TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO COMMUNITY ACTION FOR ENVIRONMENTAL SUSTAINABILITY

JT3.1

EVIDENCE REFERENCE:

1-CO-12 Table A

UNDERTAKING(S):

Provide update to the numbers and energy savings achieved to August.

RESPONSE(S):

a) Please see Table A for the information requested.

Table A - Ottawa Retrofit Accelerator Results

	2024 (April - Dec)[1]	2025 (Jan - August)
Number of Buildings Assessed through a Carbon Pathway Study	56	71[2]
Energy Savings Identified (GJ/year)[3]	0[4]	197,890[3]
Energy Savings Achieved	This program is not permitted to fund implementation of measures	
Customer Incentives Provided[5]	$817,694.02	$837,604.95

[1] Hydro Ottawa began its ORA program in April 2024.
[2] These are studies that have started in 2025. Not all of them have been completed.
[3] Combined gas and electricity savings. Note, these values are the sum of calculated potential net savings of all identified measures in completed, funded studies. Not all of the studies identified above have been completed, so additional savings will likely be identified. Implementation of these measures is up to building owners.
[4] While 56 Carbon Pathway Studies began in 2024, none had reached completion before Dec 31, 2024. Savings identified in completed studies that started in 2024 are included in the 2025 column.
[5] Funds approved and committed for carbon pathway studies.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO COMMUNITY ACTION FOR ENVIRONMENTAL SUSTAINABILITY

JT3.2

EVIDENCE REFERENCE:

N/A

UNDERTAKING(S):

Provide a copy of the presentation given to the City of Ottawa.

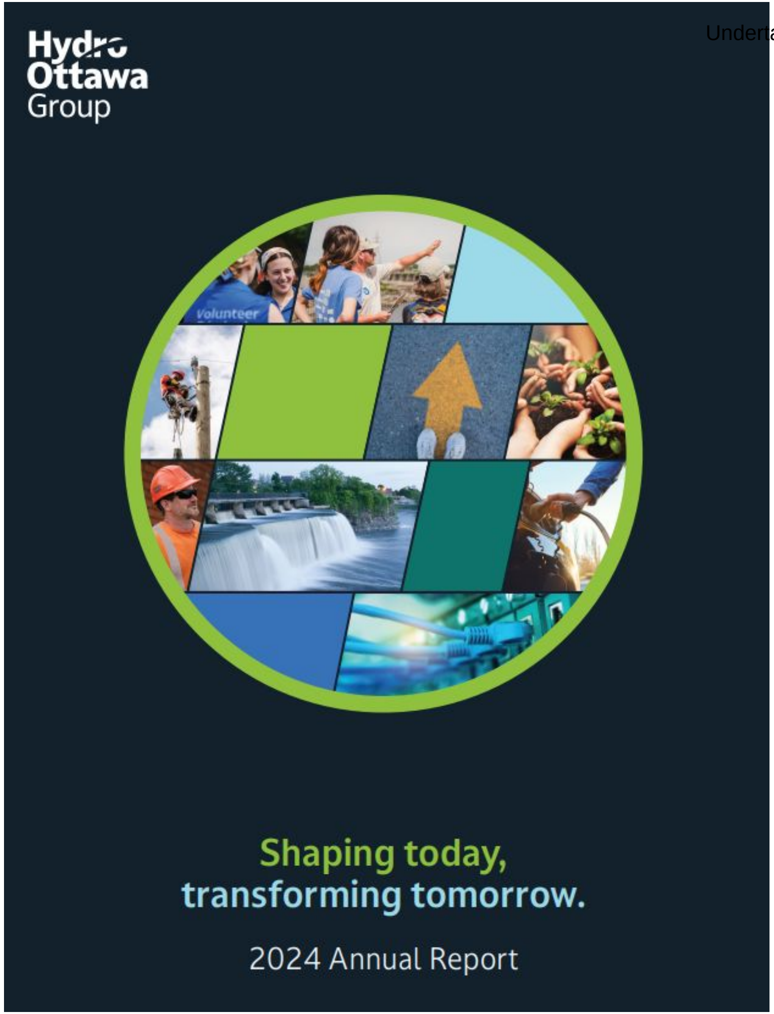
RESPONSE(S):

Please see Attachment JT3.2(A) - Hydro Ottawa 2025 AGM Presentation to Ottawa City Council.

2024 Annual Report

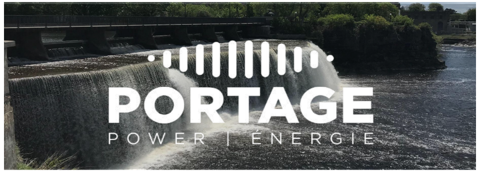
Annual General Meeting

June 25, 2025



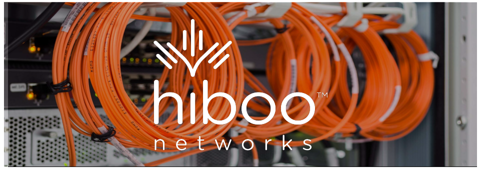
Hydro Ottawa Group overview

3rd largest municipal electricity distributor in Ontario



Ontario's largest municipally-owned green energy producer

Energy solutions and infrastructure management



High-speed fibre optic network services

100%
owned by the City of Ottawa

Operations
in Ontario, Québec, New York

372,000
customers

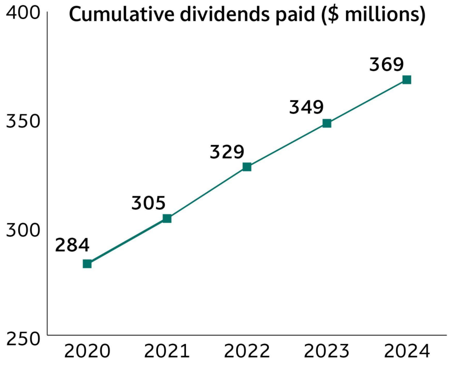
131 MW
clean energy capacity

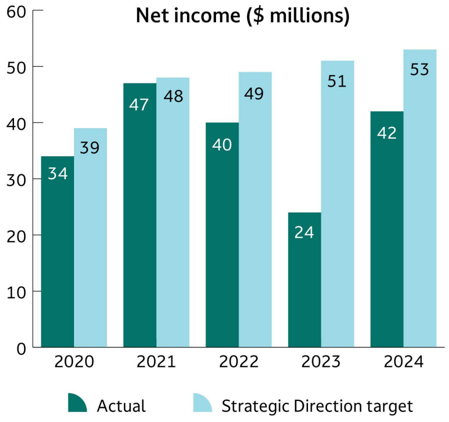
$2.8 billion
in assets

~750
employees

Our vision – *"A leading partner in a smart energy future"*

2024 at a glance





$389.4 M
in revenue (excluding power recovery)

$42.1 M
in net income

$191 M
in capital investment

$2.8 B
in assets

700+ GWh
of clean electricity production

7.8%
return on equity

Noteworthy highlights

- **New annual records:**
  - Grid investment
  - Portage Power generation
  - Envari revenue
- **Strong reliability results**
- **New corporate structure**
- **Improved credit rating**
- **Progress on net-zero**
- **Better economic conditions**
- **No severe weather events**

2024 results:

- **$22.3 M dividend; 2nd highest in our history**

Since 2005:

- **~$400 M cumulative dividends**
- **440% growth in asset base**

A community company at heart

$142,000
raised for United Way through annual employee fundraising campaign

$151,000
raised for Royal Ottawa Prompt Care Clinic

$76,000
in community sponsorships and donations

$87.5 M
paid for goods and services from local suppliers

$272,000
Low-Income Energy Assistance Program support for customers in need

A committed partner in transformational sustainability initiatives with the City

Public Transit Electrification

Zero Emission Buses,
LRT expansion

Municipal Buildings & Facilities

Energy retrofits,
building automation

Ottawa Community Housing

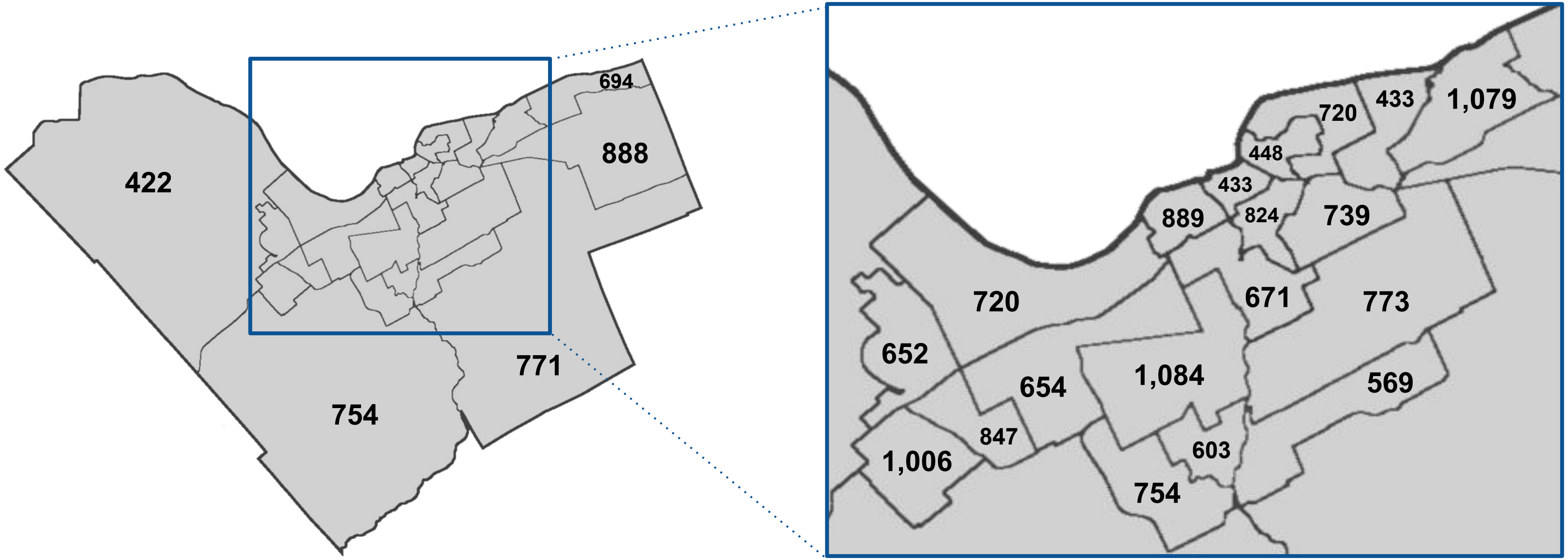
Lower costs and GHGs,
free WiFi pilot

EV & Bike Charging Infrastructure

Leading enabler of
local installations

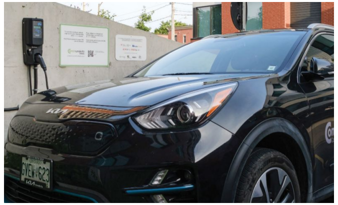
Hydro Ottawa Group

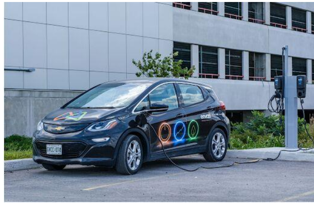
Number of registered EVs in Ottawa (by ward)



**Figures are (i) current as of April 2025 and (ii) approximate calculations, based on overlay of Ontario Ministry of Transportation postal code data and municipal ward boundaries*





Achieving sustainability at scale with local partners

Ottawa Airport Partnership

Pursuing path to net-zero

The Ottawa Hospital Central Utility Plant

Low-carbon campus energy system

Sewage Energy Exchange System

Zero-carbon solution at LeBreton

Green Energy Resilience District

Integrated energy solutions for Kanata North Tech Park

Zibi District Energy System

National Capital Region's first carbon-neutral community

Hydro Ottawa Group

The "energy transition" – meeting the moment and looking to the future…

"In energy history, we've witnessed the Age of Coal and the Age of Oil – and we're now moving at speed into the Age of Electricity, which will define the global energy system going forward and increasingly be based on clean sources of electricity."

Fatih Birol
Executive Director, International Energy Agency

Hydro Ottawa Group

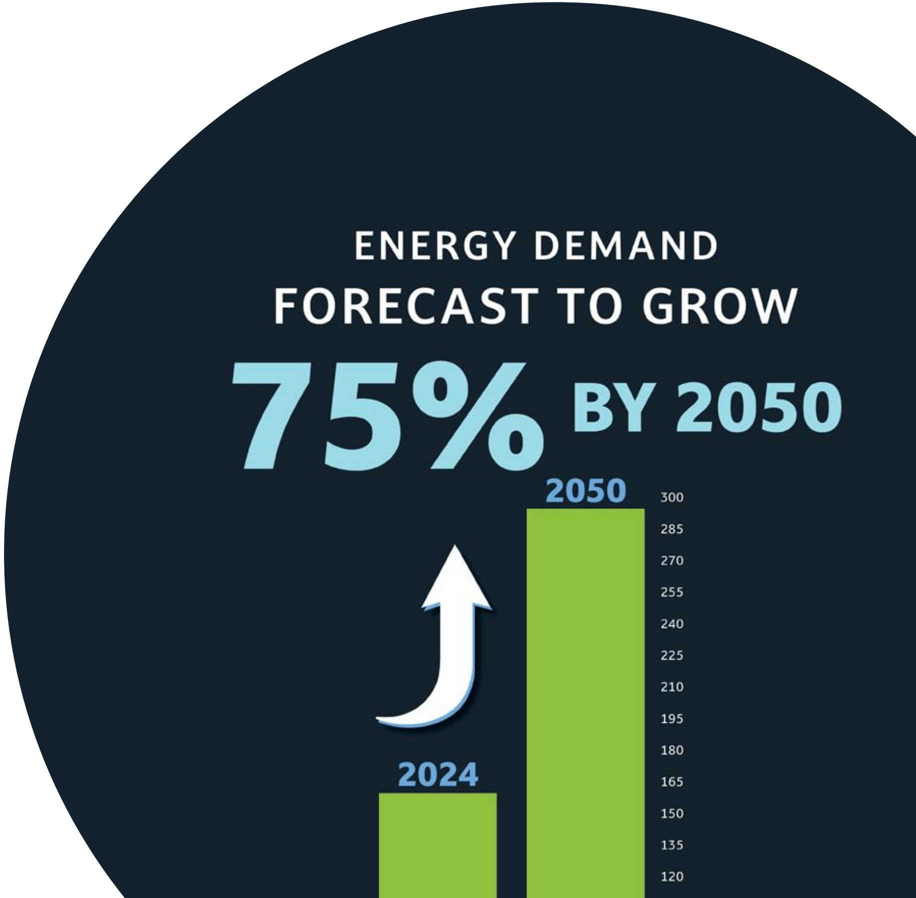
What this means for Canada...

2x-3x

Hydro Ottawa Group

What this means for Ontario...

- **Surge in demand**
- **Key drivers:**
  - Data centre growth
  - Consumers and businesses electrifying
  - Industrial expansion
  - Electric vehicle adoption
- **Largest energy procurement in Ontario's history:** Independent Electricity System Operator to acquire significant new supply through 2030s



...and closer to home

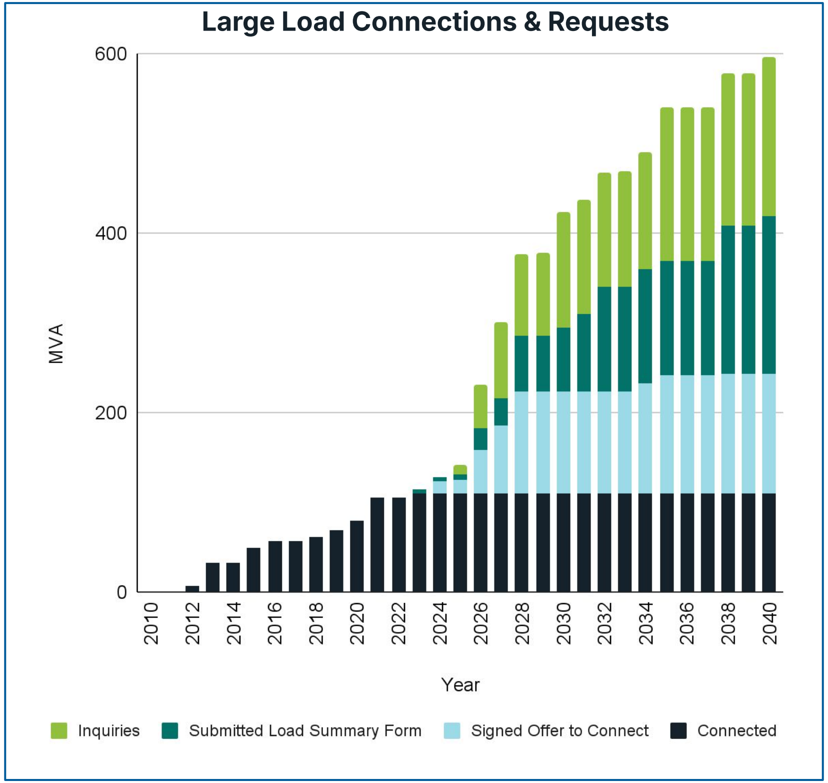
5 of 6 biggest infrastructure projects in Ottawa involve electrification/major increase in electrical demand

- *ReNew Canada* annually showcases 100 largest public sector projects in the country (3 of top 4 projects are power plants)
- 6 projects in Ottawa:
  1. Centre Block Rehabilitation
  2. **Light Rail Transit Stage 2**
  3. **Energy Services Acquisition Program modernization**
  4. **The Ottawa Hospital New Campus Development**
  5. **Dwyer Hill Training Centre (Department of National Defence)**
  6. **TerraCanada National Capital Area science & innovation hub**

Hydro Ottawa is a key project partner, offering critical services, support and expertise

Hydro Ottawa Group

...and closer to home (continued)



- Since 2018, there has been an upswing in requests from prospective customers with large load profiles (i.e. who need a significant amount of electricity) to connect to the distribution grid
- Electrification is driving increasingly large, complex connection requests
- 2010-2023: Hydro Ottawa connected 110 megavolt-amperes (MVA) of large loads – i.e. equivalent to almost 2 new substations *(**black** in the adjacent graph)*
- 2024-2030: 113 MVA of confirmed customer commitments *(**sky blue**)*; 199 MVA of potential connections *(**dark green** and **eco green**, respectively)*
- ***If all potential requests materialize, the next 6 years would represent a three-fold increase in large load connections relative to the last 13 years***

Hydro Ottawa Group

Hydro Ottawa Group

Powering a sustainable tomorrow: 2026-2030 Hydro Ottawa distribution rate application

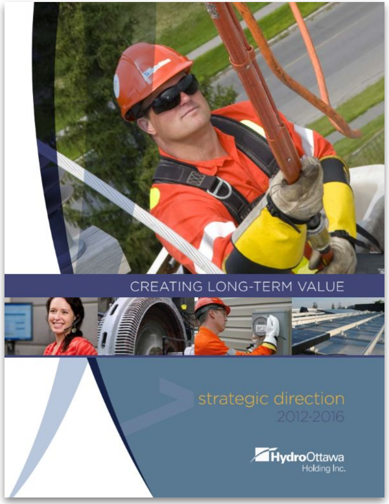
- Like all electricity distributors in Ontario, **Hydro Ottawa is subject to rate-regulation by the Ontario Energy Board (OEB)**
- Electricity distribution **rates are set on a five-year cycle**; Hydro Ottawa's current distribution rate plan is for 2021-2025
- **OEB-approved rate plan allows Hydro Ottawa to recover costs** associated with providing reliable service and operating our business
- **A successful outcome for the 2026-2030 application will be critical to meeting customer needs**
- Subject to approval, **$1.2 billion capital investment program** will be the largest in our history; key elements:
  - 1 new substation per year (historically 1 every 5 years)
  - Capacity upgrades for stations, transformers, lines
  - Distribution-scale battery storage to support growth
  - Additional storm hardening measures; strategic undergrounding
  - More intelligent, automated, efficient grid operations
  - New energy management tools for customers
- **87% average customer support for proposed investments**

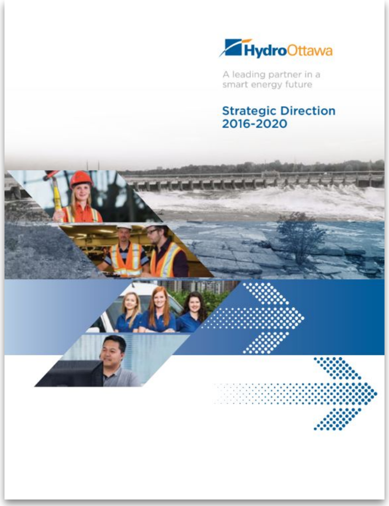
Multiple opportunities for public participation in OEB process

April 15, 2025	**Application filed with OEB**
April 29	**Completeness Letter** (Confirms OEB is processing application)
May 9	**Notice of Hearing & Letter of Direction**
June 3	**OEB Procedural Order No. 1** (Provides timeline of next steps)
Summer	**Intervenor and OEB Staff Interrogatories; Technical Conference**
Fall	**Settlement Conference; Oral Hearing (if necessary)**
December	**OEB Decision (expected)**
January 1, 2026	**Effective date of new distribution rates for 5-year term**

Hydro Ottawa Group

We're preparing a refreshed business strategy in the midst of unprecedented change, uncertainty and opportunity





Hydro Ottawa Group

AGM recommendations for Council

Hydro Ottawa Group

Recommendations

1. Receive the corporation's Audited Consolidated Financial Statements for the year ended December 31, 2024

2. Appoint KPMG LLP as the corporation's auditor for the year ending December 31, 2025

3. Approve the recommendation of the Nominating Committee of the Board of Directors, specifically, that Council appoint the persons identified to serve as members of the Board for the corresponding terms as specified

4. Authorize the Mayor and City Clerk to sign a written resolution on behalf of the City as shareholder setting out the resolutions approved by City Council

Hydro Ottawa Group

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT3.3

EVIDENCE REFERENCE:

1-Staff-1(A) -App 2-BA
1-Staff-1(A) - Table E

UNDERTAKING(S):

Provide a reconciliation of the table E fixed-asset total addition for 2023 reporting in table E what the total PP&E addition reported in Tab 2BA for 2023

RESPONSE(S):

In 2023 Hydro Ottawa received a $5.7M CCRA (Connection & Cost Recovery Agreement) credit from Hydro One related to the Cambrian station. Upon completion of the project, Hydro One compared actual construction costs incurred against estimated costs used in the CCRA and determined that actual costs were $5.7M lower. Estimated costs were used in Hydro One's original CCRA required payment under the terms of the agreement. In the Original Evidence, this $5.7M credit was shown as a disposal in Appendix 2-BA which resulted in total capital additions for 2023 totaling $92.5M with total disposals of $7.7M. The $5.7M credit was subsequently reclassified as a reduction to capital additions in Appendix 2-BA filed on June 4, 2025, resulting in a revised total capital additions amount of $86.8M and revised total disposals of $2.0M in 2023.

Table E from interrogatory 1-Staff-1(A) has been corrected to reflect this $5.7M CCRA credit reclassification for 2023. Table E shows a reconciliation of additions as per Appendix 2-BA in

Attachment 1-Staff-1(A) - Chapter 2 Appendices to additions for tax purposes as per Schedule 8 for 2023 Historical Year.

The $5.7M credit is reported in Hydro Ottawa's 2023 tax return as a deduction on Schedule 8 in the adjustments column.

Revised Table E - Reconciliation of Fixed Asset Continuity Schedule Additions from Appendix 2-BA to 2023 Tax Return for 2023 Historical Year

Reconciliation of Fixed Asset Additions (Appendix 2-BA) to 2023 Tax Return	Additions as per Original Evidence Appendix 2-BA	Additions as per Updated 1-Staff-1 Appendix 2-BA
Fixed Asset Total Additions (as per Appendix 2-BA)	$92,514,346	$86,810,248
Credit recorded as a reduction to additions in Appendix 2-BA	-	$5,704,098
Non distribution assets additions	$477,204	$477,204
Capital SR&ED Tax Credits[1]	$434,441	$434,441
SR&ED expenses capitalized[2]	($4,643,539)	($4,643,539)
AFUDC	($694,333)	($694,333)
Total Additions for Tax Return (as per Schedule 8)	**$ 88,088,119**	**$ 88,088,119**

[1] SR&ED Tax Credits are recorded as credits, included in OEB Account 2440 for accounting purposes, and depreciated over ten years. Please see Table 4 in Schedule 6-2-1.
[2] This represents current year SR&ED expenditures capitalized for accounting purposes but expensed for tax purposes. SR&ED expenditures are considered current expenditures for tax purposes.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT3.4

EVIDENCE REFERENCE:

N/A

UNDERTAKING(S):

Provide the audited 2024 HOL financial statements

RESPONSE(S):

Please see Attachment JT3.4(A) - 2024 HOL Audited Financial Statements.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO ONTARIO ENERGY BOARD STAFF

JT3.5

EVIDENCE REFERENCE:

UNDERTAKING(S):

Confirm that Hydro Ottawa's accounting treatment for contributed plant, specifically in-kind contributions or non-cash assets, is in line with the OEB Accounting Procedure Handbook.

RESPONSE(S):

Hydro Ottawa confirms that the fair value of any contributed plant (in-kind contributions or non-cash assets) is recorded in the applicable asset accounts (USofA 1606 to 1990). An offsetting amount is concurrently recorded in the deferred revenue USofA 2440. This treatment is in line with the OEB Accounting Procedure Handbook (APH), which specifies that:

"Contributions or grants in cash, services or property from governments or government agencies, corporations, individuals and others received in aid of construction or for acquisition of fixed assets"[1] shall be included in USofA 2440 (Deferred Revenues).

[1] Ontario Energy Board, *Accounting Procedures Handbook for Electricity Distributors* (January 1, 2012) Article 220, page 102.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT3.6

EVIDENCE REFERENCE:

Schedule 7-1-1

UNDERTAKING(S):

Provide information on third-party meter reading billing procedures.

RESPONSE(S):

Hydro Ottawa confirms that third party meter reading for 96% of the active meter base is charged by our third party contractors as a component of fixed annual support and maintenance contracts. For clarity, it is not adjusted based on volume. The remaining 4%, supporting suite meters, is charged on a per meter basis.

Hydro Ottawa Limited

Financial Statements

December 31, 2024

Table of Contents

Report of Management

Management is responsible for the integrity of the financial data reported by Hydro Ottawa Limited [the 'Company']. Fulfilling this responsibility requires the preparation and presentation of financial statements and other data using management's best judgment and estimates, as well as International Financial Reporting Standards as issued by the International Accounting Standards Board.

Management maintains appropriate systems of internal control and corporate-wide policies and procedures, which provide reasonable assurance that the Company's assets are safeguarded and that financial records are relevant and reliable.

The Board of Directors of the Company, with the advice of the Audit Committee of Hydro Ottawa Holding Inc., ensures that management fulfills its responsibility for financial reporting and internal control. At regular meetings, the Audit Committee, including the Chair of the Board of Directors of the Company, reviews internal controls and financial reporting matters with management for Hydro Ottawa Holding Inc. and its subsidiaries. The Chair of the Board of Directors of the Company, as well as the Chief Executive Officer and the Chief Financial Officer, advise the Board of Directors of the Company of any matters of concern raised by the Audit Committee in reviewing the financial affairs of the Company.

On behalf of Management,

DocuSigned by: Bryce Conrad 8EDB4595749C4E3...	Signed by: Geoff Simpson 43DC885CF33E43F...
Bryce Conrad	Geoff Simpson
President and Chief Executive Officer	Chief Financial Officer

KPMG LLP
150 Elgin Street, Suite 1800
Ottawa, ON K2P 2P8
Canada
Telephone 613 212 5764
Fax 613 212 2896

INDEPENDENT AUDITOR'S REPORT

To the Shareholder of Hydro Ottawa Limited

Opinion

We have audited the financial statements of Hydro Ottawa Limited (the "Entity"), which comprise:

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

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

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

Basis for Opinion

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

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

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

KPMG

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

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

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

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

Auditor's Responsibilities for the Audit of the Financial Statements

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

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

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

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

We also:

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

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

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

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity’s ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor’s report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor’s report. However, future events or conditions may cause the Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Ottawa, Canada

April 24, 2025

Hydro Ottawa Limited

Statement of Income
Year ended December 31, 2024 with comparative information for 2023
[in thousands of Canadian dollars]

	2024 **$**	2023 $
Revenue and other income		
Power recovery revenue [Note 16]	**957,565**	861,905
Distribution revenue [Note 16]	**243,062**	224,770
Other revenue [Note 16]	**29,488**	26,933
Government grant income	**5,955**	4,336
	1,236,070	1,117,944
Expenses		
Purchased power	**940,048**	878,410
Operating costs [Note 17]	**137,693**	128,873
Depreciation [Note 6]	**58,852**	55,441
Amortization [Note 7]	**9,348**	8,646
	1,145,941	1,071,370
Income before the undernoted items	**90,129**	46,574
Financing costs [Note 18]	**31,716**	31,314
Income before income taxes	**58,413**	15,260
Income tax expense [Note 19]	**15,365**	8,317
Net income	**43,048**	6,943
Net movements in regulatory balances, net of tax [Note 5]	**(5,894)**	21,855
Net income after net movements in regulatory balances	**37,154**	28,798

The accompanying notes are an integral part of these financial statements

Hydro Ottawa Limited

Statement of Comprehensive Income
Year ended December 31, 2024 with comparative information for 2023
[in thousands of Canadian dollars]

	2024 **$**	2023 $
Net income after net movements in regulatory balances	**37,154**	28,798
Other comprehensive income		
Items that will not be subsequently reclassified to net income		
Actuarial gain (loss) on post-employment benefits, net of tax	**102**	(201)
Net movement in regulatory balances related to other comprehensive income, net of tax	**(102)**	201
Total comprehensive income	**37,154**	28,798

The accompanying notes are an integral part of these financial statements

Hydro Ottawa Limited

Balance Sheet
As at December 31, 2024 with comparative information for 2023
[in thousands of Canadian dollars]

	2024 **$**	2023 $
Assets		
Current assets		
Accounts receivable [Note 4]	**210,763**	186,352
Income taxes receivable	**411**	1,139
Prepaid expenses	**8,330**	6,172
	219,504	193,663
Non-current assets		
Property, plant and equipment [Note 6]	**1,669,850**	1,542,581
Intangible assets [Note 7]	**102,204**	105,451
Investment properties, at cost	**442**	479
Total assets	**1,992,000**	1,842,174
Regulatory debit balances [Note 5]	**140,811**	131,843
Total assets and regulatory balances	**2,132,811**	1,974,017
Liabilities and equity		
Current liabilities		
Working capital facility [Note 8]	**39,894**	65,310
Accounts payable and accrued liabilities [Note 9]	**202,289**	187,484
Deferred revenue [Note 10]	**10,266**	8,399
Current portion of notes payable [Note 12]	**354,666**	-
	607,115	261,193
Non-current liabilities		
Deferred revenue [Note 10]	**327,199**	281,734
Employee future benefits [Note 11(b)]	**11,839**	11,875
Customer deposits	**21,056**	17,993
Notes payable [Note 12]	**542,519**	837,185
Deferred income tax liability [Note 19]	**95,415**	82,628
Other liabilities	**238**	337
Total liabilities	**1,605,381**	1,492,945
Equity		
Share capital [Note 14]	**167,081**	167,081
Retained earnings	**330,426**	299,032
Total liabilities and equity	**2,102,888**	1,959,058
Regulatory credit balances [Note 5]	**29,923**	14,959
Total liabilities, equity and regulatory balances	**2,132,811**	1,974,017

Contingent liabilities, commitments and subsequent events [Notes 21, 22 and 24]

On behalf of the Board:

Signed by:
4370BDA251BC492...
Director

DocuSigned by:
8EDB4595749C4E3...
Director

The accompanying notes are an integral part of these financial statements

Hydro Ottawa Limited

Statement of Changes in Equity
Year ended December 31, 2024 with comparative information for 2023
[in thousands of Canadian dollars]

	Share capital $	**Accumulated other comprehensive income** $	**Retained earnings** $	**Total** $
Balance at December 31, 2022	167,081	-	270,234	437,315
Net income after net movements in regulatory balances	-	-	28,798	28,798
Balance at December 31, 2023	167,081	-	299,032	466,113
Net income after net movements in regulatory balances	-	-	37,154	37,154
Dividends [Note 14]	-	-	(5,760)	(5,760)
Balance at December 31, 2024	**167,081**	**-**	**330,426**	**497,507**

The accompanying notes are an integral part of these financial statements

Hydro Ottawa Limited

Statement of Cash Flows
Year ended December 31, 2024 with comparative information for 2023
[in thousands of Canadian dollars]

	2024 **$**	2023 $
Net inflow (outflow) of cash related to the following activities:		
Operating		
Net income after net movements in regulatory balances	**37,154**	28,798
Adjustments for:		
Depreciation	**58,852**	55,441
Amortization	**9,348**	8,646
Loss (gain) on disposal of non-financial assets [Notes 6 and 7]	**460**	(469)
Amortization of deferred revenue [Note 16]	**(9,403)**	(7,955)
Employee future benefits	**124**	35
Financing costs	**31,716**	31,314
Income tax expense	**15,365**	8,317
Income tax credits recoverable	**(119)**	(269)
Capital contributions from customers	**21,093**	18,080
Capital contributions from developers [Note 6]	**25,114**	11,067
Changes in non-cash working capital and other operating balances [Note 20]	**(34,735)**	(2,129)
Change in customer deposits	**22,824**	6,460
Financing costs paid	**(32,673)**	(31,779)
Income tax refunded	**1,280**	1,663
Income taxes paid	**(724)**	(1,117)
Net movements in regulatory balances	**5,894**	(21,855)
	151,570	104,248
Investing		
Acquisition of property, plant and equipment	**(174,317)**	(135,981)
Acquisition of intangible assets	**(7,097)**	(2,935)
Proceeds from disposal of property, plant and equipment	**1,020**	1,770
	(180,394)	(137,146)
Financing		
Proceeds from issuance of long-term debt, net of repayments	**60,000**	30,000
Dividends paid [Note 14]	**(5,760)**	-
	54,240	30,000
Net change in working capital facility	**25,416**	(2,898)
Working capital facility, beginning of year	**(65,310)**	(62,412)
Working capital facility, end of year	**(39,894)**	(65,310)

The accompanying notes are an integral part of these financial statements

1. DESCRIPTION OF BUSINESS AND CORPORATE INFORMATION

Hydro Ottawa Limited [the 'Company'] was incorporated on October 3, 2000 pursuant to the Business Corporations Act (Ontario) as mandated by the Ontario government's Electricity Act, 1998. On October 1, 2024, Hydro Ottawa Capital Corporation, a newly incorporated company, acquired the shares and assumed the unsecured promissory notes issued by the Company, from Hydro Ottawa Holding Inc., pursuant to the terms of a *Purchase and Assumption of Liabilities Agreement*. The Company is a wholly owned subsidiary of Hydro Ottawa Capital Corporation, which is in turn a wholly owned subsidiary of Hydro Ottawa Holding Inc. The Company's ultimate shareholder is the City of Ottawa. Prior to October 1, 2024, the Company was a directly wholly owned subsidiary of Hydro Ottawa Holding Inc., a wholly owned subsidiary of the City of Ottawa. The Company is domiciled in Canada with the registered head office located at 2711 Hunt Club Road, Ottawa, Ontario, K1G 5Z9.

Hydro Ottawa Limited is a regulated electricity distribution company that owns and operates electricity infrastructure in the City of Ottawa and the Municipality of Casselman and is responsible for the safe, reliable delivery of electricity to homes and businesses in its licensed service area. In addition to billing for distribution services, Hydro Ottawa Limited invoices customers for amounts it is required to pay to other organizations in Ontario's electricity system for providing wholesale generation and transmission services.

2. BASIS OF PRESENTATION

(a) Statement of compliance

These financial statements have been prepared by management on a going-concern basis in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board ['IFRS Accounting Standards'], and have been approved and authorized by the Company's Board of Directors for issue on April 24, 2025.

(b) Basis of measurement

The Company’s financial statements are prepared on a historical cost basis, except for employee future benefits as disclosed in Note 3(i)(ii).

(c) Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Company’s functional currency.

(d) Use of estimates and judgments

The preparation of financial statements in conformity with IFRS Accounting Standards requires management to make estimates, judgments and assumptions that affect the reported amounts of revenues, expenses, assets, liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements.

Due to the inherent uncertainty involved in making estimates, actual results could differ from estimates recorded in preparing these financial statements, including changes as a result of future decisions made by the Ontario Energy Board ['OEB'] or the Ontario government. Management reviews its estimates and judgments on an ongoing basis using the most current information available. These financial statements have, in management's opinion, been properly prepared using careful judgment within reasonable limits of materiality and within the framework of the material accounting policies. Significant areas where estimates and judgments are made in the application of IFRS Accounting Standards are as follows:

i. Account receivables

Accounts receivable, which include unbilled receivables, are reported based on the amounts expected to be recovered less a loss allowance for expected credit losses. Management utilizes historical loss experience and forward-looking information in conjunction with the aging and arrears status of accounts receivable at year-end in the determination of the allowance.

ii. Regulatory balances

The recognition and measurement of regulatory balances is subject to certain estimates, judgments and assumptions, including assumptions made in the interpretation of the OEB's regulations and decisions. The Company continues to assess the likelihood of recovery of all regulatory debit balances subject to recovery through a future rate filing. The absence of OEB approval is a consideration in this evaluation.

iii. Useful lives of depreciable assets

Depreciation and amortization expense are calculated based on estimates of the useful lives of property, plant and equipment, intangible assets and investment properties. Management estimates the useful lives of the various types of assets using assumptions and estimates of life characteristics of similar assets based on a long history of industry experience.

iv. Impairment of non-financial assets

Non-financial assets are reviewed by management for impairment using the future cash flows method. By their nature, estimates of future cash flows, including estimates of future capital expenditures, revenue, operating expenses, discount rates and market pricing are subject to measurement uncertainty.

v. Employee future benefits

The measurement of employee future benefits involves the use of numerous estimates and assumptions. Actuaries make assumptions for items such as discount rates, future salary increases and mortality rates in the determination of benefits expenses and defined benefit obligations.

vi. Capital contributions

The timing of the satisfaction of performance obligations for capital contributions from customers is subject to certain estimates of future electricity usage.

(e) New standard amendment adopted

In January 2020, the International Accounting Standards Board ['IASB'] issued amendments to International Accounting Standard *Presentation of Financial Statements* ['IAS 1'] relating to the classification of liabilities as current or non-current. Specifically, the amendments clarify one of the criteria for classifying a liability as non-current is the requirement for an entity to have the right to defer settlement of the liability for at least 12 months after the reporting period. This right may be subject to compliance with covenants.

After reconsidering certain aspects of the 2020 amendments, in October 2022, the IASB issued *Non-current Liabilities with Covenants* (Amendments to IAS 1), reconfirming that only covenants with which a company must comply on or before the reporting date affect a liability as current or non-current. The amendments are effective for annual reporting periods beginning on or after January 1, 2024, with early adoption permitted. The amendments are applied retrospectively.

