies for enhancing the provision of distribution services; and of enabling characteristics or constraints in their ability to undertake innovative solutions	1.9
15	Explain how innovative alternatives have been considered in place of traditional investments. Include information about the costs, expected benefits and associated risks of innovative alternatives. An innovative approach the OEB has emphasized is for distributors to consider the use of non-wires solutions (NWSs) to address distribution system needs	1.9
15	If distributor is applying for margin on payments (MoP) incentive related to the use of third-party DERs as NWSs, eligibility criteria and filing requirements as set out in section 11 of the Distribution System Code addressed	1.9
15	If distributor includes a discrete and innovative proposal in its application, the OEB encourages the distributor to review the five considerations set out in the OEB's March 20, 2025 letter	1.9

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Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is
Financial Information		
16	Audited Financial Statements (excluding operations of affiliated companies that are not rate regulated) for two most recent historical years (i.e. one year's statements must be filed, covering two years of historical actuals); if most recent finals n/a, draft financial statements filed and finals, along with summary of main changes if there are any, provided as soon as they are available. Alternatively, if distributor publishes financial statement on its website, a link may be provided	1.8.1, Att. 1-F
16	A detailed reconciliation of the financial results shown in the audited financial statements with the regulatory financial results filed in the application, including a reconciliation of the fixed assets in order to, as one example, separate non distribution businesses. This must include the identification of any deviations that are being proposed between the audited financial statements and the regulatory financial results, including the identification of any prior OEB approvals for such deviations	1.8.2, Att. 1-G
16	Annual Report and MD&A for most recent year of distributor and parent company, as available and applicable. If an Annual Information Form is filed publicly, a link should be provided	1.8.2
16	Rating Agency Reports, if available; Prospectuses, information circulars etc. for recent and planned public debt and/or equity offerings	1.8.3
16	Any change in tax status	1.5.3
16	Description of existing accounting orders and departures from these orders, as well as any departures from the USoA	1.5.4; 1.5.2
16	Accounting Standards used for financial statements and when adopted	1.5.1
16-17	If distributor conducting non-distribution businesses, confirmation that accounting treatment used has segregated these activities from rate regulated activities	1.5.5
Distributor Consolidation		
17	Information filed on the extent to which the distributor has investigated opportunities for consolidation or collaboration/partnerships with other distributors (contained within a dedicated section of the application); conclusions from investigations, including future plans	1.10.1
17	If distributor has become party to a proposed or approved MAADs transaction since last rebasing, disclosure of this information in current application	1.10.1
17	A distributor filing an application to rebase following a consolidation must: Identify any incentives that formed part of the consolidation transaction if the incentive represents costs that are being proposed to remain or enter rate base and/or revenue requirement - list the exhibits in which incentives are discussed	1.10.1
17	Specify whether and which commitments made to shareholders are to be funded through rates	1.10.1
17	Detail of realized and projected savings as a result of consolidation compared to what was in the approved consolidation application and explanation of the nature of these savings (e.g. one-time, ongoing etc.)	1.10.1
17	Detail of efficacy of any rate plan confirmed as part of MAADs	1.10.1
17	Identify approved ACM or ICM from a previous IRM application it proposes be incorporated into rate base	1.10.1
18	Distributor rebasing for the first time following a consolidation that was approved under the 2024 MAADs handbook must also provide additional information: **(Distributors that Deferred Rebasing for Five Years or Less):**	1.10.1
18	Achieved efficiencies and savings associated with the various activities where efficiencies were expected (as documented in the consolidation application)	N/A
18	A qualitative discussion on enhanced reliability and service quality as a consolidated distributor	N/A
18	A qualitative discussion on enhanced reliability and service quality on a rate zone basis	N/A
18	Total transaction and transition costs, and whether those have been recovered over the term of the deferred rebasing period through the savings achieved	N/A
18	A discussion on any obstacles encountered since consolidation and how the distributor managed those obstacles. If applicable, a discussion of how obstacles affected the consolidated entity from reaching its targets should also be included	N/A
18	**(Distributors that Deferred Rebasing for More than Five Years):** Updates to information filed as part of mid-term report based on achieved results, including for any period not covered by the initial mid-term report	N/A
18	Regardless of the length of the elected deferred rebasing period, the distributor must provide (on a reasonable efforts basis) an updated version of the revenue requirement analysis provided in the consolidation application based on information known at the time of the filing, and a comparison and discussion of the consolidation application forecasts versus those filed in the post-consolidation rebasing application.	N/A

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Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is
EXHIBIT 2 - RATE BASE AND CAPITAL		
Rate Base		
19	Indication of whether capital expenditures are equivalent to in-service additions, and if so, variance explanations only required once. If not, specify whether variance explanations are on CAPEX or in-service additions basis	2.1.3- all figures are in service additions.
19	For rate base, opening and closing balances for each year, and the average of the opening and closing balances for gross assets and accumulated depreciation (discussion of methodology if applicant uses an alternative method); working capital allowance	2.1.2
19	Table showing components of the last OEB-approved rate base, the proposed test year rate base and the variances	Table 2-3
Fixed Asset Continuity Schedule		
19	Completed Appendix 2-BA for each year - in Excel format	incl. with Chapter 2 Appendix (separate att)
19-20	Continuity statements and year-over-year variance analysis must be provided (year end balance, including capitalized interest during construction and overhead costs). Explanations provided where there is a year-over-year variance greater than the applicable materiality threshold If applicable, explanation for any restatement (e.g. due to change in accounting standards) and reconciliation to original statements Year over year variance analysis; explanation where variance greater than materiality threshold. The following comparisons must be provided: - Hist. OEB-Approved vs Hist. Actual (for the most recent historical OEB-approved year) - Hist. Act. vs. preceding Hist. Act. (for the relevant number of years) - Hist. Act. vs. Bridge - Bridge vs. Test	•Table 2-10 to 2-15 •no restatements confirmed in section 2.1.4 Variance Analysis in Section 2.3
20	Opening and closing balances of gross assets and accumulated depreciation correspond to fixed asset continuity statements. If not, an explanation and reconciliation must be provided (e.g. CWIP, ARO). Reconciliation must be between net book value balances reported on Appendix 2-BA and balances included in rate base calculation	2.1.4
20	Distributor may include in-service balances previously recorded in DVAs, such as renewable generation/smart grid related accounts, in its opening test year property, plant and equipment balances, if these costs have not been previously reviewed and approved for disposition, and if disposition is being requested in this application. In this situation, the distributor must clearly show in its evidence (e.g. Appendix 2-BA) that the addition was included in the opening test year balances and must reconcile the closing bridge year and opening test year figures. Distributors must provide the same reconciliation for accumulated depreciation	N/A-2.1.4
20	Summary of approved and actual costs for any ICM(s) and/ or ACM approved in previous IRM applications	N/A-2.1.4
20	Continuity statements must reconcile to calculated depreciation expenses and presented by asset account	2.1.4
20	All asset disposals clearly identified in the Chapter 2 Appendices for all historical, bridge and test years	2.1.4
Depreciation, Amortization and Depletion		
21	Explanations for any useful lives of an asset that are proposed that are not within the ranges contained in the Kinectrics Report	2.2.2
21	Depreciation, amortization and depletion details by asset group for historical, bridge and test years. Include asset amount and rate of depreciation/amortization. Must complete Appendix 2-C which must agree to accumulated depreciation in Appendix 2-BA under rate base	Appendix 2-C, section 2.2., Tables 2-17 to 2-22
21	Identification of any Asset Retirement Obligations and associated depreciation or accretion expense - includes the basis for and calculation of these amounts	N/A 2.2.1
21	Identification of historical depreciation practice and proposal for test year. Variances from half year rule must be documented and supporting rationale provided	2.2.1
21	Copy of depreciation/amortization policy if available. If not, equivalent written description; summary of changes to depreciation/amortization policy since last CoS	2.2.1
21	If filing under MIFRS, explanation of any deviations from the practice of depreciating significant parts or components of PP&E separately	2.2.1
22	If no changes have been made to depreciation policy or service lives since last rebasing, a statement confirming that this is the case is required. For any depreciation expense policy or asset service lives changes since its last rebasing application: - identification of the changes and detailed explanation for the causes of the changes -use of Kinectrics study or another study to justify changes in useful life - list detailing all asset service lives tied to USoA and reconcile this list to the USoA, detail differences in asset service lives and the TULs from Kinectrics and explain differences outside of minimum and maximum TUL range from Kinectrics; Appendix 2-BB if there have been changes in asset service lives since last rebasing	2.2.2

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Allowance for Working Capital		
22	Working Capital - 7.5% allowance or Lead/Lag Study. If previously ordered by OEB as part of last rate application to file Lead/Lag Study, must comply	2.4
22	If Lead/Lag Study conducted - leads and lags measured in days, dollar-weighted and reflects the distributor's actual billing and settlement processing timelines and considers relevant changes to operating environment	N/A- 2.4.2
23	Cost of Power must be determined by split between RPP and non-RPP Class A and Class B customers based on actual data, use most current RPP (TOU) price. Calculation must include the impact of the most up to date Ontario Electricity Rebate. Distributors must complete Appendix 2-ZA - Commodity Expense and Appendix 2-ZB - Cost of Power	2.4.3
23	Use most recent approved UTRs, Smart Metering Entity Charge and regulatory charges	2.4.3
Distribution System Plan		Attachment 2-A
23	DSP filed as a stand-alone, self-sufficient element within Exhibit 2	
Policy Options for the Funding of Capital		
23	Distributor may propose ACM capital project coming into service during Price Cap IR (a discrete project documented in DSP) - provide information on need and prudence. For projects with an expected capital cost of $2 million or more, excluding general plant investments, includes documentation of the consideration of NWSs to meet the identified system need that will be addressed by the project(s) as articulated in the OEB's Benefit-Cost Analysis Framework for Addressing Electricity System Needs (BCA Framework) to assess the economic feasibility of NWSs	2.5.4
23-24	Identification that distributor is proposing ACM treatment for these future projects and provide the preliminary cost information, and ACM/ICM materiality threshold calculations - ACM Report provides further details on information required	N/A- 2.5.4
24	Complete Capital Module Applicable to ACM and ICM	N/A-2.5.4
Addition of Previously Approved ACM and ICM Project Assets to Rate Base		
24	Distributor with previously approved ACM(s) and/or ICM(s) - schedule of ACM/ICM amounts proposed to be incorporated into rate base (i.e. PP&E and associated depreciation). Comparison of actual capital spending with OEB-approved amount and explanation for variances	N/A-2.5.5
25	Balances in Account 1508 sub-accounts; rate of interest prescribed by the OEB for DVAs for the respective quarterly period as published on the OEB's website	N/A-2.5.5
25	True-up calculation if material, comparing the recalculated revenue requirement based on actual capital spending relating to the OEB-approved ACM/ICM project(s) to the rate rider revenues collected in the same period; assumptions used in the calculation noted (e.g., half-year rule)	N/A-2.5.5
25	Accelerated capital cost allowance (CCA) should not be reflected in the ACM/ICM revenue requirement associated with these projects. Distributors should include the impact of the CCA rule change associated with the ACM/ICM project(s) in Account 1592 - PILs and Tax Variances – CCA Changes sub-account for CCA changes	N/A-2.5.5
Capitalization		
25	Statement confirming accounting standard used in application - MIFRS, USGAAP, ASPE	N/A-2.5.5
26	Capitalization Policy: provide policy including changes since last rebasing application. Confirm if no changes made to capitalization policy since last rebasing application.	N/A-2.5.5
26	Overhead Costs: complete Appendix 2-D	N/A-2.5.5
26	Burden Rates: identification of burden rates, description of how burden rates were derived. If burden rates were changed since last rebasing, identification of the burden rates prior to the change	N/A-2.5.5
Costs of Eligible Investments for the Connection of Qualifying Generation Facilities		
26	See Appendix A	N/A-2.5.3

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Exhibit 1

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Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is
General & Administrative Matters		
Ch5, p2	Use of terminology and formats set out in Ch. 5	Confirmed.
Investment Categories		
Ch5, pp2-4	Investment projects and programs grouped into one of four investment categories (i.e. system access, system renewal, system service, general plant)	5.1.2
Distribution System Plan		
Ch5, p5	If a distributor's application uses alternative section headings and/or arranges the information in a different order, table provided that cross-references the headings/subheadings used in the application to the section headings/subheadings indicated in Ch. 5	N/A
Ch5, p5	DSP duration minimum of 10 years, comprising of a historical and forecast period. The historical period is the first five years of the DSP duration, consisting of five historical years, ending with the bridge year. For distributors that have not filed a DSP within the past five years, the historical period is from the test year of a distributor's last cost or service application to the bridge year. The forecast period is the last five years of the DSP duration, consisting of five forecast years, beginning with the test year of the current cost of service application	5.1.1/5.1.3
Distribution System Plan Overview		
Ch5, p6	High-level overview of information filed in DSP which includes capital investment highlights and changes since last DSP; objectives distributor plans to achieve through DSP, which will be used as a baseline comparison in the performance measurement section below	5.2.1
Coordinated Planning with Third Parties		
Ch5, p6	The distributor must demonstrate that it has coordinated planning with third parties where appropriate. Explanation of whether consultations affected distributor's DSP, and if so, how; for consultations that affected DSP - overview of consultations and relevant material supporting the effects the consultations had on the DSP	5.2.2
Ch5, p6	Overview of consultation should include: purpose, outcome, whether the distributor initiated the consultation or was invited to participate in it, and the other participants in the consultation process	5.2.2
Ch5, p6	Most recent Regional Plan filed. In the absence of a regional plan, a Regional Planning Status Letter from the transmitter filed	DSP Att G
Ch5, p6	Identification of any inconsistencies between DSP and any current Regional Plan. If there are any inconsistencies, explanation of the reasons why, particularly where a proposed investment in their DSP is different from the recommended optimal investment identified in the Regional Plan	5.2.2
Ch5, p7 & OEB Letter, Jan. 11, 2022	Telecommunications Entities: See January 11, 2022 letter for further guidance to the regulation that requires distributors to consult with any telecommunications entity that operates within its service area when preparing a capital plan for submission to the OEB, for the purpose of facilitating the provision of telecommunications services, and include the following information in its capital plan: -number of consultations conducted and a summary of the manner in which the distributor determined with whom to consult; a summary of the results of the consultation; and a statement as to whether the results of the consultations are reflected in the capital plan and, if so, a summary as to how	5.2.2.0
Ch5, p7	REG: -confirmation if there are REG investments in region -if there REG investments proposed in DSP, demonstration of coordination with IESO, other distributors/transmitters (as applicable), and that investments proposed are consistent with Regional Infrastructure Plan - IESO letter in relation to REG investments	5.2.2.1

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Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is
Performance Measurement for Continuous Improvement		5.2.3/5.2.3.0
Ch5, p7	Distribution System Plan: Summary of objectives for continuous improvement set out in last DSP and discussion on whether these objectives achieved. For objectives not achieved, explanation of how this affects current DSP and if applicable, improvements implemented to achieve the objectives in Section 5.2.1	
Ch5, p8	Service Quality and Reliability: - 5 historical years of SQRs; explanations for material changes in service quality and reliability and whether and how DSP addresses these issues - for reliability, any declining 5 year SAIDI/SAIFI trends explained - if reliability targets established in last DSP, any under-performance explained	5.2.3.1
Ch5, p8	Completed Appendix 2-G; confirmation that the data is consistent with scorecard, or explanation of any inconsistencies	5.2.3.1
Ch5, p8	Summary of performance for historical period using methods and measures (metrics/targets) identified and how performance has trended over the period. Summary must include historical period data on: - all interruptions - all interruptions excluding loss of supply - all interruptions excluding major events and loss of supply for: SAIFI, SAIDI	DSP Att. C, Section 5.2.3.1 Tables DSP 7 to 13
Ch5, p8	Summary of major events that occurred since last cost of service	MED- section 5.2.3.1
Ch5, pp8-9	For each cause of interruption for last five historical years: number of interruptions that occurred as a result of the cause of interruption, number of customer interruptions that occurred as a result of interruption, number of customer-hours of interruptions that occurred as a result of the cause of interruption	Please see reliability report (Att C) Tables 11-13
Ch5, p9	Distributor-Specific Reliability Targets: - Reliability performance targets calculated based on: (1) baseline for SAIDI and SAFI based on five-year average performance, (2) an adjustment factor based on performance trend, and (3) an adjustment reflecting benchmarking results - if establishing performance expectations based on something other than the default target, evidence provided of capital and operational plan and other factors that justify the reliability performance the distributors plan to deliver - summary of any feedback from customers regarding reliability on distributors' system	5.2.3.2
Planning Process		5.3.1. Flowchart in Table DSP-38
Ch5, p9	Overview of planning process that has informed five-year capital expenditure plan; flowchart accompanied by explanatory text **may** be helpful	
Ch5, p10	Summary of important changes in distributor's AM process since last DSP	5.3.1
Ch5, p10	Process: - provide processes used to identify, select, prioritize (including reprioritization over 5 year term), optimize, and pace execution of investments - demonstration that distributor has considered correlation between plan and customer's feedback and needs - demonstration that distributor has considered potential risks of proceeding/not proceeding with individual capital expenditures - demonstrate how it undertake grid optimization using an approach that considers the distributor's whole system - consideration, where applicable, of assessing the use of distribution rate-funded NWSs, cost-effective implementation of distribution improvements affecting reliability, and meeting customer needs as acceptable costs to customers, and other innovative technologies - demonstration that distributor has a planning process for future capacity needs, which must include, among other aspects, increased adoption of electric vehicles	5.3.1.0
Ch5, p11	On a best-efforts basis, the distributor should: - describe how its planning processes have been impacted by its multiple demand load forecasts including qualitative and quantitative risk and uncertainty assessments, as appropriate, for each demand load forecast - incorporate cost projections for future investments that reflect reasonable assumptions for cost trends - consider frequent and extreme weather impacts on energy infrastructure resilience and ensure future average, minimum and maximum temperatures are considered (this can be considered in the load forecast described in Chapter 2 Filing Requirements Section 2.3.1.3) - where a system investment, policy, or program is intended to facilitate fuel switching: consider costs and benefits across impacted energy systems	5.3.1.0
Ch5, p11	Data - identification, description and summary of data used in processes above to identify, select, prioritize, optimize and pace investments over DSP	5.3.1.1