These amendments do not have any impact on the Company's financial statements and disclosures.

(f) New standard not yet adopted

In April 2024, the IASB issued a new standard, IFRS 18 *Presentation and Disclosure of Financial Statements* ['IFRS 18'], which replaces IAS 1. IFRS 18 is effective for reporting periods beginning on or after January 1, 2027. The standard is to be applied retrospectively, with early adoption permitted. IFRS 18 is expected to improve the quality of financial reporting by requiring defined subtotals in the statement of income or loss, requiring disclosure about management-defined performance measures, and adding new principles for aggregation and disaggregation of information.

The Company has not yet determined the impact of this standard on its disclosures.

3. MATERIAL ACCOUNTING POLICIES

(a) Regulation

The Company is regulated by the OEB under the authority of the *Ontario Energy Board Act, 1998*. The OEB is charged with the responsibilities of approving or setting rates for the transmission and distribution of electricity, and ensuring that distribution companies fulfill obligations to connect and service customers.

For fiscal year ended December 31, 2024, the Company continued to operate under a custom incentive rate-setting application ['Custom IR'] prescribed by the OEB. The Custom IR is one of the rate setting options contained in the *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach policy*.

Annual IR applications are required to set rates and charges for the 2022-2025 rate years. On August 15, 2024, the Company filed its Custom IR year 5 update application seeking approval to change its base distribution rates effective January 1, 2025. Rates are adjusted using a formulaic approach following the first year base rates. The 2025 rates are based on an update to the Company's custom price escalation factor, working capital allowance, and the Company's annual incremental capital stretch factor for capital-related revenue requirement. The Company's 2025 rates were approved by the OEB on December 17, 2024.

Once rates are approved, they are not adjusted as a result of actual costs being different from those that were estimated, other than for certain prescribed costs that are eligible for deferral treatment and are either collected or refunded in future rates.

In January 2014, the International Accounting Standards Board ['IASB'] issued IFRS 14 – *Regulatory Deferral Accounts* ['IFRS 14'], which permits rate-regulated entities to use its existing rate-regulated activities practices if and only if, in its first IFRS financial statements, it recognized regulatory deferral account balances by electing to apply the requirements of IFRS 14.

The Company has determined that certain debit and credit balances arising from rate-regulated activities qualify for the application of regulatory accounting treatment in accordance with IFRS 14 and the accounting principles prescribed by the OEB in the Accounting Procedures Handbook for Electricity Distributors. Regulatory debit and credit balances primarily represent costs that have been deferred because it is probable that they will be recovered in future rates, revenues that are required to be returned or collected to/from customers or balances that arise from differences in amounts billed to customers for electricity services and the costs that the Company incurs to purchase these services.

Regulatory balances principally comprise of the following:

- Regulatory asset/liability refund account ['RARA'/'RLRA'] consists of balances of regulatory assets or regulatory liabilities approved for disposition by the OEB through temporary additional rates referred to as rate riders.

- Settlement variances relate primarily to the charges the Company incurred for transmission services, commodity, wholesale market operations and global adjustment in comparison to those settled with customers during the year. The nature of the settlement variances is such that the balance can fluctuate between assets and liabilities over time, and they are reported at year-end dates in accordance with rules prescribed by the OEB.

- Lost Revenue Adjustment Mechanism ['LRAM'] account tracks and disposes of lost electricity distribution revenues that result from Conservation and Demand Management ['CDM'] programs.

- Earnings Sharing Mechanism ['ESM'] variance account captures 50% of any regulated earnings above the Company's approved return on equity for specific rate periods.

- Other Post-employment Benefits deferral account ['OPEB deferral account'] was authorized by the OEB in 2011 to record the adjustment to employee future benefits other than pension relating to the cumulative actuarial gains or losses. This account is adjusted annually to record any changes in the cumulative actuarial gains or losses. No interest charges are recorded on this account as instructed by the OEB.

- Other Post-employment Benefits cash versus accrual account ['OPEB cash vs accrual'] tracks the interest on the differential of the Company's contributions to OPEB versus the accrued OPEB expense recorded in the Company's statement of income.

– Gain/Loss on Asset Disposal variance account is the difference between actual amount of gain or loss from disposal of fixed assets and the forecasted gain or loss.

Other variances and deferred costs include the following:

– The Connection Cost Recovery Agreement ['CCRA'] account allows the Company to record annual revenue requirements related to the difference between forecasted payments built into rates and actual payments made to Hydro One Networks Inc. ['HONI'] under the CCRAs.

– Capital Variance Account ['CVA'] account (excluding the System Access capital variance sub-account relating to plant relocation requested by third parties and residential expansion) is an asymmetrical variance account. Accordingly, the CVA tracks on an annual basis [for years 2021-2025], the cumulative revenue requirement difference resulting from the underspending in the Company's three capital spending categories: System Renewal/System Service, System Access, and General Plant. The System Access capital variance sub-account records the cumulative revenue requirement difference due to both overspending or underspending and is referred to as a symmetrical variance account.

– A Performance Outcomes Accountability Mechanism account to return up to $200 annually for each under-achieved target during the 2021-2025 custom incentive rate-setting period. The five targets impacted by this mechanism account are identified in the Company's settlement agreement.

– The OEB established a variance account for electricity distributors to record any material differences between OEB cost assessments currently built into rates, and cost assessments that will result from the application of the new cost assessment models.

The Company accrues interest on the regulatory balances as directed by the OEB.

The Company continues to assess the likelihood of recovery of all regulatory debit balances subject to recovery through a future rate filing. The absence of OEB approval is a consideration in this evaluation. If the requirement for a provision becomes more likely than not, Hydro Ottawa will recognize the provision in operating costs for the year.

(b) Revenue recognition

Depending on whether certain criteria are met, the Company recognizes revenue from contracts with customers when it transfers control over a product or service to a customer either over time or at a point in time. For revenue from other sources, the Company recognizes revenue over time taking into consideration the facts and circumstances of the arrangement.

Revenue is measured at the consideration received or receivable, excluding sales taxes and other amounts collected on behalf of third parties in the following revenue arrangements.

i. Power recovery

Power recovery revenue represents the flow-through of the cost of power to the consumer as purchased by the Company and is recognized over time as electricity is delivered to the customer, as measured by meter readings or usage estimates. Power recovery revenue is regulated by the OEB and includes charges to customers for the electricity commodity, the transmission of electricity and the administration of the wholesale electricity system. The Company has determined that it acts as a principal in this revenue arrangement and therefore has presented it on a gross basis.

ii. Distribution

The Company charges customers for the delivery of electricity, based on rates established by the OEB. The rates are intended to allow the Company to recover its prudently-incurred costs and earn a fair return on invested capital. Distribution revenue is recognized over time as electricity is delivered to the customer, as measured by meter readings or usage estimates.

iii. Other

Other revenue comprises revenue earned under contracts for service work related to distribution operations, pole attachment and duct rentals, capital contributions received from customers amortized to revenue, and other account-related charges such as account set-up and late payment fees. Revenue earned under contracts for service work related to distribution operations is recognized over time as the corresponding costs are recognized proportionately with the degree of completion of the services under contract. Losses on such contracts are fully recognized when they become evident. In certain situations, capital contributions are required from customers to finance additions to property, plant and equipment when the estimated revenue resulting from the addition to property, plant and equipment is less than the cost of providing the service or where special equipment is needed to supply the customers' specific requirements. Since the contributions will provide current and future customers with ongoing access to the supply of electricity, these contributions are classified as deferred revenue and amortized into revenue on a straight-line basis over time [the period a customer will receive services], which is typically equivalent to the rate used for the depreciation of the related property, plant and equipment [service life of the related assets]. All other revenues are recognized over time as services are rendered, except for revenue from certain account- related charges, which is recognized at a point in time.

Capital contributions received from developers to construct or acquire property, plant and equipment for the purpose of connecting future customers to the Company's distribution network are considered out of scope of IFRS 15 – *Revenue from Contracts with Customers* ['IFRS 15']. Capital contributions received from developers are recognized as deferred revenue and amortized into revenue from other sources at an equivalent rate to that used for the depreciation of the related property, plant and equipment.

(c) Financing costs

Financing costs are calculated using the effective interest rate method and are recognized as an expense unless they are capitalized as part of the cost of a qualifying asset.

(d) Income taxes

The Company is considered to be a Municipal Electric Utility ['MEU'] and is required to make payments in lieu of corporate income taxes ['PILS'] as contained in the Electricity Act, 1998, as all of its share capital is indirectly owned by the City of Ottawa and not more than 10% of its income is derived from activities carried on outside the municipal boundaries of the City of Ottawa. The *Electricity Act, 1998* provides that a MEU that is exempt from tax under the *Income Tax Act* (Canada) ['ITA'] and the *Taxation Act*, Ontario ['TAO'] is required to make, for each taxation year, a PILs payment to the Ontario Electricity Financial Corporation in an amount equal to the tax that it would be liable to pay under the ITA and the TAO if it were not exempt from tax.

The Company follows the liability method for recording income taxes. Under the liability method, current income taxes payable is recorded based on taxable income. Deferred income taxes arising from temporary differences in the accounting and tax basis of assets and liabilities are provided based on substantively enacted tax rates that will be in effect when the differences are expected to reverse.

The Company recognizes regulatory balances for the amounts of future income taxes expected to be refunded to or recovered from customers in future electricity rates as prescribed by the OEB.

(e) Financial instruments

Financial instruments are initially measured at the fair value of the consideration given or received plus transaction costs that are directly attributable to the acquisition or issue of the financial instrument.

The Company's financial assets, upon initial recognition, are classified as amortized cost or fair value [whereby subsequent changes in fair value are recognized either through OCI ['FVOCI'] or through profit and loss ['FVTPL'] as unrealized market adjustments]. Financial assets are classified based on the Company's business model for managing such assets and the contractual terms of the related cash flows.

The Company's financial liabilities, upon initial recognition, are classified as amortized cost or FVTPL. A financial liability is classified as FVTPL if it is classified as held-for-trading, it is a derivative or it is designated as such on initial recognition.

The Company classifies and subsequently measures its financial instruments as follows:

– Cash and accounts receivable are financial assets classified and measured at amortized cost using the effective interest method, less any impairment if applicable.

– Working capital facility, accounts payable and accrued liabilities, customer deposits and notes payable are financial liabilities classified and measured at amortized cost using the effective interest rate method.

The fair value of a financial instrument is the amount of consideration that would be agreed upon in an arm's-length transaction between willing parties. The Company's own credit risk and the credit risk of the counterparty are taken into account in determining the fair value of financial assets and liabilities. Financial instruments are classified using a three level hierarchy. The levels reflect the inputs used to measure the fair values of financial assets and financial liabilities, and are as follows:

– Level 1: inputs are unadjusted quoted prices of identical instruments in active markets;

– Level 2: inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly; and

– Level 3: inputs for the liabilities that are not based on observable market data [unobservable inputs].

All financial assets except for those classified as FVTPL or FVOCI are subject to review for impairment at least at each reporting date. Impairment losses, if material, are recognized in net income. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized.

The Company recognizes loss allowances for expected credit losses ['ECLs'] on financial assets measured at amortized cost. The Company measures loss allowances for electricity receivables, unbilled receivables and trade receivables via a simplified approach as permitted by IFRS 9 - *Financial Instruments* ['IFRS 9'], at an amount equal to lifetime ECLs.

When determining whether the credit risk of a financial asset has increased, the Company performs a quantitative and qualitative analysis based on the Company’s historical experience and forward-looking information. The Company assumes that the credit risk on a financial asset has increased significantly if it is more than 30 days past due. The Company considers a financial asset to be in default when the borrower is unlikely to pay its credit obligations to the Company in full, without recourse by the Company to actions such as realizing security.

Loss allowances for financial assets measured at amortized cost are deducted from the gross carrying amount of the assets. The gross carrying amount of a financial asset is written off to the extent that there is no realistic prospect of recovery.

(f) Property, plant and equipment

Property, plant and equipment consist principally of electricity distribution infrastructure, buildings and fixtures, land, rolling stock, furniture and equipment, and assets under construction.

Property, plant and equipment are measured at cost less accumulated depreciation and accumulated impairment losses, if any. Self-constructed asset costs comprise all directly attributable expenditures to bring the asset into operation including labour, materials, employee benefits, transportation, contracted services and borrowing costs. Where parts of an item in property, plant and equipment are significant and have different estimated economic useful lives, they are accounted for as separate items [major components] of property, plant and equipment. Certain assets may be acquired or constructed with financial assistance in the form of contributions from customers and developers. Assets that are acquired from customers and developers are measured at fair value. Contributions from customers and developers are treated as deferred revenue.

The cost of major inspections and maintenance is recognized in the carrying value of an asset provided that the Company will derive future economic benefits from the expenditure. The carrying amount of a replaced part is derecognized. The costs of day-to-day servicing, repairs, and maintenance are expensed as incurred.

Depreciation is recorded on a straight-line basis over the estimated service life of each component of property, plant and equipment. Emergency capital spare parts that are expected to be used for more than one year are considered to be assets under construction and are depreciated only once they are put into service.

Gains and losses on disposal of retired, sold or otherwise derecognized property, plant and equipment are recognized in income and are calculated as the difference between net proceeds from disposal and the carrying amount of the asset.

The estimated useful lives, residual values and depreciation methods are reviewed at each year-end with the effect of any changes in estimate being accounted for on a prospective basis.

Estimated service lives for property, plant and equipment classes are as follows:

Land and buildings	
Land	Indefinite
Buildings and fixtures	10 to 75 years
Electricity distribution infrastructure	10 to 60 years
Equipment and other	
Furniture and equipment	5 to 40 years
Rolling stock	7 to 15 years

Assets under construction and land are not subject to depreciation.

Borrowing costs are capitalized as a component of the cost of self-constructed property, plant and equipment assets that take a substantial period of time to get ready for their intended use. The capitalization rate is the Company's weighted average cost of borrowing.

(g) Intangible assets

Intangible assets include land rights, capital contributions, computer software and assets under development.

Intangible assets with finite lives are measured at cost less accumulated amortization and accumulated impairment losses, if any. Intangible assets are amortized on a straight-line basis over the estimated service lives of the related assets.

Intangible assets are derecognized on disposal or when no further future economic benefits are expected from their use. Gains or losses on disposal of intangible assets are recognized in income and are calculated as the difference between net proceeds from disposal and the carrying amount of the asset.

The estimated useful lives and amortization methods are reviewed at each year-end with the effect of any changes in estimate being accounted for on a prospective basis.

Estimated service lives for intangible assets with finite lives are as follows:

Land rights	50 years
Computer software	5 to 13 years
Capital contributions	45 years

Borrowing costs are capitalized as a component of cost of self-constructed intangible assets that take a substantial period of time to get ready for their intended use. The capitalization rate is the Company's weighted average cost of borrowing.

(h) Impairment of non-financial assets

At the end of each reporting period, or earlier if required, management uses its judgment to assess whether there is an indication that the carrying amount of a non-financial asset [or cash generating unit, 'CGU'] exceeds its recoverable amount. A CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. This assessment involves the consideration of whether any events or changes in circumstances could have affected the recoverability of the carrying amount of a non-financial asset or CGU. Management considers various indicators including, but not limited to, adverse changes in the industry or economic conditions, changes in the degree or method of use of an asset, a lower than expected economic performance of an asset or a significant change in market returns or interest rates. If any indication exists, the Company estimates the asset's recoverable amount, which is the higher of an asset or CGU's fair value less costs of disposal and its value in use. If the carrying value of a non-financial asset materially exceeds its recoverable amount, the difference is immediately recognized as an impairment loss in profit or loss.

Intangible assets not yet available for use are tested for impairment [within their respective CGUs] at least annually, and whenever there is an indication that the asset may be impaired.

When determining the recoverable amount, the Company determines its value-in-use by discounting estimated future cash flows to their present value using a discount rate that reflects changes in the time value of money and the risks specific to the asset or the CGU. The discount rate estimated and used by management represents the weighted average cost of capital determined for the CGU being tested.

At the end of a reporting period, if there is any indication that an impairment loss recognized in a prior period no longer exists or has decreased, the loss is reversed up to its recoverable amount. The carrying amount following the reversal must not be higher than the carrying amount that would have prevailed [net of amortization] had the original impairment not been recognized in prior periods.

(i) Employee future benefits

i. Pension plans

The Company provides pension benefits for its employees through the Ontario Municipal Employees Retirement System ['OMERS'] Fund [the 'Fund']. OMERS is a multi-employer pension plan that provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. The Fund is a defined benefit pension plan, which is financed by equal contributions from participating employers and employees and by the investment earnings of the Fund.

Although the plan is a defined benefit plan, sufficient information is not available to the Company to account for it as such because it is not possible to attribute the fund assets and liabilities between the various employers who contribute to the Fund. As a result, the Company accounts for the plan as a defined contribution plan, and contributions payable as a result of employee service are expensed as incurred as part of operating costs. The Company shares in the actuarial risks of the other participating entities in the plan, and its future contributions may therefore be increased due to actuarial losses relating to the other participating entities. In addition, the Company’s contributions could be increased if other entities withdraw from the plan.

ii. Other post-employment benefits

Other post-employment benefits provided by the Company include life insurance and a collectively bargained retirement grant. These plans provide benefits to certain employees when they are no longer providing active service.

Employee future benefits expense is recognized in the period during which the employees render services.

Employee future benefits are recorded on an accrual basis. The defined benefit obligation and current service costs are calculated using the projected benefit method prorated on service and based on assumptions that reflect management’s best estimates. The current service cost for a period is equal to the actuarial present value of benefits attributed to employees’ services rendered in the period. Actuarial gains and losses resulting from experience different from that assumed or from changes in actuarial assumptions are recognized in OCI. However, for the Company, these amounts are reclassified to a regulatory debit balance as prescribed by the OEB.

iii. Employee benefits

The Company provides short-term employee benefits, such as: salaries, employment insurance, short-term compensated absences, health and dental care. These benefits are recognized as the related service is rendered and is measured on an undiscounted basis. Short-term employee benefits are recognized as an expense unless they qualify for capitalization as part of the cost of an item of materials and supplies, property, plant and equipment, intangible assets. A liability is recognized in respect of any unpaid short-term employee benefits for services rendered in the reporting period.

[in thousands of Canadian dollars]

(j) Customer deposits

Customer deposits are cash collections from non-residential customers to guarantee the payment of future energy bills and fulfillment of construction obligations. Deposits from customers to guarantee the payment of energy bills includes related interest amounts owed to the customers. Deposits estimated to be refundable to customers within the next fiscal year are classified as current liabilities and included in accounts payable and accrued liabilities.

(k) Provisions and contingencies

The Company recognizes provisions when there is a present legal or constructive obligation as a result of a past event, it is probable that an outflow of economic benefits will be required to settle the obligation, and a reliable estimate can be made of the amount of the obligation. If the effect is material, provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and, where appropriate, the risks specific to the liability.

The evaluation of the likelihood of the contingent events requires judgment by management as to the probability of exposure to potential loss. Actual results could differ from these estimates.

A contingent asset is not recognized in the financial statements. However, a contingent asset is disclosed where an inflow of economic benefits is probable.

4. ACCOUNTS RECEIVABLE

	2024 **$**	2023 $
Receivables from contracts with customers		
Electricity receivable	**75,329**	71,600
Unbilled receivables related to electricity	**96,073**	86,259
Independent Electricity System Operator ['IESO'] receivable	**12,086**	14,065
Trade and other receivables	**13,973**	7,261
Amounts due from related parties [Note 23]	**18,405**	11,308
Less: loss allowance [Note 15(c)]	**(5,103)**	(4,141)
	210,763	186,352

[in thousands of Canadian dollars]

5. REGULATORY BALANCES

Information about the Company's regulatory balances is as follows:

	Remaining recovery/ reversal [years]	2023 $	Balances arising in the year $	Recovery/ reversal $	Other movements(1) $	**2024 $**
Regulatory debit balances						
RARA	1 - 5	8,941	2,120	(8,702)	(16)	**2,343**
Settlement variances	1 - 5	36,126	9,576	-	(6,477)	**39,225**
OPEB cash vs accrual	1 - 5	3,532	(160)	-	-	**3,372**
Regulatory asset for deferred income taxes	(2)	82,622	12,733	-	-	**95,355**
Other variances and deferred costs	1 - 5	622	(106)	-	-	**516**
		131,843	24,163	(8,702)	(6,493)	**140,811**
Regulatory credit balances						
RLRA	1 - 5	1,277	(10,799)	10,794	(16)	**1,256**
Settlement variances	1 - 5	4,841	19,673	-	(6,477)	**18,037**
ESM	1 - 5	1,541	75	-	-	**1,616**
Gain on asset disposal	1 - 5	1,093	287	-	-	**1,380**
LRAM	1 - 5	3,056	1,238	-	-	**4,294**
OPEB deferral account	1 - 5	63	38	-	-	**101**
Other variances and deferred costs	1 - 5	3,088	151	-	-	**3,239**
		14,959	10,663	10,794	(6,493)	**29,923**

Hydro Ottawa Limited

Notes to the Financial Statements
Year ended December 31, 2024
[in thousands of Canadian dollars]

	Remaining recovery/ reversal [years]	2022 $	Balances arising in the year $	Recovery/ reversal $	Other movements[1] $	2023 $
Regulatory debit balances						
RARA	1 - 5	687	7,378	949	(73)	8,941
Settlement variances	1 - 5	36,724	10,279	-	(10,877)	36,126
OPEB cash vs accrual	1 - 5	3,218	314	-	-	3,532
Loss on asset disposal	1 - 5	148	-	-	(148)	-
Regulatory asset for deferred income taxes	[2]	74,238	8,384	-	-	82,622
Other variances and deferred costs	1 - 5	1,498	(814)	-	(62)	622
		116,513	25,541	949	(11,160)	131,843
Regulatory credit balances						
RLRA	1 - 5	1,148	1,794	(1,592)	(73)	1,277
Settlement variances	1 - 5	17,033	(1,315)	-	(10,877)	4,841
ESM	1 - 5	1,467	74	-	-	1,541
Gain on asset disposal	1 - 5	-	1,241	-	(148)	1,093
LRAM	1 - 5	105	2,951	-	-	3,056
OPEB deferral account	1 - 5	30	33	-	-	63
Other variances and deferred costs	1 - 5	1,902	1,248	-	(62)	3,088
		21,685	6,026	(1,592)	(11,160)	14,959

[1] Other movements represent reclassifications of balances
[2] The balance is being reversed through timing differences in the recognition of deferred income tax assets [Note 3(d)]

Details and descriptions pertaining to the above regulatory debit and credit balances are disclosed in Note 3(a) of these financial statements.

[in thousands of Canadian dollars]

6. PROPERTY, PLANT AND EQUIPMENT

	Land, buildings and structures $	Electricity distribution infrastructure $	Equipment and other $	Assets under construction $	Total $
Cost					
Balance as at December 31, 2022	157,739	1,500,790	60,870	76,019	1,795,418
Additions, net of transfers	3,253	113,490	7,085	23,776	147,604
Disposals	(14)	(1,427)	(591)	-	(2,032)
Balance as at December 31, 2023	160,978	1,612,853	67,364	99,795	1,940,990
Additions, net of transfers	11,292	141,559	8,054	26,659	187,564
Disposals	(149)	(2,748)	(650)	-	(3,547)
Balance as at December 31, 2024	**172,121**	**1,751,664**	**74,768**	**126,454**	**2,125,007**
Accumulated depreciation					
Balance as at December 31, 2022	(19,408)	(293,545)	(31,306)	-	(344,259)
Depreciation	(3,567)	(46,002)	(5,835)	-	(55,404)
Disposals	-	726	528	-	1,254
Balance as at December 31, 2023	(22,975)	(338,821)	(36,613)	-	(398,409)
Depreciation	(3,844)	(48,832)	(6,139)	-	(58,815)
Disposals	36	1,445	586	-	2,067
Balance as at December 31, 2024	**(26,783)**	**(386,208)**	**(42,166)**	**-**	**(455,157)**
Net book value					
As at December 31, 2023	138,003	1,274,032	30,751	99,795	1,542,581
As at December 31, 2024	**145,338**	**1,365,456**	**32,602**	**126,454**	**1,669,850**

During the year, the Company capitalized borrowing costs of $836 [2023 – $510] to property, plant and equipment. The average annual interest rate for 2024 was 3.6% [2023 – 3.4%].

The Company has entered into non-cash transactions that have been excluded from the statement of cash flows as detailed in Note 20. In addition, $10,528 [2023 – $12,105] of property, plant and equipment was contributed by developers, the directly related liability of which is included in deferred revenue.

During the year, the Company recognized a loss on disposal of property, plant and equipment of $460 [2023 – gain on disposal of $469].

[in thousands of Canadian dollars]

7. INTANGIBLE ASSETS

	Land rights $	Computer software $	Capital contributions $	Assets under development $	Total $
Cost					
Balance as at December 31, 2022	3,239	79,766	83,893	3,456	170,354
Additions, net of transfers	-	6,265	(4,756)	2,280	3,789
Balance as at December 31, 2023	3,239	86,031	79,137	5,736	174,143
Additions, net of transfers	-	5,907	577	(383)	6,101
Balance as at December 31, 2024	**3,239**	**91,938**	**79,714**	**5,353**	**180,244**
Accumulated amortization					
Balance as at December 31, 2022	(546)	(53,645)	(5,855)	-	(60,046)
Amortization	(78)	(6,622)	(1,946)	-	(8,646)
Balance as at December 31, 2023	(624)	(60,267)	(7,801)	-	(68,692)
Amortization	(78)	(7,385)	(1,885)	-	(9,348)
Balance as at December 31, 2024	**(702)**	**(67,652)**	**(9,686)**	**-**	**(78,040)**
Net book value					
As at December 31, 2023	2,615	25,764	71,336	5,736	105,451
As at December 31, 2024	**2,537**	**24,286**	**70,028**	**5,353**	**102,204**

The Company is party to various Connection and Cost Recovery Agreements ['Capital contributions'] with Hydro One Networks Inc. ['HONI']. These agreements govern the construction by HONI of new or modified transformer stations for the purpose of serving the Company's customers, including anticipated electricity load growth. All terms and conditions of CCRAs follow the Transmission System Code [the 'Code'] issued by the OEB.

During the year, the Company capitalized borrowing costs of $129 [2023 – $184] to intangible assets. The average annual interest rate for 2024 was 3.6% [2023 – 3.4%].

The Company has entered into non-cash transactions that have been excluded from the statement of cash flows as detailed in Note 20.

8. WORKING CAPITAL FACILITY

The Company has access to a $90,000 [2023 – $90,000] revolving demand credit facility and a $500 [2023 – $500] commercial card facility available from its immediate parent, Hydro Ottawa Capital Corporation [prior to October 1, 2024 – Hydro Ottawa Holding Inc.]. As at December 31, 2024, the Company had drawn $14,894 [2023 – $10,310] in bank indebtedness and $25,000 [2023 – $55,000] in CORRA ['Canadian Overnight Repo Rate Average'] loans [prior to July 1, 2024 -- bankers' acceptances] against this credit facility. The rate of interest is based on the rate applicable to its immediate parent's outstanding CORRA loans drawn on that date. Otherwise, the rate of interest is based on the CanDeal/TMX Term CORRA 1 month rate, plus a CORRA loan spread.

[in thousands of Canadian dollars]

9. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	2024 **$**	2023 $
Purchased power payable	**66,951**	87,382
Trade accounts payable and accrued liabilities	**49,280**	35,271
Customer deposits	**63,034**	43,274
Customer credit balances	**14,541**	14,451
Due to related parties [Note 23]	**8,483**	7,106
	202,289	187,484

10. DEFERRED REVENUE

	2024 **$**	2023 $
Capital contributions from customers	**154,780**	138,249
Capital contributions from developers	**182,685**	151,884
	337,465	290,133
Less: current portion	**(10,266)**	(8,399)
	327,199	281,734

11. EMPLOYEE FUTURE BENEFITS

(a) Pension plans

The Company's participating employer contributions under OMERS for the year ended December 31, 2024 amounted to $6,621 [2023 – $5,340].

(a) Other post-employment benefits

Employee future benefits are calculated using an annual compensation rate increase of 2.0% [2023 – 2.0%] and a discount rate of 4.7% [2023 – 4.7%] to calculate the liabilities. The valuations also include several other economic and demographic assumptions including mortality rates. The mortality assumption is based on the *Canadian Pensioners' Mortality* report published by the Canadian Institute of Actuaries in February 2014.

[in thousands of Canadian dollars]

Information about the Company's other post-employment benefits is as follows:

	2024 **$**	2023 $
Defined benefit obligation, beginning of year	**11,875**	11,526
Current service costs	**298**	265
Interest on defined benefit obligation	**546**	613
Benefits paid	**(720)**	(843)
Actuarial (gain) loss	**(160)**	314
Defined benefit obligation, end of year	**11,839**	11,875

An actuarial extrapolation was performed as at December 31, 2024. As a result of this exercise, the Company decreased the accumulated liability by $36 [December 31, 2023 – increased by $349 based on an actuarial extrapolation].

Significant changes in actuarial assumptions related to discount rates, mortality rates and retirement age may affect the valuation of the defined benefit obligation.

12. NOTES PAYABLE

The Company currently has the following unsecured promissory notes to Hydro Ottawa Capital Corporation [December 31, 2023 – Hydro Ottawa Holding Inc.]:

	2024 **$**	2023 $
4.97% promissory note, due December 19, 2036	**50,000**	50,000
4.14% for the first five years [3.99% thereafter] promissory note, issued May 14, 2013 and due May 14, 2043	**107,185**	107,185
2.72% for the first five years [2.61% thereafter] promissory note, issued February 9, 2015 and due February 3, 2025	**138,667**	138,667
3.77% for the first five years [3.64% thereafter] promissory note, issued February 9, 2015 and due February 2, 2045	**121,333**	121,333
2.72% for the first five years [2.61% thereafter] promissory note, issued June 25, 2015 and due June 25, 2025	**15,999**	15,999
3.77% for the first five years [3.64% thereafter] promissory note, issued June 25, 2015 and due June 25, 2045	**14,001**	14,001
2.66% promissory note, due October 16, 2029	**87,500**	87,500
3.21% promissory note, due October 16, 2049	**162,500**	162,500
3.57% grid promissory note issued July 5, 2021 and due on demand	**80,000**	80,000
4.94% grid promissory note issued August 9, 2022 and due on demand	**30,000**	30,000
4.56% grid promissory note issued July 6, 2023 and due on demand	**30,000**	30,000
4.49% grid promissory note issued November 6, 2024 and due on demand	**60,000**	-
	897,185	837,185
Less: current portion	**(354,666)**	-
	542,519	837,185

[in thousands of Canadian dollars]

The grid promissory note facility bears fixed-rate interest based on the cost of long-term debt for Ontario's Regulated Utilities in accordance with the OEB`s cost of capital calculations. Hydro Ottawa Holding Inc. did not intend to recall any amounts due on demand in 2024.

The promissory notes and the grid promissory note facility are subordinated and postponed to the obligation of the Company to a third party for the payment in full of any secured indebtedness and any and all security interests granted to secure such obligations of the Company.

13. CAPITAL DISCLOSURES

The Company’s main objectives when managing capital are to:

– Ensure continued access to funding to maintain and improve the operations and infrastructure of the Company;

– Ensure compliance with covenants related to the credit facilities and senior unsecured debentures entered into by its immediate parent company, Hydro Ottawa Capital Corporation; and

– Align the Company's capital structure with the debt to equity structure recommended by the OEB.

The Company’s capital consists of the following:

	2024 **$**	2023 $
Working capital facility	**39,894**	65,310
Current portion of notes payable	**354,666**	-
Notes payable	**542,519**	837,185
Total debt	**937,079**	902,495
Shareholder's equity	**497,507**	466,113
Total capital	**1,434,586**	1,368,608
Debt capitalization ratio	**65.32 %**	65.94 %

The Company is in compliance with all financial covenants and limitations associated with its credit facilities and its long-term debt.

The Company is deemed by the OEB to have a capital structure that is funded by 56% long-term debt, 4% short-term debt and 40% equity. The OEB uses this deemed structure only as a basis for setting distribution rates. As such, the Company's actual capital structure may differ from the OEB deemed structure.

The Company met its capital management objectives, which have not changed during the year.

[in thousands of Canadian dollars]

14. SHARE CAPITAL

(a) Authorized

Unlimited number of voting first preferred shares, redeemable at one dollar per share
Unlimited number of non-voting second preferred shares, redeemable at ten dollars per share
Unlimited number of non-voting third preferred shares, redeemable at one hundred dollars per share
Unlimited number of voting fourth preferred shares [ten votes per share], redeemable at one hundred dollars per share
Unlimited number of voting Class A common shares
Unlimited number of non-voting Class B common shares
Unlimited number of non-voting Class C common shares, redeemable at the price at which such shares are issued

The above shares are without nominal or par value.

Holders of second preferred shares, fourth preferred shares and common shares are entitled to receive dividends as and when declared by the Board of Directors at their discretion.

(b) Issued

	2024 **$**	2023 $
154,789,001 Class A common shares	**167,081**	167,081

Any invitation to the public to subscribe for shares of the Company is prohibited by shareholder resolution.

On April 23, 2024, the Board of Directors declared a $5,760 dividend on the common shares of the Company outstanding on December 31, 2023. The dividend was paid to the sole shareholder, Hydro Ottawa Holding Inc. on April 30, 2024. No dividends were declared by the Board of Directors in 2023.

15. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

(a) Fair value disclosures

The carrying value of the Company's financial instruments, except for notes payable, approximates fair value because of the short maturity and nature of the instruments. The fair value measurement of the financial instrument for which the fair value has been disclosed is included in Level 2 of the fair value hierarchy [Note 3(e)].

The Company has estimated the fair value of the notes payable as at December 31, 2024 as amounting to $843,345 [2023 – $765,259]. The fair value has been determined based on discounting all estimated future repayments of principal and interest required to fully repay the notes payable at the estimated interest rate of 4.40% [2023 – 4.60%] that would be available to the Company on December 31, 2024.

(b) Market risk

The Company is exposed to market risk, which is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market prices are comprised of three types of risks: interest rate risk, foreign exchange risk and commodity price risk. As the Company has not entered into significant hedging transactions or derivative contracts, there is no exposure to commodity price risk.

i. Interest rate risk

The Company is exposed to interest rate risk on its borrowings. The Company mitigates exposure to interest rate risk by fixing interest rates on its notes payable with its immediate parent company. Under Hydro Ottawa Capital Corporation's credit facilities, any advances on its operating line would expose the Company to fluctuations in short term interest rates related to prime rate loans and CORRA loans [2023 – bankers' acceptances] as all short-term financing requirements are obtained through its immediate parent company, which passes on its borrowing costs. The interest rate risk is deemed to be low due to the immaterial cost of its short-term borrowings. For the most part, the borrowing requirements are for a very short duration as the advances serve to bridge gaps between the cash outflow related to the monthly power bill and the inflows related to the settlements with customers and, as such, there is very limited exposure to interest rate risk.

The Company is also exposed to fluctuations in interest rates as its regulated rate of return is derived using a complex formulaic approach which is in part based on the forecast for long-term Government of Canada bond yields. This rate of return is approved by the OEB as part of the approval of distribution rates.

A sensitivity analysis was conducted to examine the impact of a change in the prime rate on the Company’s advances from Hydro Ottawa Capital Corporation. A variation of 1% [100 basis points], with all other variables held constant, would increase or decrease the annual interest expense by approximately $506.

ii. Foreign exchange risk

At December 31, 2024, the Company has limited exposure to fluctuations in foreign currency exchange rates. The Company does purchase a small proportion of goods and services that are denominated in foreign currencies, predominately the US dollar. The impact of the fluctuation of foreign currencies on the gains or losses of accounts payable denoted in foreign currencies is not material.

(c) Credit risk

Credit risk is the risk that a counterparty will default on its obligations, causing a financial loss to the Company. Concentration of credit risk associated with accounts receivable is limited due to the large number of customers the Company services. The Company has approximately 372,000 customers, the majority of which are residential. As a result, the Company did not earn a significant amount of revenue and does not have a significant receivable from any individual customer.

The Company performs ongoing credit evaluations of its customers and requires collateral to support non-residential customer accounts receivable on specific accounts to mitigate significant losses in accordance with OEB legislation. As at December 31, 2024, the Company held security deposits related to power recovery and distribution revenue in the amount of $14,317 [2023 – $14,336] with respect to these customers.

The Company monitors and limits its exposure to credit risk on a continuous basis.

The Company applies the IFRS 9 – *Financial Instruments* simplified approach to measuring expected credit losses which uses a lifetime expected loss allowance for all trade and other receivables. The expected loss rates for trade receivables are based on the payment profiles of sales over a period of twelve months before December 31, 2024 or December 31, 2023 respectively and the corresponding historical credit losses experienced within this period and other information. The historical loss rates are adjusted to reflect current and forward-looking information on macroeconomic factors affecting the ability of the customers to settle the receivables.

On that basis, the loss allowance as at December 31, 2024 and December 31, 2023 was determined as follows for trade and other receivables.

[in thousands of Canadian dollars]

	Gross carrying amount $	Weighted average loss rate	Loss allowance $	Net carrying amount $
December 31, 2024				
Outstanding for 30 days or less	100,776	0.00 %	-	100,776
Outstanding for more than 30 days but no more than 120 days	13,732	12.56 %	1,725	12,007
Outstanding for more than 120 days	5,285	44.82 %	2,369	2,916
Unbilled receivables relating to electricity	96,073	1.05 %	1,009	95,064
	215,866		5,103	210,763
December 31, 2023				
Outstanding for 30 days or less	93,099	0.00 %	-	93,099
Outstanding for more than 30 days but no more than 120 days	5,764	19.67 %	1,134	4,630
Outstanding for more than 120 days	5,371	41.39 %	2,223	3,148
Unbilled receivables relating to electricity	86,259	0.91 %	784	85,475
	190,493		4,141	186,352

The following table reconciles the opening and closing loss allowance for trade and other receivables:

	2024 **$**	2023 $
Balance, beginning of year	**4,141**	4,007
Net remeasurement of loss allowance	**2,874**	2,323
Write-offs	**(2,067)**	(2,344)
Recoveries of amounts previously written-off	**155**	155
Balance, end of year	**5,103**	4,141

Impairment losses on trade and other receivables are presented as net impairment losses within the statement of income. When a receivable is deemed to be uncollectible, it is written off and the expected loss allowance is adjusted accordingly. Subsequent recoveries of receivables previously provisioned or written off result in a reduction of impairment losses included in operating costs in the statement of income.

As at December 31, 2024, the Company's maximum exposure to credit risk is equal to the carrying value of accounts receivable less customer deposits held.

(d) Liquidity risk

Liquidity risk is the risk that the Company will not meet its financial obligations as they come due. The Company's immediate parent, Hydro Ottawa Capital Corporation, manages all the financing and investing activities for the Company. The Company has access to credit facilities with Hydro Ottawa Capital Corporation [Note 8]. These credit facilities are available to the Company to help meet its financial obligations as they come due.

[in thousands of Canadian dollars]

Liquidity risks associated with financial commitments are as follows:

	2024		
	Due within one year $	**Due between one and five years $**	**Due after five years $**
Working capital facility	39,894	-	-
Accounts payable and accrued liabilities	202,289	-	-
Notes payable			
4.97% promissory note, due December 19, 2036	-	-	50,000
4.14% for the first five years [3.99% thereafter] promissory note, due May 14, 2043	-	-	107,185
2.72% for the first five years [2.61% thereafter] promissory note, due February 3, 2025	138,667	-	-
3.77% for the first five years [3.64% thereafter] promissory note, due February 2, 2045	-	-	121,333
2.72% for the first five years [2.61% thereafter] promissory note, due June 25, 2025	15,999	-	-
3.77% for the first five years [3.64% thereafter] promissory note, due June 25, 2045	-	-	14,001
2.66% promissory note, due October 16, 2029	-	87,500	-
3.21% promissory note, due October 16, 2049	-	-	162,500
3.57% grid promissory note issued July 5, 2021 and due on demand	80,000	-	-
4.94% grid promissory note issued August 9, 2022 and due on demand	30,000	-	-
4.56% grid promissory note issued July 6, 2023 and due on demand	30,000	-	-
4.49% grid promissory note issued November 6, 2024 and due on demand	60,000	-	-
Interest to be paid on notes payable	21,127	76,437	252,243
	617,976	**163,937**	**707,262**

[in thousands of Canadian dollars]

16. REVENUE FROM CONTRACTS WITH CUSTOMERS AND OTHER SOURCES

The Company's revenue breakdown is as follows:

	2024 $	2023 $
Revenue from contracts with customers		
Power recovery and distribution		
Residential service [(1)]	**484,470**	420,648
General service [(2)]	**655,029**	604,514
Large users [(3)]	**61,128**	61,513
	1,200,627	1,086,675
Other		
Service work related to distribution operations	**6,528**	5,921
Pole attachment and duct rentals	**4,068**	3,874
Capital contributions from customers amortized to revenue	**4,562**	3,829
Account-related charges	**3,855**	3,349
Shared service agreements and miscellaneous	**4,686**	4,933
	23,699	21,906
	1,224,326	1,108,581
Revenue from other sources		
Other		
Investment property rentals	**948**	901
Capital contributions from developers amortized to revenue	**4,841**	4,126
	5,789	5,027
	1,230,115	1,113,608

[(1)] Residential service means a service that is for domestic or household purposes, including single family or individually metered multifamily units and seasonal occupancy.
[(2)] General service means a service supplied to premises other than those receiving residential service and large users and typically includes small businesses and bulk-metered multi-unit residential establishments. This service is provided to customers with a monthly peak demand of less than 5,000 kW averaged over a twelve-month period.
[(3)] Large users means a service provided to a customer with a monthly peak demand of 5,000 kW or greater averaged over a twelve-month period.

[in thousands of Canadian dollars]

17. OPERATING COSTS

	2024 **$**	2023 $
Salaries, wages and benefits	**86,024**	72,570
Contracted services - distribution system maintenance	**16,279**	21,032
Contracted services - customer owned plant	**8,933**	6,493
Other electricity distribution costs	**11,272**	13,242
Other general and administrative	**48,487**	42,513
Loss (gain) on disposals of property, plant and equipment	**460**	(469)
Capital recovery	**(33,762)**	(26,508)
	137,693	128,873

18. FINANCING COSTS

	2024 **$**	2023 $
Interest on long-term debt	**29,391**	28,278
Short-term interest and fees	**3,290**	3,730
Less: capitalized borrowing costs	**(965)**	(694)
	31,716	31,314

19. INCOME TAXES

Income tax expense recognized in net income comprises the following:

	2024 **$**	2023 $
Current tax expense		
Current income tax expense (recovery)	**2,636**	(257)
Deferred income tax expense		
Origination and reversal of temporary differences	**12,729**	8,574
Income tax expense recognized in net income	**15,365**	8,317

[in thousands of Canadian dollars]

Income tax expense (recovery) recognized in OCI comprises the following:

	2024 **$**	2023 $
Income tax effect of actuarial gain (loss) on defined benefit obligations	**58**	(113)

The provision for income taxes differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rates. A reconciliation between the statutory and effective tax rates is provided as follows:

	2024 **$**	2023 $
Federal and Ontario statutory income tax rate	**26.50 %**	26.50 %
Income attributable to equity shareholder before income taxes	**52,519**	37,115
Income taxes at statutory rate	**13,918**	9,835
Increase (decrease) in income taxes resulting from:		
Permanent differences	**80**	65
Provision to return adjustment	**1,326**	(316)
Current tax recovery from loss carryback	**-**	(888)
Other	**41**	(379)
	15,365	8,317
Effective income tax rate	**29.26 %**	22.41 %

The Company, as a rate-regulated enterprise, is required to recognize deferred income tax assets and liabilities and related regulatory deferral account credit and debit balances for the amount of deferred income taxes expected to be refunded to, or recovered from, customers in future electricity rates.

Significant components of the Company's net deferred income tax liability are as follows:

	2024 **$**	2023 $
Property, plant and equipment and intangible assets	**(106,461)**	(94,999)
Employee future benefits	**4,269**	4,281
Other	**6,777**	8,090
	(95,415)	(82,628)

[in thousands of Canadian dollars]

Movements in the net deferred income tax liability balances during the year were as follows:

	2024 **$**	2023 $
Deferred income tax, beginning of year	**(82,628)**	(74,167)
Recognized in net income	**(12,729)**	(8,574)
Recognized in OCI related to employee future benefits	**(58)**	113
Deferred income tax liability, end of year	**(95,415)**	(82,628)

The Company's regulatory deferral account debit balance for the amounts of deferred income taxes expected to be collected from customers in future electricity rates is $95,355 [2023 – $82,622].

20. CHANGES IN NON-CASH WORKING CAPITAL AND OTHER OPERATING BALANCES

	2024 **$**	2023 $
Accounts receivable	**(24,411)**	(16,882)
Prepaid expenses	**(2,158)**	(1,792)
Accounts payable and accrued liabilities	**(6,344)**	16,991
Net change in accruals related to property, plant and equipment	**(2,818)**	408
Net change in accruals related to intangible assets	**996**	(854)
	(34,735)	(2,129)

21. CONTINGENT LIABILITIES

Purchasers of electricity from the IESO are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if the Company fails to make a payment required by a default notice issued by the IESO. A prudential support obligation is calculated based upon a default protection amount and the distributor's trading limit less a reduction for the distributor's credit rating. As at December 31, 2024, the Company had drawn standby letters of credit in the amount of $10,000 [2023 – $10,000] against its credit facility to cover its prudential support obligation.

The Company participates with other electrical utilities in Ontario in an agreement to exchange reciprocal contracts of indemnity through the Municipal Electrical Association Reciprocal Insurance Exchange. The Company is liable for additional assessments to the extent premiums collected and reserves established are not sufficient to cover the cost of claims and costs incurred. If any additional assessments were required in the future, their cost would be charged to income in the year during which they occur.

The Company is party to connection and cost recovery agreements with HONI as described in Note 7 of these financial statements. Each of the Company's CCRAs has a term of 25 years. To the extent that the cost of a project is not recoverable from future transformation connection revenues, the Company is obligated to pay a capital contribution equal to the difference between these revenues and the construction costs allocated to the Company. These agreements require periodic reviews whereby a comparison of actual to forecasted load is conducted, and a true-up calculation performed. When a true-up calculation shows the Company’s actual load for the past period and updated load forecast for the future period are lower than the initial load, the Company is obligated to make up this shortfall. When the Company's actual load and updated load forecast are higher than the initial load, the Company is entitled to a rebate. HONI is expected to perform true-up calculations in years 5 and 10 and in year 15 if the difference between the actual incremental load and initial load at the end of year 10 is greater than 20%.

Various lawsuits have been filed against the Company for incidents that arose in the ordinary course of business. In the opinion of management, the outcomes of the lawsuits, now pending, are neither determinable nor material. Should any loss result from the resolution of these claims, such losses would be claimed through the Company's insurance carrier, with any unrecoverable amounts charged to income in the year of resolution.

22. COMMITMENTS

As at December 31, 2024, the Company has $198,023 in total open commitments spanning between 2025 and 2031. These include commitments relating to IT infrastructure management services, construction projects, overhead and underground services and other services relating to the Company's operations.

23. RELATED PARTY TRANSACTIONS

Transactions with related parties occur in the normal course of business, and are transacted at the amount of consideration determined and agreed to by the related parties. Trade amounts due from and to related parties are non-interest bearing, result from normal operations and are due within one year.

(a) Transactions with ultimate shareholder and its subsidiaries

During the year, the Company earned power recovery and distribution revenue from the City of Ottawa and its subsidiaries, which was billed at prices and terms approved by the OEB. In addition, the Company earned commercial services revenue from the City of Ottawa and its subsidiaries totaling $193 [2023 – $294]. The Company also received $1,025 [2023 – $4,235] in contributions relating to the upgrade and/or expansion of the Company's existing electricity distribution infrastructure.

The Company incurred $3,230 [2023 – $3,399] in property taxes and purchased $1,065 [2023 – $994] in fuel, permits and other services during the year, which is included in operating costs. The Company also incurred $523 [2023 – $55] in building permit costs and development charges, which are included in property, plant and equipment.

As at December 31, 2024, the Company's accounts receivable and customer deposits include $8,399 [2023 – $8,605] and $2,090 [2023 – $1,866], respectively, while the Company's accounts payable and accrued liabilities include $94 [2023 – $152] due to the City of Ottawa and its subsidiaries in respect of the transactions described above.

(b) Transactions with ultimate parent company

During the year, the Company earned revenue of $1,578 [2023 – $1,335] from Hydro Ottawa Holding Inc. relating to the provision of administrative and corporate services.

The Company incurred $4,222 [2023 – $6,437] in operating costs related to the purchase of administrative and corporate support services that includes compensation for certain key management personnel, and $2,685 [2023 – $3,717] in short-term financing costs, net of interest income.

At December 31, 2024, the Company's accounts payable and accrued liabilities include $1,676 [2023 – $2,980] due in respect of the transactions described.

The Company incurred $21,695 [2023 – $28,278] in financing costs during the year on its notes payable to Hydro Ottawa Holding Inc. described in Note 12 of these financial statements.

(c) Transactions with immediate parent

Since October 1, 2024, the Company incurred $2,618 [2023 – $nil] in operating costs related to the purchase of administrative and corporate support services that includes compensation for certain key management personnel, and $546 [2023 – $nil] in short- term financing costs, net of interest income, from Hydro Ottawa Capital Corporation [Note 1].

At December 31, 2024, the Company's accounts payable and accrued liabilities include $2,802 [2023 – $nil] due in respect of the transactions described.

The Company incurred $7,696 [2023 – $nil] in financing costs during the year on its notes payable to Hydro Ottawa Capital Corporation described in Note 12 of these financial statements.

(d) Transactions with other related parties

During the year, the Company earned revenue from the sale of electricity to other related parties, which is billed at prices and terms approved by the OEB, and earned other revenue of $3,434 [2023 – $4,062]. The Company also received $16,533 [2023 – $343] in contributions relating to the upgrade and/or expansion of the Company's existing electricity distribution infrastructure. During the year, the Company purchased power of $16,825 [2023 – $13,499], acquired property, plant and equipment of $1,794 [2023 – $2,200], and incurred $492 [2023 – $411] in operating costs.

In 2023, the Company sold investment property to a related party for cash proceeds of $523. No gain or loss was recognized on the transaction.

At December 31, 2024, the Company's accounts receivable include $7,916 [2023 – $837] due in respect of the transactions above while accounts payable and accrued liabilities and customer deposits include $3,911 [2023 – $3,974] and $9,703 [2023 – $nil], respectively, due to other related parties.

24. SUBSEQUENT EVENTS

On February 3, 2025, $338,667 of the Company's unsecured promissory notes, which Hydro Ottawa Capital Corporation assumed on October 1, 2024, came due or were called. To replace these existing promissory notes, the Company issued a $350,000, 4.43% promissory note to Hydro Ottawa Capital Corporation on the same day. This new note is due on January 30, 2035.

On April 24, 2025, the Board of Directors declared a $7,431 dividend on the common shares of the Company outstanding on December 31, 2024.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT3.7

EVIDENCE REFERENCE:

Attachment 7-1-1 (A) OEB Workform 2026 Cost Allocation Model

UNDERTAKING(S):

Reconcile which was vendor weighting only

RESPONSE(S):

Hydro Ottawa clarifies that meter reading weighting factors depicted in Table C of 7.0-VECC-52 match the meter reading weighting factors on Tab I7.2 Meter reading in the updated cost allocation models submitted in response to interrogatory 1-Staff-1 as Attachments 1-Staff-1(H) to (L).

As stated in interrogatory response 1-Staff-1 on page 26, an adjustment was made to the Billing and Collecting weighting factors to correct a classification error in the original submission. The offset to that correction was an adjustment to meter reading weights as certain costs were not properly assigned in the original submission. The correction did not affect the trial balance as presented on Tab I3 TB Data of the models. Please see Hydro Ottawa's response to interrogatory 1-Staff-1 for a description of changes to the updated Cost Allocation Models and their impacts.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT3.8

EVIDENCE REFERENCE:

Schedule 8-4-2 Generation Charges

UNDERTAKING(S):

Calculate the additional revenue that would have been earned off of net metering customers based on approved $16 rate and escalating to 2.1 percent.

RESPONSE(S):

In addition to the undertaking recorded, Hydro Ottawa agreed to provide what it believes the net metering charge would be based on current costs and provide the revenue in that scenario.

Table A provides the illustrative revenue based on inflating the 2025 Approved Net Metering Service Charge by 2.10% annually. The annual units are based on the estimate completed for productivity savings detailed in interrogatory response Attachment 1-SEC-27(A): Supporting Calculations - Innovation and Digital Transformation Productivity Initiatives, with the addition of commercial Net-Metering count.

Table A - 2026-2030 Net Metering Service Charge Illustrative Revenue ($'000s)

	Bridge	Test Years				
	2025	2026	2027	2028	2029	2030
Net-Metering Charge	$ 16.00	$ 17.00	$ 18.00	$ 19.00	$ 20.00	$ 21.00
Illustrative Revenue	-	$ 209	$ 311	$ 447	$ 627	$ 864

Based on the incremental costs for Net-Metering customers, the updated 2026 charge is estimated to be $8.00. The 2.10% inflation rate was applied for the years 2027-2030, while rounding to the nearest dollar. Table B details the illustrative revenue based on the updating costing.

Table B - 2026-2030 Net Metering Service Charge Illustrative Revenue - Updated Costing ($'000s)

	Bridge	Test Years				
	2025	2026	2027	2028	2029	2030
Net-Metering Charge	$ 16.00	$ 8.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00
Illustrative Revenue	-	$ 98	$ 155	$ 212	$ 282	$ 370

Hydro Ottawa estimated the productivity savings for Net-Metering at the end of 2024. Since then the IESO has announced the Home Renovations Savings Plan ("HRSP") which enables homeowners to receive rebates for solar panels installed; in return the solar must be used for load displacement purposes only and they are not eligible for the Net-Metering program. Table C displays the Net Metering Service Charge illustrative revenue based on the assumption most Residential solar panel growth will result from the HRSP and not the Net-Metering program.

Table C - 2026-2030 Net Metering Service Charge Illustrative Revenue - Updated Costing and Unit Estimate ($'000s)

	Bridge	Test Years				
	2025	2026	2027	2028	2029	2030
Net-Metering Charge	$ 16.00	$ 8.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00
Illustrative Revenue		$ 74	$ 97	$ 111	$ 124	$ 138

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT3.9

EVIDENCE REFERENCE:

1.0-VECC-3

UNDERTAKING(S):

Show annual and total incremental revenue requirement associated with the change in formula for working capital allowance

Preliminary

RESPONSE(S):

Preamble:

In the 2021-2025 term for 2022-2025, both OM&A and Cost of Power (COP) for the working capital allowance (WCA) calculation purposes were escalated annually by the OEB inflation parameter. The WCA was not held at a constant amount during the 2021-2025 term.

To provide the comparison of change in methodology of annual WCA and the impact on revenue requirement, Hydro Ottawa has assumed an annual inflation rate of 2.10% as the escalation factor for 2027-2030, consistent with the inflation rate used throughout the proceeding. Please see Table A below for the impact.

Table A - Incremental Change in Working Capital Allowance and Revenue Requirement Impact ($'000s)

	2026	2027	2028	2029	2030	Total
Proposed WCA	$ 79,540	$ 81,751	$ 84,442	$ 87,076	$ 89,773	$ 422,583
WCA Per 2021-2025 Approved Method	$ 79,540	$ 81,211	$ 82,916	$ 84,657	$ 86,435	$ 414,759
Difference	-	$ 541	$ 1,526	$ 2,419	$ 3,338	$ 7,824
IMPACT ON REVENUE REQUIREMENT	**-**	**$ 32**	**$ 91**	**$ 144**	**$ 199**	**$ 467**

In 2015, as part of the 2016-2020 Custom IR proceeding,[1] Hydro Ottawa contracted Navigant Consulting Ltd. to complete a Lead Lag study. The WCA percentage results from the Navigant study, as well as the settled WCA percentages[2] are detailed in Table B below.

Table B - 2016-2020 Lead Lag and Settled WCA Percentages

	2016	2017	2018	2019	2020
Navigant WCA	8.04%	8.04%	8.08%	8.13%	8.09%
Settled WCA	7.89%	7.89%	7.92%	7.55%	7.52%

During the Technical Conference, prior to the discussion surrounding this undertaking, on page 55, line 19, Hydro Ottawa was asked "does the IESO bill retailers separately for the transmission charges for the customers they serve, or are you billed transmission service charges for all customers in your service area, regardless of whether they are a standard supply service customer or a retailer customer?" The response was "That would be correct. It's in the latter."

For clarity, this is the current situation for the retailers that are within Hydro Ottawa's service Territory. The Retail Settlement Code also allows for retailers to bill customers directly for all bill charges. Within that scenario the retailer would bill customers for the entire bill including the

[1] Hydro Ottawa Limited, *2016-2020 Custom Incentive Rate-Setting Distribution Rate Application*, EB-2015-0004 (April 29, 2015).
[2] Hydro Ottawa Limited, *2016-2020 Custom Incentive Rate-Setting Approved Settlement Proposal*, EB-2015-0004 (December 7, 2015). Page 16

distribution portion. Historically Hydro Ottawa had retailers that chose this billing option and the retailer generic rates have rates that contemplate this situation.

When looking at the current working capital forecast by Hydro Ottawa for 2026, the potential working capital that retailers could bill based on the current level of retail customers is 7.23%, which results in a working capital cost related to retailers of $298K of the forecasted costs of $4.1M.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT3.10

EVIDENCE REFERENCE:

2-SEC-56 Table A
9-SEC-87

UNDERTAKING(S):

Provide 2-SEC-56, Table A on an in-service additions basis and if the numbers do not reconcile to explain.

RESPONSE(S):

Table A below provides the CCRA In-Service Additions by project for the 2026-2030 Test Years, which balances to the amounts provided in Table A of 9-SEC-87.

1 **Table A - CCRA In-Service Additions ($'000s)**

Project	Test Years					Total
	2026	2027	2028	2029	2030	2026-2030
Riverdale	$ 400	-	-	-	-	$ 400
Piperville Station-New East	$ 4,685	-	-	-	-	$ 4,685
Mer Bleue Station	-	$ 6,330	-	-	-	$ 6,330
Hydro Rd Station	-	$ 760	-	-	-	$ 760
Greenbank Station	-	-	$ 4,709	-	-	$ 4,709
New Kanata Station	-	-	$ 5,330	-	-	$ 5,330
King Edward Cable Upgrade	-	-	-	$ 16,428	-	$ 16,428
Carling (secondary cable)	$ 2,132	-	-	-	-	$ 2,132
Russell TB SWG Renewal	-	-	-	-	$ 420	$ 420
Carling TM Relay Replace	$ 160	-	-	-	-	$ 160
Hinchey TH Relay Replace	$ 160	-	-	-	-	$ 160
King Edward TK Relay	$ 160	-	-	-	-	$ 160
Bridlewood	-	$ 552	$ 568	$ 587	$ 605	$ 2,312
Total	**$ 7,697**	**$ 7,642**	**$ 10,608**	**$ 17,015**	**$ 1,024**	**$ 43,986**

2

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION

JT3.11

EVIDENCE REFERENCE:

1-SEC-17

UNDERTAKING(S):

Show reason invoice qualified for the account, redacted if necessary.

RESPONSE(S):

In Hydro Ottawa's response to 1-SEC 17(b), there was a reference to cost increases of 25% due to "USA tariffs." Hydro Ottawa acknowledges that this phrasing was used as a broad term to represent the array of trade measures. Cost increases are not solely attributable to US tariff application but also Canadian retaliatory tariffs applied directly to specific goods and services purchased from the United States and the indirect cost pass-through resulting from US manufacturers embedding the costs of US tariffs on their raw materials into the final equipment price. Refer to Schedule 1-2-5 - Impacts of Inflationary Pressures and Schedule 1-3-1 - Rate Setting Framework for this information. Regardless of the originating jurisdiction of the tariff, these combined trade measures could represent a material, non-discretionary increase in Hydro Ottawa's final procurement cost for critical equipment.

As requested, attached are two invoices (Attachment JT3.11(A) - Invoice 1 and Attachment JT3.11 (B) - Invoice 2) confirming that suppliers are already directly billing for these tariff charges. In both cases, the purchased items were manufactured in the United States and imported into Canada with a 25% tariff charge on the supplier's cost price applied by Canada Customs upon border crossing (i.e. Canadian retaliatory tariffs).

Hydro Ottawa has also included a quote from one of our suppliers (Attachment JT3.11 (C) - Quote) for the provision of 3 step vans. The first page shows the line in the quote where the tariff cost is itemized. These vehicles are produced through a multi-stage production process involving assembly in both the U.S. and Canada, and requiring the incorporation of specific steel and aluminum components. This production process subjects the final vehicle orders to the cumulative impact of multiple tariffs, encompassing both direct vehicle and material-specific tariffs.

Although the current value of tariffs incurred to date has not been material, the current period has been marked by volatility and uncertainty in global trade policy, a situation that remains fluid even up to the date of filing these undertakings. Although certain Canadian retaliatory tariffs were eliminated in September 2025, this relief is offset by the simultaneous imposition of new U.S. tariffs on goods including softwood timber and furniture, which take effect in October 2025. Given this persistent, unpredictable risk, Hydro Ottawa remains unable to quantify the full financial impact of future tariffs. This constant market flux underscores the need of the Tariff Impact Deferral Account.

[redacted]

[redacted]

Invoice

Invoice # IN-62572
Date 2025-07-29

Invoice To	Ship To
Hydro Ottawa Limited Accounts Payable PO Box 8700 Ottawa, ON K1G 3S4 **Email Invoices**	Hydro Ottawa Limited [redacted] 2711 Hunt Club Road Ottawa, ON K1G 5Z9 613-738-5499 [redacted]

Terms	Due Date	S.O. No.	P.O. No.	Tracking #	Ship Via
Net 30	2025-08-28	SO-62572	159741-OG	01256447455	ApexPpd & Chg

Item	Description	Order	Shipped	Prev.Inv.	Cost Per	Amount
8114	Hastings - 14'6" External Rod Gripall	1	1	0	[redacted]	[redacted]
NEW-TEST-2	Testing for new item. Above 10FT. Includes certification label/Stamp	1	1	0		
	NON CANCELLABLE, NON RETURNABLE					0.00
TARIFF	This Item Has Tariff Charge	1	1	0	130.34	130.34
FREIGHT	Freight Charges tracking # 01256447455	1	1	0	[redacted]	[redacted]
	HST on sales				13.00%	

Thank you for your order, Dave

Subtotal	[redacted]
Sales Tax	[redacted]
Total	[redacted]

GST/HST No. [redacted]

Payment Terms: Please remit payment within 30 days from the invoice date. Late payments may incur a fee of 2% per 30-day period.
Thank you for your prompt attention.

[redacted]

INVOICE

INVOICE	
450641	
Invoice Date	Page
6/27/2025	1 of 1
ORDER NUMBER	
1160621	

Bill To:

Hydro Ottawa Limited
2711 Hunt Club Rd
Ottawa, ON K1G 5Z9
CA
Customer ID:13839

Ship To:

Hydro Ottawa - Dibblee Road
201 Dibblee Road
Ottawa, ON K2R 1J2
Ordered By: [redacted]

PO Number	*Term Description*	*Net Due Date*	*Disc Due Date*	*Discount Amount*
160284 - OG	Net 30	07/27/2025	07/27/2025	0.00

Order Date	*Pick Ticket No*	*Primary Salesrep Name*	*Taker*
06/16/2025 11:57:31	2198311	Account HOUSE	RMENARD

Quantities				*Item ID*	*Pricing UOM*		*Unit Price*	*Extended Price*
Ordered	*Shipped*	*Remaining*	*Disp.*	*Item Description*		*Unit Size*		
			Delivery Instructions:	**PPD**				
Carrier: CanPar				*Tracking #:* D420352470000854407001				
1.00	1.00	0.00		BUC-C20192CM-M Adj Mobility Belt Short Back D23-26 HS Code: 4205.00.00.00 In stock: 7	EA	.0000	[redacted]	[redacted]
1.00	1.00	0.00		TARIFF Tariff Charges	EA	.0000	160.4900	160.49

Total Lines: 2

SUB-TOTAL:	[redacted]
TARIFF:	0.00
Ontario HST @ 13 %:	[redacted]
AMOUNT DUE:	[redacted]

Canadian Dollar

Prices are subject to applicable tariff surcharges at the time of import. Any changes in tariffs will be reflected in the final invoicing.

Rev 20241031 *ORIGINAL*

Prepared For :
[redacted]
HYDRO OTTAWA
3025 ALBION RD N
OTTAWA, ON K1G 3S4
CANADA
Phone :613-738-5499

[redacted]

Other Factory Charges

PNZ-998	NO CARB22 BASE WARRANTY	[redacted]
PNV-998	No CARB24 Pricing Impact	[redacted]
998-034	FCCC PDI PROCESSING	[redacted]
RFY-022	Front Tire Surcharge	[redacted]
RFU-022	Rear Tire Surcharge	[redacted]
PAT-004	TARIFF IMPACT FEE FCCC WALKIN VAN DIESEL CHASSIS	$1,027.00
	STANDARD DELIVERY CHARGE	[redacted]

Extended Warranty

995-011	FREIGHTLINER CUSTOM CHASSIS CORPORATION BASIC CHASSIS WARRANTY	[redacted]
WAG-075	TOWING: 2 YEARS/UNLIMITED MILES/KM EXT TOWING COVERAGE $750 CAP FEX APPLIES	[redacted]
	Currency Exchange Rate	1.3687
	Total Extended Warranty (local Currency)	[redacted]

(+) Weights Shown are estimates only.
If weight is critical, contact Customer Application Engineering.

(**) Prices shown do not include taxes, fees, etc… "Net Equipment Selling Price" is located on the Quotation Details Proposal Report.

(***) All cost increases for major components (Engines, Transmissions, Axles, Front and Rear Tires) and government mandated requirements, tariffs, and raw material surcharges will be passed through and added to factory invoices.

Prepared For :
[redacted]
HYDRO OTTAWA
3025 ALBION RD N
OTTAWA, ON K1G 3S4
CANADA
Phone :613-738-5499

[redacted]

QUOTATION

MT55 FRONT ENGINE WALK-IN VAN CHASSIS

SET-FORWARD FRONT AXLE CHASSIS	4025MM (158 INCH) WHEELBASE
CUM B6.7 200 HP @ 2400 RPM; 2600 GOV, 600 LB/FT @ 1600 RPM	
ALLISON 2200 HS AUTOMATIC TRANSMISSION WITH PARK PAWL WITHOUT PTO PROVISION	5/16X2.81X9-1/8 INCH STEEL FRAME (7.94MMX231.8MM/0.312X9.12 INCH) 80KSI
DA-RS-13.5-2 13,500# F-SERIES SINGLE REAR AXLE	2225MM (88 INCH) REAR FRAME OVERHANG
13,500# FLAT LEAF SPRING REAR SUSPENSION WITH RADIUS LEAF	
DA-F-8.0-2 8,000# FC1 68.0 KPI/3.74DROP SINGLE FRONT AXLE	
8,000# TAPERLEAF FRONT SUSPENSION	NO TAG AXLE
NO CAB SIZE	

		PER UNIT	TOTAL
VEHICLE PRICE	TOTAL # OF UNITS (3)	$ [redacted]	$ [redacted]
EXTENDED WARRANTY		$ [redacted]	$ [redacted]
DEALER INSTALLED OPTIONS		$ [redacted]	$ [redacted]
CUSTOMER PRICE BEFORE TAX		$ [redacted]	$ [redacted]
TAXES AND FEES			
TAXES AND FEES		$ [redacted]	$ [redacted]
OTHER CHARGES		$ [redacted]	$ [redacted]
TRADE-IN			
BALANCE DUE	(LOCAL CURRENCY)	$ [redacted]	$ [redacted]

COMMENTS:
Projected delivery on ___ / ___ / ___ provided the order is received before ___ / ___ / ___.

APPROVAL:
Please indicate your acceptance of this quotation by signing below:

Customer: X______________________________________ Date: ___ / ___ / ___.

CONFIDENTIAL DRAFT FOR REVIEW

AMI 2.0 BUSINESS CASE – FINAL REPORT

Hydro Ottawa

Advanced Metering Infrastructure (AMI) Consulting Services

May 17th, 2024

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Hydro Ottawa (HOL) presently has AMI 1.0 and 1.5 meters deployed throughout its service territory and are reaching end of life. Over the past 15-years, HOL has learned many lessons into the benefits and challenges of its current mesh technology. Faced with sustaining the current solution, or upgrading to the next-generation of AMI technology, this document will outline an assessment of an AMI 2.0 investment into cellular point-to-point (P2P).

The original business drivers for the AMI 1.0 project were not overly demanding which limited key metering features that were available in the first-generation AMI technology, but not implemented. Such features included remote disconnect switches, power outage notifications and support for voltage and other instrumentation measurements. The AMI 1.0 platforms did accomplish their primary objective of supporting hourly interval data to support time-of-use rates. Another key benefit this technology did provide, and set the stage for AMI 2.0 was how consumption and other forms of data can power insights into customer behaviour, grid reliability and operations.

As Hydro Ottawa plans its next transformation, AMI 2.0 represents an opportunity to build a data-enriched organization powered by a robust, next generation AMI 2.0 system. As HOL adopts grid modernization plans, an Advanced Distribution Management System (ADMS) and manages its Distributed Energy resources (DERs), AMI 2.0 will be an essential technology to become a true Distribution System Operator (DSO) in addition to creating and deploying demand response programs at scale.

Our traditional approach to developing business cases for AMI is evaluating use cases that will build qualitative and quantitative value to HOL and its end customers. A lot of time was spent learning about Hydro Ottawa and its present system, operations, costs and future plans. Through this discovery process, we are able to assess relevant use cases and dismiss benefits that have already been acquired through AMI 1.0.

When we look at AMI 2.0 and the benefits it may provide, there are additional challenges with certain types of use cases. Our objective in any business case is to provide defendable data, benefit/cost data that is built on a sound methodology and there is support of HOL stakeholders. With AMI 2.0, there have been challenges building certain use cases which are built on estimates that may be difficult to defend in a regulatory filing. There have also been a number of instances where several use cases yielding significant benefits have resulted in the inability to claim the benefit because they have been partially recognized with AMI 1.5 technologies (i.e. remote disconnect). A summary of the use cases and net benefits are included in Figure 1. There are several use cases that are not included in the overall Net Benefit total and excluded from the NPV calculations. These use cases may be added back to the model easily should any changes be required.

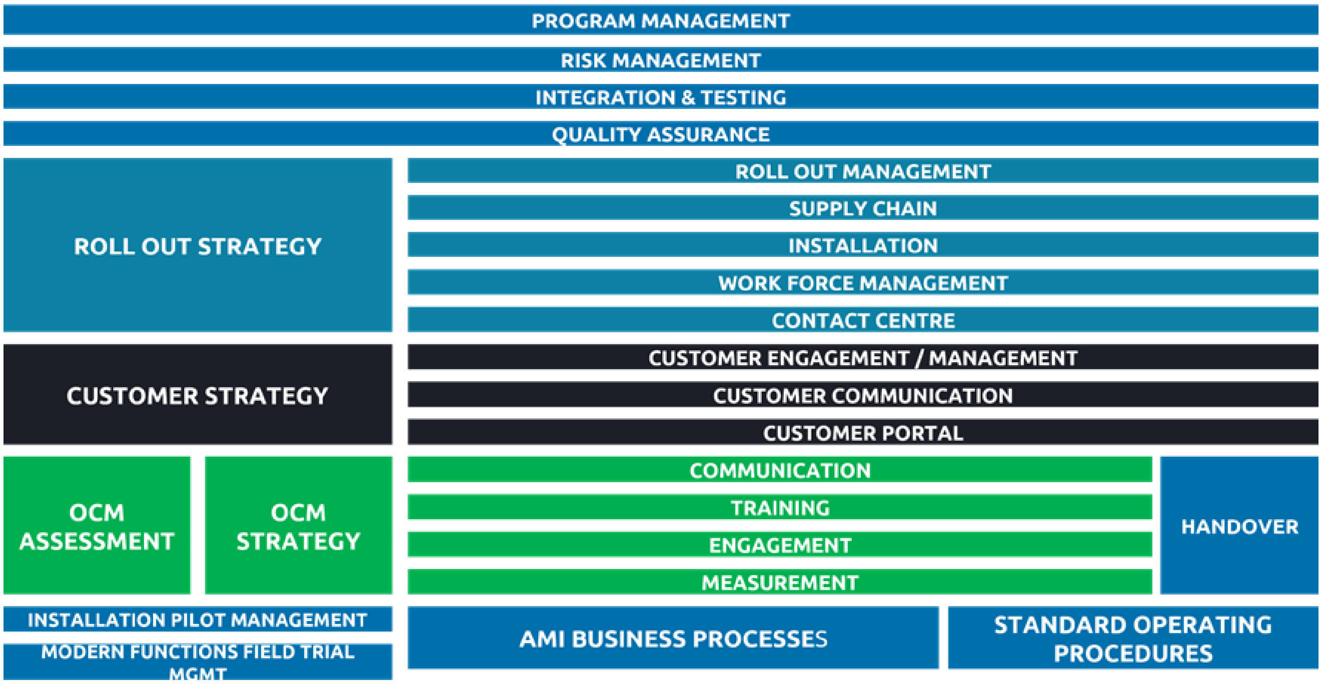
Figure 1: Use Case Net Benefits

Use Case Value & Stakeholders

Use Case	Operations	Customer Impact	Demand Reduction	Asset Mgt	System Reliability	Total Net Benefits (million)
(1) AMI Sustainment	√	√		√	√	$88.02M
(2) Customer Service Impact		√	√			$-0.031M
(3) Remote Disconnect/Reconnect	√	√		√		$-0.238M
(4) Prepayment Functionality	√	√	√	√		$5.19
(5) Outage Identification	√	√			√	$11.59
(6) Service Restoration	√	√			√	$0.366
(7) Proactive Outage Notification	√	√			√	$0.274
(8) Predictive Maintenance	√	√		√	√	$-0.080
(9) Conservation Voltage Reduction	√	√	√	√	√	$0.0
(10) Demand Response	√	√	√	√	√	$0.0
(11) Shared Services	√	√		√		$0.0
* Total Net Benefits does not include CVR, DR or Shared Services						$105.1M

Since AMI 2.0 has the potential to reach into many different HOL business lines, it will be important to address required staffing to prepare for deployment of the technology. Many of these costs have been accounted for and may be found within the financial model. Figure 2 illustrates many of the different workstreams that will be necessary in an AMI deployment for both pre-deployment and during deployment activities. This is a suggested deployment framework and is highly customizable depending on HOL's needs and internal capabilities.

Figure 2: Typical Workstreams for Pre and Present Mass Deployment



BUSINESS CASE APPROACH

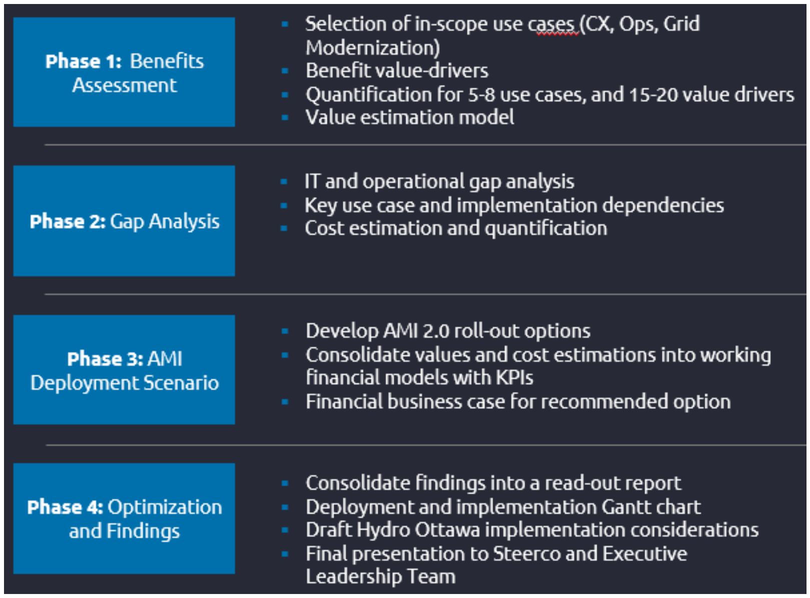
Transitioning from AMI 1.0 to 2.0 is a non-trivial journey and one that can be financially complex. Where benefits have been claimed in the AMI 1.0 business case, they are no longer eligible to be part of our financial justification for AMI 2.0. This drives the need to evaluate use cases that reside in multiple HOL business units such as customer service, operations and others. Some key characteristics of an AMI 2.0 solution that drive value into more advanced use cases include:

1. Higher bandwidth
2. Lower network latency
3. Power quality grade measurement data
4. Data streaming capabilities
5. Distributed Intelligence

Like many technologies, metering has evolved into a recorder of data that goes well beyond measuring a billable kilowatt-hour. Measurement data and advanced onboard features have transformed the traditional meter into a sensor capable of providing granular information very quickly to operational systems. Unlike AMI 1.0, AMI 2.0 is able to provide data to operational systems that serve the distribution system. As such, we take a bottoms-up approach when building an AMI 2.0 business case and look at enhancements to existing partially supported use cases in addition to those advanced use cases that have traditionally been exclusively part of operations.

For HOL, the AMI business case assessment was split into four phases outlined in Figure 3 below. Upon completion of each phase preliminary results were presented to HOL stakeholders for review, discussion, and approval. Each phase required collaboration between HOL Business Unit leaders and Capgemini's team to develop cost and benefit logic with inputs that align with HOLs business and vision.