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Overview of Assets Managed		5.3.2
Ch5, p12	Overview of service area (e.g. system configuration, urban/rural etc.) to support capital expenditures over forecast period; asset information (e.g. capacity, utilization, condition, failures/performance, asset risks, demographics) by major asset type that may help explain the specific need for the capital expenditure and demonstration of consideration of economic alternatives	
Ch5, p12	Statement as to whether distributor has had any transmission or high voltage assets deemed previously by the OEB as distribution assets, and whether there are any such assets that the distributor is asking the OEB to deem as distribution assets in the current application	5.3.2
Ch5, p12	Description of whether distributor is a host and/or embedded distributor; identification of any embedded and/or host distributors; partially embedded status identified (including % of total load supplied through host); if host distributor, identification of whether there is a separate embedded class or if any embedded distributors are included in other classes	5.3.2
Asset Lifestyle Optimization Policies and Practices		5.3.3
Ch5, p13	Demonstration that distributor has carried out cost-effective system O&M activities to sustain as asset to the end of its service life (and can include references to the Distribution System Code)	
Ch5, p13	Explanation of processes and tools used to forecast, prioritize and optimize system renewal spending and how distributor intends to operate within budget envelopes	5.3.3
Ch5, p13	Demonstration of consideration of potential risks of proceeding/not proceeding with individual capital expenditures	5.3.3
Ch5, p13	Demonstration that the distributor has considered the future capacity requirements of the asset such that it does not need to be replaced prematurely due to capacity constraints	5.3.3
Ch5, p13	Summary of important changes to the distributor's asset life optimization policies, processes, and tools since last DSP	5.3.3
System Capability Assessment for REG and DER		5.3.4- N/A
Ch5, p13	Provide list of restricted feeders by name, the feeder designation, the reason for the restriction, number of connected customers, and explain if there are plans to improve the distribution system's ability to connect distributed energy resources	
Ch5, p13	If a distributor has incurred or expects to incur costs to accommodate and connect renewable generation facilities that will be the responsibility of the distributor under the DSC, refer to Appendix A of Chapter 5 Filing Requirements	5.3.4-N/A
Ch5, pp13-14	Where a distributor plans to improve the distribution system's ability to connect additional distributed energy resources in areas with restricted hosting capacity: include an assessment of potential solutions, including infrastructure-based and non-infrastructure-based options	5.3.4
Non-Wires Solutions to Address System Needs		5.3.5
Ch5, p14	Description of how distributor has taken NWSs into consideration in its planning process	
Ch5, p14	Explanation of proposed activity in the context of the DSP, including providing details on the system need that is being addressed, infrastructure investments that are being avoided or deferred as a result of NWS, and the prioritization of proposed NWS activity relative to other system investments in the DSP	DSP Att J
Ch5, pp14-15	Evidence why the proposed NWS is the preferred approach (alone or in combination with an infrastructure solution) to meeting a system need, including an assessment of the projected benefits to customers relative to cost impacts, following the requirements of the BCA Framework	N/A DSP Att J, Material Investment Forms (DSP Att B , projects 10 and 11)
Ch5, p15	Demonstration that distributor has meaningfully explored contracting services from non-utility owned distributed energy resources for any rate funded, distributor-owned NWS proposal	N/A- no NWS proposed after applying DST

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Climate Vulnerability Assessment and System Hardening		5.3.6
These requirements apply on a best-efforts basis for 2027 rate applications		
Ch5, p15	- Perform Vulnerability Assessment using either the Generic Option or Custom Option - Vulnerability Assessment supported by documented input data sources, rationale for asset and climate peril selection, and justification for any deviations from standard approaches	
Ch5, p15	Generic Vulnerability Assessment Option: - file completed version of the Vulnerability Assessment Toolkit - include discussion of vulnerability assessment results in DSP	5.3.6
Ch5, p15	Custom Vulnerability Assessment Option: - ensure that the vulnerability assessment methodology meets criteria outlined in VASH policy - file custom vulnerability assessment study including detailed calculations - include discussion of vulnerability assessment results in DSP	5.3.6
Ch5, p16	- After Vulnerability Assessment: perform pre-assessment to determine whether technically and economically feasible system hardening investment exist - Document and explain pre-assessment approach	5.3.6
Ch5, pp16-17	If pre-assessment identifies economically plausible system harding investments: conduct benefit-cost analysis for VASH for those investments - Generic Option: file Benefit-Cost Analysis Toolkit within VASH toolkit - Custom Option: ensure Benefit-Cost Analysis methodology meets VASH policy	5.3.6
Capital Expenditure Summary		5.4, DSP table 40
Ch5, p17	Provide capital expenditure plan that sets out proposed expenditures on distribution system and general plant over a five-year planning period, including investment and asset-related operating and maintenance expenditures	
Ch5, p17	Provide a snapshot of a distributor's capital expenditures over a 10-year period, including five historical years and five forecast years	DSP table 40
Ch5, p17	The entire cost of individual projects or programs allocated to one of the four investment categories based on the primary driver of the investment	Confirmed
Ch5, p17	Completed Appendices 2-AA and 2-AB	DSP Table 40, table 2-AA excerpts throughout section 5.4
Ch5, p17	Analysis of distributor's capital expenditure performance for the DSPs historical period - should include explanation of variances by investment or category, including actuals v. OEB-approved/planned amounts for the applicant's last OEB-approved CoS or Custom IR application and DSP - explanation of variances between planned and actual volume of work completed and explanation of variances in a given year that are much higher or lower than the historical trend	5.4.1
Ch5, p18	Analysis of distributor's capital expenditure performance for the DSPs forecast period; for investments that have a lifecycle >1yr, the proposed accounting treatment, including the treatment of the cost of funds for CWIP	5.4.1
Ch5, p18	Analysis of capital expenditures in DSP forecast period v. historical	5.4.1
Ch5, p18	Summary of any important modifications to typical capital programs since the last DSP	5.4.1
Ch5, p18	Description of the impacts of capital expenditures on O&M for each year or statement that the capital plans did not impact O&M costs	5.4.1
Ch5, p18	Statement that there are no expenditures for non-distribution activities in the applicant's budget	5.4.1
Justifying Capital Expenditures		5.4.2.0
Ch5, pp18-19	Context on how overall capital expenditures over 5 years will achieve distributor's objectives; comment on lumpy investment years and rate impacts of capital investments in long term	

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Material Investments		DSP Att B
For each project that meets materiality threshold set in Ch 2A or deemed by applicant to be distinct for any other reason, guidelines are:		
Ch5, p19	General information on the project or program - Need, scope, volume of work expected to be completed, key project timings (incl. key factors that affect timing), total expenditures (inc. contributions and economic evaluation as per DSC, as applicable), comparative historical expenditures, priority, alternatives considered, benefit-cost analysis results of recommended alternative, description of the innovative nature of investment if applicable. -Where an investment within the five year forecast period involves a Leave to Construct approval, provide summary of the evidence (as available), for that investment consistent with Chapter 4 of the Filing Requirements for Electricity Transmission Applications	
Ch5, pp19-20	Evaluation criteria and information requirements for each project/program - Demonstration of need, and may include the need to address safety, cyber security, grid innovation, environmental, statutory/regulatory obligations - Where investment substantially exceeds materiality - business case justifying expenditure, alternatives (including NWSs,if applicable), benefits for customers, impact on distributor costs - If a distributor is requesting funding for an NWS, additional guidance on evidentiary requirements is provided in the NWS Guidelines - Where distributor assets that a project will support economic growth: provide evidence supporting assertion and indication of economic growth policies of the government of Ontario that are relevant to the project	DSP Att B
Ch5, p20	Explanation of how innovative project is expected to benefit customers, such as improved reliability, enhanced customer services, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate	DSP Att B
Benefit-Cost Analysis Framework		Section 5.3.5, Projects 10 and 11 in DSP Att B, DSP Att J.
Ch5, p21	The BCA Framework is mandatory when the projected capital cost of the proposed solution to an electricity system need (either NWS or traditional infrastructure) exceeds $2 million (excluding general plant investments)	
Ch5, p21	Conduct pre-assessment to identify whether there is a reasonable expectation that an NWS may be a viable approach to meeting an identified need. Should the pre-assessment conclude that an NWS is a viable approach, a distributor should proceed with completing a BCA. The BCA should be filed along with the pre-assessment results	
Ch5, p21	BCAs are to be prepared for each specific system need	
Ch5, p22	Distribution Service Test (DST) A distributor looking to file a BCA **must** employ the mandatory distribution service BCA and consider the mandatory quantitative/qualitative impacts to benefit/costs as outlined in the BCA Framework, and **must** include the Excel-based quantitative output template, BCA Data Filing Submission Template. The BCA **may** include the permitted DST qualitative impacts as applicable.	
Ch5, p23	Energy System Test (EST) Distributors **are encouraged** to do an optional EST particularly if they believe an NWS offers significant benefits beyond those of distribution service. When an EST is conducted, the mandatory EST quantitative/qualitative impacts should be included, including the DST impacts as outlined in the BCA Framework.	5.3.5-N/A
Appendix A (if applicable)		5.3.4-NA
Ch5, Appendix A	Information on the capability of distribution system to accommodate REG investments, including a summary of the distributor's load and renewable energy generation connection forecast by feeder/substation (where applicable); information identifying specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected renewable generation capacity	
Ch5, Appendix A	In relation to renewable or other distributed energy generation connections, the information that must be considered by a distributor and documented in an application (where applicable), includes: applications from renewable generators > 10 kW, number and MW of REG connections for forecast period, information from IESO and any other information about the potential for renewable generation in distributor's service area, capacity of Dx to connect REG, connection constraints	5.3.4-NA

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EXHIBIT 3 - CUSTOMER AND LOAD FORECAST		
Load Forecasts		
26	Weather normal load forecast provided	Confirmed
26	Table outlining any factors that influence the load forecast in distributor's service territory (e.g. demographics, customer composition etc.)	Table 3-2
26-27	Explanation of the causes, assumptions and adjustments for the volume forecast, including all economic assumptions and data sources used (e.g. housing outlook & forecasts, other variables used in forecasting volumes)	3.1
27	Explanation of weather normalization methodology	3.1.1
27	Completed Appendix 2-IB; the customer and load forecast for the test year entered on RRWF, Tab 10	Table 3-12, Table 3-32
Multivariate Regression Model		
27-28	- rationale to support change if the proposed model's methodology differs from the methodology used in the most recent load forecast; discussion of modelling approaches considered and alternative models tested - statistics should include, but not limited to, the regression equations coefficients and intercepts (e.g. t-stats, model statistics including R2, adjusted R2, F-stat, root-mean-squared-error and Durbin-Watson statistic), including explanation for any resulting non-intuitive relationships - explanation of weather normalization methodology (including if monthly HDD and/or CDD are used they are based on either: 10 year avg. or proposed alternative approach with supporting evidence - definitions of HDD and CDD including: climatological measurement points and why appropriate as well as identification of base degrees - sources of data for endogenous and exogenous variables. Where a variable has been constructed, explanation of the variable data used and source. Where a distributor has constructed the demand variable to model billed consumption on a class-specific basis, a full explanation of the approach used to pro-rate or interpolate non-interval data (i.e. if billing data are not based on calendar monthly readings as obtained from interval or smart meters) must be provided, including an explanation of why the constructed demand series is suitable for modelling - any binary variables used must be explained and justified - the use of binary variables should be limited and overlap with other variables should be avoided - explanation of any specific adjustments made (e.g. to adjust for loss or gain of major customers or load, significant re-classifications of customers, etc.). Note locally purchased generation should be included in the total for purchased power - description of how CDM and NWS impacts and other exogenous factors have been accounted for in the historical period, and how CDM and NWS impacts, including any targets or forecasts in the bridge and test years, are factored into the test year load forecast - data and regression model and statistics used in customer and load forecast in Excel format	3.1.1, Attachment 3-A
NAC Model		
28-29	- rationale to support NAC methodology if the model use differs from the method used in the most recent load forecast - data supporting calculation of NAC values for each rate class - description of how CDM and NWS impacts and other exogenous factors have been accounted for in historical period and how CDM and NWS impacts, including any targets or forecasts in the bridge and test years, are factored into test year forecast - discussion of weather normalization assumptions used	Not applicable- 3.1.3
Integrated Energy Plan		
29	On a best efforts basis, the load forecast should: - incorporate multiple demand scenarios (includes a reference, high, and low scenario) that takes into consideration the electrification of transportation, industry and any other areas that have electrification impacts. The high and low usage scenarios must include appropriate and substantiated assumptions. A distributor may use modelling done by others to assess multiple demand scenarios. - incorporate economic growth projections, including employment, population and housing - consider future average weather impacts and include average, minimum (HDD) and maximum (CDD) temperatures	3.1.4
Incorporating CDM and NWS Impacts in the Load Forecast for Distributors		
29	Refer to NWS Guidelines for guidance, including supporting evidence required regarding incorporating historical and forecast impact of CDM and NWS activities in load forecast	3.1.5

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Accuracy of Load Forecast and Variance Analyses		
30	Completed Appendix 2-IB (2-IA provides further instructions for filling out 2-IB)	Table 3-12, Attachment 3-A
30	For customer/connection counts: -identification as to whether customer/connection count is shown in year end or average format -year-over-year variances in changes of customer/connection counts with explanation for changes in the definition of, or major changes made in the composition of each customer class -explanations of bridge and test year forecasts by rate class -for last rebasing, variance analysis between last OEB-approved and actuals with explanations for material differences	3.2.2
30	For consumption and demand: -explanation and details to support how kWh are converted to kW for applicable demand-billed classes -year-over-year variances in consumption (kWh) and demand (kW or kVA - the latter for demand billed rate classes) by rate class and for system consumption overall (kWh) with explanations for material changes in the definition of or major changes over time (comparison done for both historical actuals against each other and historical weather-normalized actuals over time) -explanations of the bridge and test year forecasts by rate class (and how these vary from or are trending from both historical actuals and from weather-normalized actuals) -for last rebasing variance analysis between the last OEB-approved and the actual results with explanations for material differences	3.2.3
30	All data and equations used to determine customers/connections, demand and load forecasts provided in Excel format	Attachment 3-A

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EXHIBIT 4 - OPERATING EXPENSES		
Overview		
31	Brief explanation (quantitative and qualitative) of: - test year OM&A levels - how the distributor develops and receives approval of their OM&A budget - cost drivers and significant changes relative to historical and bridge years - trends in costs and relevant metrics including OM&A per customer (and its components) for the historical, bridge and test years - inflation rate assumed (if proposing different rate than IPI - provide explanation supporting proposal) - business environment changes	4.1
OM&A Summary and Cost Driver Tables		
	Inclusion of the following tables in evidence and all OM&A appendices filed:	Table 4-2
31	Summary of recoverable OM&A expenses; Appendix 2-JA	
31	Recoverable OM&A cost drivers; Appendix 2-JB	Table 4-5
31	OM&A programs table - Appendix 2-JC **or** OM&A by USoA Table - Appendix 2-JD	Table 4-9
31	Recoverable OM&A Cost per customer and per FTE; Appendix 2-L	Table 4-7
31	Distributors with 30k or more customers: present OM&A by program; Appendix 2-JC filed to provide OM&A details and variance analysis on a program basis. For each program, provide a definition of the USoA accounts included	Table 4-9
32	Only distributors with less than 30k customers: option to file OM&A by program or USoA. If USoA chosen, 2-JD filed instead of 2-JC	N/A
32	For all distributors, the table provided (2-JC or 2-JD) must reflect the entire OM&A amount proposed to be recovered through rates. Information provided for bridge and test years.	Confirmed
32	Appendix 2-JB populated to provide information on the cost drivers of OM&A expenses; 2-JA broken down into major categories; 2-L populated	Confirmed
32	Identification of change in OM&A in test year in relation to change in capitalized overhead	Table 4-7
OM&A Variance Analysis		
32	Re: 2-JC or 2-JD - variance analysis between: - Test Year vs Historical OEB approved - Historical OEB-Approved vs Historical Actuals (for the most recent historical OEB-approved year) - Test Year vs most recent Historical Actuals	4.3.2
32	If OM&A expense detailed on USoA basis, variance analysis and explanation broken down by the five major OM&A categories as per 2-JA	4.3
32	For all distributors, the variance analysis includes explanation of whether the change was within the distributor's control or not - distributors encouraged to provide explanations for costs above the threshold which have impacted historical trend	Section 4.2/4.3