Figure 3: Business Case Approach



The final deliverables include three financial models aligned to three different deployment scenarios.

Business Case Modelling Principles

Throughout the business case assessment, our team applied a number of modelling principles which include the following:

MAINTAIN CONSERVATISM FOR BENEFITS AND COSTS

- Value Assessment: Where possible the baseline for operational savings was derived from HOL'S budgets, activities and plans. Future state assumptions are based on avoidance of costs or based on industry benchmark from other utilities.
- Cost Components: AMI infrastructure costs are based on pricing from several AMI vendors that represents budgetary pricing that is partially aligned to the number of HOL meters. IT Integration costs are based on recent, comparable projects conducted by HOL in addition to other utility projects Capgemini is involved in.

BALANCE CHANGE AND SPEED OF BENEFIT REALIZATION

- Speed of AMI deployment requires increased capital and resources in the short term and drives rapid operational change. On the other hand, stretching the deployment too long delays benefit realization and negatively impacts NPV results. For modelling purposes, a balanced 5-year deployment was chosen and confirmed by HOL stakeholders to balance benefits with costs.

BE MINDFUL OF ENTERPRISE INTERDEPENDENCIES

- AMI transforms HOL's operational processes and requires IT integrations and applications. HOL stakeholders in IT, operations, metering, customer service, billing, grid modernization, etc. have been involved throughout this business case development process in addition to defining the AMI deployment scenarios. The final scenarios were defined in a leadership workshop to ensure HOL's best interests were considered in the deployment scenarios. These deployment scenarios can be adjusted as HOL's enterprise and grid modernization initiatives begin to take shape.

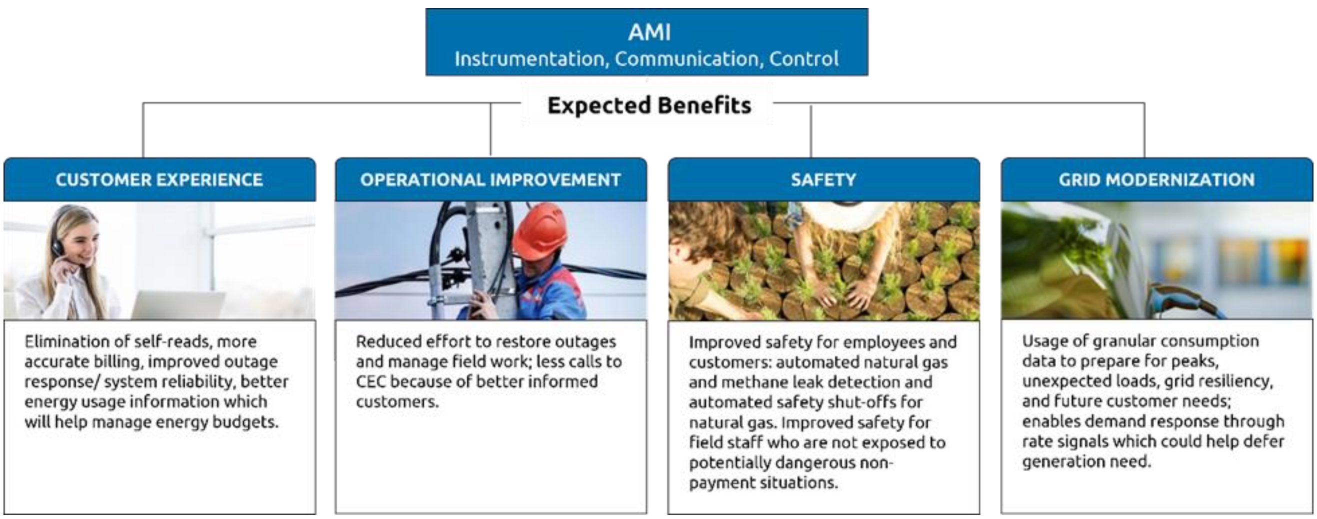
LEVERAGE LESSONS LEARNED FROM PEER UTILITIES

- HOL has learned many lessons from AMI 1.0 and 1.5. Capgemini has worked extensively with utilities that have similarly deployed AMI 1.0 and 1.5 in addition to deploying AMI 2.0. This puts HOL in a position to apply lessons learned first-hand, in addition to collaborating with Utility peers and partners that have experience in AMI 2.0 planning and deployment.

AMI 2.0 Use Case Benefits

There are four key areas of benefit realization that may be viewed in Figure 4. The value of AMI 2.0 transcends business lines by providing a wealth of data, functionality and insights to improve the customer experience, operations, safety and grid modernization. Part of our modelling process requires stakeholders from HOL business lines to share business information, processes and plans that in turn are used to build a personalized financial model. With this level of involvement, it is an opportunity to educate stakeholders that may not be aware of AMI 2.0 benefits. We have held several information sessions about AMI 2.0, advanced use cases and how this technology can deliver value.

Figure 4: Areas of Benefit Realization



Some of the more advanced benefits may be viewed in Figure 5. There are instances where AMI 2.0 will provide a direct benefit, however may be difficult to quantify. For example, the security features built into next-gen AMI provide a direct benefit, yet that feature is a qualitative benefit necessary to ensure appropriate security protocols are in place.

Figure 5: AMI 2.0 Advanced Benefits & Use Cases

Throughout the evaluation of each use case, we collaborated with HOL stakeholders to obtain data and review our benefit and costing methodologies. A summary of the benefit realization risk can be viewed in Table 1. This provides level of risk associated before realizing the benefits outlined in the use case in addition to what the value drivers consist of.

Table 1: Use Case Benefit Realization Risks

Use Case (Benefit Start date)	Risk to Benefit Realization	Primary Monetary Value Driver and Assumption
AMI Sustainment 2026/2027	**LOW** Actual AMI 1.0 and 1.5 budgets of existing programs were use as data source.	Avoided cost replacement AMI 1.0 and 1.5 meters, meter sampling program, field crew travel, labour and carbon reduction.
Customer Service Impact 2026/2027	**LOW** Actual budgets, costs and past experiences was used to model the benefits of this use case.	Reduced labour costs as a result of enhanced data and reduced inbound calls. Data was conservative and positive NPV is expected
Remote Disconnect / Reconnect 2026/2027	**LOW** Actual and estimated operating budgets and estimations to impact of reduced bad debt from past years were used as data source.	Avoided labour, field crew travel, labour, carbon reduction and reduced write-offs. Benefit already falls under AMI 1.5 device capability so benefit is not claimed in AMI 2.0.
Prepayment Functionality 2028/2029	**MEDIUM** Benefits and costs are dependent on customer enrollment which has been conservatively estimated at the lower market adoption rate. Estimations were used and verified with stakeholders for bad debt and actual costs for collections and program operating costs.	The amount of field labour will be significantly reduced for reduced disconnect/reconnect operations. Estimated bad debt reductions from past years, elimination of collections, late payment and notification processes.

Use Case (Benefit Start date)	Risk to Benefit Realization	Primary Monetary Value Driver and Assumption
Outage Identification 2026/2027	**MEDIUM** Actual and estimated benefits were modelled from annual storm responses, labour and travel costs as data sources.	Real time granular visibility into every outage location will improve response time resulting in improving SAIDI. Response time benefits include reduced travel, labour, reporting and accuracy.
Service Restoration 2027/2028	**MEDIUM** Actual and estimated benefits were on the conservative side. Restoration data was deemed to be difficult to model and defend in a business case. Reduced time for restorations	Real time granular visibility into every restoration location will improve time required to verify nested outages have been restored. Reduction in labour, travel time and reporting.
Proactive Outage Notifications 2027/2028	**LOW** Contact center data reductions was deemed to be challenging to model and defend in a business case. No data was available for this use case, however HOL had initiated a pilot for this feature in Dec 2023.	By providing proactive outage/restoration notifications to clients, reductions in inbound contact calls are expected.
Predictive Maintenance 2027/2028	**MEDIUM** Equipment failure data was deemed to be challenging to model and defend in a business case. No data was available for this use case.	Granular and real time loading data assigned to, or aggregated against distribution infrastructure can help identify loading issues, EVs and adverse conditions prolonging the life of an asset and prevent an outage.

USE CASES

Throughout our assessment of AMI 2.0 use cases, we have compiled personalized value drivers and costs to ensure the integrity of the data. The following Use Case section describes each use case in detail, in addition to pre-requisites, financial metrics, customer impact, assumptions and time-to-value.

AMI Sustainment

Description

- To-date, HOL operates an AMI 1.0 and 1.5 solution. The current system is approaching end of life and has limited capabilities related to power outage/restoration notifications and advanced use cases. The AMI sustainment use case is focused on the "do nothing" scenario. If HOL decides to maintain its current system, this use case includes all costs associated with maintaining and operating the existing AMI 1.0 system for the next 15 years. These costs are broken down into several categories that include meter hardware, collectors, gatekeepers, head end software, annual licensing, support and data collection costs.

  HOL further manages a meter compliance program for installed meters and are required to conduct accuracy testing which is mandated by Measurement Canada (MC). Installed meters are sampled on fixed frequencies (10, 8 and 6 years) to verify they remain compliant with MC regulations. This compliance program utilizes HOL resources that include labour, transportation, and meter sealing when meters are removed from the field and tested in a meter lab. If meters from a sample batch pass accuracy testing, they are typically resealed, inventoried, or redeployed in the field. All meters in the sampling batch and those meters part of the manufacturing batch, have their seal expiration dates extended if tests are successful.
- Equipment (meter and network) failures typically increase as AMI solutions age in addition to the technology becoming obsolete. Failures may occur in a variety of ways that include complete failure, accuracy issues and component failure resulting in erratic behaviour and communication issues. Replacing end-of-life meters and network equipment with next generation AMI equipment will reduce or eliminate truck rolls and replacement hardware costs for a significant number of years and improve reliability.
- With AMI 2.0, the existing meter compliance program will no longer be required for ten years once AMI installation begins and contingent on HOL obtaining an approval for temporary dispensation for meters with seals expiring in the AMI deployment window. As new AMI meters are installed, the mandatory MC testing period will reset to 10 years and the need to carry larger volumes of inventory is reduced where meter and network equipment failures be minimal.

Customer Experience Impact

There is very limited customer experience impact however an AMI project requires customer site visits to swap out AMI 1.0 meters with AMI 2.0 meters. The typical customer impact of these visits can be minimal, however there is an opportunity to evaluate how these customer interactions can improve the customer experience by creating more meaningful and personalized interactions.

Net Benefit (PV 2024): $53.47M

Value Drivers (VD)

1. **VD-1: Avoided metering-maintenance program budget-** Meters are presently replaced as a result of failure, upgrades, or meter compliance sampling. These costs are eliminated entirely once the new meters are installed. Continued installation of AMI 1.0 meters creates challenges when evaluating a switch to AMI 2.0 where they may not be fully depreciated when removed from the field during installation of the next generation technology.
2. **VD-2: Reduced inventory overheads -** Installation of AMI 2.0 devices will eliminate AMI 1.0 inventory requirements. The new meters will essentially reset the MC sampling program resulting in less inventory in addition to standardizing meter inventory codes.
3. **VD-3: Network operating cost -** All related network operating costs for the legacy AMI system will be eliminated once AMI 2.0 meters have been deployed. This would include all phone line and cellular communications used between the AMI 1.0 HES and the collectors and gatekeepers.

4. **VD-4: Avoided cost of HES systems -** This assumes the HES used for the AMI 1.0 system and related periodic upgrade costs can be eliminated where the AMI 2.0 system will require a different HES.
5. **VD-5: O&M cost of existing meter to cash systems -** All related operating costs associated with the legacy HES will gradually be eliminated once all AMI 2.0 devices have been deployed. This includes annual licensing and support.
6. **VD-6: Reduced labour to run existing meter to cash systems -** All FTE costs associated with operating the HES, troubleshooting and support required to collect meter data and generate a customer bill.
7. **VD-7: Reduced truck rolls due to newer inventory and better insights into service conditions -** The AMI 2.0 system will be more reliable for a significant number of years compared to the AMI 1.0 devices. There are additional features in the AMI 2.0 devices that allow greater insights into customer service conditions enabling more effective remote troubleshooting resulting in fewer truck rolls.
8. **VD-8: Reduced third-party costs associated with meter check/repairs, meter change -** Use of third-party contractors for specific functions such as meter sealing will no longer be needed until the meter sampling program resumes in 10 years, or in limited amounts under special circumstances.
9. **VD-9: Reduced field labour cost -** AMI 2.0 devices have enhanced monitoring capabilities allowing for a more comprehensive ability to remotely troubleshoot a customer's service. Having remote diagnostic capabilities and insights will further reduce associated costs with field visits related to meter support, troubleshooting, investigations and customer complaints. Additionally, there should be fewer field visits to address potential meter issues since the meters will be newer and more reliable than existing AMI 1.0. devices.

Key Assumptions and Inputs for VD

All Value Driver assumptions were based on IR data, or assumptions which have been reviewed with HOL business line representatives.

- VD-1: Based on conversations with HOL, the annual metering-maintenance budget appears to cover the inventory and meter sampling program. Meter maintenance program includes operating costs such as labour.
- VD-2: The AMI 2.0 platform will reduce the number of inventoried meters required for meter failures and meter sampling program. Furthermore, standardization of meter service types will reduce the number of different meters required to handle and inventory.
- VD-3: Data is based off of IR and public filings for operating costs and data collection expenses related to phone line and cellular communications.
- VD-4: This assumes the HES is not compatible with the AMI 2.0 system. The HES for AMI 1.0 will be discontinued once AMI 2.0 devices are installed.
- VD-5: Annual operating, licensing and support costs that are associated with the HES will further be eliminated.
- VD-6: FTE required to operate the existing HES will no longer be required as AMI 1.0 is phased out
- VD-7: By installing new AMI 2.0 devices, meter failures are reduced and the meter sampling program clock is reset to 10 years.
- VD-8: Data is based on reduction of meter check/repairs, meter changes resulting in 80% reduction in third party work orders (with average of 30 min per work order).
- VD-9: Assumes a ramp down and ramp up rate based on AMI 2.0 installation progress and leverages data from IRs.

AMI Infrastructure Pre-requisites AMI meters have received Measurement Canada's Notice of Approval (NOA)	**Applications, Integrations and Data** AMI 1.0 HES, MDM, Troubleshooting tools, Communication Servicer (phone line, cellular)
Use Case Dependencies None, part of standard AMI infrastructure	**Business Impact, Time-to-Value** The value realization follows the AMI deployment schedule and removal of AMI 1.0 devices

Customer Service Impact

Description

- To-date, customers have traditionally limited understanding and insights in how their power bill breaks down into individual end uses such as heating, laundry, cooking, high bills, etc. While having interval data available to them, energy usage visibility was limited to 60-minute intervals. AMI 2.0 devices can support far greater granularity with a new standard emerging consisting of 15-minute intervals. The objective of this use case is to enhance the customer experience while reducing the overall cost-to-serve. In this instance, we will be limiting the benefits to reduced labour costs as a result of lower average handling times in the customer contact centre.
- Customer energy insight platforms, ingest hourly and 15-minute interval energy data. This data can be used to illustrate how customers are using energy by leveraging machine learning and AI algorithms. Optionally, apps installed in AMI 2.0 meters also allow energy usage disaggregation to occur at the meter with potentially greater levels of accuracy. While energy insights are meant to empower customers, based on HOL's experience a previously deployed energy insight platform caused an increase in calls to the contact centre. While there is still value to such systems and HOL has indicated a desire to deploy similar technology in the future, we have excluded such platforms and features from this use case.
- With AMI 2.0, energy usage is recorded in more granular intervals providing even more valuable time-based insights about when energy is used. This information can be quite useful when assisting customer calls inquiring about high bills, usage patterns, energy spikes outside of occupied hours, etc. This granular data in addition to power quality notifications can reduce customer call time and enable HOL to operate in a proactive fashion to resolve issues before the customer is even aware there is an issue.

Customer Experience Impact

While the objective of this use case is to provide systems that can provide value to customers, a secondary objective is to reduce the cost-to-serve. While disaggregation systems have potential to reduce overall cost-to-serve, it is apparent that customer education must be included to ideally reduce contact center calls to support these systems. Regardless, the granular AMI 2.0 data and instrumentation data will help HOL be proactive with customers and resolve customer inquiries more quickly.

Net Benefit (PV 2024): $-0.075M

Value Drivers (VD)

1. **VD-1: FTE efficiencies (reduction in cost-to-serve/AHT)** – Based on HOL's experience with disaggregation systems, the primary value driver is limited to 5% to overall average handling time focused on calls related to high bills, and energy savings utilizing 15-minute intervals. A 5% reduction in calls is also based on availability of more granular data.

Key Assumptions and Inputs for VD

- VD-1: Presently assumes an overall reduction in effort based on number of billable minutes.

AMI Infrastructure Pre-requisites Standard AMI Infrastructure, 15-minute (or 1, 5, 10 minute) Interval Data	**Applications, Integrations and Data** MDM, CRM, CIS
Use Case Dependencies This use case builds on the use cases: Energy Use Information and Time-varying rates.	**Business Impact, Time-to-Value** One complete day of recorded usage and ongoing.

Remote Disconnect / Reconnect

Description ▪ To-date, HOL has a hybrid approach to connect, disconnect and reconnect a customer's service. The disconnect/reconnect operation is typically performed via a series of two truck rolls, or remotely with upgraded AMI 1.0 equipment equipped with a remote disconnect switch (RDS). There are associated costs with these truck rolls in addition to potentially exposing field crews to personal danger in situations related to disconnect for non-pay (DNP). Furthermore, there are typically delays between when a DNP order is created and when the actual disconnect occurs. ▪ With RDS equipped AMI meters, HOL can remotely disconnect and reconnect all meters in a timely manner without involving a field crew. AMI 2.0 will provide a lower latency network than AMI 1.0 mesh systems which can be important to improve the customer experience. These devices may also provide additional real-time diagnostic and even load limiting features which can facilitate additional benefits and reduce the cost of load limiters if disconnections are periodically suspended during peak cooling, or heating periods.	
Customer Experience Impact The RDS will improve the overall customer experience by enabling pre-paid programs, reduce delays in customer requested disconnection/reconnection service for maintenance work in addition to improved reconnection time when DNP orders result in an actual disconnection. The RDS may also be used for safety purposes in power outages by defaulting to a disconnect state. By defaulting the RDS to a disconnect state, homes that are operating generators during a power outage could create hazardous conditions that could result in injuries to field crew members.	
Net Benefit (PV 2024): $-0.227M	
Value Drivers (VD) 2. **VD-1: Reduced travel operating cost -** With RDS enabled AMI devices, disconnection/reconnections may be executed remotely. This reduces/eliminates field visits to customer sites that would have traditionally been made to disconnect/reconnect a service. The presence of the RDS reduces previously required travel and labour. 3. **VD-2: FTE efficiencies -** The RDS will allow disconnects and reconnects to be performed remote which eliminates previously required field visits. Cost savings are focused on reduced FTE hours. 4. **VD-3: Cost savings due to reduced write offs -** The RDS will allow quicker remote disconnects and reconnects. While this in turn does not eliminate write-offs, the time to disconnect will represent a savings and overall reduction in amounts written off.	
Key Assumptions and Inputs for VD ▪ VD-1: Utilize IR information for labour, truck type, average cost, average transit time and wrench time. ▪ VD-2: Overall estimated reduction of 90% for reduction in standard labour hours and 90% reduction in overtime hours. ▪ VD-3: Assumed a 15% reduction in delay between DNP order issued and actual disconnection	
AMI Infrastructure Pre-requisites Standard AMI Infrastructure with RDS equipped meters. Medium-to-low latency networks are preferred, however are not necessarily required.	**Applications, Integrations and Data** MDM, HES, Customer Care and Billing (optional);
Use Case Dependencies Enables Pre-payment	**Business Impact, Time-to-value** Immediate benefits with reduction in overall cost-to-serve, remote disconnect/reconnect in addition to potential benefits with a pre-payment program.

Pre-Payment

Description

To-date, HOL experiences annual write-offs due to non-payment of customer bills and performs manual and automated service disconnect/reconnects. Customers that are late making bill payments will further trigger late payment processes that require FTE and system intervention in the form of reviews, emails, physical mail, phone calls, etc. Furthermore, use of security deposits has been a risk management method to guard against non-payment customers and act as a mechanism to recover unpaid customer balances that could be written off.

With Pre-Pay, the concept of late payments will no longer exist. Since customers pay for electricity prior to consuming (similar to purchasing groceries), security deposits will no longer be required which further removes financial burdens from the customer. With remote disconnect functionality and a pre-pay management system, HOL will be able to offer a program to customers that can help them manage their energy use more efficiently, provide payment flexibility, eliminate/reduce security deposit requirements, avoid credit risk penalties, reduce write-offs and improve operational costs.

Customer Experience Impact

Improves participation options to customers by offering an alternative to existing programs. Customers may not be required to make security deposits and they may purchase pre-pay power at increments of their choosing which are aligned with their budgets. Late payments, penalties, adverse credit rating impact will be eliminated and call volumes for pre-pay customers would be expected to decrease. The pre-pay management system would be responsible to notify customers when their balances are getting low, set up recurring or one-time energy purchases and show what their energy usage levels are. A pre-pay program should be viewed as an opt-in program for all customers and not necessarily limited to those who are simply late with payments.

Net Benefit (PV 2024): $2.30M

Value Drivers (VD)

Quantified benefits:

1. **VD-1: Reduced travel operating costs –** With RDS enabled AMI devices, disconnection/reconnections may be executed remotely. This reduces/eliminates field visits to customer sites that would have traditionally been made to disconnect/reconnect a service. The presence of the RDS reduces previously required travel and labour. In a pre-pay program with an RDS capable meter, when customer balances are depleted, or hit a certain threshold the meter may be turned off automatically by the pre-pay management system and reconnected automatically once the customer purchases more energy.
2. **VD-2: FTE efficiencies:** The pre-paid management system monitors and manages disconnections and reconnections based on a customer's balance. This will result in FTE efficiencies where the prepaid management system plays an active role in notification, processing and taking action compared with manual processes.
3. **VD-3: Cost savings due to reduced write-offs:** By shifting to a prepaid paradigm, energy is purchased before it is consumed. Bad debts are unable to occur based on the inherent nature of the program.
4. **VD-4: Reduced cost of collections processing:** Under a pre-pay program, collection efforts are not required. HOL utilizes third-party collection services in addition to its own which will be reduced.
5. **VD-5: Reduction in contact centre FTE efforts due to reduced call volume and AHT –** Where pre-pay customers are predominantly self-managed, these customers will typically not need to contact the utility to make payments, setup payment plans, request reconnections, etc.
6. **VD-6:** Line loss savings due to reduced energy consumption: Pre-payment encourages customers to be more active participants in managing their energy consumption. The reduced energy consumption leads to decrease in line losses of the electricity that needs to be transmitted and distributed.

Key Assumptions and Inputs

Requires AMI devices equipped with an RDS and a pre-pay management system.

VD-1: Energy savings for each pre-paid customer is 8% and line-loss savings for the electricity consumption reduced is 5%	
AMI Infrastructure Pre-requisites RDS-Equipped AMI devices and a medium-low latency network.	**Applications, Integrations and Data** MDM, HES, Pre-pay system, Payment Processing System
Use Case Dependencies This use case relies on the remote disconnect/reconnect use case	**Business Impact, Time-to-Value** Immediate benefits with reduction in overall cost-to-serve, remote disconnect/reconnect, elimination of late payments, improve overall cashflow and reduced write-offs.
OCM Considerations [n/a] Creation and training of a broader pre-paid customer program, process changes and integrations.	**Project Resources** Program Manager and Customer Service Representatives. Marketing for program roll-out and education

Outage Identification

Description

- To-date, Hydro Ottawa relies on its OMS to locate outages and faults, but largely depends on customers to report an outage incident. Once a customer reports an outage, HOL typically takes up to twelve (12) minutes to qualify the outage. The AMI 1.0 system does not have power outage notification capability and HOL does not have visibility downstream from monitored equipment. AMI 2.0 has last gasp capability and all devices in a point-to-point system are able to report outages and restoration info automatically, or on demand. By leveraging real time outage notifications from AMI 2.0 devices, outage response time should improve in addition to identifying nested outages.
- Granular outage identification and real time notifications in addition to other types of power quality information will result in improved triaging in addition to many operational savings resulting in improvements to SAIDI. Further integration of AMI 2.0 data into an ADMS and ingestion of outage, momentary interruptions, voltage sags/swells and other forms of power quality data can help with FLISR and vegetation management operations further improving SAIDI.
- With power outage and restoration reporting from all meters, HOL will know exactly which customers are experiencing outages and those that are not. This will help HOL to accurately identify the full extent of an outage and reduce the time for fault identification / location / isolation. This information will further assist in the recall of field crews when addressing nested outages, intermittent power and inaccurate reports.
- In addition, this use case automatically generates accurate outage reports, including SIR (System Interruption Report), and eliminates dispatch of truck rolls for partial power as operations can remotely confirm power quality and status.

Customer Experience Impact

Outages and restoration activities are reported automatically by the AMI devices enabling faster identification, mobilizing the field response and reducing the time for isolation duration.

Net Benefit (PV 2024): $5.94M

Value Drivers (VD):

1. **VD-1: Travel operating cost benefits –** Outage identification and power quality data from AMI 2.0 devices can potentially reduce the number of truck rolls associated with unplanned outages and travel duration. Power quality information can provide indicators there are potential vegetation risks at a specific service address. This can help HOL prioritize tree trimming operations to reduce potential outages. Where all AMI devices are capable of providing real time outage information, field crews know exactly where outages have occurred reducing travel time when investigating outage causes. There are additional notification capabilities for commercial polyphase customers where customers may not be aware a phase is out which can cause equipment to malfunction or shut down like commercial refrigeration units. Service information received preceding an inevitable outage event can be used in a proactive way to prevent the outage.
2. **VD-2: FTE efficiencies** – By having granular and real time outage information from AMI 2.0 devices, time spent searching for the location and cause of different types of outages may be reduced. This benefit applies to both standard and overtime hours.
4. **VD-3: Back-office FTE cost savings for outage reporting SIR and SAIDI reporting –** Having real time outage information in addition to GIS data from outage notifications will help optimize the back-office efforts required to compile SIR, SAIDI and other forms of reporting.
5. **VD-4: Improved accuracy Interruption duration Index -** Real time outage notifications can improve the qualification and field crew response times. This ultimately results in an improved SAIDI and revenues.

Key Assumptions and Inputs for VD	
▪ VD-1: The bulk of power outages will be identified upstream through distribution components that are monitored through SCADA, or ADMS (future). AMI can provide outage notifications at every service point enhancing the visibility and insights when outages occur thus reducing travel costs. ▪ VD-2: Value is driven by reduced time to identify outage locations, scope and help triage the cause of the outage.	
AMI Infrastructure Pre-requisites Standard AMI Infrastructure, Power Outage Reporting, Power Restoration, or Power Status Check	**Applications, Integrations and Data** OMS Outage Management System, or ADMS, ESB Enterprise Service Bus, CCB Customer Care Billing (optional)
Use Case Dependencies Deploy in tandem with Proactive Outage notification. This use case is the foundation for Service Restoration.	**Business Impact, Time-to-Value** Immediate benefits assuming integrations to OMS and other applications is complete.

Service Restoration

Description ▪ To-date, HOL's mesh AMI system does not have power restoration notification capability. While power status checks, or pinging meters may be performed, this information is typically not timely. Therefore, once power has been restored in an area, field crews must travel and verify customers downstream of an outage have their power restored. This is a manual process involving travel and FTE. ▪ With AMI 2.0, meters have power outage and restoration notification capability that is near real time. Timely access to this information can help field crews verify all service points down stream of an outage point have had their power restored without manual verification. This capability will eliminate or reduce manual verification time in addition to any instances where a field crew has left the area, only to return because of a customer(s) that may still be experiencing an outage.
Customer Experience Impact Outage duration will be reduced in addition to receiving details when the outage is resolved for those customers that have opted into these types of notifications.
Net Benefit (PV 2024): $0.066M
Value Drivers (VD) 1. **VD-1: Travel operating cost benefits –** Power restoration notifications will allow field crews to verify all homes that have power and reducing or eliminating manual site visits to verify customers restoration status. This value driver consists of reducing the travel costs of field crews looking for nested outages. 2. **VD-2: FTE efficiencies –** Similar to the reduction in travel operating costs, outage and restoration notifications from AMI 2.0 devices will reduce the overall efforts required to verify a customer service has been restored.
Key Assumptions and Inputs ▪ VD-1: Assumes a 5% improvement in restoration efforts related to vegetation related outages and 10% reduction in travel costs related to storm related outages. ▪ VD-2: Assumes significant number of FTE standard hours reduced for both vegetation and storm related outages with mixed FTE hour reduction for overtime hours.

AMI Infrastructure Pre-requisites Near-real time power outage and restoration messaging. processing of meter's last gasp and power status checks (PSC).	**Applications, Integrations and Data** OMS, or ADMS, HES, WFMS
Use Case Dependencies This use case builds on the Outage Identification use case.	**Business Impact, Time-to-Value** Immediate benefits once use case is implemented.

Proactive Outage Notification

Description ▪ <u>To-date,</u> HOL presently sends proactive outage notifications to customers who signed up for this service. The notification algorithm is informed by customer reported outages, or outages based on grid-level equipment status. HOL has indicated that it may take up to 12-minutes to qualify an outage once the first outage report has been received. Outages that are visible at the grid-level will typically result in customers downstream of that asset being proactively notified. There may be instances where customers that are experiencing an outage may not be proactively notified because the outage is not visible at the system level. ▪ <u>With AMI 2.0 meters,</u> HOL will be able to rely on meter outage notifications. This allows HOL to operate proactively before customers are aware of, or have time to report an outage. This will help reduce call volumes to live agents and the IVR through proactive notifications. Savings are achieved by being proactive and utilizing digital/low-cost communication channels such as text messages versus calls to live agents.
Customer Experience Impact Outage is a key brand and customer satisfaction driver. Customers who receive timely and accurate outage information typically score their utility higher, because it allows customers to make informed decisions and minimizes the impact the outage has on them.
Net Benefit (PV 2024): $0.125M
Value Drivers (VD) This value driver involves leveraging real time power outage and restoration information from AMI 2.0 devices to send proactive notifications to customers. Value is realized by leveraging low-cost communication channels in a proactive way to reduce inbound customer communications. 1. **VD-1: Reduction in outage related effort by live agents** – By sending timely and informative outage and restoration notifications to impacted customers, there is a reduced need for customers to make outage reports, or inquiries. This results in a reduction the overall customer cost-to-serve.
Key Assumptions and Inputs HOL presently provides proactive notifications, so the benefits included here are quite conservative. ▪ VD-1: This value driver makes assumptions tied to notifications only being available to 50% of those customers that are signed up in the customer portal and an overall AHT reduction of 15%.

AMI Infrastructure Pre-requisites Near-real time processing of meter's last gasp and power restorations, or power status checks (PSC).	**Applications, Integrations and Data** OMS Outage Management System, Consumer Engagement Portal with preference mgmt. for automated notifications;
Use Case Dependencies Deploy in tandem with outage identification. Also, service restoration use case drives a reduction in outage duration which will also slightly contribute to a further reduction in call center effort.	**Business Impact, Time-to-Value** Immediate benefits once use case is implemented and outages are experienced.

Predictive Maintenance

Description

- To-date, various systems are used to plan maintenance activities around vegetation management and potential unplanned outages. AMI 2.0 devices have the capability to provide instrumentation data in near real-time that can be used to identify various types of anomalies. Some of these anomalies may be attributed to vegetation contact with lines in addition to other forms of potentially hazardous service issues.
- With AMI 2.0, the capability to provide instrumentation data and service conditions will assist HOL in identifying potential issues before they actually become customer problems. In this instance, we are focusing on reducing outage-related field visits related to vegetation management and distribution transformer issues. By proactively addressing issues, HOL will not need to respond in a crisis-mode.
- High-resolution interval data, provides the energy, demand, voltage and current profiles of the service points connected to upstream equipment. This data can be further used to create a model that will identify 'signatures' of a failing equipment, leading to proactive, planned maintenance. This application monitors loading / events of distribution assets to predict maintenance work, pre-empt failure of overloaded assets, and shifts maintenance to proactive planned events. In addition, it identifies underloaded assets which are performing inefficiently and faulty assets which impact other assets.

Customer Experience Impact

With a Predictive Maintenance program, customers can be notified prior to planned maintenance and service interruptions will be minimized.

Net Benefit (PV 2024): -$0.150M

Value Drivers (VD)

1. **VD-1: Reduced travel operating cost –** This is a reduction in travel time and cost related to both vegetation related and unplanned equipment failure outages.
2. **VD-2: Reduced FTE costs due to reduced field crew efforts –** Similar to reduced travel costs, this is overall reduction of FTE efforts directly related to field visits.

Key Assumptions and Inputs

- VD-1: Inputs were received from IRs and assume a percentage of vegetation work orders may be reduced from enhanced visibility into the distribution system. Inputs were also received for workorders addressing unplanned equipment failures and we assume 80% are attributed to distribution transformers resulting in an overall work order reduction of 20%
- VD-2: All data received from IRs and dependent on VD-1 reductions.

AMI Infrastructure Pre-requisites Standard AMI Infrastructure with instrumentation recording capability	**Applications, Integrations and Data** HES, MDM, GIS
Use Case Dependencies This use case can be implemented in tandem with Virtual Meter functionality of Asset Load Monitoring	**Business Impact, Time-to-Value** Ability to see real-time asset loading immediately, or utilizing past data for predictive maintenance models that may require several months of interval data.

Conservation Voltage Reduction (CVR)

Description

- To-date, HOL has previously completed a Conversation Voltage Reduction proof-of-concept project within its service territory. The project was limited to a single substation over a relatively short period of time. The purpose of this use case is to reduce voltage (costs) at the substation while maintaining power quality and reliability to the end customer downstream. AMI 2.0 meters are used as sensors throughout a feeder and send frequent instrumentation data to the CVR control system. If voltages downstream reach a certain threshold, it will result in customer impact issues, so voltages need to be increased at the substation to compensate for the line loss and prevent any impact to the customer.
- Leveraging existing infrastructure, by using AMI 2.0 devices results in a significant cost avoidance for line sensors and installation costs. Typical line sensors have a lifespan of approximately 10 years, requiring the asset to be refreshed at the end of that period.
- CVR benefits, will drive annual energy savings for both HOL and its end customers in addition to reducing demand at the substation. Typical savings are 1 – 3% of substation capacity and can act as a form of continued demand reduction when CVR is enabled.

Customer Experience Impact

Overall reduced energy usage and savings to the customer. Leveraging AMI 2.0 devices to maintain quality of service will ideally result in no customer impact in the form of interruptions.

Net Benefit (PV 2024): $0.0M

Value Drivers (VD)

1. **VD-1: Value of avoided line sensor cost –** AMI 2.0 devices that are capable of measuring voltage and other instrumentation quantities may be used as line sensors to monitor service voltages downstream from the substation. This benefit pertains to the hardware and communication costs of a typical line sensor.
2. **VD-2: Value of avoided line sensor installation costs –** Traditional line sensors require installation and use of a bucket truck. This benefit eliminates the need for installation, travel, wrench time and a service vehicle.
3. **VD-3: Value of energy savings across service territory** – As a result of reduced voltage at the substation, less energy is transmitted to customers. Customers are not impacted by this voltage drop but enjoy the benefit of reduced energy usage (lower bills). This is a reciprocal benefit to HOL whereby they reduce the total amount of energy required to maintain the customers quality of service.
4. **VD-4: Value of demand savings throughout service territory** – The reduction in energy usage results in an average demand reduction at the substation between 1-3%. This value represents a benefit as an avoided capacity cost at each substation but has not been included in this evaluation at this time.
5. **VD-5: Value of line-loss savings from energy savings** – The line loss savings is calculated from the reduction in energy savings multiplied by the number of feeders and line loss percentage.

Key Assumptions and Inputs for VD

We are leveraging information from the CVR pilot that is documented in the “Impact Evaluation of Hydro Ottawa’s Conservation Voltage Reduction Pilot”, dated December 13, 2018.

- VD-1: Line sensor cost was based on another Canadian client in a PUC rate filing of $855/sensor.
- VD-2: Line sensor installation costs were based on another Canadian client in a PUC filing of an all-in cost of $1,200 per sensor.
- VD-3: Value of energy savings came from the CVR pilot report (1.27 GWh) and reduced to 85%. This was multiplied by the average 2022 RPP Supply Cost to calculate a reduced savings. This benefit was further applied to an estimated 8-substations that have a similar capacity as the substation used in the CVR pilot.
- VD-4: Value of demand savings comes from the CVR pilot report which is used as a baseline and discounted. This baseline data is applied to all other station feeders provided by asset management.
- VD-5: Value of line-loss savings is derived from CVR pilot report and asset management station data.

AMI Infrastructure Pre-requisites Standard AMI Infrastructure, Instrumentation Profiling Capability, Low Latency Network	**Applications, Integrations and Data** CVR Management System, SCADA, HES.
Use Case Dependencies This use case is dependent on AMI 2.0 meters being deployed, CVR pre-requisites including software and hardware is in place.	**Business Impact, Time-to-Value** Value is realized over time when CVR is enabled during peak periods and continues over time.

FOUNDATIONAL & SYSTEM COSTS

What is a Cellular Point-to-Point AMI Solution

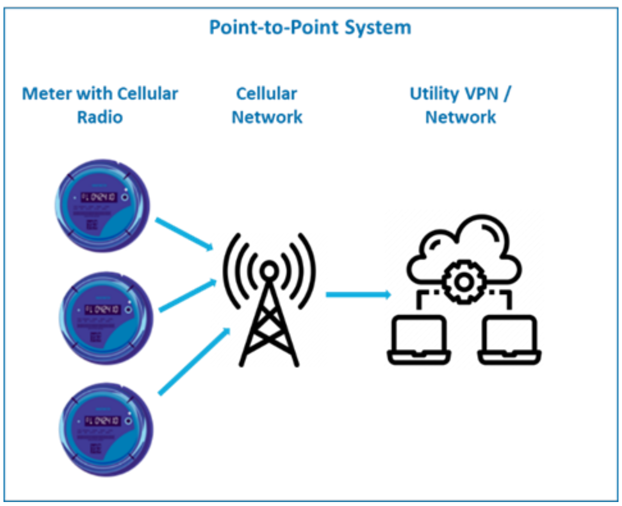
A P2P AMI solution typically operates on a public, or private cellular network. They consist of three primary components:

1. Meters with WAN radios
2. HES
3. Private/Public wireless network

An overview of a point-to-point AMI system can be seen in Figure 6 below. A point-to-point (P2P) system relies on licensed radio frequency that AMI meters utilize for two-way communications. The meters communicate directly with the HES and is a very low latency network. No gateways are required in this configuration, although cellular repeaters may be used to extend signal coverage into areas with questionable network visibility.

P2P systems may be used in urban, suburban and rural areas provided there is network coverage. The WAN network is typically public cellular infrastructure that requires no network build-out, or infrastructure.

Figure 6: Point-to- Point Cellular AMI Solution



P2P DEPLOYMENT

When deploying P2P solutions, network planning is required to identify coverage throughout a service territory. This is typically performed with the public cellular carriers who can provide detailed assistance in verifying coverage, alignment with their own network build out and potential options in areas with no coverage. In this instance, no network build out is necessary and meter installation can proceed more quickly.

CAPITAL COSTS

Within a P2P system, there are components that may be capitalized. These would include:

1. Meters
2. Meter and potential repeater installation
3. HES

4. HES integrations

Under the rate recovery option included in the financial model, these costs would be subject to recovery and reflect in the overall financials and NPV.

OPERATING COSTS

These costs are those necessary for the ongoing operation of the AMI system. These costs would typically include the following:

1. WAN costs (public cellular, phone line, satellite, etc. costs)
2. HES software licensing
3. RF-licensing cost (if applicable)
4. AMI support

There are methods to prepay the WAN costs at the time of purchase to capitalize this cost. This increases the per unit meter cost significantly since 15-years of communications is being paid up front. This would shift traditional opex into the meter capex thereby allowing HOL to recover a significant portion of the AMI investment and not adding to existing Opex. This practice would need to be verified by HOL regulatory and OEB to ensure compliance.

Foundational AMI Costs

Foundational AMI costs are those required to install an AMI solution and ensure the integrity of the meter-to-cash process. Incremental use case costs are typically not included in this section and are treated as add-ons to an AMI project that may be implemented as AMI is deployed, or at a future date. This section goes into some detail around each type of foundational cost that are included in the financial model.

AMI Head End System (HES)

An AMI HES is designed by each AMI vendor and responsible for managing meter communications, data collection/troubleshooting activities and the network. These systems may be on-premise, or cloud based providing options to utilities. There are certain HES's that may be able to manage other third-party OEM AMI devices providing some interoperability benefits, however generally a HES is optimized to a single AMI vendors meter.

Supervisory Head End System (S-HES)

A supervisory AMI HES is one designed to manage one-to-many AMI vendor HES. Deployment scenario 3 models a S-HES which manages two AMI vendor HES applications. This is required to support two different AMI vendors while maintaining a single HES with integrations to HOL internal applications. This is a common practice in Europe, and gaining popularity in North America. This does increase the overall cost of the AMI solution over the life of the project since there are two additional systems. In this instance, this would add roughly $12M to the overall cost of the project.

CAPITAL COSTS

For this cost category, it is assumed that there are two HES and one S-HES, all of which manage both the meters and the network devices in an on-premise configuration. There is a cost for the hardware infrastructure (i.e., database and application servers), as well as an annual licensing cost. The configuration, implementation and testing of the HES is also included in this section. This does include integration estimates from AMI vendor HES into the S-HES in addition to integrations from the S-HES into HOL applications.

OPERATING COSTS

The operating costs consist of technical support which include system maintenance and Smart Metering Operations Center (SMOC) operator resources. The technical support and maintenance of the system includes an annual support fee paid to the vendor, as well as an additional FTE as an internal IT resource. SMOC operators are FTEs that are the functional specialists who manage the day-to-day operations within the HES.

Integrations

This category includes the costs to design, develop, test, and deploy the integrations between the AMI HES and other systems required for meter-to-cash, outage management, workforce management, MDM, CVR, DR, vegetation management, customer care, billing and customer self-serve portals. The integrations are highly dependent on those systems in the meter-to-cash process and those that will be required to support the final use cases in an AMI business case.

To cost estimating, we are assuming a finite number of integrations which can be used as placeholders until a final list is determined. These integrations consist of the following:

1. CIS and Workforce Management System
2. Workforce Management System to HES
3. Meter Inventory and AMI HES
4. MDM and AMI HES
5. CIS and AMI HES
6. CIS and MDM

CIS TO WFM (COMPLEXITY: HIGH, IMPACT: HIGH)

During the mass meter deployment phase of AMI projects, there may be a requirement to integrate HOL'S CIS system with the Meter Installation Vendor's (MIV) Workforce Management (WFM) tool. Due to the complexity and potential impact to billing, the assumption has been made that the MIV would leverage HOL's internal WFM tool to complete the meter service orders.

METER INVENTORY TO AMI HES (COMPLEXITY: LOW, IMPACT: LOW)

Once meters are received from the manufacturer and the records are imported into the Meter Inventory tool, there is a data synchronization required with the HES. If a meter is physically installed at a service point, and the record doesn't exist in the HES, an exception will be raised and will need to be resolved before the meter can be fully provisioned.

CIS TO AMI HES (COMPLEXITY: LOW, IMPACT: LOW)

There is a data synchronization integration required between CIS and the HES that maintains the premise-meter relationship, as well as the meter installation date. Using this information, the HES can display the meters on a map to indicate which ones have been installed and how reliably they are communicating. It is recommended to have this integration in place, prior to beginning the AMI meter installs.

WORKFORCE MANAGEMENT TO HES (COMPLEXITY: LOW, IMPACT: LOW)

To track and troubleshoot AMI network device installations, a data synchronization integration is required between the Workforce Management System and the HES. As network devices are installed in the field, the location information should be updated daily in the HES.

MDM & AMI HES (COMPLEXITY: MEDIUM, IMPACT: HIGH)

The integration between the MDM and the HES is one of the major integrations that will be completed in an AMI project. There are a few types of integrations required between the two systems:

1. Scheduled batch jobs that transfer the meter reading and event data from the HES to the MDM,
2. Real-time alarms from meters that are sent as soon as they occur, and,
3. On-demand reads (and other device commands such as remote-disconnects) that are initiated in the MDM and sent to the meter via the HES.

These integrations are usually facilitated by out-of-the-box adapters provided by the respective software vendors.

CIS TO MDM

The last integration required for the AMI Foundation is between CIS and the MDM and it is the most complex. The integrations can be split into two main functions: Data Synchronization and Billing. This integration is critical to ensure meter-to-cash process remains intact.

Data Synchronization

During the initial implementation of the MDM system, an extract from CIS, which includes account, premise and meter information, must be imported into the MDM. Then, on a scheduled basis (usually daily), any changes that occur in CIS (e.g., meter exchanges, customer move-in/move-out, rate changes, etc.) must be captured and sent to the MDM. This is referred to as an incremental sync

Program Management Office (PMO)

Standing up a designated project team is a standard practice and important consideration for a large AMI implementation. Based on similarly sized projects, we have compiled a proposed PMO option for HOL.

The PMO team would be broken down into six focus areas:

1. **Program Management & Leadership:** These are Senior roles that are accountable for the overall AMI deployment success.
2. **Support**: These roles provide support for leadership and the team and include finance and administrative functions
3. **Change Management, Customer Experience, Communications:** This area includes multiple roles covering Customer Communications, Marketing, Stakeholder Engagement, Training and Business Process and Standard Operating Procedure re-design for AMI foundations.
4. **Technology & Quality Assurance**: These roles represent leaders and subject matter experts in each technology component being deployed in an AMI program and those roles that can verify they are functioning as expected prior to AMI devices being deployed.
5. **Network Resources:** These roles provide leadership, technical oversight and advisory regarding network communication, security, architecture, and infrastructure integration.
6. **Meter Resources**: This area is focused on those skilled in the metering functions in addition to the AMI features the new technology bring. These roles are tasked to provide leadership and guidance into how the technology works, best practices and troubleshooting.

Complementing in-house staff with specialized consultant services is an approach many utilities take when staffing their AMI PMO. This ensures utility-specific items can be addressed during the deployment, while augmenting it with leading industry best practices. A blended fully-load cost for in-house FTEs is used. This PMO operates during project ramp up, deployment, acceptance-testing and hand-off.

DEPLOYMENT SCENARIOS

Approach for AMI Deployment Scenarios

In order to define a suitable AMI deployment approach for Hydro Ottawa, three deployment scenarios with various levers were assessed. The options were jointly developed during a workshop with HOL stakeholders across various business units.

A set of criteria was considered to assess deployment scenarios that covered various aspects of Program, Critical Path and Use Case Prioritization as depicted in Figure 7.

Figure 7: AMI Deployment Levers

Criteria	Description
PROGRAM	
▪ **Meter Upgrade duration**	This represents the number of years to complete the next-gen AMI upgrade (3/4/5/other)
▪ **Managed Services - AMI HES Operations**	The day-to-day AMI HES operations is outsourced to a third-party that also includes software hosting managed by the vendor. (No/Managed Services)
▪ **Managed Services - MDM Operations**	The day-to-day AMI MDM operations are managed by a third-party that also includes software hosting managed by the vendor. (No/Managed Services)
▪ **Backhaul Network Options**	Defines the method of data transmission between field access point and head end system. Options include cellular, HOL fiber, future FAN, or combination.
CRITICAL PATH	
▪ **Pilot**	A pilot program to validate brownfield installation procedures, meter-to-cash process, business processes, logistics, etc. prior to mass deployment.
▪ **Next Gen OMS**	Based on deployment scenario priorities, the year the Next-Gen OMS will need to be installed and ready to accept AMI data including power outage/restoration data.
▪ **ADMS Implementation**	Based on deployment scenario priorities, the year the ADMS will need to be installed and ready to accept AMI data including power quality and power outage/restoration data.
USE CASE PRIORITIZATION	
▪ **Use Case Priority**	Based on the objective of the deployment scenario, the use case priority determines which use cases are in scope as well as their sequencing. The selection and sequencing will have a direct impact on project NPV.

Capgemini modelled and analyzed each scenario by defining the scenario based on deployment criteria. In order to arrive at the most suitable deployment option for HOL, all options were compiled to define the deployment options that balanced the pros and cons of each option.

Mesh, point-to-point and point-to-multipoint AMI systems have different topologies and have different CapEx and OpEx structures. As such, these systems perform similar functions, but have inherent complexities with pros and cons to each.

Deployment Scenario- Considerations and Insights

Deployment Scenario 1: Baseline Case

The baseline case consists of the foundational use cases with optional demand response and predictive maintenance use cases scheduled for deployment in the near-term. A P2P cellular solution is modeled from a single vendor. There is no backhaul in cellular P2P so use of fiber is not applicable.

Criteria	1. Baseline Case
PROGRAM	
Meter upgrade duration	5 yrs
Managed Services - AMI HES Operations	No
Managed Services - MDM Operations	No
Backhaul Network Options	Cellular + Fiber-Optic
CRITICAL PATH	
Pilot	Y
Next Gen OMS (required by date)	2026
ADMS Implementation (required by date)	2026
USE CASE PRIORITIZATION	
Foundational use cases	AMI Sustainment, Customer Service Impact, Remote Disconnect/Reconnect
Wave 1	Outage Identification, Proactive Outage Notification, Service Restoration
Wave 2	
Future Use cases	Demand Response, Predictive Maintenance

Figure 8 Deployment Scenario 1: Baseline Case

Deployment Scenario 2: Improved OMS Before CVR

The second deployment scenario includes the baseline case and focus on outage identification, outage notification and service restoration. Demand response and predictive maintenance use cases scheduled for deployment in the near-term. A P2P cellular solution is modeled from a single vendor. There is no backhaul in cellular P2P so use of fiber is not applicable.

Criteria	2. Improved OMS Before CVR
PROGRAM	
Meter upgrade duration	5 yrs
Managed Services - AMI HES Operations	No
Managed Services - MDM Operations	No
Backhaul Network Options	Cellular + Fiber-Optic
CRITICAL PATH	
Pilot	Y
Next Gen OMS (required by date)	2026
ADMS Implementation (required by date)	2026
USE CASE PRIORITIZATION	
Foundational use cases	AMI Sustainment, Customer Service Impact, Remote Disconnect/Reconnect
Wave 1	Outage Identification, Proactive Outage Notification, Service Restoration
Wave 2	
Future Use cases	Demand Response, Predictive Maintenance

Figure 9 Deployment Scenario 2: Improved OMS Before CVR

Deployment Scenario 3: Supervisory AMI HES (S-HES)

The third deployment scenario consists of foundational use cases followed by demand response and outage/restoration features. This deployment scenario also assumes support for two different AMI solutions. This requires a supervisory HES that will control the native HES from the two AMI vendors. While this does increase software costs it also diversifies the supply chain and ideally allow for more competitive pricing.

While this option is modeled on a cellular P2P architecture, it technically would support multiple architectures from multiple AMI vendors. For example, with this configuration HOL would be able to deploy point-to-multipoint (P2MP) system from vendor A (HES 1) and a P2P system from vendor B (HES 2) and operate both systems through the S-HES. There are no backhaul costs, or network infrastructure to build out in a cellular P2P where each devices has direct connectivity to a public (or private) cellular network. In this particular scenario, the meter hardware costs include communication costs for the 15-year meter life which eliminates any Opex for communications (backhaul). Under this scenario, use of a fiber network is not applicable.

Criteria	3. Supervisory AMI HES
PROGRAM	
Meter upgrade duration	5 yrs
Managed Services - AMI HES Operations	Optional
Managed Services - MDM Operations	Optional
Backhaul Network Options	Cellular + Fiber-Optic
CRITICAL PATH	
Pilot	Y
Next Gen OMS (required by date)	2026
ADMS Implementation (required by date)	2026
USE CASE PRIORITIZATION	
Foundational use cases	AMI Sustainment, Customer Service Impact, Remote Disconnect/Reconnect
Wave 1	Demand Response
Wave 2	Outage Identification, Proactive Outage Notification, Service Restoration
Future Use cases	Predictive Maintenance

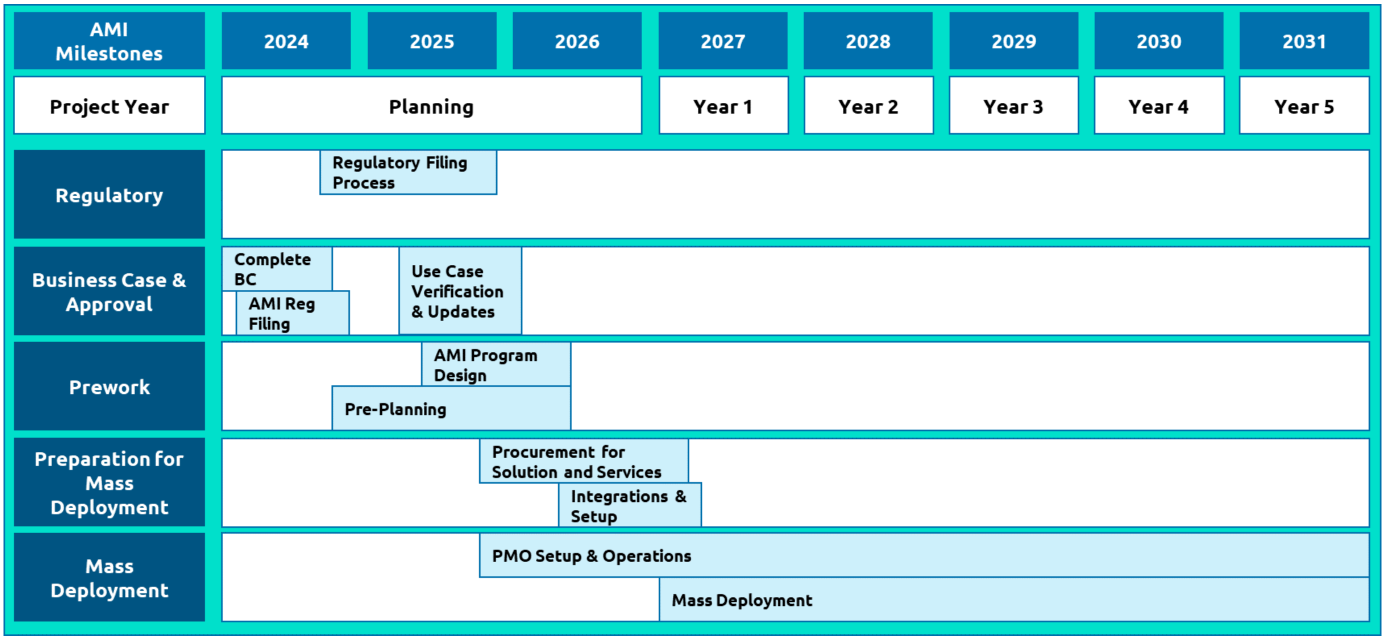
Figure 10 Deployment Scenario 3: Supervisory AMI HES

Proposed Deployment Scenario

Based on the direction from HOL, deployment scenario 3 is the recommended deployment scenario. This option has a lower NPV which is directly attributed to support of multiple HES and the S-HES. However, this does provide HOL with the capability diversity and secure its supply chain in addition to providing bargaining power in AMI procurements.

Figure 11 provides a preliminary project timeline for a P2P AMI 2.0 solution consisting of pre-planning and deployment activities based on 2025/2026 start year and 2027 deployment year.

Figure 11: High-level AMI Deployment Timeline



SUMMARY OF RESULTS

Overview of Cost Components

An AMI deployment is a capital-intensive project. There are three notable and significant cost components to an AMI project:

1. AMI Meters
2. Project Office
3. Network infrastructure.

The AMI business case uses customer, internal, vendor and publicly available sources to estimate the AMI related costs for the project. Recent and applicable utility sources were used to inform the estimates. Adjustments were made to account for HOL specifics, leaning towards the conservative side of the cost boundaries and applying a 10% contingency adder for all capital and operating costs. Once vendor quotes are available, especially for AMI hardware, software and integration costs, the range of uncertainty regarding the investment will decrease.

Cost Summary (in $M)

	Total			PV 2024$		
Cost Component	**Capital**	**Operating Costs**	**Total**	**Capital**	**Operating Costs**	**Total**
AMI Preliminary Engineering	$0.0 M		$0.0 M	$0.0 M	-	$0.0 M
AMI Meters	$114.7 M		$114.7 M	$83.1 M	-	$83.1 M
Network Infrastructure - Mesh	$0.0 M	$0.0 M	$0.0 M	$0.0 M	$0.0 M	$0.0 M
Network Infrastructure - Point to Point (Public)	$17.8 M	$0.0 M	$17.9 M	$15.7 M	$0.0 M	$15.7 M
Network Infrastructure - Point to Multi-point	$0.0 M	$0.0 M	$0.0 M	$0.0 M	$0.0 M	$0.0 M
HES	$0.9 M	$27.8 M	$28.6 M	$0.8 M	$15.7 M	$16.5 M
MDMS	$0.0 M	$0.0 M	$0.0 M	$0.0 M	$0.0 M	$0.0 M
Integrations	$2.55 M	$2.0 M	$4.5 M	$2.32 M	$1.1 M	$3.4 M
Project Office	$11.1 M		$11.1 M	$8.6 M	-	$8.6 M
Subtotal Foundational Cost	$147.0 M	$29.7 M	$176.7 M	$110.5 M	$16.8 M	$127.4 M
Contingency - 10%	$14.7 M	$3.0 M	$17.7 M	$11.1 M	$1.7 M	$12.7 M
Incremental Use case costs	$6.2 M	$18.1 M	$24.3 M	$4.0 M	$9.5 M	$13.5 M
Total Project Cost			**$218.7 M**			**$153.6 M**

Figure 12 Overview of Cost Components

The financial model is configurable allowing HOL to add/remove use cases, or modify when they will be unlocked including a ramp-up period, over the life of the project. A summary of the use cases and their gross benefits, costs and net benefits can be seen in Figure 13. Those use cases checked off are included in the NPV calculation for the final financial model.

Figure 13: Use Case Value Summary

Use Case Value

Use Case ID	Use case Name	Include in NPV?	Unlocks in Year	Benefit Realization (%) year 1	Benefit Realization (%) year 2	Benefit Realization (%) year 3	Total Benefit (In Millions)	Total Cost (In Millions)	Net Benefit (In Millions)
1	AMI Sustainment	☑	2026	100%	100%	100%	$91.21 M	$3.19 M	$88.02 M
2	Customer Service Impact	☑	2026	100%	100%	100%	$0.90 M	$0.93 M	-$0.03 M
3	Remote Disconnect Reconnect	☑	2026	100%	100%	100%	$0.32 M	$0.56 M	-$0.24 M
4	Prepayment Functionality	☑	2029	100%	100%	100%	$22.05 M	$16.86 M	$5.19 M
5	Outage Identification	☑	2028	100%	100%	100%	$12.43 M	$0.84 M	$11.59 M
6	Service Restoration	☑	2028	100%	100%	100%	$1.27 M	$0.90 M	$0.37 M
7	Proactive Outage Notification	☑	2028	100%	100%	100%	$0.42 M	$0.15 M	$0.27 M
8	Predictive Maintenance	☑	2029	100%	100%	100%	$0.81 M	$0.89 M	-$0.08 M
9	Conservation Voltage Reduction	☐	2029	100%	100%	100%	$0.00 M	$0.00 M	$0.00 M
10	Demand Response	☐	2027	100%	100%	100%	$0.00 M	$0.00 M	$0.00 M
11	Shared Services (Optional)	☐	2029	100%	100%	100%	$0.00 M	$0.00 M	$0.00 M
	Total						$129.40 M	$24.31 M	$105.09 M

Total Costs & Benefits

CASHFLOW INFORMATION

Figure 14: Total Cost & Benefits

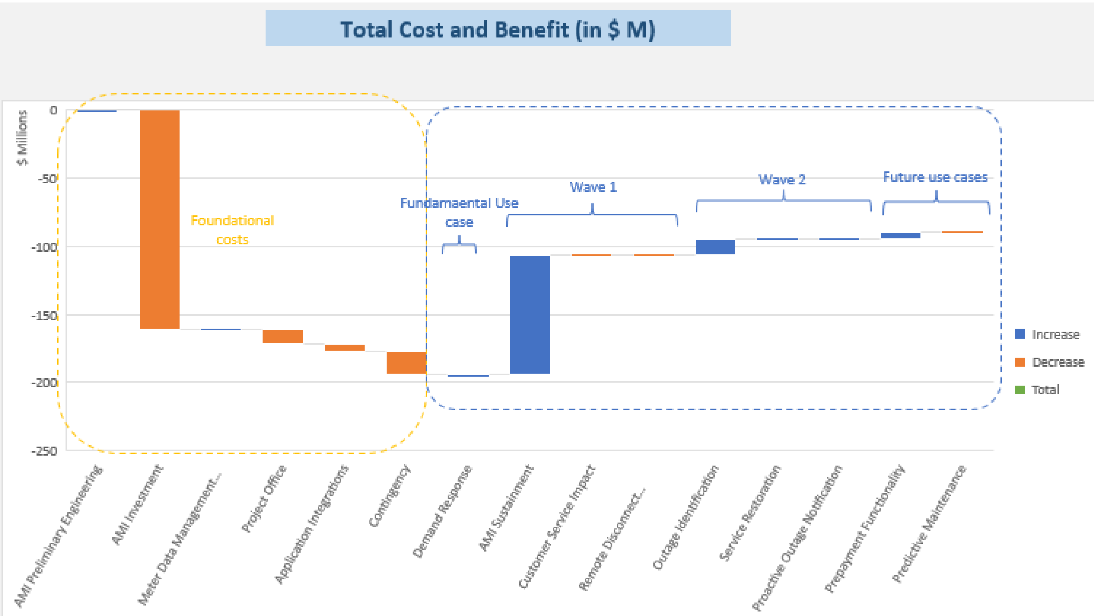


Figure 15: Net Use Case Benefits

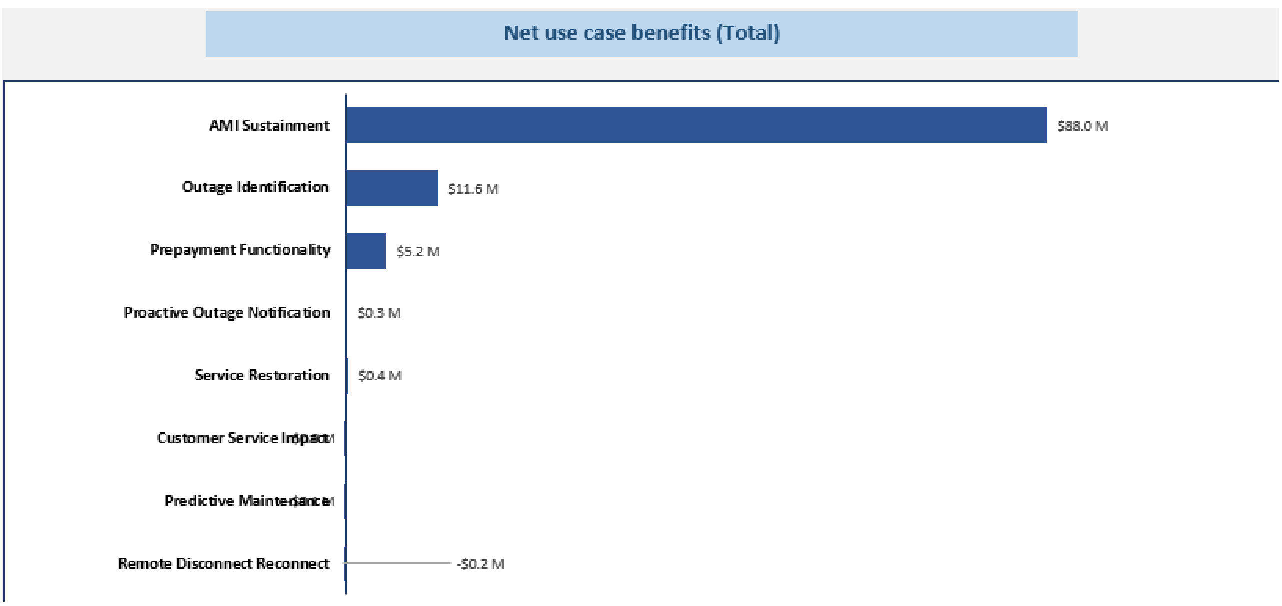


Figure 16: Project Costs at PV 2024$

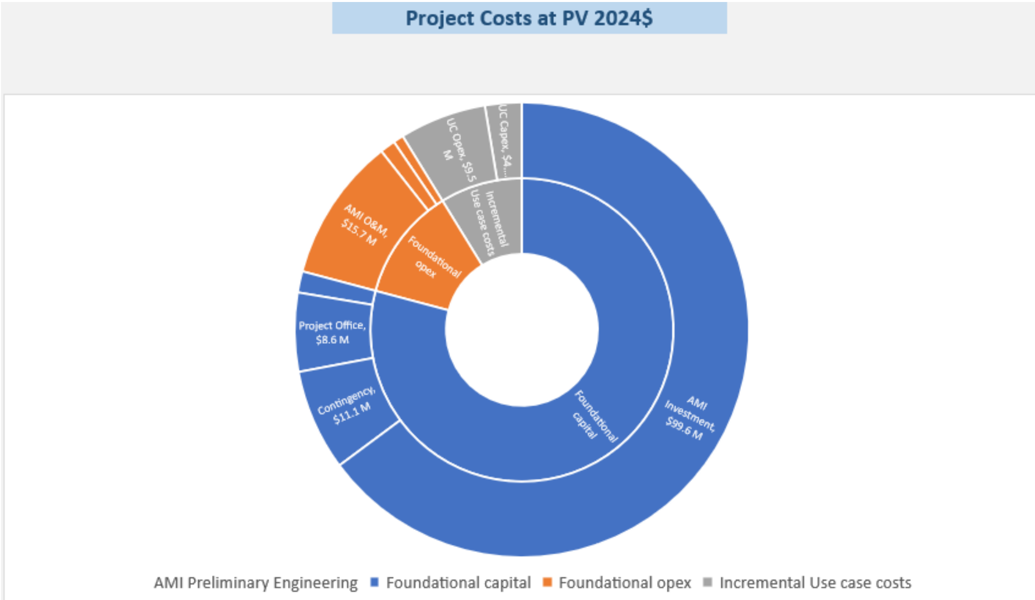


Figure 17: Cashflow Analysis

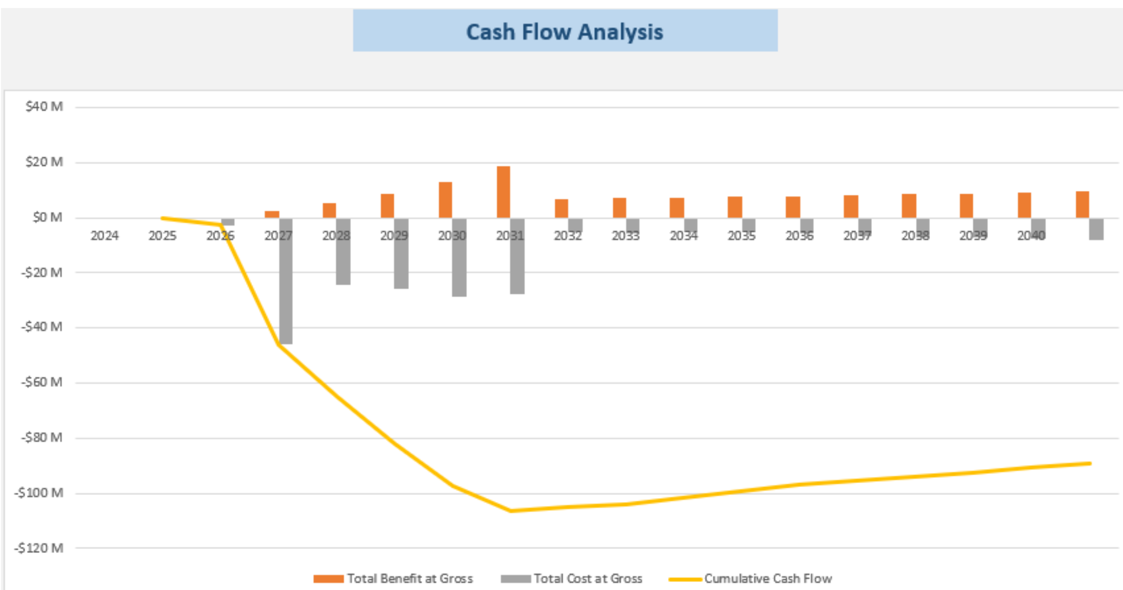


Figure 18: Cashflow at PV 2024($M)

Cash Flow at PV 2024$ ($M)

Year in Timeline	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Business case year	Year 0	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15
Financial Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Benefit2024$	0.0	0.0	2.2	4.4	6.8	9.6	12.7	4.4	4.3	4.2	4.1	4.0	3.9	3.8	3.7	3.6	3.5
Cost2024$	0.0	-2.6	-40.4	-20.1	-20.2	-20.8	-18.9	-3.4	-3.5	-2.9	-2.9	-2.8	-3.2	-3.1	-3.0	-2.9	-3.0
Recovery rate	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Federal Fundings	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cumulative Cash Flow2024	0.0	-2.6	-40.7	-56.4	-69.8	-81.0	-87.3	-86.2	-85.5	-84.2	-83.1	-81.9	-81.2	-80.5	-79.8	-79.2	-78.7

APPENDIX A - AMI 2.0 INTANGIBLE BENEFITS

As stated earlier, AMI 2.0 will provide benefits to a myriad of use cases and business units within HOL. Many of these benefits are quantitative, while others are qualitative. There are many use cases with benefits that are difficult to quantify where they are purely speculative, however the benefits are real and will be delivered. This section highlights some of the qualitative benefits of AMI 2.0

AMI 2.0 - Overall

a) **Improved customer satisfaction**: AMI 2.0 enables real-time monitoring and control, allowing HOL, to respond quickly to outages and customer inquiries, enhancing overall customer experience.
b) **Enhanced grid reliability**: AMI 2.0 helps HOL, detect and prevent outages, reducing the frequency and duration of power interruptions.
c) **Increased operational efficiency**: AMI 2.0 automates meter reading, reducing manual errors and labour costs.
d) **Better demand response management**: AMI 2.0 enables HOL, to manage peak demand more effectively, reducing strain on the grid.
e) **Enhanced cybersecurity**: AMI 2.0 systems can detect and respond to cyber threats, improving grid security.
f) **Improved data analytics**: AMI 2.0 provides granular data, enabling HOL, to optimize grid operations, predict energy demand, and identify areas for improvement.
g) **Enhanced environmental sustainability**: AMI 2.0 supports renewable energy integration, energy efficiency, and reduced carbon emissions.
h) **Improved workforce productivity**: AMI 2.0 enables HOL, to optimize field crew workflows, reducing manual tasks and increasing productivity.
i) **Enhanced regulatory compliance**: AMI 2.0 helps HOL, meet regulatory requirements, reducing compliance costs and risks.
j) **Improved grid resilience**: AMI 2.0 enables HOL, to detect and respond to grid events, enhancing overall grid resilience.
k) **Data Analytics**: AMI 2.0 provides valuable data insights, enabling HOL, to optimize operations, reduce energy waste, and decrease carbon emissions.
l) **Carbon Pricing**: AMI 2.0 enables HOL, to implement carbon pricing, providing a financial incentive for customers to reduce their carbon emissions.

Customer Service Impact

a) **Improved customer experience**: AMI 2.0 enables HOL, to provide personalized and proactive customer service, enhancing overall customer satisfaction.
b) **Increased customer loyalty**: AMI 2.0 demonstrates a commitment to customer satisfaction, fostering loyalty and long-term relationships.
c) **Enhanced utility reputation**: AMI 2.0 showcases a customer-centric approach, enhancing the utility's reputation and brand value.
d) **Better issue resolution**: AMI 2.0 enables HOL, to resolve issues more effectively, reducing customer complaints and frustration.
e) **Improved communication**: AMI 2.0 enables HOL, to communicate more effectively with customers, providing timely and relevant information.
f) **Increased customer engagement**: AMI 2.0 encourages customers to take an active role in managing their energy usage, promoting energy literacy and awareness.
g) **Improved customer insights**: AMI 2.0 provides valuable data on customer behavior and preferences, enabling HOL, to tailor their services to customers.

h) **Enhanced customer trust**: AMI 2.0 demonstrates a commitment to transparency and accountability, building trust and confidence with customers.
i) **Competitive advantage**: AMI 2.0 enables HOL, to differentiate themselves from competitors, attracting and retaining customers in a competitive market.

Remote Disconnect/Reconnect

a) **Improved customer experience**: Remote disconnect/reconnect enables HOL, to quickly respond to customer requests, reducing wait times and enhancing overall satisfaction and convenience.
b) **Increased safety**: Remote disconnect/reconnect minimizes the need for field visits, reducing the risk of accidents and improving worker safety.
c) **Reduced carbon footprint**: By reducing the need for physical visits, remote disconnect/reconnect helps decrease carbon emissions from utility vehicles.
d) **Improved regulatory compliance**: Remote disconnect/reconnect enables HOL, to quickly respond to regulatory requirements, reducing compliance risks.
e) **Enhanced grid reliability**: Remote control capabilities enable HOL, to quickly respond to grid events, reducing the likelihood of power outages.
f) **Improved data analytics**: Remote disconnect/reconnect provides valuable insights into customer behaviour, enabling HOL, to optimize grid operations and improve demand response.
g) **Enhanced utility reputation**: Remote disconnect/reconnect showcases a commitment to innovation, customer satisfaction, and operational efficiency.

Pre-Payment

a) **Improved financial management**: Pre-payment enables customers to budget and manage their energy expenses more effectively.
b) **Enhanced customer control**: Pre-payment gives customers more control over their energy usage and spending.
c) **Increased customer engagement**: Pre-payment encourages customers to be more active participants in managing their energy consumption.
d) **Reduced energy poverty**: Pre-payment helps vulnerable customers avoid energy debt and disconnection.
e) **Improved utility customer relationships**: Pre-payment demonstrates a commitment to customer empowerment, financial inclusion, customer satisfaction and financial well-being.
f) **Enhanced data insights**: Pre-payment provides HOL, with valuable data on customer behaviour and energy usage patterns.

Outage Identification

a) **Enhanced customer satisfaction**: AMI 2.0 minimizes the impact of outages on customers, improving overall customer experience and satisfaction.
b) **Increased utility reputation**: AMI 2.0 demonstrates a proactive approach to grid management, enhancing the utility's reputation and brand value.
c) **Improved safety**: AMI 2.0 quickly identifies potential safety hazards, reducing the risk of accidents and injuries.
d) **Reduced energy waste**: AMI 2.0 helps HOL, identify and address energy losses, reducing waste and improving overall efficiency.
e) **Enhanced data insights**: AMI 2.0 provides valuable data on grid performance and asset health, enabling HOL, to optimize operations and improve reliability.
f) **Improved regulatory compliance**: AMI 2.0 helps HOL, meet regulatory requirements and standards for grid reliability and safety.

g) **Environmental benefits**: AMI 2.0 reduces the likelihood of grid failures, which can lead to environmental hazards and carbon emissions.

Service Restoration

a) **Improved customer satisfaction**: AMI 2.0 enables HOL, to quickly restore power, reducing the impact of outages on customers.
b) **Enhanced utility reputation**: AMI 2.0 demonstrates a commitment to reliability and enhancing the utility's reputation and brand value.
c) **Improved safety**: AMI 2.0 quickly identifies potential safety hazards, reducing the risk of accidents and injuries.
d) **Reduced energy waste**: AMI 2.0 helps HOL, identify and address energy losses, reducing waste and improving overall efficiency.
e) **Enhanced data insights**: AMI 2.0 provides valuable data on grid performance and asset health, enabling HOL, to optimize operations and improve reliability.
f) **Improved regulatory compliance**: AMI 2.0 helps HOL, meet regulatory requirements and standards for grid reliability and safety.
g) **Environmental benefits**: AMI 2.0 reduces the likelihood of grid failures, which can lead to environmental hazards and carbon emissions.
h) **Improved grid resilience**: AMI 2.0 enables HOL, to quickly respond to grid events, enhancing overall grid resilience.
i) **Enhanced customer communication**: AMI 2.0 enables HOL, to communicate more effectively with customers, providing timely and relevant information.

Proactive Outage Notification

a) **Improved customer satisfaction**: Proactive notification shows a commitment to customer satisfaction and care.
b) **Enhanced utility reputation**: Proactive notification demonstrates a proactive approach to grid management, enhancing the utility's reputation and brand value.
c) **Better customer communication**: Proactive notification enables HOL, to communicate more effectively with customers, providing timely and relevant information.
d) **Reduced customer effort**: Proactive notification reduces the effort required by customers to report outages, improving overall customer experience.
e) **Improved safety**: Proactive notification quickly identifies potential safety hazards, reducing the risk of accidents and injuries.
f) **Improved regulatory compliance**: Proactive notification helps HOL, meet regulatory requirements and standards for grid reliability and safety.
g) **Reduced anxiety and stress**: Proactive notification reduces customer anxiety and stress by providing timely information and updates.