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Workforce Planning and Employee Compensation		
32	Completed Appendix 2-K; information on labour and compensation includes total amount, whether expensed or capitalized	4.4
32-33	If there are three or fewer employees in any category, aggregate with the category to which it is most closely related. This higher level of aggregation must be continued, if required, to ensure that no category contains three or fewer employees.	Confirmed
33	Description of proposed workforce plans, including compensation strategy and any changes from previous plan	4.4.1/4.4.3
33	Discussion of the outcomes of previous plans and how those outcomes have impacted their proposed plans including an explanation of the reasons for all material changes to FTEs and compensation. Explanation for all years includes: - variances with an explanation of contributing factors, inflation rates used for forecasts, and the plan for any new employees - basis for performance pay, eligible employee groups, goals, measures, and review process for pay-for-performance plans - relevant studies (e.g. compensation benchmarking)	4.4.1 Attachment 4-A
33	Details of employee benefit programs including pensions, OPEBs, and other costs charged to OM&A. A breakdown of the pension and OPEBs amounts included in OM&A and capital provided for the last OEB-approved rebasing application, and for historical, bridge and test years	4.4.3
33	Most recent actuarial report and be reconciled with pension and OPEBs amounts (as applicable)	Attachment 4-B
33	Explanation of the basis of which pension and OPEBs amounts are forecast for the bridge and test years; what is documented in the tax section agrees with analysis	4.4.3
33	For virtual distributors - Appendix K completed in relation to the employees of the affiliates who are doing the work of the regulated distributor. Provide the status of pension funding and all assumptions used in the analysis	N/A- not a virtual distributor.
33-34	Indication if pension and OPEBs to be recovered using cash or accrual method. If cash method, sufficient supporting rationale and evidence for cash method. If proposing to change the basis in which pension and OPEB costs are included in OM&A from last rebasing, quantification of impact of transition provided	4.4.3
Shared Services and Corporate Cost Allocation		
34	Identification of all shared services among affiliates, including the extent to which the applicant is a "virtual utility" and justification of proposed shared services and cost allocation	4.5.1
34	For shared services among affiliated entities: type of service provided or received, pricing methodology	4.5.1
34	Allocation methodology for corporate services, list of shared services, list of costs and allocators and how the allocator was derived, any third party review of cost allocation methodology	4.5.1
34	Completed Appendix 2-N for service provided or received for historical actuals, bridge and test; including reconciliation with revenue included in Other Revenue	4.5.1 reconciliation to other revenue notapplicable (explained in 4.5.1)
34	Shared Service and Corporate Cost Variance analysis - test year vs last OEB approved and test year vs most recent actual	4.5.1
35	Identification of any Board of Director costs for affiliates included in LDC costs	4.5.1
Purchase of Non-Affiliate Services		4.6.1/ Attachment 4-D
35	Copy of procurement policy (including information on signing authority, tendering process, non-affiliate service purchase compliance)	
35	For material transactions not in compliance with procurement policy, or that were undertaken pursuant to exceptions contemplated within the policy, an explanation as to why as well as a summary of the nature and cost of the product, and a description of the specific methodology used for selecting the vendor	4.6.1
Regulatory One-Time Costs		4.7
35	Information supporting the incremental costs associated with the preparation and review of the current application	
35	Identification of one-time costs in historical, bridge, test years. Explanation provided if distributor is not proposing to recover one-time costs over the test year and subsequent IRM term)	4.7
35	Completed Appendix 2-M	4.7
35	Ongoing regulatory costs included in the administration costs of OM&A expense and any material change reported in Appendix 2-JB OM&A Cost Drivers.	Confirmed

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LEAP, Charitable and Political Donations		
36	LEAP - the greater of 0.12% of forecasted service revenue requirement or $2,000 included in OM&A and recovered from all rate classes. If proposing LEAP funding higher than 0.12%, details of demographics provided	4.8.1
36	For any charitable contributions claimed for recovery, detailed information provided	4.8.1
36	Confirmation that no political contributions have been included for recovery	4.8.2
Cost of Non-Wires Solution and Conservation and Demand Management		
37	Statement confirming that no costs for supporting IESO programs funded under the eDSM Framework are included in revenue requirement	4.9.1
37	Distributor should generally not include any forecast costs associated with partnership in the IESO's Local Initiative Program (LIP) within its revenue requirement; distributor can seek to recover partnership costs at a future date through the LIP deferral account. If distributor plans to partner with the IESO for the LIP at the time of its cost of service application, description of proposed approach to partnership, including a forecast of LIP costs	4.9.1
Funding Options for Non-Wires Solutions		
37-38	If NWSs included in COS where NWSs expected to come into service during Price Cap IR term, identification of if costs of such NWSs included in the revenue requirement, or if the distributor intends to propose treatment similar to an ACM for these future NWSs	4.9.2
38	If the latter as noted above, supporting rationale provided (e.g., the preliminary cost information and ACM/ICM materiality threshold calculations to show that a similar capital project would qualify for ACM treatment based on the forecasted information at the time of the DSP and cost of service application)	4.9.2

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EXHIBIT 5 - COST OF CAPITAL AND CAPITAL STRUCTURE		
38	Use of most recent parameters issued by the OEB, subject to update if new parameters available prior to OEB decision	5.1
38	If applying for distributor specific cost of capital parameters and equity ratios, supporting evidence and justification provided. This evidence must provide strong rationale for departing from the OEB's policy and why the Fair Return Standard cannot be met	5.1
Capital Structure		
39	Completed Appendix 2-OA for last OEB approved and test years	Table 5-5
39	Completed Appendix 2-OB for historical, bridge and test years with respect to long-term debt, short-term debt, preference shares, and common equity	Table 5-6
39	Explanation for any material changes in actual capital structure or material differences between actual and deemed capital structure including: retirement of debt or preference shares and buy-back of common shares; short-term debt, long-term debt, preference shares and common share offerings	5.1,5.3
Cost of Capital (Return on Equity and Cost of Debt)		
The following provided for each year:		
39	For affiliated debt held by the holding company, other affiliated company or related party debt of the utility, an explanation of how the debt rate is no higher than it would have been if funds were borrowed directly by the utility through the external markets	5.1.2
39	Evidence explaining how distributor manages their long-term debt, including actual debt and the forecast of future debt	5.1.2
39	For utilities incurring transactions/issuance costs to secure financing from the market - transaction/issuance costs incorporated into the debt interest rate used to set rates (so that the transaction costs are amortized over the term of the debt instrument using the effective interest rate methodology)	5.1.2
40	Calculation of cost for each capital component	Table 5-1
40	Profit or loss on redemption of debt, if applicable	N/A
40	Copies of current promissory notes or other debt arrangements with affiliates	Attachment 5-A
40	Explanation of debt rate for each existing debt instrument including an explanation on how the debt rate was determined and is in compliance with the policies documented in the Cost of Capital Decision or applicant's proposed approach (including the justification and key assumptions)	5.1.2
40	Forecast of new debt in bridge and test year - details including estimate of rate and other pertinent information (e.g. affiliated debt or third party)	5.1.2
40	Historical return on equity achieved	Table 5-3
40	If applicable (only when there are material variances relating to notional debt with material impacts on revenue requirement) - the rate for notional debt is at the lower of the deemed long-term debt rate at the time of issuance and the weighted average cost of actual long-term debt	N/A- 5.1.1
Not-for-Profit Corporations		
40	Requested capital structure and cost of capital (including the proposed cost of long-term and short-term debt and proposed return on equity)	N/A- section 5.3
40	Statement as to whether the revenues derived from the return on equity component of the cost of capital is to be used to fund reserves or will be used for other purposes	N/A- section 5.3
41	If the revenues derived from the return on equity component will be used to fund reserves, specifications for each proposed reserve fund and a description of the governance (policies, procedures, sign-off authority, etc.) that will be applied	
41	If the revenues derived from the return on equity component will be used for other purposes, statement as to whether these revenues will be used for non-distribution activities (in the situation where the excess revenues are greater than the amounts needed to fund distribution activities); rationale provided supporting the use of the revenues in this manner. Also, governance (policies, procedures, sign-off authority, etc.) that will be applied to the funding of non-distribution activities provided	N/A- section 5.3
41	If there are approved reserves from previous OEB decisions provide the following: -the limits of any capital and/or operating reserves as approved by the OEB, and identifying the decisions establishing these reserve accounts and their limits -the current balances of any established capital and/or operating reserves	

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EXHIBIT 6 - REVENUE REQUIREMENT AND REVENUE DEFICIENCY OR SUFFICIENCY		
41	The following information must be provided in this exhibit (with cross references to where in the application further details can be found for each) excluding energy costs and revenues and unregulated costs and revenues: -determination of net income, statement of rate base, actual return on rate base, indicated rate of return, requested rate of return, deficiency or sufficiency in revenue, gross deficiency or sufficiency in revenue	6.2.1, 6.2.3, 6.2.4, 6.2.5, 6.3.
41-42	Revenue deficiency or sufficiency calculations net of electricity price differentials captured in the Retail Settlement Variance Accounts (RSVAs) and also net of any cost associated with low voltage (LV) charges or DVA balances of distribution expenditures/revenues being tracked through approved deferral and variance accounts for certain distribution assets (e.g. ICM and ACM capital projects) and for which disposition is not being sought in the application.	6.3.1
42	Summary of drivers for test year deficiency/sufficiency, how much each driver contributes; references in application evidence mapped to drivers	6.3.2, Table 6-7
42	Impacts of any changes in methodologies on deficiency/sufficiency and on individual cost drivers contributing to it	6.3.3
Revenue Requirement Work Form		
42	Completed RRWF. Revenue requirement, def/sufficiency, data entered in RRWF must correspond with other exhibits	Attachment 6-A
42	If the enhanced RRWF cannot reflect a distributor's proposed rates accurately, the distributor must file its rate generator model	N/A.
43	For revenues - calculation of bridge year forecast of revenues at existing rates; calculation of test year forecasted revenues at each of existing rates and proposed rates	Table 6-6
Income Tax or PILs		
43	Detailed calculations of income tax or PILS. Must include a completed Excel version of the PILs model available on the OEB's website, including derivation of adjustments for historical, bridge and test years. Regulatory assets and liabilities must excluded from PILs calculations when they were created and when they were disposed, regardless of the actual tax treatment accorded those amounts	6.4.1, Attachment 6-B
43	Supporting schedules and calculations identifying reconciling items	6.4.1, Attachment 6-B
43	Most recent federal and provincial tax returns	6.4.1, Attachment 6-C
43	Financial Statements included with tax returns if different from those filed with application	N/A
43-44	Calculation of tax credits; redact where required (filing of unredacted versions is not required)	N/A Section 6.4.1
44	Supporting schedules, calculations and explanations for other additions and deductions	N/A Section 6.4.1
44	Completion of the integrity checks in the PILs Model	Section 6.4.2
44	Accelerated CCA - confirm whether Accelerated Investment Incentive Program (AIIP) was applied to eligible capital additions in tax filings. If distributor committed to applying (or not applying) AIIP through the previous IRM term, it is expected to maintain that approach unless the OEB has approved otherwise - Confirm whether a smoothing mechanism was applied to the PILs expense and approved in the last cost of service decision and order. If yes, the use of Account 1592 to record the specific CCA changes during the rate term contemplated in the smoothing proposal is no longer applicable - full revenue requirement impact recorded in Account 1592 and the balance sought for review and disposition, detailed calculations by year for the full revenue requirement impact recorded in Account 1592 in Excel format	6.4.2
44-45	If applying accelerated CCA to the PILs in the test year, proposal for a smoothing mechanism to reduce the test year's PILs expense	6.4.2
Other Taxes		
45	Account 6105 is not an OM&A account and should be excluded from all OM&A totals. Applicant should provide an explanation of how these tax amounts are derived	6.5

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Non-recoverable and Disallowed Expenses		
45	Exclude from regulatory tax calculation any non-recoverable or disallowed expenses	6.6
Other Revenue		
45-46	Completed Appendix 2-H, including the breakdown of each account showing the components of each	6.7.1, table 6-16
45-46	For each other distribution revenue account: -comparison of actual revenues for historical years to forecast revenue for bridge and test year, including explanations for significant variances year-over-year -revenue from any new proposed specific service charges, changes to rates, or new rules for applying existing specific service charges (incl. any credits to customers) -revenue from affiliate transactions, shared services, or corporate cost allocation. For each affiliate transaction identification of service, the nature of service provided, accounts used to record revenue, and costs to provide service -revenue from affiliate transactions recorded in Account 4375 -expenses from affiliate transactions recorded in Account 4380	6.7.2
46	Balances recorded in Account 4375 and Account 4380 reconcile to the balances recorded in Appendix 2-N – Shared Services and Corporate Allocation for the three historical years, the bridge year and the test year. Any differences must be reconciled	6.7.4
46	Revenue related to microFIT recorded as revenue offset in Account 4235	6.7.1
46	Transfer pricing and allocation of cost methods do not result in cross-subsidization between regulated and non-regulated lines of business and compliance with article 340 of APH; explanations for any deviations	6.7.4
46	Identification of any discrete customer groups that may be materially impacted by changes to other rates and charges	6.7.3
47	Revenues or costs (including interest) associated with deferral and variance accounts not included in other revenues	6.7.1

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EXHIBIT 7 - COST ALLOCATION		
Cost Allocation Study Requirements		
47	Completed cost allocation study using the OEB-approved methodology or the distributor's study and model reflecting forecasted test year loads and costs and supported by appropriate explanations and live Excel spreadsheets; sheets 11 and 13 of the RRWF complete	7.1.1
47	Description of weighting factors, rationale for use of default values (if applicable)	7.1.1, 7.1.4
47	If distributor is choosing to use the same weightings as its previous rebasing application (on the condition that these were accepted by the OEB and there have been no significant changes in the distributor's policies or practices that would impact the weightings), a reference to the previous application provided	7.1.4
48	Complete live Excel cost allocation model, whether using the OEB-issued one or a different model. If using the OEB-issued model, Input sheet I.2, cells c15 and c17 must be used to identify the final run of the model on each sheet. If using another model, the distributor must file equivalent information	Attachment 7-B
Load Profiles and Demand Allocators		
48	Updated load profiles for all classes and update demand allocators	7.1.3
48	Discussion of how load profiles have been normalized for weather and any notable events impacting usage patterns	7.1.3
48	If multivariate regression model is used, the following must be provided: -statistics and statistical tests related to regression equation(s) coefficients and intercept, results of tests for autocorrelation and multicollinearity -explanation of the weather-normalization methodology including: relationship between demand and Heating and/or Cooling requirements, determination of normal weather: the hourly for daily Heating and/or Cooling required -sources of data used for both endogenous and exogenous variables. Where a variable has been constructed, explanation of the variable, data used and the source of the data provided -explanation of any specific adjustments made (e.g. to address gaps in historical meter data)	7.1.3-N/A
48	Data and regression model and statistics used in the weather normalization of load profiles provided in Excel format (includes showing the derivation of any constructed variables)	7.1.3-N/A
49	Spreadsheet and a description with calculations to show how demand allocators are derived from the historical weather normal or weather actual load profiles	7.1.3, Attachment 7-C
49	Historical Average: Where the annual demand allocators are based on weather actual load profiles, at least three, and ideally five years of historical data should be used to perform weather normalization. Where the annual demand allocators are based on weather normalized load profiles, fewer years may be used	7.1.3
49-50	Host Distributor only - evidence of consultation with embedded Dx prior to rate filing - statement regarding embedded Dx support for approach to allocation of costs - if embedded Dx is separate class - class in cost allocation study and RRWF - if new embedded Dx class - rationale and supporting evidence (cost of serving, load served, asset ownership information, distribution charges levied); include in cost allocation study and RRWF - if embedded Dx billed as GS customer - include with the GS class in cost allocation model and the RRWF. Provide cost of serving, load served, asset ownership information, distribution charges levied, appropriateness of rates for the GS class recovering costs of providing low voltage dx services to embedded distributor(s). Completed Appendix 2-Q - Cost of Serving Embedded Distributors	7.1.5
50	microFIT - if the applicant believes that it has unique circumstances which would justify a different rate than the generic rate, documentation to support rate must be provided	7.1.5 N/A
50	Standby Rates - distributors with interim standby rates to request approval for final standby rates and provide evidence confirming that they have advised all affected customers of the proposal	7.1.5
51	Standby Rates - distributor that seeks to establish new standby rates or changes to standby charges, including a change in the methodology on which these rates are based, must provide full documentation supporting its proposal, and confirm that all affected customers have been notified of the proposed change(s)	7.1.5
51	If new customer class or changing definition of existing classes, rationale and restatement of revenue requirement from previous cost of service	7.1.5
51	If eliminating or combining customer classes, rationale and restatement of revenue requirement from previous cost of service, where possible	7.1.5

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Class Revenue Requirements		
51-52	To support a proposal to rebalance rates, information on the revenue by class that would apply if all rates were changed by a uniform percentage provided. Ratios compared with the ratios that will result from the rates being proposed by the distributor	7.2.1, Table 7-6
Revenue to Cost Ratios		
52	If R:C ratios outside dead band - cost allocation proposal to bring them within the OEB-approved ranges provided. In making any such adjustments, potential mitigation measures addressed if the impact of the adjustments on the rates of any particular class or classes is significant	7.3.2
53	If distributor proposes to continue rebalancing rates after the cost of service test year, the ratios proposed for subsequent year(s) must be provided	7.3.2
53	If Cost Allocation Model other than OEB model used - exclude LV and exclude DVA balances and that revenues exclude rate riders, rate adders and the Smart Metering Entity Charge. Distributor must also ensure that information relevant to customer charge unit costs, microFIT unit costs and revenue is consistent with the output from the OEB's model	N/A
EXHIBIT 8 - RATE DESIGN		
53	Monthly fixed charges - 2 decimal places; variable charges - 4 decimal places; if departing from this approach, explanation provided as to why necessary and appropriate	8.1.2
Fixed Variable Proportion		
53	The following is to be provided in relation to the fixed/variable proportion of proposed rates: -Current F/V for each rate class with supporting info -Proposed F/V for each rate class with explanation for any changes from current proportions -Table comparing current and proposed monthly fixed charges with the floor and ceiling as in cost allocation study Analysis must be net of rate adders, funding adders, and rate riders	8.1.2; Tables in 8.1.2 inc. 8-8
RTSRs		
54	Completed RTSR Model in Excel	Att. 8-C
54	Identification of the quantity of load (energy and demand) used by EV charging facilities. EV charging volume only counted in the rows pertaining to EV charging and not be included in the volume for the remainder of the applicable rate class	8.2.1
54	If proposing to update RTSRs to reflect updated cost causation data: provide additional tables beyond RTSR model	N/A, 8.2.1
54	RTSR information consistent with working capital allowance calculation; explanation for any differences	8.2.1, no diff.
Retail Service Charges		
55	Use of current approved generic retail service rates and charges per most recent rate order	8.2.2
Regulatory Charges		
55	If applying for a rate other than the generic rate set by the OEB, distributors must provide justification as to why their specific circumstances would warrant a different rate, in addition to a detailed derivation of their proposed rate	N/A 8.2.3
Specific Service Charges		
55-56	If requesting new specific service charge or a change to the level of an existing charge, description of the purpose of charge, or reason for change to an existing charge; calculations to support charges	N/A 8.2.4
56	Identification in the Application Summary all proposed changes that will have an impact on customers, including changes to other rates and charges that may affect a discrete group; identification of specific customers or customer groups impacted by each proposal	8.2.4, N/A for SSC.
56	Calculation of charge includes: direct labour, labour rate, burden rate, incidental, other	8.2.4, N/A for SSC.
56	Identification of any rates and charges in Conditions of Service that do not appear on tariff sheet. Explain nature of costs, provide schedule outlining revenues or capital contributions recovered from these rates from last OEB-approved year to most recent actuals and the revenue or capital contributions forecasted for the bridge and test years. A proposal and explanation as to whether these charges should be included on tariff sheet	8.2.4
56	Revenue from specific service charges corresponds with Other Revenue evidence	8.2.4
Wireline Pole Attachment Charge		
56-57	Use of most recent charge per OEB generic order	8.2.5
Low Voltage Service Rates		
If the distributor is fully or partially embedded, information on the following must be provided:		8.2.6
57	Forecast LV Cost	

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57	Actual LV Cost for the last three historical years along with bridge and test year forecasts; year-over-year variances and explanations for substantive changes in costs over time up to and including test year forecast	8.2.6
57	Support for forecast LV, e.g. Hydro One Sub-Transmission charges	8.2.6
57	Allocation of forecasted LV cost to customer classes (typically proportional to Tx connection revenue)	8.2.6
57	Proposed LV rates by customer class	8.2.6
Smart Meter Entity Charge		
58	Current OEB-approved Smart Metering Entity Charge until the OEB approves any updated charge	8.2.7
Loss Factors		
58	Proposed SFLF and Total Loss Factor for test year	8.3
58	Statement as to whether LDC is embedded including whether fully or partially	8.3
58	Study of losses if required by previous decision	N/A
58	3-5 years of historical loss factor data - Completed Appendix 2-R	8.3.3, Table 8-19
58	If proposed distribution loss factor >5% or is showing an increasing trend, explanation for level of losses, details of actions taken to reduce losses in the previous five years, and actions planned to reduce losses going forward	N/A, 8.3.4
58	Explanation of SFLF if not standard	8.3.1
58	Reconciliation between the application and RRR filing	Table 8-20
Tariff of Rates and Charges		
59	Current and proposed Tariff of Rates and Charges - **must be filed in Excel format and PDF format** Explanation and support of each change in the appropriate section of the application	Att. 8-A and 8-B
59	Completed Tariff Schedule and Bill Impacts Model	Att 8-D
59	Explanation of changes to terms and conditions of service if changes affect application of rates and rationale behind those changes	N/A
59	Proposed tariffs must include applicable regulatory charges, and any other generic rates as ordered by the OEB	Confirmed
Revenue Reconciliation		
59	Calculations of revenue per class under current and proposed rates; reconciliation of rate class revenue and other revenue to total revenue requirement (i.e. breakout volumes, rates and revenues by rate component etc.)	8.3.6
59	Completed RRWF - Sheet 13 (table reconciling base revenue requirement against revenues recovered through proposed rates)	8.3.6
Bill Impact Information		
59	Bill impacts filed for all customer classes on a representative sample of end-users, which identifies existing rates, proposed changes to rates, and detailed bill impacts (including % change in distribution excluding pass through costs - Sub-Total A, % change in distribution - Sub-Total B, % change in delivery - Sub-Total C, and $ change in total bill)	8.3.7
60	Bill impacts provided for typical customers and consumption levels. Must provide residential 750 kWh and GS<50 2,000 kWh. Bill impacts must be provided for a range of consumption levels relevant to the service territory for each class	8.3.7
60	If applicable, for certain classes where one or more customers have unique consumption and demand patterns, the distributor must show a typical impact and provide an explanation	8.3.7
Rate Mitigation		
60	Mitigation plan if total bill increase for any customer class is >10% including: specification of class and magnitude of increase, description of mitigation measures, justification for mitigation measure including reasons if no mitigation proposed, other relevant information. The Tariff Schedule and Bill Impacts Model must reflect any mitigation plan proposed.	8.3.8
Rate Harmonization Mitigation Issues		N/A 8.3.8
61	If part of a MAADs transaction, and rate harmonization plan not yet approved by the OEB, a rate harmonization plan must be filed	
61	Plan includes a detailed explanation and justification for the implementation plan, and an impact analysis	N/A 8.3.8
61	If consolidated distributor does not intend to undertake rate harmonization: explanation for not doing so	N/A 8.3.8
61	If impact of COS increases and harmonization effects result in total bill increases for any customer class exceeding 10%, discussion on of proposed measures to mitigate increases in its mitigation plan, or justification provided as to why mitigation is not required	N/A 8.3.8
61	Migration plan that includes fully harmonizing rates that is to be accomplished over more than one year must be supported by a detailed plan for accomplishing this during the subsequent Price Cap IR period	N/A 8.3.8

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EXHIBIT 9 - DEFERRAL AND VARIANCE ACCOUNTS		
61	Summary table showing all active DVAs not disposed of yet, showing principal and interest/carrying charges, total balance for each account, whether account being proposed for disposition and (for Group 2 DVAs) whether the account is proposed to be continued or discontinued	Table 9-2
61	In a separate section under the summary table: - For any account identified in the summary table as not being proposed for disposition, provide an explanation as to why it is not being proposed for disposition - For any Group 2 account identified in the summary table that are proposed to be discontinued, provide an explanation as to why it is being discontinued	
61	If applicable, description of DVAs that were used differently than as described in the APH, relevant accounting order or other OEB document	N/A 9.1.1 confirms compliance with APH
62	Completed DVA continuity schedule for period from last disposition to present - live Excel format. Continuity schedule must show separate itemization of opening balances, annual adjustments, transactions, dispositions, interest and closing balances for all active DVAs. The opening principal amounts and interest amounts for Group 1 and 2 balances, shown in the DVA Continuity Schedule, must reconcile with the last applicable approved closing balances.	Attachment 9-A
62	Explanation if account balances in continuity schedule differs from trial balance reported through RRR and documented in AFS - included in tab Appendix A of DVA schedule. This includes all Account 1508 sub-accounts. A reconciliation of all the Account 1508 sub-accounts to the Account 1508 control account reported in the RRR is to be provided in the DVA continuity schedule	Attachment 9-A
62	Statement whether any adjustments made to DVA balances previously approved by OEB on final basis - the OEB expects that no adjustment will be made to any deferral and variance account balances previously approved by the OEB on a final basis. If any adjustments have been made, explanation for the nature and the amount of the adjustment(s), and appropriate supporting documentation, under a section titled "Adjustments to Deferral and Variance Accounts"	9.1.1
62	Confirmation of use of interest rates established by the OEB by month or by quarter for each year; most recently published rate used as a placeholder for future periods	9.1.1
62	If requesting proposal for a differing carrying charge on a DVA involving long-term expenditures: include evidence justifying departure from standard practice.	N/A 9.1.1
Disposition of Deferral and Variance Accounts **63**	Refer to DVA Continuity Schedule Instructions for instructions on completing the DVA Continuity Schedule, annual updates and discussions on default treatments and expectations for DVAs	Confirmed
63	Confirmation that distributor is allocating DVAs using an approved allocator. If proposing to allocate a DVA which the OEB has not established an allocator, proposed allocation based on cost driver must be provided with justification; indication of proposed billing determinants, including charge type for recovery purposes and included in cont. schedule	9.2.1
63	Propose rate riders that dispose of the balances. If the distributor is proposing an alternative recovery period other than one year, explanation provided	Section 9.4 including Table 9-9
63	Support (e.g., explanations, calculations) on how each material Group 2 balance is determined. For distributor-specific Group 2 accounts that are not material, provide a brief explanation of the account balance	9.2.2
Disposition of Accounts 1588 and 1589 **63**	If a distributor has not implemented OEB's February 21, 2019 accounting guidance, indication that this is the case	N/A- implemented 9.1.1
63	Indication of the year in which Account 1588 and Account 1589 balances were last approved for disposition, and whether the balances were approved on an interim or final basis. If the balances were last disposed on an interim basis, indicate the year in which balances were last disposed on a final basis	9.2.3
64	Transactions recorded in Accounts 1588 and 1589 are accounted for in accordance with the respective year's accounting guidance	9.1.1
64-65	**Commodity Accounts Analysis Workform (Formerly GA Analysis Workform)** - filed in in live Excel format for each year that has not previously been approved by the OEB for disposition - If the distributor is adjusting the Account 1588 and 1589 balance that was previously approved on an interim basis, Commodity Account Analysis Workform completed from the year after the distributor last received final disposition for Account 1588 and1589 - If the distributor is proposing adjustments to final disposed balances in Account 1588 and 1589, completed Workform from the year(s) that contain the error(s) and the associated adjustment(s) to the year the balance is being requested - for any unexplained discrepancy between the actual and expected balance (i.e., greater than +/- 1% of the total annual IESO GA charges), further analysis and supporting evidence - completed reasonability test for the balance in Account 1588. The reasonability test is included in the Commodity Accounts Analysis Workform.	9.2.3, Attachment 9-B
65-66	**Two-Year Limitation Period** - if seeking OEB approval of exception from the limitation period for a payment or adjustment, detailed justification for seeking approval - explanation of the actions taken to resolve the issue to avoid the need for an exception to the limitation period, and why the applicant was not successful in its efforts to resolve the issue - consideration of factors per OEB's October 31, 2019 letter - accounting adjustments recorded in the continuity schedule of the related commodity variance accounts and include these accounting adjustments in the Commodity Accounts Analysis Workform for the purpose of reasonability tests in Accounts 1588 and 1589.	9.2.3

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Disposition of Account 1580, Sub-account CBR Class B Variance		9.2.4
66	Proposed disposition of Account 1580 sub-account CBR Class B in accordance with the CBR Accounting Guidance. Must be disposed over one year.	
66	Account 1580 sub-account CBR Class A is not to be disposed through rates proceedings but rather follow the OEB's accounting guidance	9.2.4
Disposition of Account 1595		9.2.5
66	Distributors are expected to request disposition of residual balances in Account 1595 Sub-accounts for each vintage year once, on a final basis	
67	Explanation for any material residual balances being proposed for disposition, including quantifying significant drivers of the residual balance	9.2.5
Disposition of Retail Service Charges Related Accounts		
67	Distributors that have not yet disposed of Accounts 1508 sub-account Retail Service Charges Incremental Revenue, 1518 or 1548 may forecast balances up to the end of the incentive rate-setting period, provided it can do so with reasonable accuracy, and the OEB may consider disposing of the forecast amounts and then closing the accounts	9.2.6
67	Provide cost drivers for any material balances for disposition in Accounts 1518, 1548 or 1508 (sub-account Retail Service Charges Incremental Revenue)	9.2.6
Disposition of Account 1592, Sub-account CCA Changes		9.2.7
67	Provide full revenue requirement impact recorded in Account 1592, Sub-account CCA Changes and the balance sought for review and disposition	
68	Calculations for accelerated CCA differences per year, based on actual capital additions. Calculations include: underpreciated capital cost continuity schedules for each year itemized by CCA class, calculated PILs/tax differences, grossed-up PILs/tax differences, other applicable information	9.2.7
68	Confirmation that Account 1592 amounts related to ICM/ACM have been included in the account, if applicable	9.2.7
68	Reconciliation of these amounts to the amounts presented in Account 1592 sub-account CCA changes in the DVA continuity schedule	9.2.7
68	If a distributor does not have a balance in this sub-account, the distributor must explain why	9.2.7
Disposition of Account 1509 Impacts Arising from the COVID-19 Emergency		9.2.8
68	If requesting disposition of any amounts related to the COVID-19 Account, filing requirements as set out in the Filing Requirements for Electricity Distribution Rate Applications, 2025 Edition for 2026 Rate Applications has been provided	
Disposition of Account 1508, Sub-account Pole Attachment Revenue Variance		
68-69	A table showing the calculation of the account balance, the annual balance broken down customer type, if applicable and: - the number of poles used in the calculation - the pole attachment charge incorporated in rates - the updated charge May also forecast the balance to the effective date of its new rates	9.2.9; Table 9-8
Disposition of Account 1508, Sub-account Getting Ontario Connected Act		
69-70	Distributors requesting disposition of any amounts recorded are to file, at a minimum, the following information: - statement confirming that distributor has reflected the GOCA impact in the locate costs of the test year's revenue requirement - supporting calculations for the amounts recorded in the sub-accounts, including the methodology used to measure incremental costs - proposed disposition of the GOCA Variance account under Account 1508 Sub-Account GOCA Variance Account and discontinuance of the account after the rebasing application - rationale if the distributor proposes to continue the GOCA Variance account in the rate term	N/A -9.2.10
Disposition of Account 1511 Incremental Cloud Computing Implementation Costs		N/A-9.2.10
	Distributors requesting disposition of any amounts recorded in the Cloud Computing Implementation Account are to file, at a minimum, the following information:	
70	Discussion and supporting explanation for the annual amounts recorded, including the methodology used to measure incremental costs and offsetting savings, as applicable. If there are no offsetting savings, explanation provided	N/A-9.2.10
70	List of the cloud solution(s), actual or forecast amount(s), type(s) of expenditure, and nature of costs	N/A-9.2.10
70	List of costs requested by projects (each with the business purpose of the projects) and a statement for each project regarding whether the cost associated for each project is material	N/A-9.2.10
70	Discussion of whether the distributor would be able to reasonably forecast any further entries in the account, up to the effective data of new rates, so that the account may be disposed in its entirety in the current proceeding (and whether the distributor would be amenable to such an approach)	N/A-9.2.10
70-71	Proposal for disposition of balance - the nature of the cloud solution considered in determining disposition methodology. Recovery would generally be expected to be over the remaining contract term unless the distributor has a strong rationale for doing otherwise	N/A-9.2.10
71	If applicable, proposed treatment of any future cloud solutions during the rate term. If no proposal is made in a rebasing rate application, the Cloud Computing Deferral Account will be closed	N/A-9.2.10
71	Use of prescribed interest rate for DVAs	N/A-9.2.10
71	If applicable, proposal for the rate treatment of the unamortized balance of cloud-based solutions and for any future projects which considers the risk profile of cloud computing solutions versus on-premise solutions and different options that are available for the rate treatment	N/A-9.2.10
Disposition of Account 1508, Sub Account Extended Horizons Variance Account		N/A-9.2.10
	If requesting disposition, the following must be filed at a minimum:	
71	Details of the forecasted connections embedded in rates as of the last cost of service application	N/A-9.2.10
71	Statement confirming that the forecasted connections were eligible for the extension of connection and revenue horizons	N/A-9.2.10
71	Supporting calculations for the amounts recorded in the account, including methodology used to determine those customer connections eligible for extension	N/A-9.2.10
72	Statement confirming that distributor has reflected the impact of the expansions of the horizons into its forecast for the test year and beyond	N/A-9.2.10
72	Proposed disposition of the account and discontinuance after the rebasing application	N/A-9.2.10