Predictive Maintenance

a) **Improved grid reliability**: Predictive maintenance reduces the likelihood of unexpected outages and grid asset failures.
b) **Enhanced customer satisfaction**: Predictive maintenance minimizes the likelihood of power interruptions, improving overall customer experience, SAIDI and costs.
c) **Improved safety**: Predictive maintenance reduces the risk of accidents and injuries by identifying potential issues before they become safety hazards.
d) **Enhanced data insights**: Predictive maintenance provides valuable data on grid performance and asset health, enabling HOL, to optimize operations and proactive maintenance plans.

e) **Improved regulatory compliance**: Predictive maintenance helps HOL, meet regulatory requirements and standards for grid reliability, safety and Measurement Canada and OEB regulations.
f) **Environmental benefits**: Predictive maintenance reduces the likelihood of grid failures, which can lead to environmental hazards and carbon emissions.

Conservation Voltage Reduction (CVR)

a) **Enhanced grid flexibility**: CVR optimizes voltage levels, allowing for more efficient grid operations and better integration of renewable energy sources.
b) **Improved power quality**: CVR reduces voltage fluctuations, providing a more stable power supply for customers.
c) **Increased customer comfort**: CVR helps maintain consistent voltage levels, reducing the likelihood of appliances overheating or malfunctioning.
d) **Enhanced environmental sustainability**: CVR supports energy efficiency and reduced carbon emissions.
e) **Increased utility reputation**: CVR demonstrates a commitment to innovation and environmental responsibility.

DEPLOYMENT SCENARIO FINANCIAL SUMMARIES

Deployment Scenario 1: Baseline Case

Cost Summary

Mesh	0%
Point to Point (public)	100%
Point to multi-point	0%

Use Hydro Ottawa Limited Field Area Network?	No
Use Data charges as Capex/Opex (Point to Point	Opex

	Year 1 (2026)	Year 2 (2027)	Year 3 (2028)	Year 4 (2029)	Year 5 (2030)	
Foundational Capital (Point to Point)						
Labour	$ 3,656,352	$ 3,759,819	$ 3,866,279	$ 3,975,821	$ 4,088,536	Includes Meter Installation, Project Office costs
Materials	$ 16,373,402	$ 16,770,173	$ 17,176,588	$ 17,592,881	$ 18,019,293	Includes meter hardware cost, network devices cost
Outside Services						
Software - IT	$ 1,550,215	$ -	$ -	$ -	$ -	Includes Head End System setup cost, Imtegratiosn
Total Foundational Capital (Po	**$ 21,579,969**	**$ 20,529,992**	**$ 21,042,867**	**$ 21,568,701**	**$ 22,107,828**	
Foundational Operational (Point to Point)						
Labour						
Maintenance						
Outside Services	$ 391,268	$ 819,472	$ 1,268,144	$ 1,744,418	$ 2,249,593	Includes cellular data charges and APN charges
Software - Licensing & Maintenance	$ 658,802	$ 675,468	$ 692,560	$ 710,092	$ 728,074	Includes SaaS cost for Head End System, Integrations
Total Foundational Operationa	**$ 1,050,070**	**$ 1,494,939**	**$ 1,960,704**	**$ 2,454,510**	**$ 2,977,667**	
Use Case Capital						
AMI Sustainment	$ -	$ -	$ -	$ -	$ -	
Customer Service Impact	$ 55,168	$ -	$ -	$ -	$ -	
Remote Disconnect/ Reconnect	$ 441,347	$ -	$ -	$ -	$ -	
Prepayment Functionality	$ -	$ -	$ -	$ -	$ -	
Outage Identification	$ -	$ 398,730	$ -	$ -	$ -	
Service Restoration	$ -	$ 455,691	$ -	$ -	$ -	
Proactive Outage Notification	$ -	$ 56,961	$ -	$ -	$ -	
Predictive Maintenance	$ -	$ -	$ 470,501	$ -	$ -	
Total Use Case Capital	**$ 496,516**	**$ 911,382**	**$ 470,501**	**$ -**	**$ -**	
Use Case Operational						
AMI Sustainment	$ -	$ -	$ -	$ -	$ -	
Customer Service Impact	$ 56,933	$ 50,053	$ 51,254	$ 52,484	$ 53,744	
Remote Disconnect/ Reconnect	$ 33,667	$ 26,518	$ 27,586	$ 28,696	$ 0	
Prepayment Functionality	$ -	$ -	$ -	$ -	$ -	
Outage Identification	$ -	$ 28,679	$ 26,773	$ 27,643	$ 28,542	
Service Restoration	$ -	$ 31,428	$ 26,773	$ 27,643	$ 28,542	
Proactive Outage Notification	$ -	$ 10,995	$ 5,629	$ 5,765	$ 5,903	
Predictive Maintenance	$ -	$ -	$ 29,588	$ 27,643	$ 28,542	
Total Use Case Operational	**$ 90,600**	**$ 147,674**	**$ 167,603**	**$ 169,874**	**$ 145,272**	
Grand Total (Point to Point)	**$ 23,217,155**	**$ 23,083,987**	**$ 23,641,675**	**$ 24,193,086**	**$ 25,230,768**	
Capex. Cont.	$ 2,157,996.92	$ 2,052,999.22	$ 2,104,286.66	$ 2,156,870.13	$ 2,210,782.84	
Opex. Cont.	$ 105,007.00	$ 149,493.92	$ 196,070.43	$ 245,451.04	$ 297,766.75	
Total	**$ 25,480,159**	**$ 25,286,480**	**$ 25,942,032**	**$ 26,595,407**	**$ 27,739,318**	

Deployment Scenario 2: Improved OMS Before CVR

Costs summary

Mesh	0%
Point to Point (public)	100%
Point to multi-point	0%

Use Hydro Ottawa Limited Field Area Network?	No
Use Data charges as Capex/Opex (Point to Point)	Opex

	Year 1 (2026)	Year 2 (2027)	Year 3 (2028)	Year 4 (2029)	Year 5 (2030)	
Foundational Capital (Point to Point)						
Labour	$ 3,656,352	$ 3,759,819	$ 3,866,279	$ 3,975,821	$ 4,088,536	Includes Meter Installation, Project Office costs
Materials	$ 16,373,402	$ 16,770,173	$ 17,176,588	$ 17,592,881	$ 18,019,293	Includes meter hardware cost, network devices cost
Outside Services						
Software - IT	$ 1,550,215	$ -	$ -	$ -	$ -	Includes Head End System setup cost, Imtegratiosn
Total Foundational Capital (P	**$ 21,579,969**	**$ 20,529,992**	**$ 21,042,867**	**$ 21,568,701**	**$ 22,107,828**	
Foundational Operational (Point to Point)						
Labour						
Maintenance						
Outside Services	$ 391,268	$ 819,472	$ 1,268,144	$ 1,744,418	$ 2,249,593	Includes cellular data charges and APN charges
Software - Licensing & Maintenance	$ 658,802	$ 675,468	$ 692,560	$ 710,092	$ 728,074	Includes SaaS cost for Head End System, Integrations
Total Foundational Operation	**$ 1,050,070**	**$ 1,494,939**	**$ 1,960,704**	**$ 2,454,510**	**$ 2,977,667**	
Use Case Capital						
AMI Sustainment	$ -	$ -	$ -	$ -	$ -	
Customer Service Impact	$ 55,168	$ -	$ -	$ -	$ -	
Remote Disconnect/ Reconnect	$ 441,347	$ -	$ -	$ -	$ -	
Prepayment Functionality	$ -	$ -	$ 1,046,865	$ -	$ -	
Outage Identification	$ -	$ 398,730	$ -	$ -	$ -	
Service Restoration	$ -	$ 455,691	$ -	$ -	$ -	
Proactive Outage Notification	$ -	$ 56,961	$ -	$ -	$ -	
Predictive Maintenance	$ -	$ -	$ -	$ 485,792	$ -	
Total Use Case Capital	**$ 496,516**	**$ 911,382**	**$ 1,046,865**	**$ 485,792**	**$ -**	
Use Case Operational						
AMI Sustainment	$ -	$ -	$ -	$ -	$ -	
Customer Service Impact	$ 56,933	$ 50,053	$ 51,254	$ 52,484	$ 53,744	
Remote Disconnect/ Reconnect	$ 33,667	$ 26,518	$ 27,586	$ 28,696	$ 0	
Prepayment Functionality	$ -	$ -	$ 1,176,118	$ 1,081,030	$ 1,124,828	
Outage Identification	$ -	$ 28,679	$ 26,773	$ 27,643	$ 28,542	
Service Restoration	$ -	$ 31,428	$ 26,773	$ 27,643	$ 28,542	
Proactive Outage Notification	$ -	$ 10,995	$ 5,629	$ 5,765	$ 5,903	
Predictive Maintenance	$ -	$ -	$ -	$ 30,526	$ 28,542	
Total Use Case Operational	**$ 90,600**	**$ 147,674**	**$ 1,314,134**	**$ 1,253,787**	**$ 1,270,100**	
Grand Total (Point to Point)	**$ 23,217,155**	**$ 23,083,987**	**$ 25,364,569**	**$ 25,762,791**	**$ 26,355,596**	
Foundational Capex. Contingency	$ 2,157,996.92	$ 2,052,999.22	$ 2,104,286.66	$ 2,156,870.13	$ 2,210,782.84	
Foundational Opex. Contingency	$ 105,007.00	$ 149,493.92	$ 196,070.43	$ 245,451.04	$ 297,766.75	
Total	**$ 25,480,159**	**$ 25,286,480**	**$ 27,664,926**	**$ 28,165,112**	**$ 28,864,145**	

Deployment Scenario 3: Supervisory AMI HES

Costs summary

Mesh	0%	
Point to Point (public)	100%	
Point to multi-point	0%	

Use Hydro Ottawa Limited Field Area Network?	No
Use Data charges as Capex/Opex (Point to Poin	Capex

	Year 1 (2026)	Year 2 (2027)	Year 3 (2028)	Year 4 (2029)	Year 5 (2030)	
Foundational Capital (Point to Point)						
Labour	$ 3,656,352	$ 3,759,819	$ 3,866,279	$ 3,975,821	$ 4,088,536	Includes Meter Installation, Project Office costs
Materials	$ 16,373,402	$ 16,770,173	$ 17,176,588	$ 17,592,881	$ 18,019,293	Includes meter hardware cost, network devices cost
Outside Services	$ 17,836,474	$ -	$ -	$ -	$ -	Includes cellular data charges
Software - IT	$ 1,952,868	$ -	$ -	$ -	$ -	Includes Head End System setup cost, Imtegratiosn
Total Foundational Capital (Point to Point)	**$ 39,819,096**	**$ 20,529,992**	**$ 21,042,867**	**$ 21,568,701**	**$ 22,107,828**	
Foundational Operational (Point to Point)						
Labour						
Maintenance						
Outside Services	$ 206	$ 422	$ 649	$ 885	$ 1,133	Includes APN charges
Software - Licensing & Maintenance	$ 1,306,668	$ 1,434,707	$ 1,568,178	$ 1,708,733	$ 1,856,690	Includes SaaS cost for Head End System, Integrations
Total Foundational Operational (Point to Poir	**$ 1,306,874**	**$ 1,435,129**	**$ 1,568,826**	**$ 1,709,619**	**$ 1,857,823**	
Use Case Capital						
AMI Sustainment	$ -	$ -	$ -	$ -	$ -	
Customer Service Impact	$ 55,168	$ -	$ -	$ -	$ -	
Remote Disconnect/ Reconnect	$ 441,347	$ -	$ -	$ -	$ -	
Prepayment Functionality	$ -	$ -	$ -	$ 1,080,888	$ -	
Outage Identification	$ -	$ -	$ 411,688	$ -	$ -	
Service Restoration	$ -	$ -	$ 470,501	$ -	$ -	
Proactive Outage Notification	$ -	$ -	$ 58,813	$ -	$ -	
Predictive Maintenance	$ -	$ -	$ -	$ 485,792	$ -	
Total Use Case Capital	**$ 496,516**	**$ -**	**$ 941,002**	**$ 1,566,680**	**$ -**	
Use Case Operational						
AMI Sustainment	$ -	$ -	$ -	$ -	$ -	
Customer Service Impact	$ 56,933	$ 50,053	$ 51,254	$ 52,484	$ 53,744	
Remote Disconnect/ Reconnect	$ 33,667	$ 26,518	$ 27,586	$ 28,696	$ 0	
Prepayment Functionality	$ -	$ -	$ -	$ 1,213,850	$ 1,124,828	
Outage Identification	$ -	$ -	$ 29,588	$ 27,643	$ 28,542	
Service Restoration	$ -	$ -	$ 32,403	$ 27,643	$ 28,542	
Proactive Outage Notification	$ -	$ -	$ 11,259	$ 5,765	$ 5,903	
Predictive Maintenance	$ -	$ -	$ -	$ 30,526	$ 28,542	
Total Use Case Operational	**$ 90,600**	**$ 76,571**	**$ 152,089**	**$ 1,386,607**	**$ 1,270,100**	
Grand Total (Point to Point)	**$ 41,713,086**	**$ 22,041,693**	**$ 23,704,784**	**$ 26,231,607**	**$ 25,235,751**	
Foundational Capex. Contingency	$ 3,981,909.64	$ 2,052,999.22	$ 2,104,286.66	$ 2,156,870.13	$ 2,210,782.84	
Foundational Opex. Contingency	$ 130,687.45	$ 143,512.91	$ 156,882.65	$ 170,961.88	$ 185,782.30	
Total	**$ 45,825,683**	**$ 24,238,205**	**$ 25,965,954**	**$ 28,559,439**	**$ 27,632,316**	

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT3.12

EVIDENCE REFERENCE:

1-SEC-17

UNDERTAKING(S):

Update the balance of the customer account as of Hydro Ottawa's latest information by the end of September 2025

RESPONSE(S):

Hydro Ottawa notes the word "customer" should have been omitted from the undertaking. If a deferral account had been in place since February 2025, the balance in the account as of September 30, 2025 would be $3,249.88. The previous balance provided in response to 1-SEC-17(e) included an error.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT3.13

EVIDENCE REFERENCE:

1-Staff-6 Table A

UNDERTAKING(S):

Determine how much money Hydro Ottawa would receive under price cap versus under Hydro Ottawa's proposal based on billing determinants Hydro Ottawa is forecasting over next five years

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RESPONSE(S):

Please find below an updated Table A using the rates as calculated through the Price Cap IR option using the updated Base Revenue Requirement (revenue from distribution rates) provided in 1-Staff-1 and the Hydro Ottawa proposed Load Forecast as provided in Schedule 3-1-1 - Revenue Load and Customer Forecast. An inflation factor of 2.1% for this analysis is used. The fixed charges were not held and therefore also increased over the rate term.

Of note is that the anticipated uneven increase in the Large Load customer demand in comparison to other rate classes over the rate period does not get reflected in the rates of a Price Cap IR option. Through the proposed Custom Incentive Rate (CIR) plan, this change is recognized through the proposed 5 years cost allocation models (including adjustment demand factors) and rate design. As a result of using the Price Cap IR option, while most rate classes experience a similar % of less revenue being collected, the Large User rate class has an approximate additional 2% savings over the other rate classes. This indicates that while the Large Use Class costs have increased over the rate period, this would not be reflected in their rates in a Price Cap IR option.

The other noticeable exception is the Street Light Class which would generate a small amount of additional revenue over the five year rate period under the Price Cap IR option. The Price Cap IR option does not accommodate the phased-in approach utilized in Hydro Ottawa's current updated rate design. Which brings the class back within its upper rate bound over the five year period. Thus the Price Cap IR option will collect more revenue in years two and three of the rate period. As described in the response to part (a) of interrogatory 7-Staff-195, consumption by the Street Light class declined through the period 2018 to 2023 as the LED conversion project took effect. After completion of the bulk of the conversion project in 2023, consumption begins to increase again as street lights are added to the network, thus increasing the proportion of demand allocated costs assigned to the Street Light class. By 2029 revenue generated under the proposed CIR rate design equals, and then exceeds in 2030, that generated under the Price Cap IR option.

Table A provides the underfunding through a Price Cap IR option if Hydro Ottawa completed its plan as outlined in its 2026-2030 CIR Application Plan.

Table A - Illustrative 2026-2030 Base Revenue Requirement under Price Cap IR Parameters using the CIR 2026-2030 Load Forecast ($'000s)

	2026	2027	2028	2029	2030	TOTAL
Cohort III						
Cohort III - 0.30%	$297,163	$304,563	$313,089	$321,813	$330,230	**$1,566,858**
HOL Proposed	$297,163	$320,510	$351,903	$376,124	$399,843	**$1,745,543**
DEFICIENCY	**$0**	**$15,946**	**$38,814**	**$54,311**	**$69,613**	**$178,684**
Cohort IV - 0.45%	$297,163	$304,047	$312,084	$320,308	$328,168	**$1,561,769**
HOL Proposed	$297,163	$320,510	$351,903	$376,124	$399,843	**$1,745,543**
DEFICIENCY	**$0**	**$16,463**	**$39,819**	**$55,816**	**$71,675**	**$183,774**

The dollars of uncollected revenue by Class is provided in Table B and the percentage of uncollected revenue is provided in Table C, both using the Cohort IV. This provides the aforementioned benefit to the Large User Class and how the Street Light class would be the only class that sees little impact related to a Price Cap IR option.

Table B - Illustrative 2027-2030 Lost Revenue through the use of a Price Cap IR ($’000s)

Rate Class	2027	2028	2029	2030	TOTAL
Residential	$ (9,498)	$ (22,939)	$ (32,135)	$ (41,345)	$ (105,916)
GS < 50 kW	$ (1,924)	$ (4,635)	$ (6,456)	$ (8,206)	$ (21,222)
GS 50 to 1,499 kW	$ (3,479)	$ (8,325)	$ (11,490)	$ (14,591)	$ (37,886)
GS 1,500 to 4,999 kW	$ (823)	$ (1,958)	$ (2,681)	$ (3,378)	$ (8,839)
Large Use	$ (745)	$ (1,824)	$ (2,834)	$ (3,841)	$ (9,244)
Street Lighting	$ 72	$ 20	$ 1	$ (29)	$ 65
Sentinel Lighting	$ (0)	$ (1)	$ (2)	$ (2)	$ (5)
Unmetered Scattered Load	$ (52)	$ (125)	$ (177)	$ (230)	$ (584)
Standby Power GS 50 to 1,499 kW	$ (3)	$ (8)	$ (11)	$ (14)	$ (36)
Standby Power GS 1,500 to 4,999 kW	$ (1)	$ (3)	$ (4)	$ (5)	$ (12)
Standby Power Large Use	$ (10)	$ (21)	$ (29)	$ (35)	$ (95)
Base Revenue Requirement	**$ (16,463)**	**$ (39,819)**	**$ (55,816)**	**$ (71,675)**	**$ (183,774)**

Table C - Illustrative 2027-2030 Lost Revenue percentage through the use of a Price Cap IR

Rate Class	2027	2028	2029	2030
Residential	-5.1%	-11.3%	-14.8%	-17.9%
GS < 50 kW	-5.1%	-11.4%	-14.9%	-18.0%
GS 50 to 1,499 kW	-5.1%	-11.3%	-14.8%	-17.9%
GS 1,500 to 4,999 kW	-5.1%	-11.3%	-14.8%	-17.8%
Large Use	-6.4%	-12.9%	-16.8%	-20.2%
Street Lighting	4.9%	1.3%	0.0%	-1.7%
Sentinel Lighting	-5.1%	-11.3%	-14.8%	-17.9%
Unmetered Scattered Load	-5.0%	-10.8%	-14.2%	-17.3%
Standby Power GS 50 to 1,499 kW	-5.4%	-11.9%	-15.5%	-18.7%
Standby Power GS 1,500 to 4,999 kW	-5.2%	-11.4%	-14.9%	-17.9%
Standby Power Large Use	-7.9%	-15.5%	-19.8%	-23.3%
Base Revenue Requirement	**-5.1%**	**-11.3%**	**-14.8%**	**-17.9%**

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT3.15

EVIDENCE REFERENCE:

1-SEC-3

UNDERTAKING(S):

Consider providing studies Mr. Rubenstein referenced in the lead up to the question and provide them, if possible, or provide a reason why not

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RESPONSE(S):

Mr. Rubenstein requested the following studies.

1. *The customer capability assessment*
2. *The grid modernization strategy and roadmap phases 1 and 2*
3. *The grid modernization key performance indicator development*
4. *Review of Copperleaf predictive analytics value framework*
5. *Hydro Ottawa AMI 2.0 business case deliverables benefits assessment and value drivers*
6. *AMI 2.0 business case final report*
7. *A fleet process study*
8. *A jurisdictional research and analysis (related to inflation)*
9. *Peer group analysis (only if it is different from what is provided on the record)"*

For item #4, please refer to Attachment JT1.9(A) - HOL PA Distribution Model Review.

For the remaining of SEC's request, please see the below Attachment references and notes:

- Attachment JT3.15(A) - Customer Capability Assessment
- Attachment JT3.15(B) - HOL Grid Modernization Roadmap Ph 1 - Current and Future State *Assessment (forthcoming, pending confirmation of confidentiality requirements with third party vendor)*
- Attachment JT3.15(C) - HOL Grid Modernization Roadmap Ph 2 - Grid Modernization Strategy *(forthcoming, pending confirmation of confidentiality requirements with third party vendor)*
- Attachment JT3.15(D) - HOL Grid Modernization Key Performance Indicator (KPI) Development *(forthcoming, pending confirmation of confidentiality requirements with third party vendor)*
- Attachment JT3.15(E) - Hydro Ottawa AMI 2.0 Business Case Deliverable 1 Benefits Assessment & Values Drivers
- Attachment JT3.15(F) - AMI 2.0 Business Case Final Report
- Attachment JT3.15(G) - Fleet Process Study
- Attachment JT3.15(H) - Inflation Jurisdictional Research and Analysis
- Attachment JT3.15(I) - HOL Benchmarking (Master Cust Num Cohort)
- Attachment JT3.15(J) - HOL Benchmarking (Load Distribution Cohort)
- Attachment JT3.15(K) - HOL Benchmarking (Rural Cohort)

As noted in Hydro Ottawa's response to interrogatory 1-SEC-3, these reports, analyses and studies were not directly relied upon in the preparation of evidence for this proceeding. Accordingly, the specific focus areas, timelines, and details included in these materials may not align precisely with the content or parameters of Hydro Ottawa's current application.

In particular, Hydro Ottawa notes that Attachments JT3.15(E) - Hydro Ottawa AMI 2.0 Business Case Del 1 Benefits Assessment and Value Drivers and JT3.15(F) - Hydro Ottawa AMI 2.0 Business Case Final Report, related to the AMI 2.0 Business Case, were based on an analysis of use case benefits and associated implementation costs over a five-year implementation. This does not align with the ten-year implementation plan ultimately proposed in this application. Further details regarding the implementation plan are provided in Section 5.7 of Schedule 2-5-7 - System Renewal Investments.

CX Strategy and Roadmaps

Customer Capability Assessment

October 10, 2024

HydroOttawa

Table of Contents

Executive Summary

CX Strategy Overview

Energy providers are facing a multitude of external factors that are changing their role and relationship with consumers. These trends are directly impacting approaches to customer experience (CX) as **consumers are beginning to seek a more comprehensive energy experience**.

This disruption is being felt across many sectors, and is **necessitating that CX becomes a central component of all energy providers' strategy**. As this pace of change accelerates, the greater the pressure a delay will cause.

This understanding has **prompted the creation of the *CX Strategy and Roadmaps***, which **proposes 10 Focus Areas** (see next slides) to address this disruption at the required pace over the next 10 years.

The result of this strategy is to **enable Hydro Ottawa to become a market leader and differentiated service provider that will advance its ability to deliver an exceptional customer experience.**

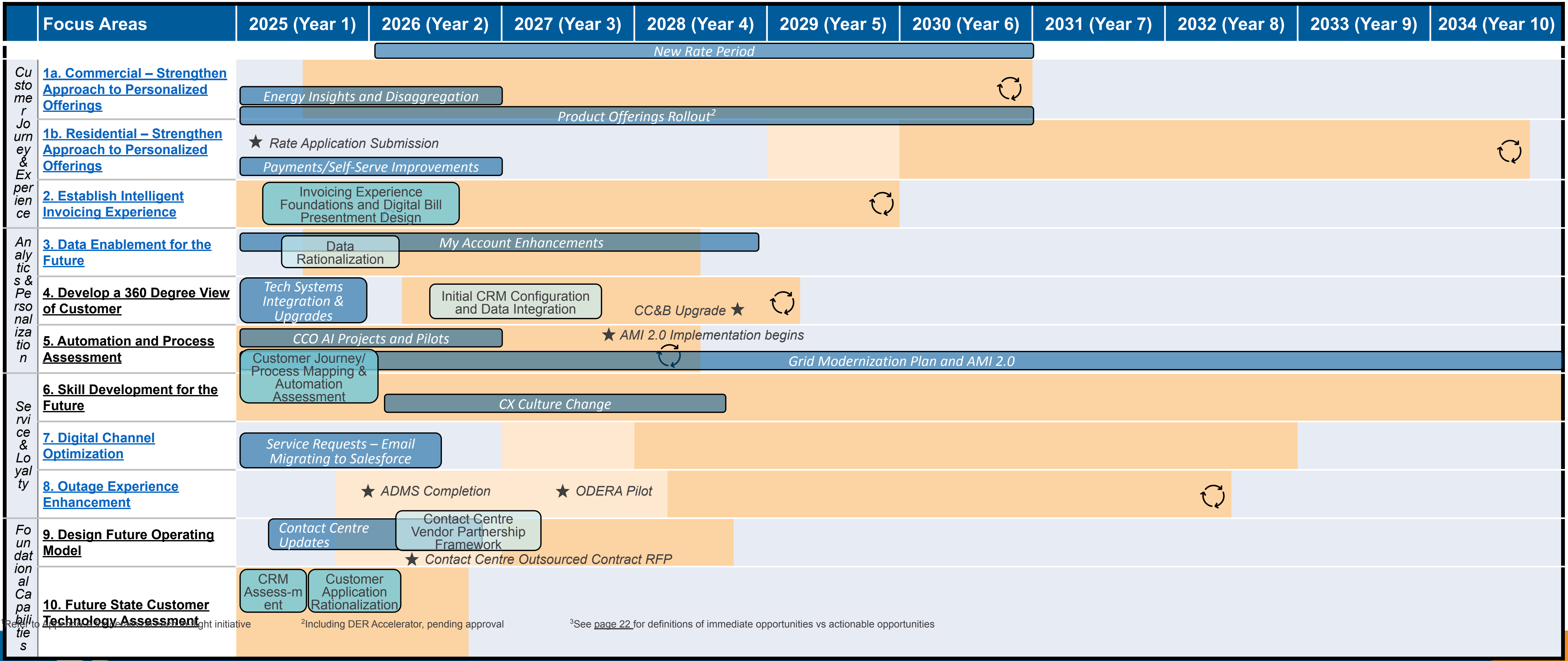
To accomplish this, five future state outcomes have been outlined, as represented on the right.

Hydro Ottawa CX Roadmap

Legend:

- Focus Area
- Pre-work and Preparation
- Future Review Activities/ Iterations
- Immediate Opportunity
- Actionable Opportunity[3]
- Hydro Ottawa In-Flight Initiative

The Focus Areas have been sequenced along the ten-year timeline. Actionable opportunities and in-flight initiatives[1] have been called out. This sequencing has been validated by Hydro Ottawa stakeholders. The roadmap is a living document that should be continually assessed and updated for any changes in the business (e.g. new technologies, priorities, etc.).



[1]Refer to Appendix for a list of each in-flight initiative

[2]Including DER Accelerator, pending approval

[3]See page 22 for definitions of immediate opportunities vs actionable opportunities

Focus Areas Overview

The 10 Focus Areas, as summarized below, look to advance the organization's maturity across a number of capabilities.

Focus Area Overview

The 10 Focus Areas build the foundation for the business to move forward with confidence in developing its business and customer experience capabilities. Each Focus Area comprises multiple initiatives/projects that are proposed for execution in the short- (now), medium- (next), and long-term (beyond). The Focus Areas have been prioritized and sequenced on the ten-year roadmap that reflects the current internal (in-flight) initiatives that are scheduled, as well as dependencies between the Focus Areas. The first Focus Areas are generally assessments and strategy on specific areas of the customer organization to inform future action. The latter Focus Areas build off this foundation and compile these advancements into tangible customer offerings and benefits.

Target Outcome

The Focus Areas are designed to create value for both the customer and the business throughout the capability maturation process. The target outcomes will help the business achieve improvements to the efficiency and effectiveness of delivering positive customer experiences in addition to broader Hydro Ottawa ambitions. Improving the data and understanding of customer interactions will help drive continuous improvement with broader metrics, knowledge sharing, and streamlined access to customer insights.

Stakeholders

- Customer Experience
- Commercial Group
- Energy Innovation
- Grid Technology
- Customer Care
- Billing and Collections
- IT – Web Applications
- Data Management
- Enterprise Applications
- Enterprise Architecture
- Service Desk
- CITO
- Metering Systems
- Meter to Cash Support
- Communications and Public Affairs
- Human Resources
- Finance

Prioritized Capabilities

The Focus Areas have been developed to advance the three prioritized Customer Business Capabilities: *Customer Journey & Experience*, *Analytics & Personalization*, and *Service & Loyalty*.

Ten-Year Program

Individual Focus Areas are estimated to occur during this time range. Implementation of these initiatives have been mapped out over the 2- and 10-year periods.

Dependency Identification

Each Focus Area has internal (in-flight) and dependent initiatives/Focus Areas that have been identified.

Approach

HydroOttawa

Overview and Approach

The Hydro Ottawa *CX Strategy and Roadmaps* is a culmination of activities including the Current State Analysis, Future State Definition, and the Roadmaps work areas. The key activities and outputs of each work area led to the creation of the 10 Focus Areas.

1. Current State Analysis

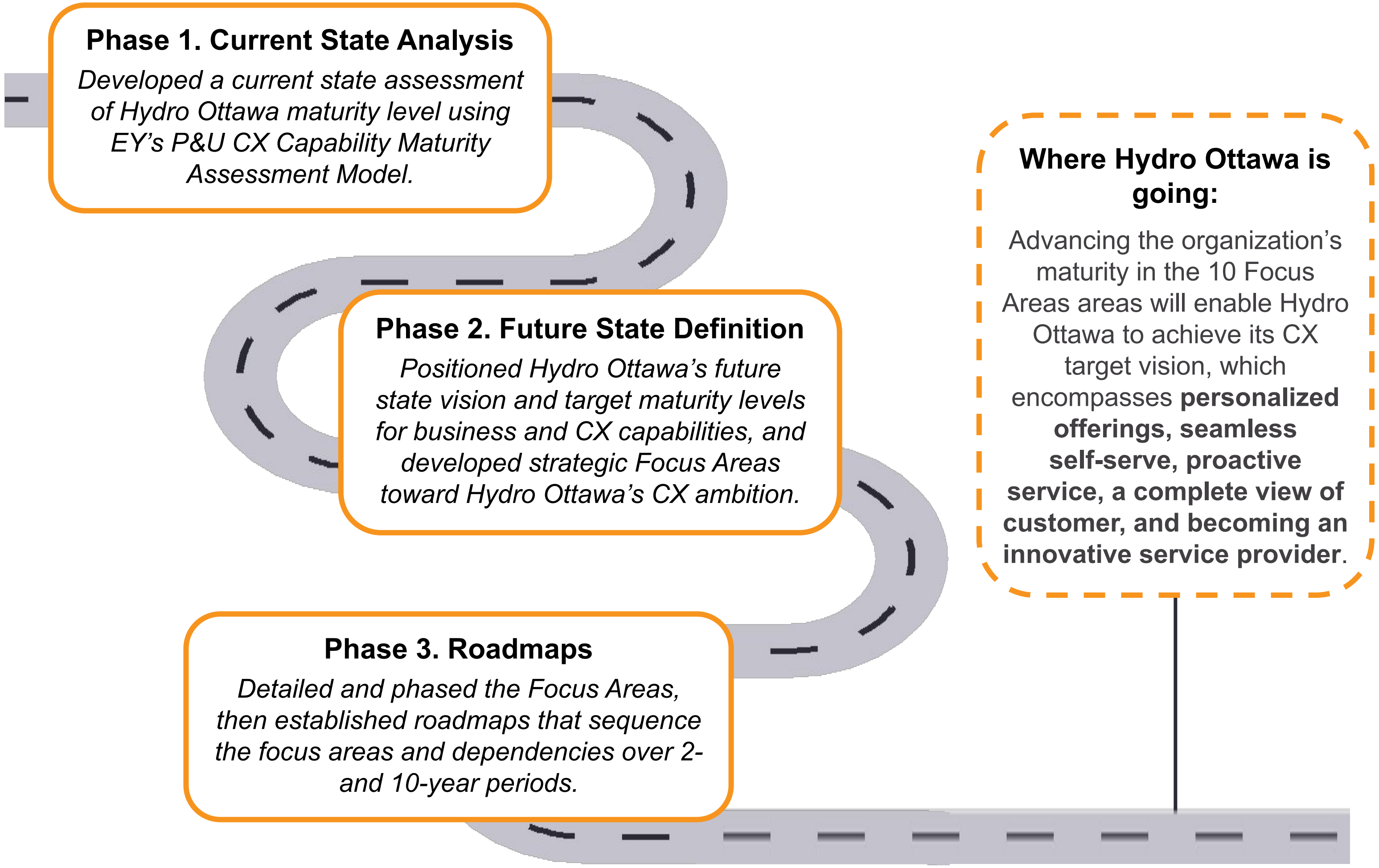
- Documentation and data collection activities through interviews, workshops and a survey
- Current state analysis using EY's P&U CX Capability Maturity Assessment Model.

2. Future State Definition

- Industry trends review through an Art of Possible Workshop
- Focus Areas Ideation and Validation Sessions

3. Roadmaps

- Focus Areas Review
- Roadmaps Workshop



CX Strategy

Energy is at the Centre of a ‘Decade of Disruption’

The **energy transition is expected to be one of the largest macrotrends over the next decade**. Navigating this will be at the top of both energy providers and energy consumers minds as its impacts will affect their relationship and the role energy plays in society.

Consumer shifts

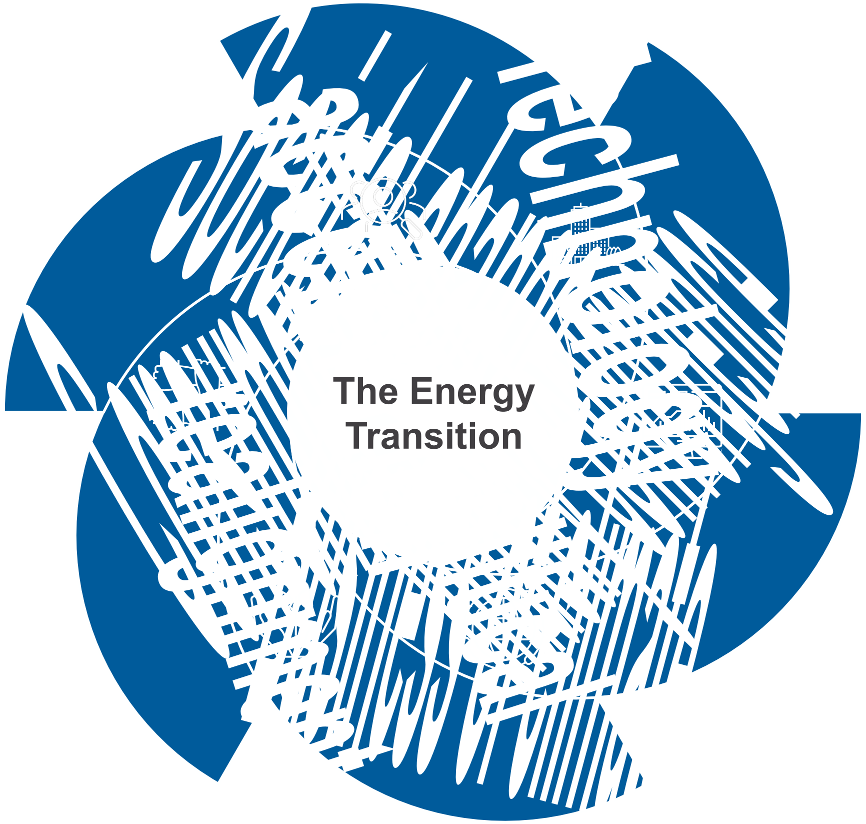
Gen Z and millennials are now the majority of the population amidst a mass refocusing on sustainability and purposeful consumption.

Geopolitical realignment

The war in Ukraine and broader shifts in globalization are putting energy in the spotlight for consumers and governments.

Business of climate

Decarbonization, sustainability and more broadly ESG are top of mind for businesses, boards and investors speeding the pace of change.



Societal change

Mass shifts in our society towards more openness, sustainability, and working from home are reshaping everyday lives.

Technology acceleration

The pace of technology development and digitization is creating mass amounts of data, connecting digital and physical worlds, and lower the cost of things like renewables faster than ever thought.

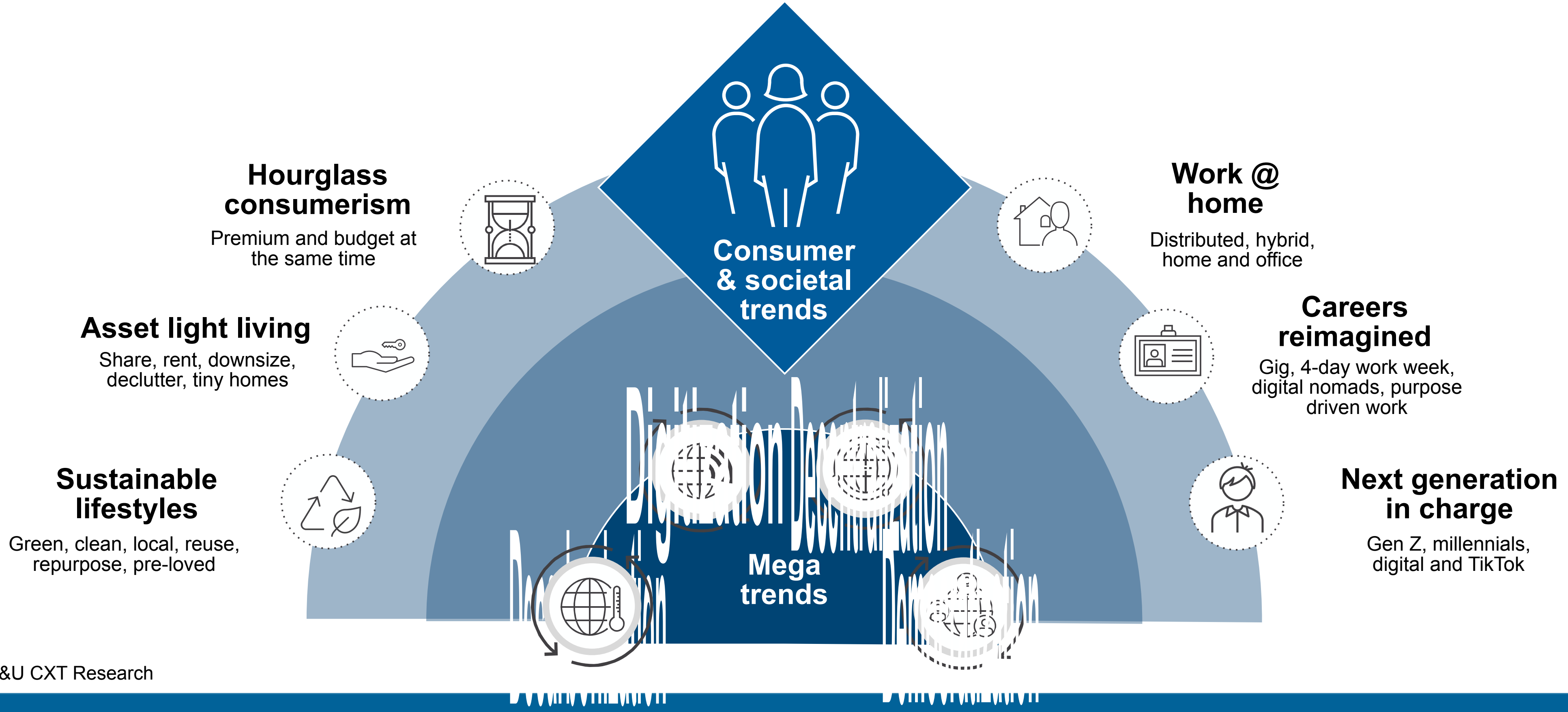
Industry convergence

The 4th industrial revolution is upon us and blurring of industries is restructuring where value is created and opportunities for the future.

Source: EY P&U CXT Research

Broader Trends are Shaping the Future for Energy Providers

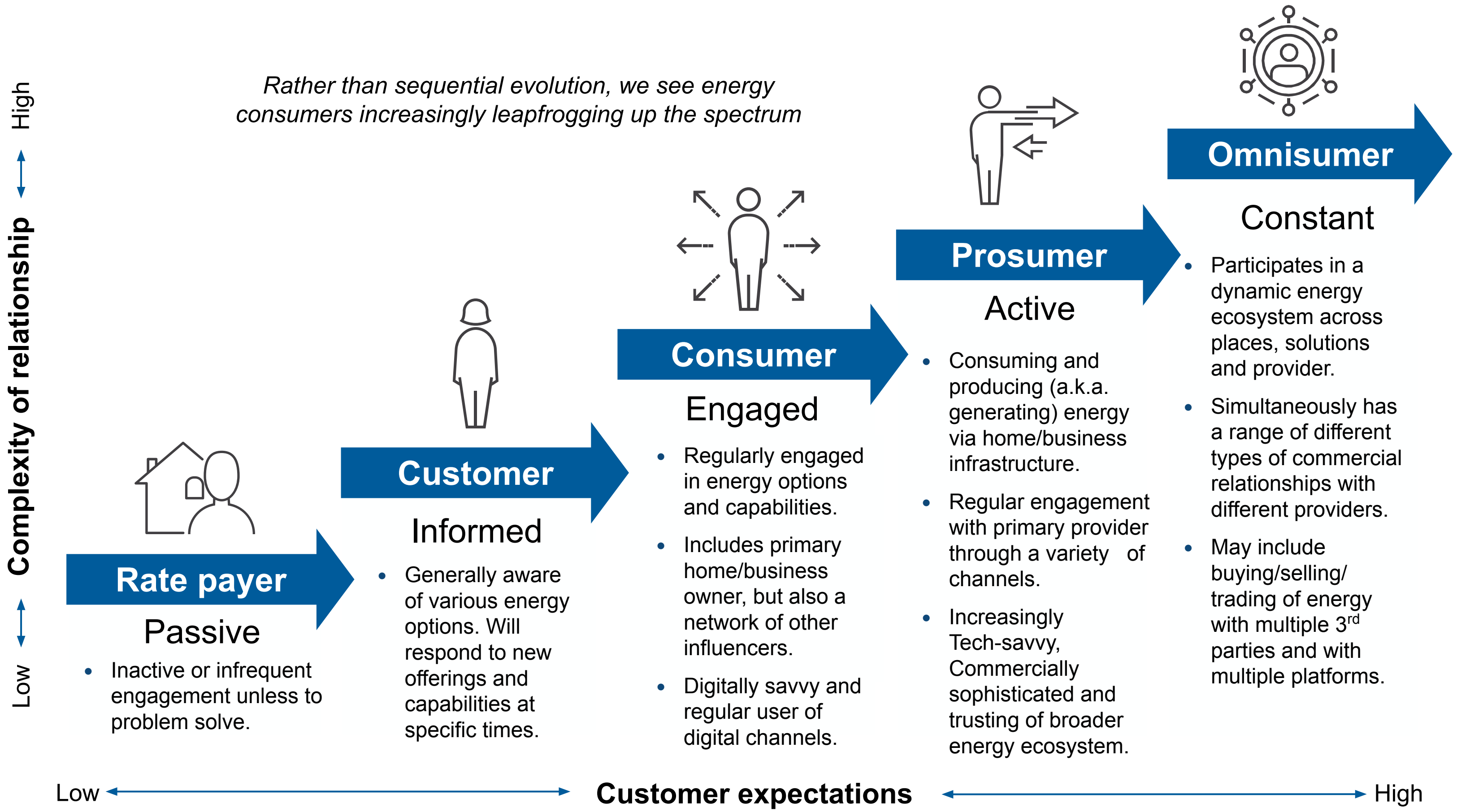
Consumer's preferences and expectations are not isolated to an industry, but are informed and influenced by all service providers they interact with. For energy providers, consumer and societal trends are changing the status quo that has informed the industry over the last number of decades. **To keep pace, energy providers need to consider these broad and aligning trends holistically.**



Source: EY P&U CXT Research

Rise of the Energy "Omnisumer"

New types of energy consumers are evolving, each with **higher expectations** for their relationship with service providers. To support these increasingly complex relationships, **personalized data enabled through technology** is required at a minimum and is no longer a luxury.



Source: EY P&U CXT Research

Future CX Strategic Imperatives

As energy providers shape their customer strategy for the future, they should consider the following **no regrets priorities** for the future energy experience.

1. Consumer Engagement

Deliver seamless, low cost journeys across interactions while enabling effortless experiences, digital commerce, insight-driven interaction, and curated choice.

2. Operational Agility

Focus on simplification and applying analytics, robotic automation and advanced operating models to deliver increased service consistency, responsiveness and flexibility.

3. Digital Enablement

Leverage technologies that are increasingly more scalable, open and cost effective to deliver expanded CIS, CRM, Digital and Analytics capabilities.

4. Adaptive Workforce

Engage employees and put them at the center of transformations by upskilling for new skills, enabling distributed working and engaging flexible workforce models.

5. Innovative Growth

Develop, scale and profitably manage new and/or non-traditional revenue generating propositions for an increasingly diverse range of consumers.

6. Energy Enablement

Enabling the end-to-end CX for new programs, products and services while driving customer-centric field and grid approaches for outages and energy flexibility.

Source: EY P&U CXT Research

Hydro Ottawa Customer Experience Vision

The business aspires to advance its capability maturity from its current level and form today. Advancing its maturity in multiple areas will **enable the development of deeper relationship with customers** as their preferences evolve. We see a new vision for Hydro Ottawa's customer experience…

CX Target

Personalized Offerings
Products and services are agile based on market conditions, conservation drivers, and customer preferences!

Seamless Self Serve
Optimized experience and channel-agnostic self serve function!

Proactive Service
Insight-led, predictive & transparent customer interactions!

Complete View of Customer
Informed decisions based on fulsome customer interactions data!

Innovative Solution Provider
Integrated and innovative energy related consumer offerings!

CX Today

Trustworthy Services
Offer reliable and transparent services

Limited Self Serve
Current self serve is limited and the contact center handles most service

Responsive Service
Help customers when they have an issue

Siloed Customer Information
Customer data exists but disjointed, limiting insight

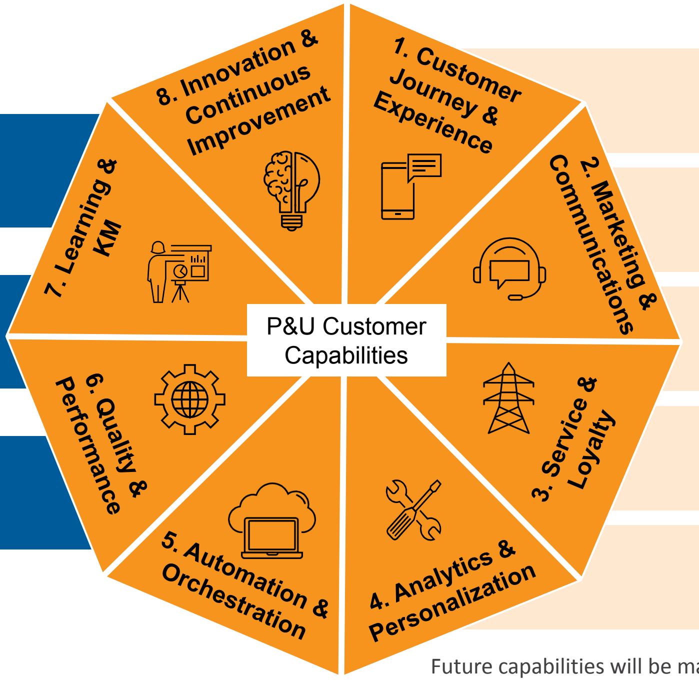
Dependable Energy Provider
Reliable, safe, dependable energy provider

Prioritized Customer Business Capabilities

To focus efforts and achieve practical outcomes for a vision for the future, **three prioritized customer business capabilities** were defined. These were prioritized by Hydro Ottawa stakeholders for actioning "now", while not limiting the business from pursuing the other capabilities "next".

Now: Prioritized Focus

- Customer Journey & Experience
- Analytics & Personalization
- Service & Loyalty



Next: Future Focus

- Automation & Orchestration
- Marketing & Communication
- Innovation & Continuous Improvement
- Learning & Knowledge Management
- Quality & Performance

Future capabilities will be maintained at current level with possible re-evaluation

Prioritized Business Outcomes:

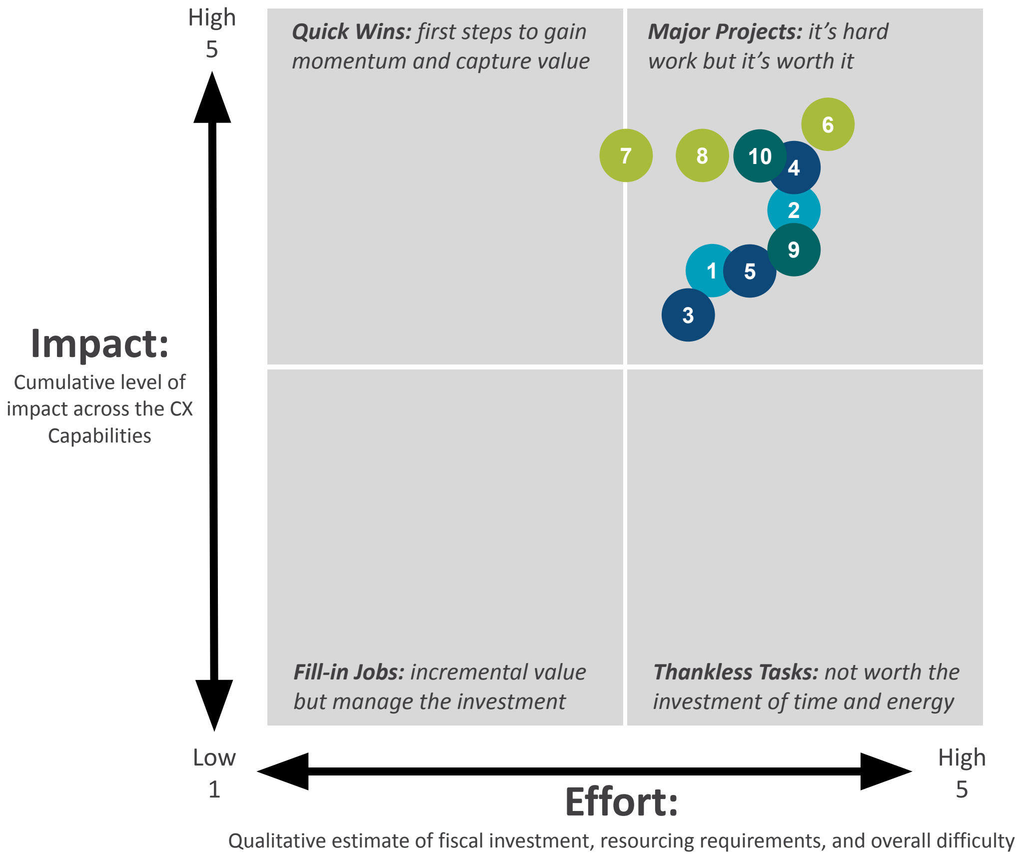
Improve customer experience / satisfaction

Enhance operational agility / flexibility

Action customer affordability pillars
(conservation, prevention, crisis management)

Focus Area Prioritization

The CX Strategy is comprised of 10 Focus Areas that look to **advance the organization's CX maturity** across a number of business capabilities. The CX Focus Areas were **prioritized by Hydro Ottawa stakeholders** as well as EY input based on perceived impact and effort.



Focus Areas			
Customer Journey & Experience			
1	Strengthen Approach to Personalized Offerings		
2	Establish Intelligent Invoicing Experience		
Analytics & Personalization		**Service & Loyalty**	
3	Data Enablement for the Future	6	Skill Development for the Future
4	Develop a 360 Degree View of Customer	7	Digital Channel Optimization
5	Automation and Process Assessment + Action	8	Outage Experience Enhancement
Foundational Capabilities			
9	Design Future State Operating Model	10	Future State Customer Technology Assessment

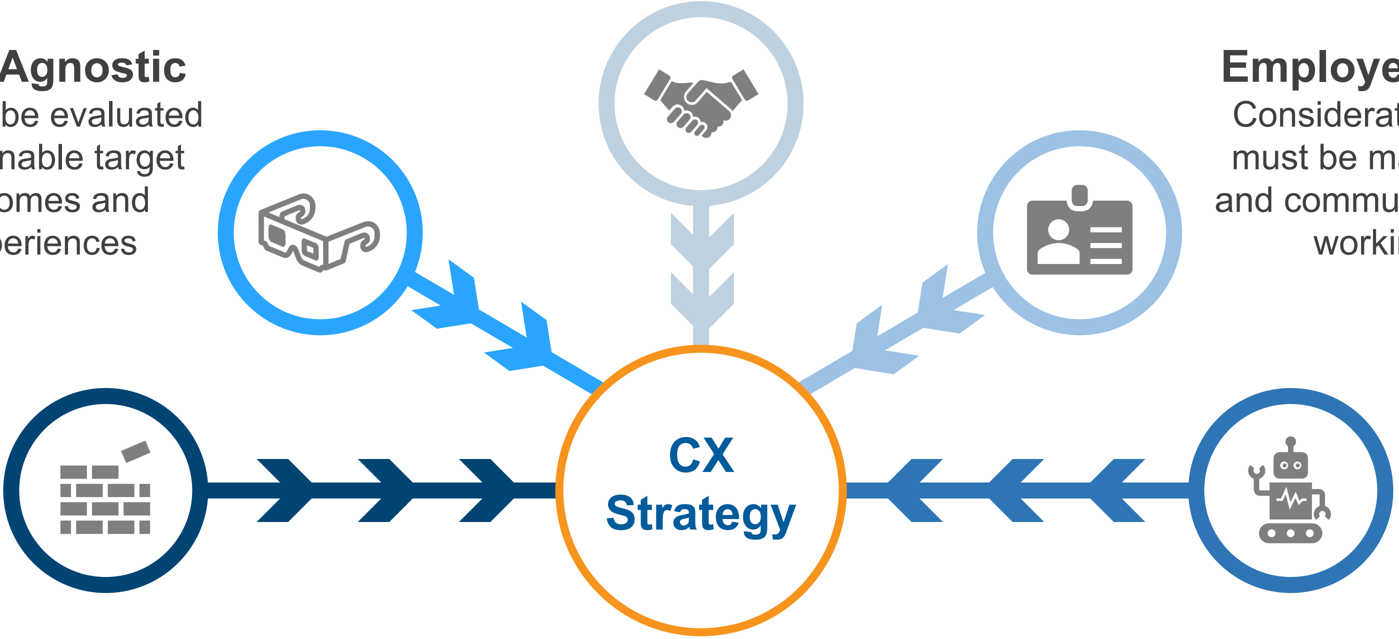
Critical Success Factors

The CX Strategy creates a foundation for the business to **continually advance its business and CX maturity** across multiple capabilities. To ensure this focus on immediate priorities as well as the focus areas, five critical success factors have been identified.

Partner for Success
Actively partner and advocate with government/regulator to forge collaborative relationship while having an agile alliance with managed service partners.

Technology Agnostic
Technology must be evaluated on its ability to enable target business outcomes and customer experiences

Employee Enablement
Considerations and planning must be made to understand and communicate new ways of working as a team



Resource Capacity
External and/or additional capacity required to complete all in-flight and new initiatives, as planned

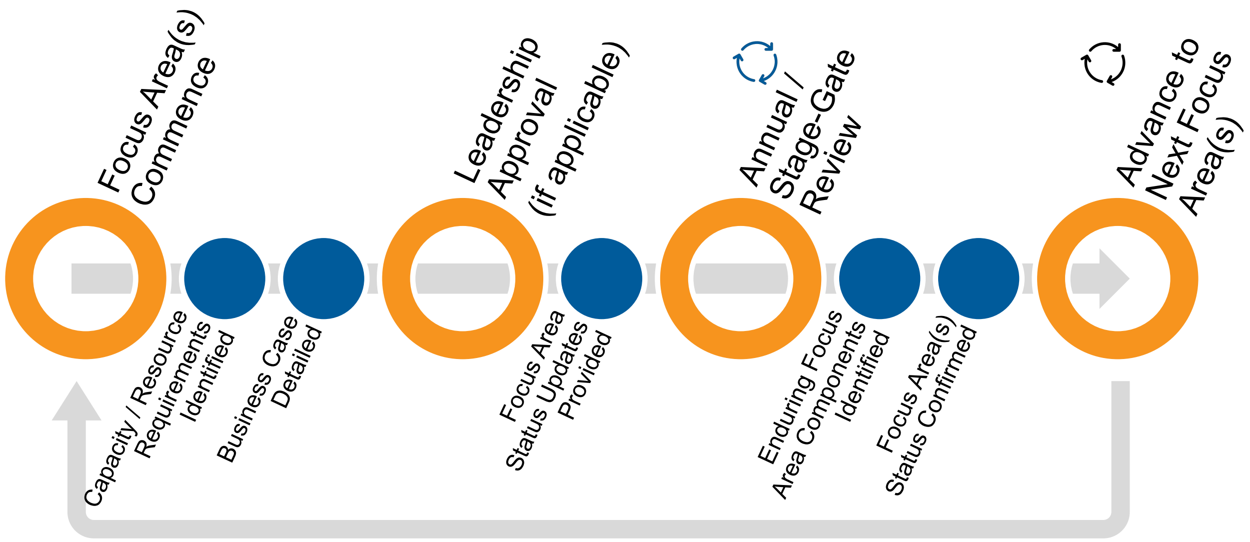
Future Focus
Focus must be beyond immediate functions, but look at future of utilities / customers

Roadmap Implementation

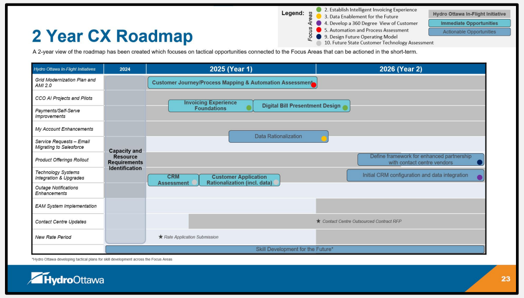
For the long-term success of the CX strategy, an annual stage-gate review with specific tactical items culminating in a 2-year roadmap are recommended. For each of the Focus Areas, internal staging will be required to ensure adequate resourcing and capacity is available.

A **strategy assessment** could be completed at either stage-gates (i.e. Focus Area completion status) or on an annual basis, as Focus Areas will be following different timelines. Additionally, some Focus Areas will have components that will require **reviews to ensure they are meeting target outcomes** and updating for any changes in the business (e.g. new technologies, priorities, etc.).

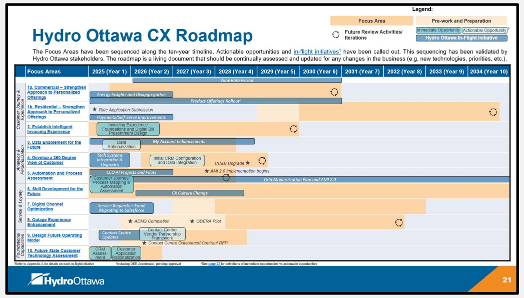
The graphic below illustrates this staging and the relevant “Review Activities”, which are included in the CX Roadmaps as shown on the right:



2 Year CX Roadmap:



CX Roadmap:



Indicates Stage Gate Focus Area Reviews on CX Roadmap.

Indicates Future Review Activities for Focus Areas.

CX Roadmaps

Roadmaps Overview

The proposed **Roadmap** sequences the 10 Focus Areas over the ten-year timeline, which **considers the focus area's dependencies and other Hydro Ottawa in-flight initiatives**.

Roadmap's value proposition:

- **Strategic Investment:** 3 of the 10 Focus Areas have "Immediate Opportunities" which are intended to inform future work and outcomes of subsequent Focus Areas
- **Efficient Timeline:** Sequence of Focus Areas enables the achievement of the CX ambition on an efficient timeline required to keep pace with the rate of disruption.
- **Balanced Capacity:** The Focus Areas are sequenced with consideration for in-flight initiatives and staggered so that capacity can be allowed sufficiently across ten-year program.
- **Foundational Outcomes**: Each Focus Area will develop Hydro Ottawa's prioritized business and customer capabilities and provide it with the ability for continued advancements.

Roadmap Key Facts:

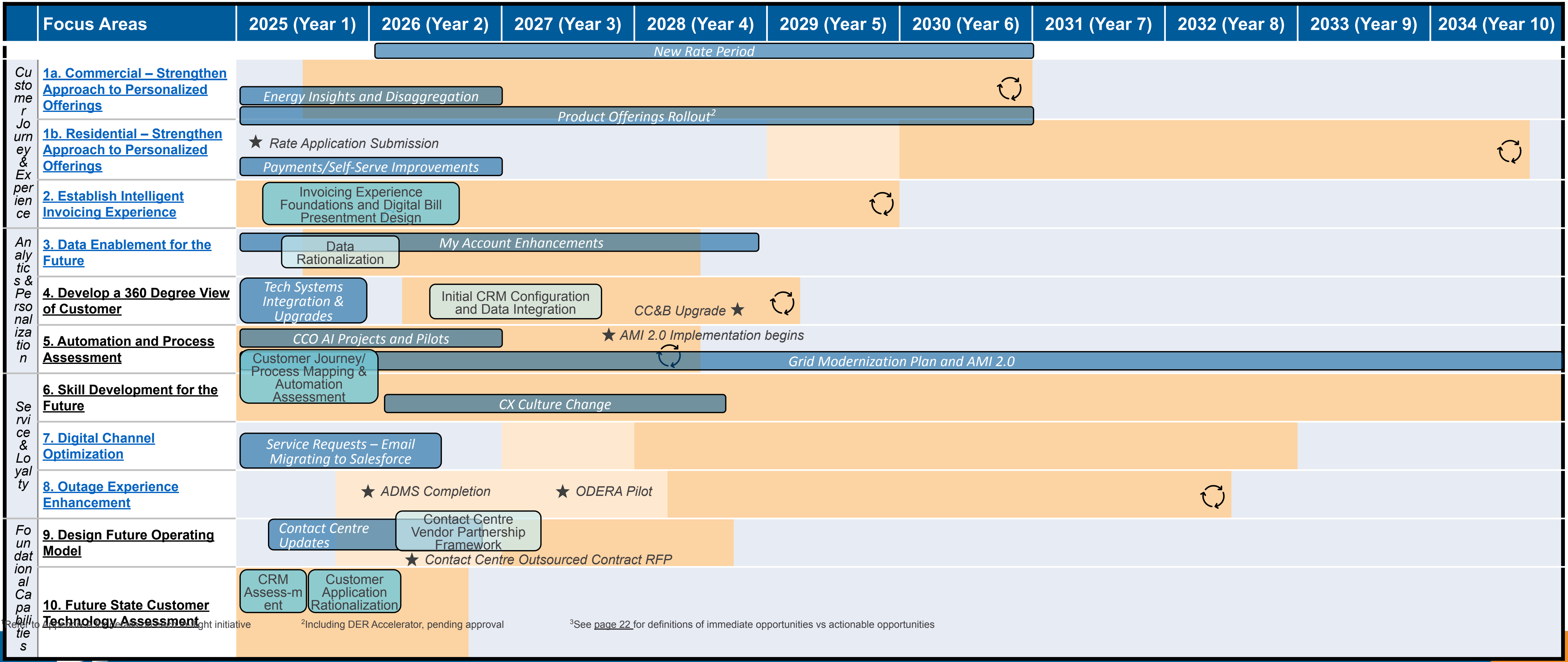
10 Focus Areas included as part of **ten-year program**	10 Hydro Ottawa **in-flight initiatives** considered
5 **immediate** actionable opportunities	**Increased** Focus Areas **implementation by year**

Hydro Ottawa CX Roadmap

Legend:

- Focus Area
- Pre-work and Preparation
- Future Review Activities/ Iterations
- Immediate Opportunity
- Actionable Opportunity[3]
- Hydro Ottawa In-Flight Initiative

The Focus Areas have been sequenced along the ten-year timeline. Actionable opportunities and in-flight initiatives[1] have been called out. This sequencing has been validated by Hydro Ottawa stakeholders. The roadmap is a living document that should be continually assessed and updated for any changes in the business (e.g. new technologies, priorities, etc.).



[1]Refer to Appendix A for details on each in-flight initiative

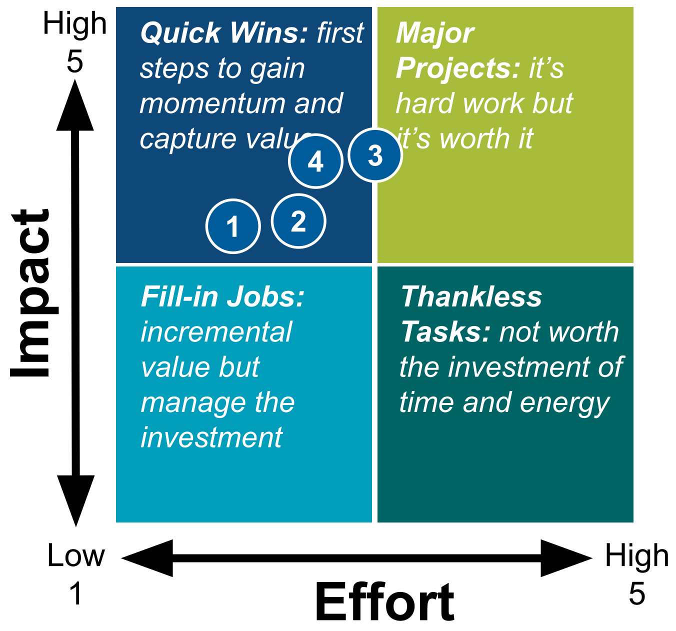
[2]Including DER Accelerator, pending approval

[3]See page 22 for definitions of immediate opportunities vs actionable opportunities

Immediate Opportunities

The following opportunities can be actioned within the next 6-12 months, having been assessed with a high potential to immediately impact the maturity of Hydro Ottawa's customer capabilities.

#	Immediate Opportunity	Why Immediate	When
1.	**CRM Assessment** Assess current state CRM against the needs of customer service, billing operations, product, and marketing to identify opportunities to enhance Hydro Ottawa's CRM and develop an achievable implementation plan.	*Establishes building blocks for 360-degree view of customer including CX opportunities identified*	***Next 6 Months***
2.	**Customer Application Rationalization (incl. data)** Conduct a technology fit-gap of internal and external facing systems to assess the alignment between current applications, data infrastructure, and the future customer strategy.	*Facilitates future projects by identifying what current systems need rationalizing/ investment first*	***Next 6 Months***
3.	**Invoicing Experience Foundations (personas/journey mapping) & Digital Bill Presentment Design** Develop personas and visioning for the new invoicing experience and create the business and technology requirements in order to then design and create an interactive digital bill presentment experience within My Account.	*Lays foundation for an informed redesign of key aspects of the customer invoicing experience, taking a digital first approach.*	***Next 12 Months***
4.	**Customer Journey/Process Mapping & Automation Assessment** Conduct an automation assessment and formulate a strategic approach (meter to cash, customer sign-up/move, customer capacity requests).	*Establishes building blocks for all future automation projects*	***Next 12 Months***



Immediate Opportunities have been identified as foundational and have dependencies between initiatives with high potential for immediate impact on the maturity of Hydro Ottawa's customer capabilities with a relatively low level of effort required.
Actionable Opportunities (as displayed on the CX Roadmap and Focus Area Dashboards) can be actioned once the foundational work has been completed.

2 Year CX Roadmap

Legend:

Focus Areas

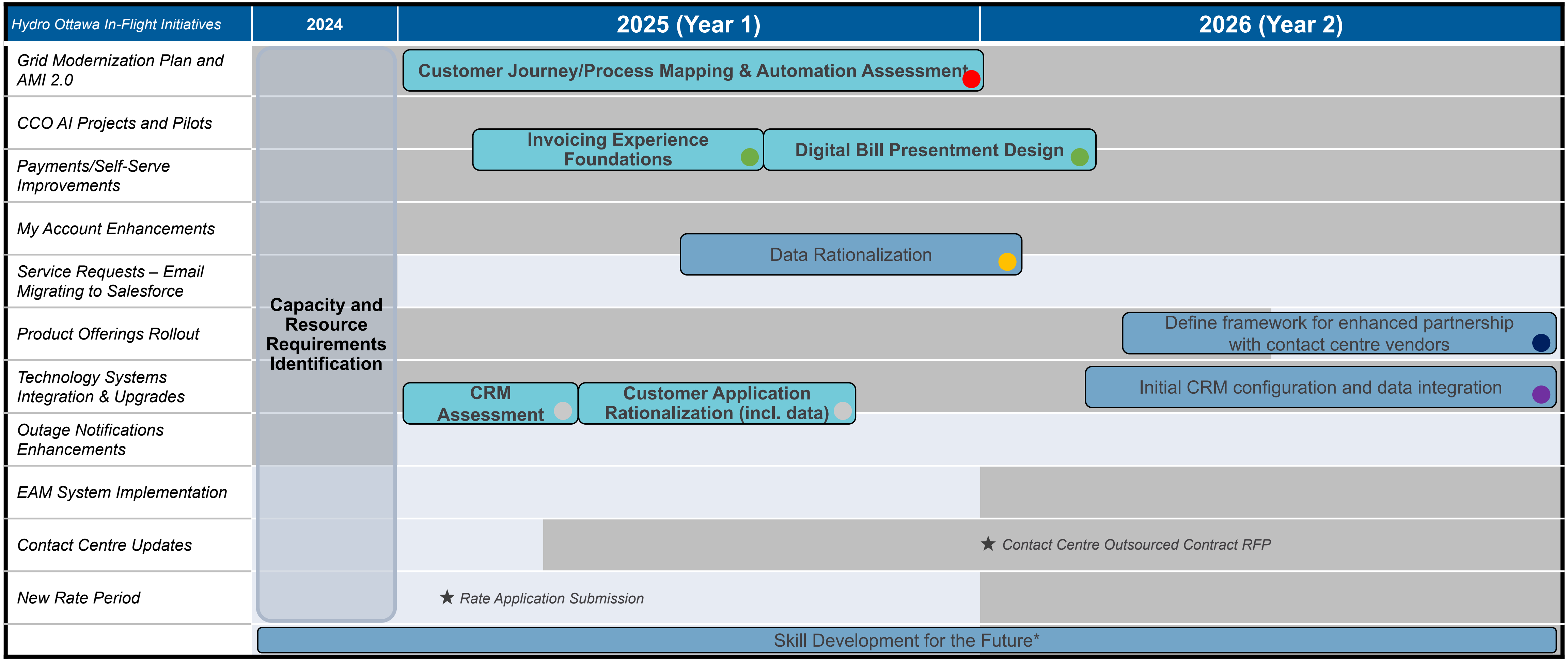
- 2. Establish Intelligent Invoicing Experience
- 3. Data Enablement for the Future
- 4. Develop a 360 Degree View of Customer
- 5. Automation and Process Assessment
- 9. Design Future Operating Model
- 10. Future State Customer Technology Assessment

Hydro Ottawa In-Flight Initiative

Immediate Opportunities

Actionable Opportunities

A 2-year view of the roadmap has been created which focuses on tactical opportunities connected to the Focus Areas that can be actioned in the short-term.



*Hydro Ottawa developing tactical plans for skill development across the Focus Areas

Focus Area Dashboards

Focus Areas Overview

The 10 Focus Areas look to advance the organization's maturity across a number of capabilities, as described by the following dashboards. Each one is illustrated in further detail with relevant stakeholders, target outcomes, and dependencies (in-flight initiatives and other focus areas).

Focus Area Overview

The 10 Focus Areas build the foundation for the business to move forward with confidence in developing its business and customer experience capabilities. Each Focus Area comprises multiple initiatives/projects that are proposed for execution in the short- (now), medium- (next), and long-term (beyond). The Focus Areas have been prioritized and sequenced on the ten-year roadmap that reflects the current internal (in-flight) initiatives that are scheduled, as well as dependencies between the Focus Areas. The first Focus Areas are generally assessments and strategy on specific areas of the customer organization to inform future action. The latter Focus Areas build off this foundation and compile these advancements into tangible customer offerings and benefits.

Target Outcome

The Focus Areas are designed to create value for both the customer and the business throughout the capability maturation process. The target outcomes will help the business achieve improvements to the efficiency and effectiveness of delivering positive customer experiences in addition to broader Hydro Ottawa ambitions. Improving the data and understanding of customer interactions will help drive continuous improvement with broader metrics, knowledge sharing, and streamlined access to customer insights.

Stakeholders

- Customer Experience
- Commercial Group
- Energy Innovation
- Grid Technology
- Customer Care
- Billing and Collections
- IT – Web Applications
- Data Management
- Enterprise Applications
- Enterprise Architecture
- Service Desk
- CITO
- Metering Systems
- Meter to Cash Support
- Communications and Public Affairs
- Human Resources
- Finance

Prioritized Capabilities

The Focus Areas have been developed to advance the three prioritized Customer Business Capabilities: *Customer Journey & Experience*, *Analytics & Personalization*, and *Service & Loyalty*.

Ten-Year Program

Individual Focus Areas are estimated to occur during this time range. Implementation of these initiatives have been mapped out over the 2- and 10-year periods.

Dependency Identification

Each Focus Area has internal (in-flight) and dependent initiatives/Focus Areas that have been identified.

Focus Areas Summary

The 10 Focus Areas have each been detailed with a dashboard containing key information and actions. The table below summarizes these Focus Areas and provides a summary of the target outcome. A legend for the dashboards has been included in the following slide.

Capabilities	Focus Areas
Customer Journey & Experience	**1. Strengthen Approach to Personalized Offerings** *Enabling a strategy around innovative offerings to become a trusted energy partner for customers and optimize grid outcomes.*
	2. Establish Intelligent Invoicing Experience *Providing customers with a dynamic digital experience (billing, energy insights, FAQs).*
Analytics & Personalization	**3. Data Enablement for the Future** *Enhancing facets of data framework (focusing on right information, data cleansing, learning, etc.) to establish data driven decision making.*
	4. Develop a 360 Degree View of Customer *Enhancing employee experience through enabling personalized service for customers.*
	5. Automation and Process Assessment + Action *Streamlining workflows to address bottlenecks and enhance employee experience.*
Service & Loyalty	**6. Skill Development for the Future** *Delivering superior customer support to improve overall customer experience.*
	7. Digital Channel Optimization *Strategically consolidating and optimizing customer communication channels for the future.*
	8. Outage Experience Enhancement *Creating a targeted, cohesive, and user-friendly customer interaction experience.*

9. Design Future Operating Model *Restructure Future Model to Align with Hydro Ottawa's Future Customer Strategy*	**10. Future State Customer Technology** *Align strategy with technological needs for the future*

How to Read: Focus Area Dashboards

Provides a high-level description and overall goal of the specified focus area.

Focus Area Overview

This explains the focus area and the many elements that come together for the desired business outcome. Reading this will provide core understanding of the need for the focus area, the activities that will ensue, and the impact on Hydro Ottawa's ability to better serve its customers throughout the energy transition.

Target Outcomes

These are the main Customer Experience impacts and business outcomes resulting from the initiative. Refer to Appendix B for specific measurable components of the target outcomes for each Focus Area.

Stakeholder(s)

These are the key groups or individuals who will take part in this focus area or who will be impacted by the business outcomes.

In-Flight Initiatives & Dependencies

This will highlight any ongoing or planned work that will impact or be impacted by the foundational focus area, and will show the suggested sequence of initiatives. Refer to Appendix A for details on the in-flight initiative.

In-Flight:

In-Flight Initiative

Dependent:

Outline of required sequencing for relevant Focus Areas.

Dependent Focus Area → CX Focus Area → Dependent Focus Area

Now: Actionable Opportunities

This outlines each action that can be taken to progress the maturity of the mapped business capability in the short term and set Hydro Ottawa up for success in the long term. Each actionable opportunity has a high-level description of what is needed to achieve it.

Next

This outlines the opportunities that are the focus of the next 5 years to advance the maturity of the mapped business capability.

Beyond

This outlines the opportunities and initiatives that Hydro Ottawa will take in the future to further advance the maturity of the mapped business capability, up to 2035 and beyond.

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1. Strengthen Approach to Personalized Offerings

Enable a strategy around innovative offerings to become a trusted energy partner for customers

Customer Journey & Experience

Focus Area Overview

This focus area represents a strategic move towards developing innovative products and services, aiming to solidify Hydro Ottawa's role as a trusted energy partner. It will encompass the identification and delivery of new offerings for both a) commercial and b) residential customers, closely aligned with Hydro Ottawa's evolving position as an energy advisor. A key element of this focus area is the adoption of a structured approach to the development of offerings, with an initial focus on providing innovative solutions for commercial customers, followed by residential. This will ensure a systematic and efficient process from ideation to market launch. By focusing on innovation and customer-centric solutions, Hydro Ottawa is poised to address the future energy needs of its customers, offering solutions that not only meet but anticipate market demands.

Target Outcomes

Understand and align on classifications (core, adjacent, non-core) of new offerings and deployment options to enable the delivery of innovative offerings, becoming a trusted energy partner for customers.

Refer to Appendix B for specific measurable components.