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Disposition of Account 1508, Sub-Account Electric Vehicle Charging Rate (EVC Rate)		
72	If requesting disposition: supporting calculations for the amounts recorded, including methodology used to measure incremental costs; proposed disposition of the account and discontinuance after the rebasing application	N/A-9.2.10
Disposition of Distributor-Specific Accounts		
72	For any material, distributor-specific accounts requested for disposition (e.g., Account 1508 sub-accounts), supporting evidence showing how the annual balance is derived and relevant accounting order provided. For distributor-specific accounts requested for disposition that are not material, provide a brief explanation for the account balance	9.2.2
Establishment of New Deferral and Variance Accounts		
72-73	If new DVA - evidence provided which demonstrates that the requested DVA meets the following criteria: causation, materiality, prudence; include draft accounting order with description of the mechanics of the account, provide examples of general journal entries and the proposed account duration	9.3.1
Lost Revenue Adjustment Mechanism Variance Account for NWS Activities		
73-74	Indication of whether distributor is requesting an LRAMVA for one or more activities related to distribution rate-funded NWS activities or LIP activities if this request has not been addressed in a previous application	9.5.1
74	If applicable, where a distributor is requesting access to, and the use of, an LRAMVA for a distribution rate-funded NWS activity or a LIP activity, the distributor should refer to the NWS Guidelines for the nature of the evidence the OEB requires to assess such a proposal	9.5.1
Appendix A Cost of Eligible Investments for the Connection of Qualifying Generation Facilities		9.5.2
Appendix A	If applicable, proposal to divide the costs of eligible investments between the distributor's ratepayers and all Ontario ratepayers per O.Reg. 330/09	
Appendix A	For distributors that are already receiving rate protection as a result of a previous application the new (current) cost of service application should include an update to include the actual costs incurred for the investments as well as a depreciation adjustment to calculate a new capital amount for input into Appendices 2-FA through 2-FC. This would generate a new up-to-date rate protection amount for the test year and beyond, which will be subject to the materiality threshold	9.5.2 (N.A)

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

ATTACHMENT 1-D:
EXECUTIVE AND BOARD CERTIFICATIONS/CONFIRMATIONS

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

CERTIFICATION OF THE EVIDENCE

EB-2026-0029

I, Duane Fecteau, Vice President and Chief Financial Officer of Canadian Niagara Power Inc. ("CNPI"), hereby make the following certifications regarding the evidence filed in CNPI's 2027 Cost of Service Application:

1. I certify, that to the best of my knowledge, the evidence filed, including the models and appendices, is accurate, consistent and complete; and complies with the Board's *Filing Requirements for Electricity Distribution Rate Applications, 2026 Edition for 2027 Rate Applications – Chapter 2 Cost of Service*, dated December 16, 2025.

2. I certify, that to the best of my knowledge, CNPI has robust processes and internal controls in place for the preparation, review, verification and oversight of account balances being disposed of.

3. I certify, that to the best of my knowledge, the evidence filed in support of this Application does not include any personal information unless it is filed in accordance with Rule 9A of the OEB's Rules of Practice and Procedure (and the Practice Direction on Confidential Filings, as applicable).

4. I confirm that generative artificial intelligence (AI) was used to generate content in the filing and that the accuracy of the filing generated by AI has been verified by CNPI without the assistance of generative AI.



Vice President and Chief Financial Officer

Canadian Niagara Power Inc.

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

BOARD CERTIFICATION

The Board of Directors of Canadian Niagara Power Inc. ("**CNPI**") certifies that it is aware of and approves the submission of CNPI's 2027 Cost of Service Application.

This certification is provided pursuant to the Ontario Energy Board's *Chapter 1, Filing Requirement for Electricity Distribution Rate Applications*, as amended from time to time.

DATED: May 6, 2026

Glen King
Chair, Board of Directors
Canadian Niagara Power Inc.

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

ATTACHMENT 1-E:
PDF AND EXCEL COPY OF CURRENT (2026) TARIFF

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2025-0050

RESIDENTIAL SERVICE CLASSIFICATION

The Residential Class (Regular) refers to a service taking electricity normally at 750 volts or less where the electricity is used for domestic and household purposes in a single family unit. A single family unit being a permanent structure located on a single parcel of land and approved by a civic authority as a dwelling and occupied for that purpose by a single customer. Residential rates are also applied to apartment buildings with 6 units or less that are bulk metered. Apartment buildings with more than 6 units that are bulk metered are deemed to be General Service. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	46.08
Smart Metering Entity Charge - effective until December 31, 2027	$	0.42
Low Voltage Service Rate	$/kWh	0.0003
Rate Rider for Disposition of Global Adjustment Account (2026) - effective until December 31, 2026 Applicable only for Non-RPP Customers - Approved on an Interim Basis	$/kWh	(0.0061)
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026 - Approved on an Interim Basis	$/kWh	(0.0027)
Rate Rider for Disposition of Capacity Based Recovery Account (2026) - effective until December 31, 2026 Applicable only for Class B Customers	$/kWh	0.0004
Retail Transmission Rate - Network Service Rate	$/kWh	0.0117
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0087

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2025-0050

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to single commercial or industrial customer and whose average peak demand is (or is forecasted to be) less than 50 kW. Single commercial or industrial customers are interpreted as a structure or structures on a single parcel of land occupied by one customer. An apartment building with more than 6 units that is bulk metered and has an average peak demand less than 50 kW is deemed to be General Service less than 50 kW. The common area of a separately metered apartment building having a demand less than 50 kW is also deemed to be General Service less than 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	38.83
Smart Metering Entity Charge - effective until December 31, 2027	$	0.42
Distribution Volumetric Rate	$/kWh	0.0315
Low Voltage Service Rate	$/kWh	0.0003
Rate Rider for Disposition of Global Adjustment Account (2026) - effective until December 31, 2026 Applicable only for Non-RPP Customers - Approved on an Interim Basis	$/kWh	(0.0061)
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026 - Approved on an Interim Basis	$/kWh	(0.0026)
Rate Rider for Disposition of Capacity Based Recovery Account (2026) - effective until December 31, 2026 Applicable only for Class B Customers	$/kWh	0.0004
Retail Transmission Rate - Network Service Rate	$/kWh	0.0100
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0076

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2025-0050

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification refers to the supply of electrical energy to single commercial or industrial customer and whose average peak demand is (or is forecasted to be) equal to or greater than 50 kW but less than 5000 kW. Single commercial or industrial customers are interpreted as a structure or structures on a single parcel of land occupied by one customer. Class A and Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	194.73
Distribution Volumetric Rate	$/kW	9.1941
Low Voltage Service Rate	$/kW	0.1151
Rate Rider for Disposition of Global Adjustment Account (2026) - effective until December 31, 2026 Applicable only for Non-RPP Customers - Approved on an Interim Basis	$/kWh	(0.0061)

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

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		EB-2025-0050
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026 - Approved on an Interim Basis	$/kW	(0.8295)
Rate Rider for Disposition of Capacity Based Recovery Account (2026) - effective until December 31, 2026 Applicable only for Class B Customers	$/kW	0.1386
Retail Transmission Rate - Network Service Rate	$/kW	4.2243
Retail Transmission Rate - Network Service Rate - EV CHARGING	$/kW	0.7181
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	3.0987
Retail Transmission Rate - Line and Transformation Connection Service Rate - EV CHARGING	$/kW	0.5268

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2025-0050

EMBEDDED DISTRIBUTOR SERVICE CLASSIFICATION

This classification applies to an electricity distributor licensed by the Board, that is provided electricity by means of this distributor's facilities. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	700.69
Distribution Volumetric Rate	$/kW	10.5874
Low Voltage Service Rate	$/kW	0.1151
Rate Rider for Disposition of Global Adjustment Account (2026) - effective until December 31, 2026 Applicable only for Non-RPP Customers - Approved on an Interim Basis	$/kWh	(0.0061)
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026 - Approved on an Interim Basis	$/kW	(0.9542)
Rate Rider for Disposition of Capacity Based Recovery Account (2026) - effective until December 31, 2026 Applicable only for Class B Customers	$/kW	0.1646
Retail Transmission Rate - Network Service Rate	$/kW	4.2243
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	3.0987

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2025-0050

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to the supply of electrical service to a customer that is deemed to have a constant load over a billing period, normally with minimum electrical consumption and the consumption is unmetered. Energy consumption is based on connected wattage and calculated hours of use. Examples of unmetered scattered load are cable television amplifiers, billboards, area lighting. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per account)	$	61.23
Distribution Volumetric Rate	$/kWh	0.0332
Low Voltage Service Rate	$/kWh	0.0003
Rate Rider for Disposition of Global Adjustment Account (2026) - effective until December 31, 2026 Applicable only for Non-RPP Customers - Approved on an Interim Basis	$/kWh	(0.0061)
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026 - Approved on an Interim Basis	$/kWh	(0.0025)
Rate Rider for Disposition of Capacity Based Recovery Account (2026) - effective until December 31, 2026 Applicable only for Class B Customers	$/kWh	0.0004
Retail Transmission Rate - Network Service Rate	$/kWh	0.0103
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0077

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

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EB-2025-0050

STANDBY POWER SERVICE CLASSIFICATION

The Standby subclass charge is applied to a customer with load displacement facilities behind its meter but is dependent on Canadian Niagara Power Inc. to supply a minimum amount of electricity in the event the customer's own facilities are out of service. The minimum amount of supply that Canadian Niagara Power Inc. must supply is a contracted amount agreed upon between the customer and Canadian Niagara Power Inc. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - APPROVED ON AN INTERIM BASIS

Standby Charge - for a month where standby power is not provided. The charge is applied to the contracted amount (e.g. nameplate rating of generation facility)	$/kW	1.5104

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

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EB-2025-0050

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to all services required to supply sentinel lighting equipment. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per device)	$	7.01
Distribution Volumetric Rate	$/kW	8.1011
Low Voltage Service Rate	$/kW	0.0939
Rate Rider for Disposition of Capacity Based Recovery Account (2026) - effective until December 31, 2026 Applicable only for Class B Customers	$/kW	0.1347
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026 - Approved on an Interim Basis	$/kW	(0.8088)
Retail Transmission Rate - Network Service Rate	$/kW	3.5999
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.5287

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2025-0050

STREET LIGHTING SERVICE CLASSIFICATION

This classification refers to the supply of electrical service for roadway lighting. Energy consumption is based on connected wattage and calculated hours of use. Customers are usually a Municipality, Region or the Ministry of Transportation. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per device)	$	4.69
Distribution Volumetric Rate	$/kW	9.3574
Low Voltage Service Rate	$/kW	0.0878
Rate Rider for Disposition of Global Adjustment Account (2026) - effective until December 31, 2026 Applicable only for Non-RPP Customers - Approved on an Interim Basis	$/kWh	(0.0061)
Rate Rider for Disposition of Deferral/Variance Accounts (2026) - effective until December 31, 2026 - Approved on an Interim Basis	$/kW	(0.8351)
Rate Rider for Disposition of Capacity Based Recovery Account (2026) - effective until December 31, 2026 Applicable only for Class B Customers	$/kW	0.1450
Retail Transmission Rate - Network Service Rate	$/kW	3.1267
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.3643

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0041
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0006
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0006
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

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EB-2025-0050

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.00

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

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EB-2025-0050

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)

SPECIFIC SERVICE CHARGES

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Customer Administration

Arrears certificate (credit reference)	$	15.00
Statement of account	$	15.00
Pulling post dated cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Notification charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned cheque (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection at meter - during regular hours	$	65.00
Reconnection at meter - after regular hours	$	185.00
Reconnection at pole - during regular hours	$	185.00
Reconnection at pole - after regular hours	$	415.00

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2025-0050

Other

Special meter reads	$	30.00
Service call - customer owned equipment	$	30.00
Service call - after regular hours	$	165.00
Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service install & remove - underground - no transformer	$	300.00
Temporary service install & remove - overhead - with transformer	$	1,000.00
Specific charge for access to the power poles - per pole/year (with the exception of wireless attachments)	$	40.59

Canadian Niagara Power Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date January 1, 2026

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2025-0050

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	125.72
Monthly fixed charge, per retailer	$	50.29
Monthly variable charge, per customer, per retailer	$/cust.	1.24
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.74
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.74)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.63
Processing fee, per request, applied to the requesting party	$	1.24
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	5.03
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.51

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0524
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0419

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

ATTACHMENT 1-F:
2025 AUDITED FINANCIAL STATEMENTS

Financial statements of
Canadian Niagara Power Inc.

December 31, 2025

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Independent Auditor's Report

To the Shareholder of
Canadian Niagara Power Inc.

Opinion

We have audited the financial statements of Canadian Niagara Power Inc. (the "Corporation"), which comprise the balance sheet as at December 31, 2025, and the statements of earnings and retained earnings, and cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2025, and the results of its operations and its cash flows for the year then ended in accordance with Canadian accounting standards for private enterprises ("ASPE").

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards ("Canadian GAAS"). Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Corporation 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 ASPE, 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 Corporation'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 Corporation or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Corporation'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 GAAS will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian GAAS, 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 Corporation'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 Corporation'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 Corporation to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

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

Deloitte LLP

Chartered Professional Accountants
Licensed Public Accountants
March 6, 2026

Exhibit 1

Canadian Niagara Power Inc.

Balance sheet

As at December 31, 2025

(In thousands of dollars, unless otherwise stated)

	Notes	2025 $	2024 $
Assets			
Current assets			
Cash		**3,750**	2,137
Accounts receivable	11	**14,299**	14,627
Income taxes receivable	5	**14**	335
Materials and supplies		**281**	204
Regulatory assets	13	**—**	19
Prepaid expenses		**763**	804
Due from related parties	6	**—**	2
		19,107	18,128
Utility capital assets, net	2	**200,450**	192,207
Intangible assets, net	3	**8,009**	7,862
Accrued pension benefit asset	4	**5,379**	5,225
Regulatory assets	13	**20,437**	17,301
Goodwill		**7,232**	7,232
		260,614	247,955
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	11	**9,522**	9,972
Customer deposits	11	**2,459**	2,454
Regulatory liabilities	13	**1,794**	961
Due to related parties	6	**45,216**	40,696
		58,991	54,083
Long-term customer deposits	11	**1,433**	1,051
Long-term debt	7, 11 and 12	**74,762**	74,751
Future tax liabilities	5	**19,136**	17,380
Accrued other retirement benefit liability	4	**6,112**	6,338
Contributions in aid of construction		**22,320**	20,842
Regulatory liabilities	13	**5,169**	3,278
		187,923	177,723
Shareholder's equity			
Capital stock	8	**23,900**	23,900
Retained earnings		**48,791**	46,332
		72,691	70,232
		260,614	247,955

The accompanying notes are an integral part of the financial statements.

Approved by the Board

_____, Director

_____, Director

Exhibit 1

Canadian Niagara Power Inc.

Statement of earnings and retained earnings

Year ended December 31, 2025

(In thousands of dollars, unless otherwise stated)

	Notes	2025 $	2024 $
Revenue			
Sale of energy		**63,325**	64,034
Distribution		**24,654**	23,834
Transmission		**5,206**	4,910
Other		**2,492**	2,407
		95,677	95,185
Expenses			
Cost of power purchased		**63,324**	64,034
Operating		**14,854**	14,173
Amortization	9	**6,806**	6,394
		84,984	84,601
Operating earnings before the following		**10,693**	10,584
Other regulatory adjustment		**(40)**	2
Interest expense	6, 7 and 11	**(4,938)**	(5,654)
Earnings before income taxes		**5,715**	4,932
Provision for income taxes	5	**256**	319
Net earnings for the year		**5,459**	4,613
Retained earnings, beginning of year		**46,332**	44,719
Dividends paid	6	**(3,000)**	(3,000)
Retained earnings, end of year		**48,791**	46,332

The accompanying notes are an integral part of the financial statements.

Exhibit 1

Canadian Niagara Power Inc.

Statement of cash flows

Year ended December 31, 2025

(In thousands of dollars, unless otherwise stated)

	Notes	2025 $	2024 $
Operating activities			
Net earnings for the year		**5,459**	4,613
Add (deduct) items not involving cash			
Amortization of utility capital assets	9	**6,684**	6,278
Amortization of intangible assets	9	**1,174**	1,157
Amortization of contributions in aid of construction	9	**(628)**	(594)
Amortization of debt issuance costs		**11**	10
Future income taxes		**1,756**	1,371
(Gain) loss on sale of utility capital assets		**(81)**	90
Loss on disposal of contributions in aid of construction		**(15)**	(6)
Accrued pension benefits		**(154)**	(431)
Accrued other retirement benefits		**(226)**	(804)
Customer deposits		**382**	(977)
Long-term regulatory assets and liabilities		**(1,245)**	(798)
		13,117	9,909
Net change in non-cash working capital balances related to operations	10	**5,542**	18,136
		18,659	28,045
Investing activities			
Additions to utility capital assets		**(15,107)**	(16,734)
Additions to intangible assets		**(1,321)**	(641)
Proceeds on sale of utility capital assets		**261**	176
		(16,167)	(17,199)
Financing activities			
Increase in contributions in aid of construction		**2,121**	1,386
Decrease in loan payable		**—**	(8,000)
Dividends		**(3,000)**	(3,000)
		(879)	(9,614)
Net increase in cash during the year		**1,613**	1,232
Cash, beginning of year		**2,137**	905
Cash, end of year		**3,750**	2,137

The accompanying notes are an integral part of the financial statements.

1. Basis of accounting and summary of significant accounting policies

Incorporation

Canadian Niagara Power Inc. (the "Corporation" or "CNPI"), formerly Canadian Niagara Power Company, Limited, is a wholly owned subsidiary of FortisOntario Inc. (the "parent company") that was incorporated on February 17, 1999 to comply with the *Electricity Act*, 1998 (Ontario) (the "Act"). The Act requires that the electric power transmission and distribution businesses, previously carried out by the parent company, be carried out by a separate legal entity. Effective March 31, 1999, the Corporation purchased the electric power transmission and distribution assets of its parent company and commenced operations. On January 1, 2004, the Corporation was amalgamated with Eastern Ontario Power Inc. and continued as Canadian Niagara Power Inc. The business of the Corporation is the transmission and distribution of electricity to customers within Ontario. The business is regulated by the Ontario Energy Board ("OEB").

These financial statements include the operating results of the Niagara and Eastern Ontario Power (Gananoque) distribution centers and the Niagara transmission center.

(a) Basis of accounting

These financial statements have been prepared in accordance with Canadian accounting standards for private enterprises ("ASPE"), as per Part II of the CPA Handbook - Accounting, which constitutes generally accepted accounting principles for non-publicly accountable enterprises in Canada.

(b) Significant accounting policies

Regulation

CNPI distribution

The distribution rates of CNPI are based upon Cost of Service ("CoS") rate regulation by the OEB. Earnings are regulated on the basis of a rate of return on rate base plus a recovery of all allowable distribution costs.

On August 17, 2023, CNPI filed an application with the OEB seeking approval to change electricity distribution rates, effective January 1, 2024, based on Fourth Generation Incentive Rate Mechanism ("4GIRM"). A revised Decision and Order was issued December 15, 2023, that approved the net price cap index adjustment for CNPI of 4.35% (Inflation factor net of a productivity and stretch factor 4.80% (0% + 0.45%)). The 4.35% adjustment will be applied to distribution rates (fixed and variable charges) uniformly across all customer classes. The Decision and Order also approved CNPI requests to recover $977 in 2022 extraordinary event costs related to a severe storm (Z-Factor) as well as $47 related to Lost Revenue Adjustment Mechanism.

On August 15, 2024, CNPI filed an application with the OEB seeking approval to change electricity distribution rates, effective January 1, 2025, based on 4GIRM. A Decision and Order was issued December 12, 2024, that approved the net price cap index adjustment for CNPI of 3.15% (Inflation factor net of a productivity and stretch factor 3.60% - (0% + 0.45%)). The 3.15% adjustment will be applied to distribution rates (fixed and variable charges) uniformly across all customer classes.

On August 14, 2025, CNPI filed an application with the OEB seeking approval to change electricity distribution rates, effective January 1, 2026, based on 4GIRM. A Decision and Order was issued December 18, 2025, that approved the net price cap index adjustment for CNPI of 3.25% (Inflation factor net of a productivity and stretch factor 3.70% - (0% + 0.45%)). The 3.25% adjustment will be applied to distribution rates (fixed and variable charges) uniformly across all customer classes.

1. Basis of accounting and summary of significant accounting policies (continued)

(b) Significant accounting policies (continued)

Regulation (continued)

CNPI transmission

The transmission rates of CNPI are based upon CoS rate regulation by the OEB. Earnings are regulated on the basis of a rate of return on rate base plus a recovery of all allowable transmission costs.

On November 17, 2014, CNPI submitted a Revenue Requirement Application for its Transmission business. The Application sought approval of CNPI's 2015 and 2016 Transmission Revenue Requirement.

On June 25, 2015, the OEB issued its Decision and Order. The Decision and Order approved final revenue requirements of $4,246 and $4,647 for 2015 and 2016 respectively, and provided a 9.3% Return on Equity ("ROE") with a 60%/40% debt equity structure.

The provincial Uniform Transmission Rates ("UTR") for the 2017-2025 rate years continued to include CNPI's approved 2016 revenue requirement of $4.6 million. A Decision and Order was issued January 18, 2024, relating to CNPI's 2024 transmission revenue requirement which remains unchanged from CNPI's approved 2016 revenue requirement of $4.6 million. A Decision and Order was issued January 21, 2025, relating to CNPI's 2025 transmission revenue requirement which remains unchanged from CNPI's approved 2016 revenue requirement of $4.6 million. CNPI filed a letter with the OEB on July 28, 2025, confirming it would not be seeking any updates to its transmission revenue requirement for 2026 rates. A letter was issued October 9, 2025, setting 2026 preliminary UTR including CNPI's 2026 transmission revenue requirement which remains unchanged from CNPI's approved 2016 revenue requirement of $4.6 million.

Materials and supplies

Materials and supplies are recorded at average cost. Materials and supplies expensed to operating expenses in 2025 were $118 ($157 in 2024).

Utility capital assets and capitalization policy

Nature of distribution and transmission assets

Distribution assets

Distribution assets are those used to distribute electricity at lower voltages (generally below 50 kilovolts). These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

Transmission assets

Transmission assets are those used to transmit electricity at higher voltages (generally at 50 kilovolts and above). These assets include poles, wires and conductors, substations, support structures and other related equipment.

1. Basis of accounting and summary of significant accounting policies (continued)

(b) Significant accounting policies (continued)

Service life range and average remaining service life of utility capital assets

The service life range and average remaining service life of the utility capital assets are as follows:

	Service life range (years)	Average remaining service life (years)
Distribution	10 to 50	34.3
Transmission	20 to 50	31.7
Other	5 to 50	8.6

Utility capital assets are stated at cost less accumulated amortization. Amortization is provided over the estimated useful lives of the utility capital assets using the straight-line method at a composite rate of 2.3% (2.3% in 2024).

Contributions in aid of construction represent funding of utility capital assets contributed by customers. These accounts are being reduced annually by an amount equal to the charge for amortization provided on the contributed portion of the utility capital assets involved.

Capitalization policy

The Corporation's capitalization policy is in accordance with the OEB's requirements to use a "modified IFRS" accounting basis to allow for more consistency amongst electricity distribution utilities in Ontario and this includes having asset useful lives that align with guidelines, and certain directly attributable costs that are capitalized while general overhead costs are not.

Intangible assets

Intangible assets are stated at cost less accumulated amortization. Amortization is provided over the estimated useful lives of the intangible assets using the straight-line method.

The service life range and average remaining service life of the intangible assets are as follows:

	Service life range (years)	Average remaining service life (years)
Software costs	5 to 10	4.3
Land and transmission rights	40	17.7
Other	40 to 45	28.4

Goodwill

Goodwill represents the excess of the acquisition cost of the shares of the Corporation, and Eastern Ontario Power Inc. (amalgamated with the Corporation on January 1, 2004) over the assigned value of identifiable net assets acquired, as well as the excess of the purchase price of the remaining utility capital assets of Port Colborne Hydro Inc. ("PCHI") over the fair value of these assets.

1. Basis of accounting and summary of significant accounting policies (continued)

(b) Significant accounting policies (continued)

Goodwill (continued)

ASPE requires that goodwill shall be tested for impairment whenever events or changes in circumstances indicate that the carrying amount of the reporting unit to which the goodwill is assigned may exceed the fair value of the reporting unit. Any impairment in value is charged to earnings during the year.

Revenue recognition

Revenue from the sale, transmission and distribution of electricity is recognized on the accrual basis. Electricity is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of the year a certain amount of consumed electricity will not have been billed. Electricity that is consumed but not yet billed to the customers is estimated and accrued as revenue in the current year. Unbilled revenue included in accounts receivable as at December 31, 2025, is $6,553 ($7,256 in 2024). Other revenue is recognized when services are provided and the customer takes ownership and assumes risk of loss in accordance with customer contracts, collection of the related receivable is probable, persuasive evidence of an arrangement exists and the sales price is fixed or determinable. Amounts received for future services are deferred until the service is provided.

Foreign currency translation

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at the exchange rate prevailing at the balance sheet date. Gains and losses on translation are included in the statement of earnings and retained earnings. Revenue and expenses are translated at the exchange rate prevailing on the transaction date.

Employee benefit plans

The cost of the Corporation’s defined benefit pension plans is determined periodically by independent actuaries. The Corporation has chosen an accounting policy to measure its defined benefit plan obligations using the funding valuation approach. This approach uses the most recent completed actuarial valuations prepared for funding purposes as the basis of measuring defined benefit plan obligations. As well, the Corporation is using a roll-forward technique in the years between valuations to estimate the defined benefit plan obligations. Pension plan assets are valued at fair value as at the balance sheet date.

In 2013, the Corporation made an application to the OEB to allow recognition of regulatory assets related to unamortized amounts, and restatement of prior years’ pension and other retirement benefit expenses, that would otherwise be collected from customers through rates in subsequent years. In December 2013, the OEB issued a Decision and Order approving the establishment of specific deferral accounts to recognize these amounts as long-term regulatory assets, which will be disposed of in future CoS proceedings, subject to the OEB’s prudence review at that time. As well, the Corporation reversed previously recognized future income tax liabilities related to the changes in the pension and other retirement benefit liabilities as of January 1, 2014. The Corporation recognized offsetting regulatory liabilities related to the future income taxes expected to be recovered from customers in future electricity rates as of January 1, 2014.

The Corporation made an application to the OEB to continue to account for pension and other retirement benefits under the former Section 3461.

1. Basis of accounting and summary of significant accounting policies (continued)

(b) Significant accounting policies (continued)

Employee benefit plans (continued)

In December 2013, the OEB issued a Decision and Order approving the establishment of specific variance accounts as of January 1, 2013, to recognize the difference in expense between Sections 3461 and 3462 as long-term regulatory assets or liabilities for 2013 and future years, which will be disposed of in future CoS proceedings, subject to the OEB's prudence review at that time.

Financial instruments

Financial assets and financial liabilities are initially recognized at fair value when the Corporation becomes a party to the contractual provisions of the financial instrument. Subsequently, all financial instruments are measured at amortized cost.

Transaction costs related to financial instruments measured subsequent to initial recognition at fair value are expensed as incurred. Transaction costs related to other financial instruments are added to the carrying value of the asset or netted against the carrying value of the liability and are then recognized over the expected life of the instrument using the effective interest method. Any premium or discount related to an instrument measured at amortized cost is amortized over the expected life of the item using the effective interest method and recognized in net earnings as interest income or expense.

With respect to financial assets measured at cost or amortized cost, the Corporation recognizes an impairment loss, if any, in net earnings when there are indicators of impairment and it determines that a significant adverse change has occurred during the period in the expected timing or amount of future cash flows. When the extent of impairment of a previously written-down asset decreases and the decrease can be related to an event occurring after the impairment was recognized, the previously recognized impairment loss is reversed to net earnings in the period the reversal occurs.

Income taxes

The Corporation follows the future income taxes method of accounting for income taxes. Under this method, future tax assets and liabilities are recognized for the temporary differences between the tax and accounting bases of assets and liabilities. Future tax assets and liabilities are measured using the enacted and substantively enacted tax rates and laws expected to apply to taxable income in the period in which the temporary differences are expected to be recovered or settled. The Corporation recognizes regulatory assets related to future income tax liabilities in the amount of future income taxes expected to be recovered from customers in future electricity rates.

Use of estimates

The preparation of financial statements in conformity with ASPE requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Unbilled revenue, valuation of pension and post-retirement obligations, amortization, and income taxes are specific areas where the use of estimates and assumptions are significant. Actual results may vary from the current estimates. These estimates are reviewed periodically and, as adjustments become necessary, they are reported in earnings in the period in which they become known.

2. Utility capital assets

Utility capital assets consist of the following:

	Cost $	Accumulated amortization $	2025 Net book value $
Transmission	**40,650**	**19,444**	**21,206**
Distribution	**246,016**	**73,558**	**172,458**
Other	**19,937**	**13,151**	**6,786**
	306,603	**106,153**	**200,450**

	Cost $	Accumulated amortization $	2024 Net book value $
Transmission	38,026	18,764	19,262
Distribution	237,215	69,621	167,594
Other	17,880	12,529	5,351
	293,121	100,914	192,207

The amounts above include assets under construction of $6,939 ($12,597 in 2024) which are not subject to amortization.

3. Intangible assets

Intangible assets consist of the following:

	Cost $	Accumulated amortization $	2025 Net book value $
Software costs	**18,375**	**14,332**	**4,043**
Land and transmission rights	**8,800**	**5,094**	**3,706**
Other	**443**	**183**	**260**
	27,618	**19,609**	**8,009**

	Cost $	Accumulated amortization $	2024 Net book value $
Software costs	17,133	13,386	3,747
Land and transmission rights	8,720	4,877	3,843
Other	444	172	272
	26,297	18,435	7,862

4. Employee future benefits

The Corporation is a participating employer with its parent company in a defined benefit pension plan and a defined benefit plan providing other retirement benefits. The Corporation also maintains a defined contribution pension plan providing pension benefits and makes contributions to the Ontario Municipal Employees' Retirement Plan ("OMERS") plan on behalf of some of its employees. OMERS is a multi-employer defined benefit pension plan providing pension benefits and is accounted for as a defined contribution pension plan.

Information about the Corporation's defined benefit plans is as follows:

	Pension benefit plan		Other retirement plan	
	2025	2024	**2025**	2024
	$	$	**$**	$
Accrued benefit obligation				
Balance, beginning of year	**16,874**	16,858	**6,338**	7,142
Current service costs	**190**	180	**64**	67
Finance costs	**936**	936	**298**	329
Benefits paid	**(947)**	(980)	**(300)**	(313)
Actuarial gains	**(117)**	(120)	**(288)**	(887)
Balance, end of year	**16,936**	16,874	**6,112**	6,338
Plan assets				
Fair value, beginning of year	**22,099**	21,652	**—**	—
Interest income	**1,226**	1,202	**—**	—
Return on plan assets	**(63)**	225	**—**	—
Contributions	**—**	—	**300**	313
Benefits paid	**(947)**	(980)	**(300)**	(313)
Fair value, end of year	**22,315**	22,099	**—**	—
Funded status – plan surplus (deficit)	**5,379**	5,225	**(6,112)**	(6,338)

The measurement date for the plan assets and the accrued benefit obligation was as at December 31, 2025. The effective date of the most recent actuarial valuation was as at December 31, 2022, and the date of the next required valuation for funding purposes is as at December 31, 2025, and will be completed by September 2026. The measurement date for other retirement plans was as at December 31, 2025. The effective date of the most recent actuarial valuation was as at December 31, 2024.

The defined benefit pension plan assets held at the measurement date are represented by the following categories:

	%
Canadian equity funds	**6**
Foreign equity funds	**37**
Canadian fixed income funds	**56**
Cash	**1**

4. Employee future benefits (continued)

	Pension benefit plan		Other retirement plan	
	2025	2024	**2025**	2024
	$	$	**$**	$
Significant assumptions used				
Discount rate, beginning of year	**5.55%**	5.55%	**4.60%**	5.30%
Discount rate, end of year	**5.55%**	5.55%	**4.70%**	4.60%
Rate of compensation increase	**3.50%**	3.50%	**3.50%**	3.50%
Initial health care trend rate	**—**	—	**4.79%**	4.88%
Average remaining service of active employees (years)	**2**	3	**16**	17
Net benefit expense for the year				
Current service costs	**189**	180	**64**	67
Finance costs	**(290)**	(266)	**297**	329
Remeasurement costs	**(53)**	(344)	**(287)**	(887)
Regulatory adjustments	**109**	331	**279**	890
Net benefit (recovery) expense	**(45)**	(99)	**353**	399

The total expense for the Corporation's defined contribution pension plan for the year amounted to $462 ($455 in 2024). The pension cost associated with the OMERS plan was $98 ($96 in 2024).

5. Income taxes

The following is a reconciliation of the combined statutory income tax rate to the effective income tax rate:

	2025	2024
	%	%
Statutory income tax rate	**26.50**	26.50
Future income taxes transferred to regulatory assets	**(30.11)**	(27.05)
Tax adjustments from prior years	**(0.05)**	(0.28)
Other	**8.15**	7.30
Effective income tax rate	**4.49**	6.47

The provision for income taxes consists of the following:

	2025	2024
	$	$
Current income taxes	**224**	295
Current income tax adjustments from prior years	**(3)**	(14)
	221	281
Future income taxes	**1,756**	1,371
Future income taxes transferred to regulatory assets (Note 13)	**(1,721)**	(1,333)
	35	38
	256	319

5. Income taxes (continued)

Future income taxes are provided for temporary differences. Net future tax liabilities consist of the following:

	2025	2024
	$	$
Future tax assets (liabilities)		
Utility capital assets	**(15,260)**	(13,747)
Employee future benefits	**742**	708
Regulatory assets	**(5,022)**	(4,530)
Other assets	**404**	189
Net future tax liabilities	**(19,136)**	(17,380)

6. Related party transactions

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

	2025	2024
	$	$
Receipts		
Administrative services to		
FortisOntario Inc.	**248**	237
Cornwall Street Railway, Light and Power Company Limited	**1,994**	1,973
Algoma Power Inc.	**2,613**	2,581
Advances of funds to (from)		
FortisOntario Inc.	**2,210**	2,300
Cornwall Street Railway, Light and Power Company Limited	**10,600**	9,500
Algoma Power Inc.	**(2,300)**	(10,700)
Reimbursement of expenses paid on behalf of and services provided to		
FortisOntario Inc.	**573**	661
Cornwall Street Railway, Light and Power Company Limited	**106**	—
Algoma Power Inc.	**639**	706
Payments		
Management fees paid to FortisOntario Inc.	**1,155**	1,089
Rent paid to FortisOntario Inc.	**843**	656
Interest expense paid to FortisOntario Inc.	**1,428**	1,374
Dividends paid to FortisOntario Inc.	**3,000**	3,000
Reimbursement for expenses paid on behalf of and services provided from		
Rebate program funding processed through the Corporation on behalf of Cornwall Street Railway, Light and Power Company Limited	**10,071**	11,344
FortisOntario Inc.	**5,186**	4,802
Cornwall Street Railway, Light and Power Company Limited	**—**	79

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

6. Related party transactions (continued)

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

	2025 **$**	2024 $
FortisOntario Inc.	**(45,216)**	(40,696)
CH Energy Group Inc.	**—**	2
	(45,216)	(40,694)

Details of relationships with related parties are as follows:

- Fortis Inc. owns a 100% interest in the capital stock of FortisOntario Inc.
- FortisOntario Inc. owns a 100% interest in the capital stock of the Corporation
- Cornwall Street Railway, Light and Power Company Limited is a wholly owned subsidiary of FortisOntario Inc.
- Algoma Power Inc. is a wholly owned subsidiary of FortisOntario Inc.
- CH Energy Group Inc. is a wholly-owned subsidiary of Fortis Inc.

7. Long-term debt

Long-term debt consists of the following:

	2025 **$**	2024 $
4.102% senior unsecured notes due August 14, 2048	**75,000**	75,000
Unamortized debt issue costs	**(238)**	(249)
	74,762	74,751

The senior unsecured notes bear interest at 4.102% and are repayable at maturity on August 14, 2048. Interest expense on long-term debt for the year was $3,077 ($3,077 in 2024). The Corporation incurred debt issue costs in 2018 of $316 that are being amortized over the term of the loan. As at December 31, 2025, the accumulated amortization amounted to $78 ($67 in 2024).

The Corporation's long-term debt obligations and credit facility agreements have covenants that restrict the issuance of additional debt such that debt cannot exceed 75% of their capital structures as defined in the agreements. As at December 31, 2025, the Corporation was in compliance with its debt covenants (in compliance in 2024).

8. Capital stock

The authorized and issued capital stock consists of 23,900,001 common shares without par value.

9. Amortization

Amortization consists of the following:

	2025 $	2024 $
Amortization of utility capital assets	**6,684**	6,278
Amortization of intangible assets	**1,174**	1,157
Amortization of contributions in aid of construction	**(628)**	(594)
	7,230	6,841
Vehicle amortization allocated	**(424)**	(447)
	6,806	6,394

Vehicle amortization is allocated to utility capital assets and operating expenses on a labour distribution basis.

10. Statement of cash flows

The net change in non-cash working capital balances related to operations consists of the following:

	2025 $	2024 $
Accounts receivable	**328**	(1,313)
Materials and supplies	**(77)**	52
Prepaid expenses	**41**	(80)
Due to/from related parties	**4,522**	14,639
Income taxes receivable	**321**	120
Accounts payable and accrued liabilities	**(450)**	487
Customer deposits	**5**	948
Regulatory assets/liabilities	**852**	3,283
	5,542	18,136

Supplemental cash flow information:

	2025 $	2024 $
Interest paid	**3,168**	3,780
Income taxes paid (received)	**(100)**	630
	3,068	4,410

11. Financial risk management

The Corporation is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit risk - Risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument.

Liquidity risk - Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.

11. Financial risk management (continued)

Market risk and interest rate risk - Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices.

Credit risk

For cash, trade and other accounts receivable due from customers, the Corporation's credit risk is limited to the carrying value on the balance sheet.

The Corporation is exposed to credit risk from its distribution customers but has various policies to minimize this risk. These policies include requiring customer deposits, performing disconnections and using third party collection agencies for overdue accounts. The Corporation has a large and diversified distribution customer base, which minimizes the concentration of this risk.

The aging of the Corporation's trade and other receivables due from customers is as follows:

	2025	2024
	$	$
Not past due	**13,100**	12,948
Past due 0–30 days	**352**	879
Past due 31–60 days	**220**	202
Past due 61 days and over	**1,087**	915
	14,759	14,944
Less allowance for doubtful accounts	**(460)**	(317)
	14,299	14,627

Liquidity risk

Liquidity risk to the Corporation is minimized. Financing of regulated capital and other expenditures is done through internally generated funds. These funds are a result of allowable rate regulated returns and recoveries under the OEB rate regulation mechanism.

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

To mitigate any liquidity risk, the Corporation is a party to a committed revolving credit facilities and letters of credit facilities totaling $65,000 ($65,000 in 2024), of which $50,700 ($50,700 in 2024) was unused. The revolving credit facilities and letters of credit facilities are renewed on an annual basis. Loans payable are renewed on a rolling one month period from time to time as needed by the Corporation. This credit agreement is shared among the subsidiaries of FortisOntario Inc. and is renewed on an annual basis.

The following summary outlines the credit facilities among the subsidiaries of FortisOntario Inc:

	2025	2024
	$	$
Total credit facilities	**65,000**	65,000
Letters of credit outstanding	**(14,300)**	(14,300)
Credit facilities available	**50,700**	50,700

11. Financial risk management (continued)

Liquidity risk (continued)

The facility is guaranteed by the parent company and the revolving credit facilities bear interest at the bankers' acceptance rate plus 1.00% in the case of bankers' acceptances, and at the bank's prime lending rate plus 0.20% in the case of bank loans.

The following is an analysis of the contractual maturities of the Corporation's financial liabilities as at December 31:

	< 1 year $	**1 - 3 years $**	**4 - 5 years $**	**> 5 years $**	**2025 Total $**
Accounts payable and accrued liabilites	**9,522**	**—**	**—**	**—**	**9,522**
Customer deposits	**2,459**	**600**	**272**	**561**	**3,892**
Due to related parties	**45,216**	**—**	**—**	**—**	**45,216**
Long-term debt	**—**	**—**	**—**	**75,000**	**75,000**
	57,197	**600**	**272**	**75,561**	**133,630**

	< 1 year $	1 - 3 years $	4 - 5 years $	> 5 years $	2024 Total $
Accounts payable and accrued liabilites	9,972	—	—	—	9,972
Customer deposits	2,454	652	279	120	3,505
Due to related parties	40,696	—	—	—	40,696
Long-term debt	—	—	—	75,000	75,000
	53,122	652	279	75,120	129,173

The long-term debt above is presented at gross of any deferred financing costs (see Note 7).

Market risk

Interest rate risk

Long-term debt is at fixed interest rates thereby minimizing cash flow and interest rate fluctuation exposure. The Corporation is primarily subject to risks associated with fluctuating interest rates on its short-term borrowings. As of December 31, 2025, the Corporation's short-term borrowings are nil (nil in 2024).

12. Capital management

The Corporation manages its capital to approximate the deemed capital structure reflected in the utility's customer rates. Effective January 1, 2022, the distribution rates are based on a deemed capital structure of 60% debt and 40% equity. The Corporation's capital structure consists of third party debt, affiliated debt and common equity but excludes unamortized debt issue costs.

12. Capital management (continued)

The managed capital is as follows:

	2025 $	**Actual %**	2024 $	Actual %
Debt	**75,000**	**51**	75,000	52
Equity	**72,691**	**49**	70,232	48
	147,691	**100**	145,232	100

13. Regulatory assets and liabilities

Regulatory assets and liabilities arise as a result of regulatory requirements.

The Corporation pays the cost of power on behalf of its customers and recovers these costs through retail billings to its customers. The cost of power includes charges for transmission, wholesale market operations and the power itself from Ontario's Independent Electricity System Operator. The balance of the retail settlement variance account represent the costs that have not been recovered from, or settled through, customers as of the balance sheet date. The OEB's Distribution Rate Handbook and Accounting Procedures Handbook allow these costs to be deferred and recovered through future rate adjustments, as discussed in Note 1. In the absence of rate regulation, these costs would be expensed in the period that they are incurred.

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

In 2019, the OEB directed all regulated utilities to recognize a regulatory liability for any cash tax savings related to the new accelerated capital cost allowance rules enacted by the federal government in late 2018. As at December 31, 2021, the Corporation is no longer required to track variances related to accelerated capital cost allowance for its distribution business unit as approved in the Decision and Order issued for CNPI's 2022 CoS. In the Decision and Order for CNPI's 2022 CoS, the OEB approved the disposition over a period of one year for the accumulated tax savings related to the new accelerated capital cost allowance rules. CNPI's transmission business unit continues to track variances related to accelerated capital cost allowance.

13. Regulatory assets and liabilities (continued)

Regulatory assets and liabilities are generally not subject to a regulatory return; however, the balances include an accrual for interest recovery/payable as permitted by the regulators. The purpose of the following table is to provide reconciliation between the regulatory assets and liabilities and the remaining rebate period:

	Remaining rebate period	**2025 $**	2024 $
Current regulatory assets			
Amounts approved	1 year	**—**	19
Long-term regulatory assets			
Retail settlement and other variance accounts	2 plus years	**1,935**	520
Future income taxes to be recovered from customers	Life of assets	**18,489**	16,768
Other	2 plus years	**13**	13
		20,437	17,301
Current regulatory liabilities			
Amounts approved	1 year	**1,794**	961
Long-term regulatory liabilities			
Retail settlement and other variance accounts	2 years	**3,132**	1,666
Tax expense variances related to accelerated capital cost allowance	2 plus years	**108**	67
Pension and other retirement benefits	EARSL	**1,929**	1,545
		5,169	3,278

14. Segmented information

(a) Earnings

	CNPI distribution $	**CNPI transmission $**	**2025 Total $**
Revenue	**90,471**	**5,206**	**95,677**
Cost of purchased power	**63,324**	**—**	**63,324**
Operating expenses	**12,709**	**2,145**	**14,854**
Amortization	**5,911**	**895**	**6,806**
Operating earnings	**8,527**	**2,166**	**10,693**
Other regulatory adjustment	**—**	**40**	**40**
Interest expense	**4,357**	**581**	**4,938**
Income taxes	**223**	**33**	**256**
Net earnings	**3,947**	**1,512**	**5,459**

	CNPI distribution $	CNPI transmission $	2024 Total $
Revenue	90,275	4,910	95,185
Cost of purchased power	64,034	—	64,034
Operating expenses	12,220	1,953	14,173
Amortization	5,493	901	6,394
Operating earnings	8,528	2,056	10,584
Other regulatory adjustment	—	(2)	(2)
Interest expense	5,065	589	5,654
Income taxes	234	85	319
Net earnings	3,229	1,384	4,613

(b) Utility capital assets

	CNPI distribution $	**CNPI transmission $**	**2025 Total $**
Cost	**265,647**	**40,956**	**306,603**
Accumulated amortization	**86,497**	**19,656**	**106,153**
	179,150	**21,300**	**200,450**

	CNPI distribution $	CNPI transmission $	2024 Total $
Cost	254,789	38,332	293,121
Accumulated amortization	81,949	18,965	100,914
	172,840	19,367	192,207

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

ATTACHMENT 1-G:
RECONCILIATION – AFS TO RRR

CANADIAN NIAGARA POWER INC. - DISTRIBUTION
($000's)

	2025 AUDITED FINANCIAL STATEMENTS ("AFS")	2025 2.1.7 RRR	VARIANCE	2.1.7 RRR OEB Accts Mapped	EXPLANATION
BALANCE SHEET VARIANCES					
Goodwill	7,232	7,232	0	**2060**	
Capital Assets - Distribution (Cost)	265,647	265,647	(0)	**1805 to 1875, 1905 to 1990, 2055**	
Intangibles - Distribution (Cost)	19,262	19,262	(0)	**1606 to 1612**	AFS 27,618 less 8,356 transmission
Net Contributions - Distribution (Cost less Amortization)	(22,176)	(22,176)	(0)	**1995**	AFS 22,320 less 144 transmission
Accumulated Amortization of Assets - Distribution	(101,185)	(101,185)	0	**2105, 2120**	AFS 86,497 plus 19,609 less 4,921 transmisssion
Net Capital Assets	**168,780**	**168,781**	**1**	**immaterial, rouding**	
Less: Goodwill	(7,232)				excluded from rate base
Less: OEB 1606 (Net of Accumulated Amortization)	(24)				excluded from rate base
Less: Other Non-Rate Regulated per FAC	(433)				excluded from rate base
Adjusted Net Capital Assets	**161,091**				agrees to FAC per COS
INCOME STATEMENT VARIANCES					
Sales of Electricity		63,324		**4006 to 4076**	
Distribution Services Revenue		24,670		**4080 to 4090**	
Other Operating Revenue		943		**4205 to 4245**	
Other Revenue		669		**4305 to 4415**	
Revenue	90,471	89,606	(865)		Other operating revenue (costs) grouped with expenses in AFS, and regulatory debits grouped with regulatory adjustments on AFS; Fixed asset fee recoveries grouped with expenses in 2.1.7
Power Supply Expenses (Working Capital)		63,324		**4705 to 4751**	
Operation and Maintenance (Working Capital)		4,775		**5005 to 5195**	
Billing and Collection, Community Relations (Working Capital)		2,062		**5305 to 5425**	
Administrative and General Expenses (Working Capital)		4,845		**5605 to 5695**	
Operating Expenses	76,033	75,006	(1,027)		Other revenue (costs), donations and property taxes grouped with expenses in AFS; Fixed asset fee recoveries grouped with expenses in 2.1.7
Amortization of Assets	5,911	5,911	(0)	**5705 to 5740**	
Donations		29	29	**6205**	Donations grouped with operating expenses in AFS
Interest Expense	4,357	4,357	(0)	**6005 to 6045**	
Tax Expense	223	356	133	**6105 to 6115**	Property taxes grouped with operating expenses in AFS
Profit (Loss)	3,947	3,948	1	**immaterial, rouding**	

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

ATTACHMENT 1-H:
DISTRIBUTION LICENCE

Electricity Distribution Licence

ED-2002-0572

Canadian Niagara Power Inc.

Valid Until

November 1, 2043

Brian Hewson
Vice President, Consumer Protection & Industry Performance
Ontario Energy Board

Date of Issuance: November 2, 2023

Ontario Energy Board	Commission de l'énergie de l'Ontario
P.O. Box 2319	C.P. 2319
2300 Yonge Street	2300, rue Yonge
27th Floor	27e étage
Toronto ON M4P 1E4	Toronto ON M4P 1E4

LIST OF AMENDMENTS

OEB File No.	Date of Amendment
EB-2002-0572	November 6, 2003 – original licence issue date
EB-2003-0318	August 31, 2004
EB-2004-0443	November 23, 2004
EB-2006-0131	November 20, 2006
EB-2008-0143	September 10, 2008
EB-2010-0215	November 12, 2010
EB-2010-0307	March 29, 2011
EB-2011-0401	April 25, 2012 (corrected December 21, 2012)
EB-2014-0324	December 18, 2014
EB-2016-0015	January 28, 2016
EB-2015-0365	February 11, 2016
EB-2016-0163	May 19, 2016
EB-2016-0292	November 3, 2016
EB-2017-0101	March 31, 2017
EB-2017-0170, EB-2017-0186 and EB-2017-0201	June 29, 2017
EB-2017-0318	February 8, 2018
EB-2019-0167	September 12, 2019
EB-2020-0085	March 2, 2020
EB-2020-0185	September 11, 2020
EB-2023-0265	November 2, 2023 – licence renewal date

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1 Definitions

In this Licence:

"**Accounting Procedures Handbook**" means the handbook, approved by the Ontario Energy Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee;

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

"**distribution services**" means services related to the distribution of electricity and the services the Ontario Energy Board has required distributors to carry out, including the sales of electricity to consumers under section 29 of the Act, for which a charge or rate has been established in the Rate Order;

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

"**IESO**" means the Independent Electricity System Operator;

"**Licensee**" means Canadian Niagara Power Inc.;

"**Market Rules**" means the rules made under section 32 of the Electricity Act;

"**Rate Order**" means an Order or Orders of the Ontario Energy Board establishing rates the Licensee is permitted to charge;

"**regulation"** means a regulation made under the Act or the Electricity Act;

"**service area**" means the area in which the distributor is authorized by its licence to distribute electricity;

2 Interpretation

2.1 In this Licence, words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the Licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this Licence, where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day that is not a holiday.

3 Authorization

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence:

a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence;

b) to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act in the manner specified in Schedule 2 of this Licence; and

c) to act as a wholesaler for the purposes of fulfilling its obligations under the Retail Settlement Code or under section 29 of the Electricity Act.

4 Obligation to Comply with Legislation, Regulations and Market Rules

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts, except where the Licensee has been exempted from such compliance by regulation.

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

5.1 The Licensee shall at all times comply with the following Codes (collectively the "Codes") approved by the Ontario Energy Board, except where the Licensee has been specifically exempted from such compliance. Any exemptions granted to the licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence:

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters;

b) the Distribution System Code;

c) the Retail Settlement Code; and

d) the Standard Supply Service Code.

5.2 The Licensee shall:

a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

6 Obligation to Provide Non-discriminatory Access

6.1 The Licensee shall, upon the request of a consumer, generator or retailer, provide such consumer, generator or retailer with access to the Licensee's distribution system and shall convey electricity on behalf of such consumer, generator or retailer in accordance with the terms of this Licence.

7 Obligation to Connect

7.1 The Licensee shall connect a building to its distribution system if:

a) the building lies along any of the lines of the distributor's distribution system; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.2 The Licensee shall make an offer to connect a building to its distribution system if:

a) the building is within the Licensee's service area as described in Schedule 1; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.3 The terms of such connection or offer to connect shall be fair and reasonable and made in accordance with the Distribution System Code, and the Licensee's Rate Order.

7.4 The Licensee shall not refuse to connect or refuse to make an offer to connect unless it is permitted to do so by the Act or a regulation or any Codes to which the Licensee is obligated to comply with as a condition of this Licence.

8 Obligation to Sell Electricity

8.1 The Licensee shall fulfill its obligation under section 29 of the Electricity Act to sell electricity in accordance with the requirements established in the Standard Supply Service Code, the Retail Settlement Code and the Licensee's Rate Order.

9 Obligation to Maintain System Integrity

9.1 The Licensee shall maintain its distribution system in accordance with the standards established in the Distribution System Code and Market Rules, and have regard to any other recognized industry operating or planning standards adopted by the Ontario Energy Board.

10 Market Power Mitigation Rebates

10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence.

11 Distribution Rates

11.1 The Licensee shall not charge for connection to the distribution system, the distribution of electricity or the retailing of electricity to meet its obligation under section 29 of the Electricity Act except in accordance with a Rate Order

12 Separation of Business Activities

12.1 The Licensee shall keep financial records associated with distributing electricity separate from its financial records associated with transmitting electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Ontario Energy Board.

13 Expansion of Distribution System

13.1 The Licensee shall not construct, expand or reinforce an electricity distribution system or make an interconnection except in accordance with the Act and regulations, the Distribution System Code and applicable provisions of the Market Rules.

13.2 In order to ensure and maintain system integrity or reliable and adequate capacity and supply of electricity, the Ontario Energy Board may order the Licensee to expand or reinforce its distribution system in accordance with Market Rules and the Distribution System Code, or in such a manner as the Ontario Energy Board may determine.

14 Provision of Information to the Ontario Energy Board

14.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Ontario Energy Board, such information as the Ontario Energy Board may require from time to time.

14.2 Without limiting the generality of paragraph 14.1, the Licensee shall notify the Ontario Energy Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

15 Restrictions on Provision of Information

15.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator.

15.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed:

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence;

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator.

15.3 The Licensee may disclose information regarding consumers, retailers, wholesalers or generators where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified.

15.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under which their information may be released to a third party without their consent.

15.5 If the Licensee discloses information under this section, the Licensee shall ensure that the information provided will not be used for any other purpose except the purpose for which it was disclosed.

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner;

b) publish information which will make its customers aware of and help them to use its dispute resolution process;

c) make a copy of the dispute resolution process available for inspection by members of the public at each of the Licensee's premises during normal business hours; and

d) give or send free of charge a copy of the process to any person who reasonably requests it.

17 Term of Licence

17.1 This Licence shall take effect on November 2, 2023 and expire on November 1, 2043. The term of this Licence may be extended by the Ontario Energy Board.

18 Fees and Assessments

18.1 The Licensee shall pay all fees charged and amounts assessed by the Ontario Energy Board.

19 Communication

19.1 The Licensee shall designate a person that will act as a primary contact with the Ontario Energy Board on matters related to this Licence. The Licensee shall notify the Ontario Energy Board promptly should the contact details change.

19.2 All official communication relating to this Licence shall be in writing.

19.3 All written communication is to be regarded as having been given by the sender and received by the addressee:

a) when delivered in person to the addressee by hand, by registered mail or by courier;

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and

c) when received by facsimile transmission by the addressee, according to the sender's transmission report.

20 Copies of the Licence

20.1 The Licensee shall:

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of this Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

21 Pole Attachments

21.1 The Licensee shall provide access to its distribution poles to all Canadian carriers, as defined by the Telecommunications Act, and to all cable companies that operate in the Province of Ontario. For each attachment, with the exception of wireless attachments, the Licensee shall charge the rate approved by the Ontario Energy Board and included in the Licensee's tariff.

21.2 The Licensee shall:

a) annually report the net revenue, and the calculations used to determine that net revenue, earned from allowing wireless attachments to its poles. Net revenues will be accumulated in a deferral account approved by the Ontario Energy Board;

b) credit that net revenue against its revenue requirement subject to Ontario Energy Board approval in rate proceedings; and

c) provide access for wireless attachments to its poles on commercial terms normally found in a competitive market.

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with paragraph 8.1 of this Licence.

1. The Town of Fort Erie as of December 31, 1990 as per *Regional Municipality of Niagara Act*, R.S.O. 1990,

   • Including the customers located at the following physical addresses:
   - i. 14761 Sodom Road, Niagara Falls
   - ii. 14785 Schauble Road, Welland
   - iii. 7378 Durliat Road, Welland
   - iv. 6625 Willow Road, Port Robinson
   - v. 6541 Willow Road, Port Robinson
   - vi. 6409 Willow Road, Port Robinson
   - vii. 6113 Willow Road, Port Robinson
   - viii. 5981 Willow Road, Port Robinson
   - ix. 3400 Newgate Road, Port Robinson

   • Excluding the customers located at the following physical addresses:
   - i. 3288 Montrose Road, Stevensville
   - ii. 3362 Montrose Road, Stevensville
   - iii. 3392 Montrose Road, Stevensville

2. The customer located at 7780 Stanley Avenue, Niagara Falls.

3. The Town of Gananoque as of the date of this Licence, except for three customers located at 795 King Street East, 797 King Street East and 799 King Street East.

4. The customers located in the Township of Leeds and the Thousand Islands, formerly in the Townships of the Front of Leeds and Lansdowne:

   - Concession 1 Broken Front lots 1-8 the portions of Concession 1 lots 9-11, the south of Hwy 401; the portion of Concession 1 Lot A south of County Rd. 2; and the islands of Pike Island, Sister Island, Cherry Island, Orniston Island (formerly known as Cunningham Island) and Red Horse Island.

5. The customers located in the Township of Frontenac Islands, formerly in the Township of Howe Islands:

   - Fuller Road: Lot 21, Concession NR.

6. The customers located at the following lots and concessions or with the following civic numbers and future customers that lie along the Licensee's distribution system in the City of Kingston, formerly the Township of Pittsburgh:

- Concession 2 lots 7 – 18 excluding existing customers that front on Joyceville Road and future customers that lie along that Hydro One Networks Inc. (HONI) distribution system, but including CNPI customers with civic numbers 1680,1682 and 1776 Joyceville Road, and including lots 25 to 38 excluding one HONI navigation light service in lot 27.
-
- Concession 3 lots 2 to 38, south of Hwy 401 including the existing customers on John F Scott Rd and future customers that lie along that CNPI distribution system, excluding existing customers that front on Joyceville Road and future customers that lie along that HONI distribution system and excluding one customer lot 18 with address Highway 401 at Exit 632 and excluding lot 38 customers with civic numbers 2101,2931,2131 and 2173 Deer Ridge Road and excluding future customers that lie along that HONI distribution system.

- Concession 7 one station service Washburn Generating Station.

- Concession 8 one house with civic address 3012 Brewer's Mill Road and one station service Brewers Mills Generating Station.

- Concession 9 one station service at Jones Falls Generating Station.

- Kingston Mills Road: 563, 537, 531, 513, 509, 501,503, 500, 497, 493, 492, 490, 480,484, 473, 474, 464, 462, 460, 456, 452, 448, 445, 444, 440, 436, 432, 429, and 431.

- Old Kingston Mills Road: 946 and 950.

- County Road #15: 1967, 1986 and 1993.

- Abbey Dawn Road: 1707,1671,1660,1655,1635,1619,1597,1570,1560 and 1569.

- County Road #2: 3206, 3211, 3122 and 3275.

7. The customers located at the following civic numbers and future customers that lie along the Licensee's distribution system in the City of Kingston, formerly in the Township of Kingston:

- Italia Lane: 1174, 1110 and 1104.

- Montreal Street: 401 Parking lot, 1648, 1620, 1684, 1670,1658 and 1702.

- Thompson Cresent: 965, 949, 943, 937, 931, 927, 924, 921, 916, 905, 906, 903 and 893.

- Kingston Mills Road: 892, 885, 876, 875, 799, 793, 787, 781, 775, 773, 765, 759, 753, 749, 743, 737, 733, 727, 723, 719, 715, 711,710 709, 707, 703, 697, 693, 689, 685, 681, 675, 669, 661 and 636.

- Daylan Avenue: 1622,1628, 1633, 1632, 1672, 1668, 1646, 1650, 1654, 1656, 1655, 1658, 1660,1682, 1692, and 1686.

- John F Scott Road: 991,1015,1021,1050, and the sign under the bridge by Hwy 401.

- Battersea Road: 1616, 1618, 1624, 1642, 1658, 1670, 1684, and 1702.

- Station Road: 1699.

8. The Town of Port Colborne as of December 31, 1990 as per Regional Municipality of Niagara Act, R.S.O. 1990.

    - Excluding the customers located at the following civic numbers and locations:
        i. 3334 Nugent Road, Port Colborne
        ii. 3386 Nugent Road, Port Colborne
        iii. 3512 Nugent Road, Port Colborne
        iv. 3562 Nugent Road, Port Colborne
        v. 3770 West Side Road, Port Colborne
        vi. Nugent Road at West Side Road (Streetlight), Port Colborne
        vii. 3397 Townline Road, Port Colborne
        viii. 3429 Townline Road, Port Colborne

9. The customers located at the following civic numbers in the Township of Wainfleet:

    - 20116 Port Colborne Wainfleet Road S.
    - 20122 Port Colborne Wainfleet Road S.
    - 20136 Port Colborne Wainfleet Road S.
    - 20146 Port Colborne Wainfleet Road S.
    - 20154 Port Colborne Wainfleet Road S.

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act.

The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with paragraph 8.1 of this Licence, any applicable exemptions to this Licence, and at the rates set by the Ontario Energy Board.

SCHEDULE 3 LIST OF CODE EXEMPTIONS

This Schedule specifies any specific Code requirements from which the Licensee has been exempted.

1. The Licensee is exempt from the requirements of the following sections of the Affiliate Relationships Code for Electricity Distributors and Transmitters under the conditions specified in section 2 of this Schedule:

   Section 2.2.2

   Where a utility shares information services with an affiliate, all confidential information must be protected from access by the affiliate. Access to a utility's information services shall include appropriate computer data management and data access protocols as well as contractual provisions regarding the breach of any access protocols. A utility shall, if required to do so by the Board, conduct a review of the adequacy, implementation or operating effectiveness of the access protocols and associated contractual provisions which complies with the provision of section 5970 of the CICA Handbook. A utility shall also conduct such a review when the utility considers that there may have been a breach of the access protocols or associated contractual provisions and that such review is required to identify any corrective action that may be required to address the matter. The utility shall comply with such directions as may be given by the Board in relations to the terms of section 5970 review. The results of any such review shall be made available to the Board.

   Section 2.2.3

   A utility shall not share with an affiliate that is an energy service provider employees that are directly involved in collecting, or have access to, confidential information.

2. The Exemptions from the requirements of the Affiliate Relationship Code for Electricity Distributors and Transmitters referred to section 1 of this Schedule (the "Exemptions") are subject to the following conditions:

   a) The exemptions only apply in respect of the relationship between the Licensee and the following affiliates and not with respect to any other affiliates of the Licensee:

      - FortisOntario Inc.;
      - Cornwall Street Railway Light and Power Company Limited; and
      - Algoma Power Inc.

   b) The Licensee shall not share facilities, confidential information or employees with any affiliate identified in paragraph a) for any purpose other than the provision of services to, or the receipt of services from, the affiliate under the Services Agreements dated September 15, 2010 (the "Services Agreements") as filed with the Board as part of the materials filed in support of the application for the Exemptions, as such Services Agreements may be amended from time to time.

c) The activities of the Licensee relative to the affiliates identified in paragraph a) shall be governed by, and the Licensee shall be bound by and comply with, the Services Agreements, as amended from time to time.

d) The Licensee shall notify the Board of any material change relative to the materials filed in support of the application for the Exemptions as soon as possible upon becoming aware of such change and in no event later than fifteen days following the date on which the change occurs. Without limiting the generality of the foregoing, this obligation includes notifying the Board in the event of a change in the market activities of FortisOntario Inc.

e) The Board may, on its own initiative or upon receipt of notice from the Licensee under paragraph d), by order revoke one or more of the Exemptions, vary one or more of the conditions set out above or impose additional conditions upon becoming aware of any material change relative to the materials filed in support of the application for Exemptions, or for such other reason as the Board considers appropriate.

APPENDIX A

MARKET POWER MITIGATION REBATES

8. **Definitions and Interpretations**

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

9. **Information Given to IESO**

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

"ONTARIO POWER GENERATION INC. rebate"

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

ONTARIO POWER GENERATION INC. REBATES

For the payments that relate to the period from May 1, 2006 to April 30, 2009, the rules set out below shall apply.

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

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a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

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a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented and the

consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

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Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

CANADIAN NIAGARA POWER INC.
A FORTIS ONTARIO Company

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