Stakeholder(s)

- Customer Experience
- Commercial group (Key Accounts/Energy Transition/Energy Conservation)
- Energy Innovation
- Grid Technology

In-Flight Initiatives & Dependencies

In-Flight:

Product Offerings Rollout (EV rate for charging stations, Retrofit Accelerator Program, IESO Local Initiative Programs)

Dependent:

7. Digital Channel Optimization

4. Develop 360 Degree View of Customer

1. Strengthen Approach to Personalized Offerings

These are the most relevant in-flight projects for the Focus Area. For a complete illustration of how each Focus Area impacts and overlaps with in-flight initiatives and other Focus Areas, please see the Hydro Ottawa Roadmaps on page 21.

Now: Actionable Opportunities

a	**Offerings customer journey mapping:** Map future customer journeys (e.g. new offerings - residential solar, commercial micro grids) across the organization to envision the new offerings and establish the business and technology requirements.
b	**Conduct customer segmentation:** Create customer segments and profiles to create offering specific strategies and tailored communications for each segment.
c	**Offerings (future products/services) strategy:** Develop a commercial and a residential offerings strategy that clearly defines the future products and services and deployment tactics in alignment with Hydro Ottawa's future role as an energy advisor.
d	**Structured offering development approach:** Adopt a structured development approach for progression of new offerings from concept to market readiness.

Next

- Develop dynamic tailored messaging/offering capabilities (next best offer) across channels
- Expand partnerships to support product/service strategy and offerings

Beyond

- Establish product/service portfolio management capability and scaled operating model
- Develop ecosystem platforms to share data and enable products and services with partners
- Offer innovative rates (e.g. subscription, digital prepay, device specific plans)

2. Establish Intelligent Invoicing Experience

Provide customers with a dynamic digital experience (billing, energy insights, FAQs)

Customer Journey & Experience

Focus Area Overview

This focus area aims to enhance the invoicing experience, with a goal of providing an integrated digital experience complete with billing, payment, and energy insights for a) commercial and b) residential and other unique customer types, e.g. landlords. It includes the development of an interactive digital bill presentment and redesigned digital payment experience (including direct bills to customers from finance) and customer energy insights platform. A redesign of the paper bill and e-bill remains an option, should the organization choose to pursue this following the digital deployment. The payment process will be streamlined for ease of use, and invoices will become the central hub on customer account homepages, offering direct access to energy insights and account management.

Target Outcomes

Improve customer interaction levels and satisfaction scores by providing a dynamic digital billing experience with insights, information and interactive options.

Refer to <u>Appendix B</u> for specific measurable components.

Stakeholder(s)

- Customer Experience
- Customer Care
- Billing and Collections
- IT – Web Applications
- Finance
- Commercial

In-Flight Initiatives & Dependencies

In-Flight:

- *Payments/Self-Serve Improvements*
- *MyAccount Enhancements (commercial & residential) + Website Revamp*

Dependent:

- 10. Future State Customer Technology Assessment
- 2. Establish Intelligent Invoicing Experience
- 7. Digital Channel Optimization

These are the most relevant in-flight projects for the Focus Area. For a complete illustration of how each Focus Area impacts and overlaps with in-flight initiatives and other Focus Areas, please see the Hydro Ottawa Roadmaps on page 21.

Now: Actionable Opportunities

	Develop personas and visioning for the new invoicing experience (for both commercial and residential customers) and create the business and technology roadmap.
b	**Digital bill presentment design*:** Design and create an interactive digital bill presentment experience within My Account.
c	**Digital payment experience enhancement:** Improve online payment experience including adding payment options for service requests and payment tracking for service requests/payment plans.
d	**[Optionality] Paper/e-bill redesign:** Should it still be desired following the digital deployment, redesign the paper and e-bills for improved clarity and reduced customer inquiries.

*Immediate Opportunity

Next

- Invoice as the homepage
- Expand customer self-serve, notification and preference management functionalities
- Energy insights program
- Integrate Real-Time Energy Monitoring
- Personalized bill/digital landing page messaging
- Introduce customer education programs on digital landing page

Beyond

- Enhanced digital dashboard for customer groups (Res, SMB, C&I)
- Customizable billing cycles
- Predictive billing and insights
- Digital enablement to manage EVs, solar, battery, and demand management programs
- Integrated/automated preference-based device control

3 . Data Enablement for the Future

Enhance facets of data framework to establish data driven decision making

Analytics & Personalization

Focus Area Overview

This focus area builds on the current data landscape at Hydro Ottawa and aims to foster a robust data culture where data ownership and integration are deeply embedded across Hydro Ottawa. This focus area will focus on rationalizing applications and data, transitioning to a model where data needs are driven by specific use cases. A significant effort will be placed on integrating customer data architectures to unify disparate data sources, providing a holistic view of customer information. Additionally, the focus area will prioritize training, learning, and development programs to cultivate a mindset of data-driven decision making among employees.

In-Flight Initiatives & Dependencies

In-Flight:

N/A

Dependent:

- 10. Future State Customer Technology Assessment
- 3. Data Enablement for the Future
- 4. Develop 360 Degree View of Customer

These are the most relevant in-flight projects for the Focus Area. For a complete illustration of how each Focus Area impacts and overlaps with in-flight initiatives and other Focus Areas, please see the Hydro Ottawa Roadmaps on page 21.

Target Outcomes

Define customer data owners for each team, establish overall data framework, and improve data literacy across the organization to enable data-driven decision making.

Refer to Appendix B for specific measurable components.

Stakeholder(s)

- Customer Experience
- Data Management
- Enterprise Applications
- Enterprise Architecture

Now: Actionable Opportunities

a	**Data rationalization:** Streamline applications and data management (collection, storage and usage) to transition to use case driven data needs.
b	**Customer segmentation – data needs:** Identify data needs of customer segments and leverage to enhance data collection and quality to provide personalized data insights for different segments.
c	**Customer data architecture:** Integrate and enhance customer data architectures for a comprehensive data ecosystem.
d	**Data training programs:** Implement learning solutions like training programs to enhance data literacy and promote data-driven decision making.

Next

- Enhance data integration platforms
- Update and formalize data framework
- "Pilot" program to bridge customer and Dx network data (outage management, network planning and DER management)

Beyond

- Launch data-driven pilot programs
- Explore partner/3rd party data sharing, monetization and integration opportunities

4. Develop a 360 Degree View of Customer

Enhance employee experience through enabling personalized service for customers

Analytics & Personalization

Focus Area Overview

This focus area is a strategic effort to consolidate disparate customer data sources into a comprehensive “single pane of glass” view. By integrating various touchpoints and interactions, Hydro Ottawa aims to gain a holistic understanding of each customer's preferences, behaviors, requests and needs. This unified structure will enable the organization to derive valuable insights, facilitating personalized service and informed decision-making. The focus area is a critical step towards enhancing customer relationships and ensuring that every interaction with Hydro Ottawa is informed by a complete customer profile.

Target Outcomes

Turn the customer data into the central point of truth across the organization and achieve a comprehensive understanding of each customer across all touchpoints, enabling personalized service & informed decision-making. Establish tailored customer views for various users.

Refer to Appendix B for specific measurable components.

Stakeholder(s)

- Customer Experience
- Commercial group (Key Accounts/Energy Conservation)
- Customer Care
- Service Desk
- CITO

In-Flight Initiatives & Dependencies

In-Flight:

Technology Systems Integration & Upgrades

Dependent:

3. Data Enablement for the Future → 4. Develop 360 Degree View of Customer → 1. Strengthen Approach to Personalized Offerings

These are the most relevant in-flight projects for the Focus Area. For a complete illustration of how each Focus Area impacts and overlaps with in-flight initiatives and other Focus Areas, please see the Hydro Ottawa Roadmaps on page 21.

Now: Actionable Opportunities

a	**Initial CRM configuration and data integration:** First stage CRM upgrade with data integrations and configurations to support a more detailed view of customer interactions and history.
b	**Consolidate customer data:** Identify all sources of truth for data, understand all interaction points for customer data to consolidate all customer data to a central data repository and keep complex transactions in their source systems.
c	**Customer specific performance reporting:** Update reporting to include comprehensive customer specific reporting such as key account reports, personalized reliability reports for outages, consumption insights, etc.

Next

- Enable personalized offerings for customers through building a personalization engine that takes customer data to deliver tailored offerings/recommendations
- Pilot new tools like advanced analytics
- Tailored customer insights
- Field data collection
- Connect CRM and social media

Beyond

- Tailored customer views for various Hydro Ottawa users/ functions
- End-to-end fulfillment for program/product /service support in CRM

5. Automation and Process Assessment + Action

Streamline workflows to address bottlenecks and enhance employee experience

Analytics & Personalization

Focus Area Overview

This focus area aims to address inefficiencies and bottlenecks within current Hydro Ottawa workflows. It is designed to pave the way for the adoption of automation technologies that streamline operations and boost productivity. This involves conducting a process mapping exercise with an automation assessment and developing a strategic approach to identify key areas where automation can have the most significant impact. Following this, the establishment of a Center of Excellence (COE) for automation will ensure proper governance and oversight of automation projects. Additionally, a targeted review of processes will be undertaken to assess and prioritize them for automation.

Target Outcomes

Identify inefficiencies and bottlenecks within existing workflows and enable the implementation of automation solutions that minimize errors, create time saving opportunities, increase efficiency and improve productivity while enhancing self-serve functionality on the back end.

Refer to Appendix B for specific measurable components.

Stakeholder(s)

- Service Desk
- Billing and Collections
- Energy Innovation
- Metering Systems
- Meter to Cash Support

In-Flight Initiatives & Dependencies

In-Flight:

AI Projects & Pilots (Call System project, AI customer insights platform)

Grid Modernization Plan & AMI 2.0

Dependent:

5. Automation and Process Enhancement

9. Design Future State Operating Model

2. Establish Intelligent Invoicing Experience

These are the most relevant in-flight projects for the Focus Area. For a complete illustration of how each Focus Area impacts and overlaps with in-flight initiatives and other Focus Areas, please see the Hydro Ottawa Roadmaps on page 21.

Now: Actionable Opportunities

Obtain training in customer journey mapping. Map out processes (meter to cash, customer sign-up/move, customer capacity requests) for customer journeys within the organization to identify areas for optimization (what should be true, what is not true today, and break points in the process).

b **Automation assessment*:** Conduct an overall automation assessment to determine the business and technology requirements for automation and formulate a strategic approach.

c **Center of Excellence (CoE) standup:** Establish a CoE for automation to ensure governance and oversight; identify key personnel across organization for the CoE.

d **Automated self-serve back-end functionality:** Create fully automated self-serve options for customers on all transactions – service desk, collections, move requests.

*Immediate Opportunity

Next

- Develop an automation roadmap and implement via CoE
- Update and formalize AI framework
- Expand CoE to support monitoring and management of automations

Beyond

- Assess use cases and develop AI/ML integration into process optimization
- Assess/develop cross-functional automation platform

6. Skill Development for the Future

Enhance employee experience to improve overall customer experience

Service & Loyalty

Focus Area Overview

This focus area is designed to empower Hydro Ottawa's various customer-facing employees (CCO & CEDO) with advanced tools and comprehensive training to become energy utility advisors. The objective is to enhance capabilities, ensuring Hydro Ottawa employees are well-equipped to provide superior support, based on each role's unique circumstances, and become advisors on emerging and complex interactions that align with the company's future offerings. By focusing on knowledge enhancement and proficiency in state-of-the-art software, agents will deliver an improved overall customer experience. Significant effort will be required to build momentum for this Focus Area, which will be on-going and updated regularly to match the needs of various teams (customer organization: front and back office, field operations) over the years.

Target Outcomes

Equip Hydro Ottawa customer-facing employees with advanced tools and training that enhance their capabilities, enabling them to deliver superior support and improve overall customer experience.

Refer to Appendix B for specific measurable components.

Stakeholder(s)

- Customer Care
- Customer Experience
- Billing and Collections
- Service Requests (CCO & CEDO)
- Human Resources

In-Flight Initiatives & Dependencies

In-Flight:

- *Product Offerings Rollout*
- *Technology Systems Integration & Upgrades*

Dependent:

5. Automation and Process Enhancement → 9. Design Future State Operating Model → 6. Skill Development for the Future

These are the most relevant in-flight projects for the Focus Area. For a complete illustration of how each Focus Area impacts and overlaps with in-flight initiatives and other Focus Areas, please see the Hydro Ottawa Roadmaps on page 21.

Now: Actionable Opportunities

a	**Modernized training program:** Develop a comprehensive, integrated and gamified centralized learning program with digital, classroom and mentorship opportunities to build future-ready skills. Include considerations for data training. The intended audience are the various customer-facing employees.
b	**Field-specific learnings:** In addition to that actioned through the grid modernization projects, create field specific trainings for advanced topics such as smart grid technologies and create a feedback loop for field crews to share insights and challenges.
c	**Organization-wide agent-assist tools:** Integrate AI tool for agent assist in real-time during customer interactions with regular trainings for agents and regular updates of the AI tool.

Next

- Update recognition and reward systems
- Establish real-time feedback and coaching capability
- Define new agent/skill profiles, roles, and development paths

Beyond

- Explore use of AI, augmented reality and next gen learning capabilities
- Integrate personalized learning/skill development plans
- Evaluate knowledge management approach, platform and capabilities to support expanded programs, products and services

7. Digital Channel Optimization

Strategically consolidate and optimize customer communication channels for the future

Service & Loyalty

Focus Area Overview

This focus area aims to streamline and simplify communication channels to enhance customer engagement and operational efficiency, while enhancing self service capabilities. The goal is to consolidate Hydro Ottawa's multiple communication touchpoints into an optimized system that delivers a seamless customer experience. By optimizing the use of preferred channels and introducing advanced technologies, this strategy will transform the way customers interact with Hydro Ottawa, reinforcing its reputation as a customer-centric energy provider. This approach ensures that every interaction is intuitive, consistent, and aligned with Hydro Ottawa's commitment to excellence in customer service.

Target Outcomes

Consolidate and optimize communication channels, resulting in a more efficient, cohesive, and user-friendly customer interaction experience with additional advanced self-serve options.

Refer to Appendix B for specific measurable components.

Stakeholder(s)

- Customer Experience
- Service Desk
- Key Accounts
- Enterprise Applications

In-Flight Initiatives & Dependencies

In-Flight:

- *MyAccount Enhancements (Commercial & Residential)*
- *Service Requests – Migrating to Salesforce*
- *EAM System Implementation*

Dependent:

- 10. Future State Customer Technology Assessment
- 7. Digital Channel Optimization
- 8. Outage Experience Enhancement

These are the most relevant in-flight projects for the Focus Area. For a complete illustration of how each Focus Area impacts and overlaps with in-flight initiatives and other Focus Areas, please see the Hydro Ottawa Roadmaps on page 21.

Now: Actionable Opportunities

a **Channel usage analysis:** Use defined metrics to understand usage patterns and effectiveness across all customer channels.

b **Overall channel strategy:** Create overall strategy to enhance top customer preferred channels and support other channels. Identified desired and require channels based on long-term organization vision and future role.

c **Additional self-serve options:** Perform gap analysis to understand where and how self-serve capabilities need to be improved. Target improvement in self-serve containment in prioritized digital channels with agile approach.

d **Automated response systems:** Implement chatbots and other automated response systems into communication channels.

Next

- Digital adoption campaigns
- Omnichannel integration and analytics
- Channel performance and customer experience analytics
- Mobile device optimization
- Cross-channel voice of the customer/customer feedback loops

Beyond

- AI enabled personalization across channels
- Enable voice and conversational interfaces (digital, IVR, etc.)
- Integrated program, product, and service experience (including with 3rd parties)

8. Outage Experience Enhancement

Create a targeted, cohesive, and user-friendly customer interaction experience

Service & Loyalty

Focus Area Overview

This focus area refines the approach to managing and communicating outages. By harnessing predictive analytics, Hydro Ottawa seeks to proactively manage outages and provide timely notifications to all stakeholders, including non-customers who may be affected. This focus area is focused on enhancing the effectiveness of communication and minimizing disruption for all parties involved. The integration of automation into the extensive internal processes related to outages will further streamline operations, ensuring that outage management is as efficient and customer-centric as possible.

Target Outcomes

Enhance communication effectiveness and minimize disruption, enabling proactive management and timely notification of planned outages to stakeholders.

Refer to Appendix B for specific measurable components.

Stakeholder(s)

- Customer Experience
- Customer Care
- Service Desk
- Key Accounts
- Communications and Public Affairs

In-Flight Initiatives & Dependencies

In-Flight:

Outage Notifications Enhancements

AMI 2.0 Implementation

Dependent:

7. Digital Channel Optimization

5. Automation and Process Enhancement

8. Outage Experience Enhancement

These are the most relevant in-flight projects for the Focus Area. For a complete illustration of how each Focus Area impacts and overlaps with in-flight initiatives and other Focus Areas, please see the Hydro Ottawa Roadmaps on page 21.

Now: Actionable Opportunities

a	**Planned outage communications:** Streamline communications processes and systems for planned outages to work towards a 100% delivery success rate for communications.
b	**Non-customer communication strategies:** Develop communication strategies and business/technology requirements that extend to non-customers for outage communication.
c	**Predictive analytics:** Implement predictive analytics to forecast and proactively manage unplanned outages.
d	**Introduce Automation:** Introduce automation to simplify and expedite internal outage-related processes.

Next

- ETR Optimization
- Enhance customer facing outage management tools
- Update outage “playbook” with latest tools/strategies
- Enhance customer outage notifications and preference management

Beyond

- AI-enhanced outage prediction
- Personalized outage impact reports
- Resiliency/back-up energy offerings (e.g. DERs, microgrid, etc.)
- EV owner outage experience

9. Design Future Operating Model

Restructure Future Model to Align with Hydro Ottawa's Future Customer Strategy

Operating Model

Focus Area Overview

This focus area is aimed towards setting Hydro Ottawa up to successfully take on the customer and offerings of the future. The main goal of this focus area to develop an organizational architecture that is agile, resilient and customer-focused, ensuring that internal processes, systems and capabilities are aligned with the expectations and needs of the customers. By instituting a robust framework for continuous improvement and innovation, Hydro Ottawa is poised to not only meet but exceed the evolving demands of the energy market.

In-Flight Initiatives & Dependencies

In-Flight:

Product Offerings Rollout

Technology Systems Integration & Upgrades

Dependent:

5. Automation and Process Enhancement → 9. Design Future State Operating Model → 6. Skill Development for the Future

These are the most relevant in-flight projects for the Focus Area. For a complete illustration of how each Focus Area impacts and overlaps with in-flight initiatives and other Focus Areas, please see the Hydro Ottawa Roadmaps on page 21.

Target Outcomes

Create a future-proof operating model that optimizes structure, processes, and technology, supporting agile decision-making and operational efficiency to meet evolving market and customer needs. Maintain flexibility to manage unknowns and future opportunities.

Refer to Appendix B for specific measurable components.

Stakeholder(s)

- CCO
- With support/alignment from CITO & CEDO

Now: Actionable Opportunities

a	**Design future operating model:** Assess the organization's desired technology and experience outcomes as well as desired service and capability models, and develop an operating model for the future to achieve them.
b	**Define framework for enhanced partnership with contact centre vendors:** Based on the desired future state stakeholder experiences and service delivery approach, define the requirements to establish the appropriate sourcing strategy of the future.

Next

- Optimize operating model and realign organization based on digital and automation capabilities and new products/services
- Implement performance management framework (including KPIs and regulatory/vendor service levels)
- Implement agile methodologies across business and technology for specific programs

Beyond

- Assess customer operations organizational structure with scaled products and services
- Update collaboration tools with latest available options

10. Future State Customer Technology Assessment

Align strategy with technological needs for the future

Technology Enablement

Focus Area Overview

This focus area aims to ensure that Hydro Ottawa's technological infrastructure is fully aligned with its strategic ambitions and prepared to meet future challenges. The focus area is centered on the CRM and assessing the current CRM capabilities against the desired target capabilities. Beyond this, an evaluation of the current technology landscape to meet operational needs and enhance customer engagement is also an important part of this focus area. This will enable Hydro Ottawa to make informed decisions, prioritize investments and deploy solutions that drive innovation and efficiency.

Target Outcomes

Align Hydro Ottawa's technological infrastructure, including CRM systems, with its strategic objectives to meet future needs to ensure that the technology supports and enhances operational efficiency, customer engagement, and service delivery.

Refer to Appendix B for specific measurable components.

Stakeholder(s)

- Service Desk
- Customer Care
- Customer Experience
- CITO

In-Flight Initiatives & Dependencies

In-Flight:

Outage Notifications Enhancements

Technology Systems Integration and Upgrades

Dependent:

10. Future State Customer Technology Assessment → 4. Develop 360 Degree View of Customer

2. Establish Intelligent Invoicing Experience

5. Automation and Process Enhancement

These are the most relevant in-flight projects for the Focus Area. For a complete illustration of how each Focus Area impacts and overlaps with in-flight initiatives and other Focus Areas, please see the Hydro Ottawa Roadmaps on page 21.

Now: Actionable Opportunities

Conduct a customer technology fit-gap of internal and external facing systems to assess the alignment between current applications, data infrastructure, and the future customer strategy.

b **CRM Assessment (requirements gathering)*:** Assess current state CRM (current platform) capabilities, usability and integration with other tools to determine requirements and identify solutions for future CRM business needs.

c **Customer technology roadmap:** Create a strategic technology roadmap that outlines the adoption of new technologies, upgrades to existing systems, and phasing out of obsolete tools over a defined timeline. Provide and analyze consideration for the customer benefits that can be achieved through the deployment of grid technology that aligns with the Grid Modernization roadmap.

*Immediate Opportunity

Next

- Digital skills assessment and training
- Customer feedback integration

Beyond

- Pilot innovative technologies
- Continuous technology innovation culture

Appendix A:
In-Flight Initiatives
Details

In Flight Initiatives Details

Ongoing and approved in-flight initiatives are illustrated on the CX Roadmap, with further details on specific projects highlighted below.

Category	Details / Projects to highlight
Grid Modernization Plan and AMI 2.0	1. ADMS, OMS, Self-Healing Grid
	2. AMI 2.0 Implementation
	3. Electrification study on the impact on Hydro Ottawa distribution system
CCO AI Projects and Pilots	1. AI Call Categorization
	2. AI Smart Search (potential to provide external customers and internal resources with a more intelligent search capability for website)
	3. Agent Assist - Provide agents with a tool to help assist in quickly finding answers to customer questions across sources, provide ready-made responses, and supplement agent training and knowledge in a high turnover environment
Payments/Self-Serve Improvements	1. MyAccount Net Metering Generation Tracker and Rate Plan Selection [automation & billing via the provincial MDM/R (Enhanced Self Serve)]
	2. Enhanced Self Serve (Payments) - Automating payment reporting, payment plan setup, and remote service reconnects so customers can manage their accounts on their own terms, 24/7
My Account Enhancements	1. Expansion of Capabilities for Customer Facing Portal: - Providing guest access - Improved billing experience for customers with multiple accounts - Improved billing and payment experience for mobile app users
	2. MyAccount: Large Commercial - Enhanced dashboard - Advanced usage analytics - Improved billing features - New self-serve options
Service Requests – Email Migrating to Salesforce	Salesforce work to migrate from Gmail to Salesforce for email handling of cases

In Flight Initiatives Details

Ongoing and approved in-flight initiatives are illustrated on the CX Roadmap, with further details on specific projects highlighted below.

Category	Details / Projects to highlight
Product Offerings Rollout	1. Supporting IESO Local Initiatives Programs (Ottawa Large DER solar program, Coolsaver, BizEnergy Saver) with marketing, communications, and customer engagement - local CDM programs
	2. Delivery of Ottawa Retrofit Accelerator program
	3. DER Accelerator (pending approval)
	4. New EV rate for charging stations (regulatory)
Technology Systems Integration & Upgrades	1. JD Edwards integration project
	2. CC&B Upgrade
Contact Centre Updates	1. Evaluate, select & migrate to Scalable Cloud Contact Centre
	2. Cloud migration and software upgrades (IVR configurations once new Cloud Contact Centre is set up)
	3. Integration with set of tools for CRM
New Rate Period	Rate application submission by February 2026, with new rate period until 2030
Energy Insights and Disaggregation	1. Internal tools to support program design and target program enrollment
	2. Extension to customers to assist in energy transition
CX Culture Change	1. Leverage comprehensive training platform for eLearning, AI, VR courses in customer service skills
	2. Corporate eLearning for CX Strategy and Roadmap
ODERA Pilot	Unlocks outage prevention communication

Appendix B:
Target Outcomes
Measurable Components

HydroOttawa

Target Outcomes – Measurable Components

Measurable components for each Focus Area's target outcome are listed below, which can provide the business with tactical goals for gauging progress.

Focus Areas	Target Outcome	Measurable Components
1. Strengthen Approach to Personalized Offerings	*Understand and align on classifications (core, adjacent, non-core) of new offerings and deployment options to enable the delivery of innovative offerings, becoming a trusted energy partner for customers.*	Becoming a trusted energy partner for customers through: 1. Understanding and aligning on classifications (core, adjacent, non-core) of new offerings based on regulatory environment, strategic fit, customer demand, etc. with an initial direction on the development methods (build, ally, buy/acquire) for each. 2. Leveraging a segmentation and journey mapping framework to develop a playbook for new products which includes strategy (target audience, delivery approach, new capability requirements, effort, impact) and a rollout plan for expected adoption (KPIs by % to be set by business).
2. Establish Intelligent Invoicing Experience	*Improve customer interaction levels and satisfaction scores by providing a dynamic digital billing experience with insights, information and interactive options.*	Improving customer interaction levels and satisfaction scores through: 1. Leveraging personas and journey mapping to design digital experiences aligned with specific customer needs and preferences with a view of future customer interactions with Hydro Ottawa (e.g. smart charging, solar/net metering, demand management, etc.). 2. Designing and implementing a dynamic digital bill and payment experience that aligns with customer needs and preferences to achieve a digital adoption rate of 90%. 3. Creating a framework for providing customers with personalized insights and recommendations based on their energy usage patterns in order to decrease call volume and increase solution adoption (KPIs by % to be set by business).
3. Data Enablement for the Future	*Define customer data owners for each team, establish overall data framework, and improve data literacy across the organization to enable data-driven decision making.*	Enabling data-driven decision making across the organization through: 1. Establishing a data framework that defines specific methods for validating and collecting customer data to maintain low query response and processing times. 2. Facilitating integration between customer data architectures. 3. Improving data skills and overall literacy across the organization, with a certain # of employees trained in data proficiency (KPIs by % to be set by business).
4. Develop a 360 Degree View of Customer	*Turn the customer data into the central point of truth across the organization and achieve a comprehensive understanding of each customer across all touchpoints, enabling personalized service and informed decision-making. Established tailored customer views for various Hydro Ottawa users.*	Achieving a comprehensive understanding of each customer across all touchpoints through: 1. Identifying a single Source of Truth across all data points and develop integrations and data sharing needed to bring a full view of data together. 2. Ensuring accessibility to single Source of Truth data (with varying permission levels) across all teams. 3. Establishing tailored customer views for various Hydro Ottawa users, enabling first call resolution for 90% of inquiries.
5. Automation and Process Assessment + Action	*Identify inefficiencies and bottlenecks within existing workflows and enable the implementation of automation solutions that minimize errors, create time saving opportunities, increase efficiency and improve productivity while enhancing self-serve functionality on the back end.*	Identify inefficiencies and enable automation solutions that improve productivity through: 1. Conducting automation and process assessment for 3 key identified end to end processes. 2. Expanding self-serve functionalities within the website and MyAccount (KPIs for # of functionalities to be set by business). 3. Creating a structure around automation CoE with regularly scheduled meetings to discuss progress and uptake. 4. Developing an AI framework that identifies how Hydro Ottawa will use AI models for customer use cases going forward, what those projects entail, customer opt-in/out policies, and what kind of data will be used (KPIs by % to be set by business).

Target Outcomes – Measurable Components

Measurable components for each Focus Area's target outcome are listed below, which can provide the business with tactical goals for gauging progress.

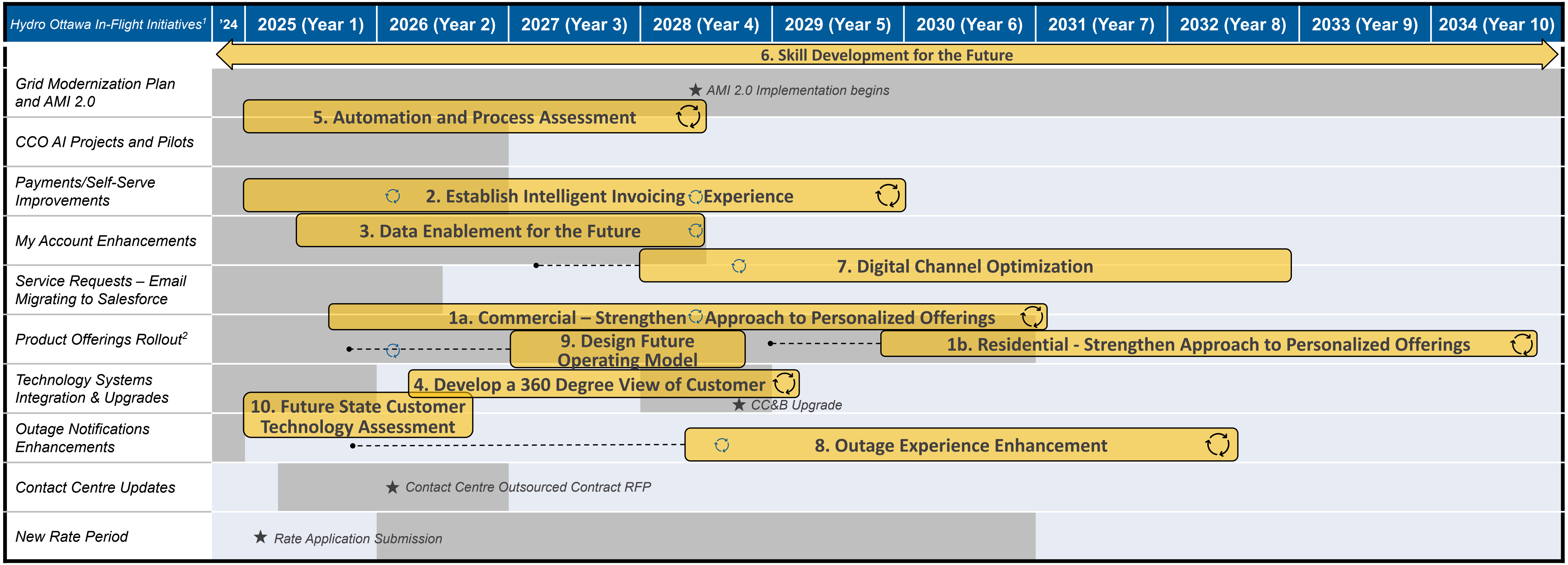
Focus Areas	Target Outcome	Measurable Components
6. Skill Development for the Future	*Equip Hydro Ottawa customer-facing employees with advanced tools and training that enhance their capabilities, enabling them to deliver superior support and improve overall customer experience.*	Equipping Hydro Ottawa customer-facing employees to deliver superior support through: 1. Conducting forward looking learning needs analysis for multiple groups, including field-specific learnings for field employees to achieve a specific training completion rate (KPIs by % to be set by business). 2. Developing interaction management tool and training all employees across the organization that have any touchpoints with customers on its use to increase Customer Satisfaction scores (KPIs by % to be set by business). 3. Establish high-level future capability and skill profiles of key customer operations roles aligned with strategic roadmap and plan to help anchor longer-term hiring, training, etc. (e.g. data & analytics, digital, product management, etc.)
7. Digital Channel Optimization	*Consolidate and optimize communication channels, resulting in a more efficient, cohesive, and user-friendly customer interaction experience with additional advanced self-serve options.*	Creating a more efficient, cohesive, and user-friendly customer interaction experience across channels through: 1. Creating a channel strategy leveraging insights from usage patterns and effectiveness across all customer channels. 2. Increasing self-serve options in areas of high-volume interactions (from data analysis) targeting decreased call volumes (KPIs by % to be set by business).
8. Outage Experience Enhancement	*Enhance communication effectiveness and minimize disruption, enabling proactive management and timely notification of planned outages to stakeholders.*	Enhancing communication effectiveness and minimizing disruption in outages by: 1. Streamlining communications processes and systems for planned outages to work towards a 100% delivery success rate for communications. 2. Establishing bi-directional outage communication framework with customers for outage notifications reaching a high channel adoption rate and new non-customers (KPIs by % to be set by business). 3. Implementing predictive analytics to forecast and proactively manage unplanned outages, to provide advance notice before outages.
9. Design Future Operating Model	*Create a future-proof operating model for Hydro Ottawa that optimizes structure, processes, and technology, supporting agile decision-making and operational efficiency to meet evolving market and customer needs. Maintain flexibility to manage unknowns and future opportunities.*	Creating a future-proof operating model for Hydro Ottawa to meet evolving market and customer needs through: 1. Deciding on new operating model structure to support agile decision making and operational efficiency based on Hydro Ottawa's future goals; targeting an effective time to launch (from ideation) for new projects and pilots, support agile digital enhancements, and enable automation and AI across customer operations (KPIs by % to be set by business). 2. Based on the desired future state stakeholder experiences and service delivery approach, defining a set of requirements to establish the appropriate sourcing strategy of the future.
10. Future State Customer Technology Assessment	*Align Hydro Ottawa's technological infrastructure, including CRM systems, with its strategic objectives to meet future needs to ensure that the technology supports and enhances operational efficiency, customer engagement, and service delivery.*	Aligning Hydro Ottawa's technological infrastructure with its strategic objectives to meet future needs through: 1. Conducting a CRM assessment and implementing suggested upgrades and enhancements, increasing usability and integration with other tools 2. Ensuring the technology supports and enhances operational efficiency and service delivery, aiming to increase system performance metrics like speed, uptime, and technical performance (KPIs by % to be set by business)

Appendix C:
Alternate Roadmap View

CX Roadmap – Alternate View

Legend:
- Hydro Ottawa In-Flight Initiative
- Focus Area
- Pre-work and Preparation
- Future Review Activities and Iterations
- Stage-Gate Focus Area Review

The Focus Areas have been sequenced along the ten-year timeline. Internal (in-flight) initiatives have been called out in the background. This sequencing has been validated by Hydro Ottawa stakeholders. The roadmap is a living document that should be continually assessed and updated for any changes in the business (e.g. new technologies, priorities, etc.).



[1]Refer to Appendix A for details on each in-flight initiative

[2]Including DER Accelerator, pending approval

CONFIDENTIAL DRAFT FOR REVIEW

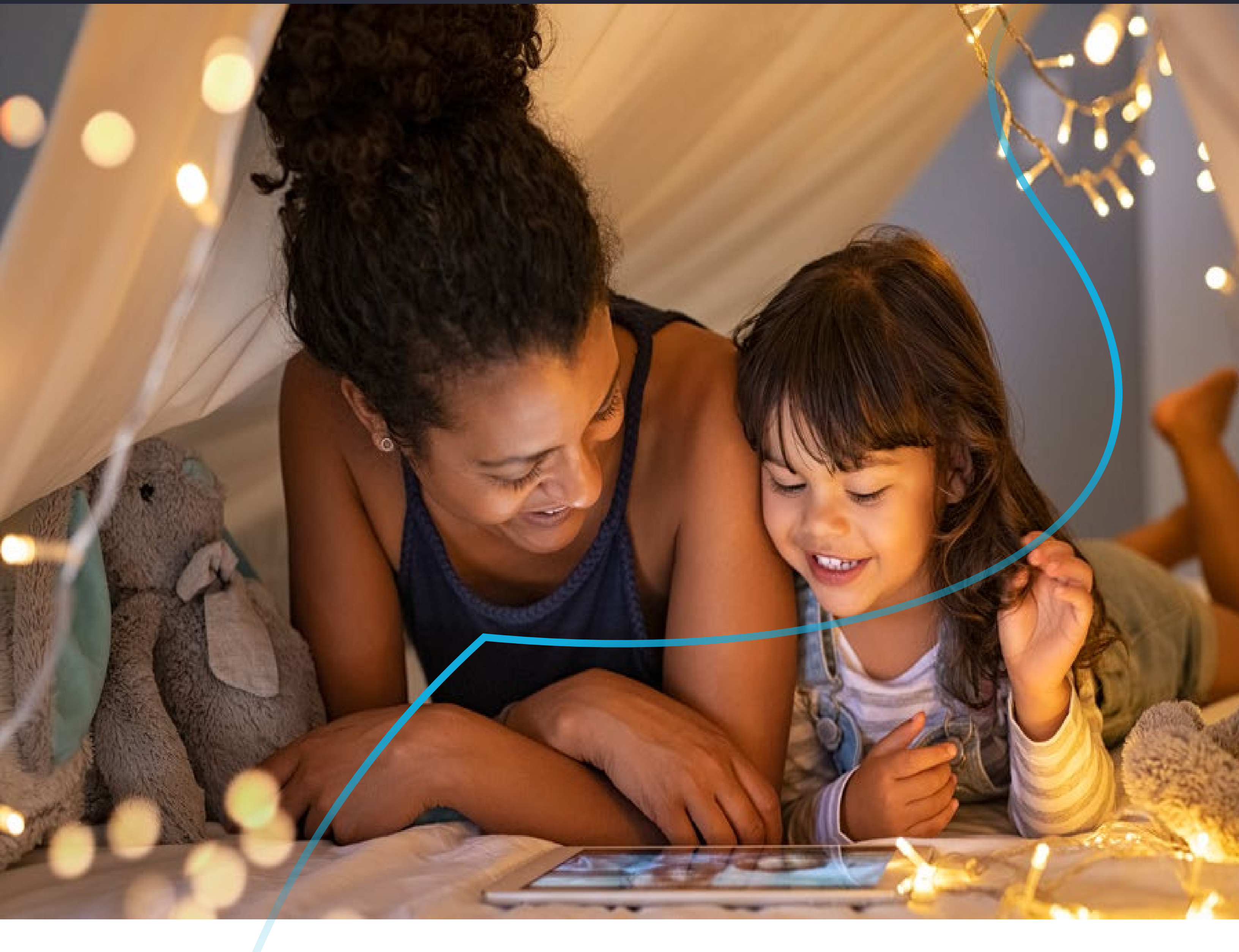
AMI 2.0 BUSINESS CASE – DELIVERABLE 1 BENEFITS ASSESSMENT

USE CASE DESCRIPTION

Hydro Ottawa

Advanced Metering Infrastructure (AMI) Consulting Services

Dec 22nd, 2023



Preamble

The objective of this draft benefits assessment and use case description document is to present the progress made during Deliverable 1, which is the first of a 4-step engagement for the AMI 2.0 Business Case. The deliverable 1 benefits assessment and use case description document provides a summary of the selected use cases and value drivers that will become foundational for the AMI 2.0 Business Case for Hydro Ottawa. These results represent a culmination of interviews, Hydro Ottawa historical data, and benchmark assumptions where appropriate. The results of this assessment do not include costs and represent gross benefits only. Costs will be included in the Deliverable 2 - Gap Analysis.

It is expected that assumptions and inputs will be updated during Deliverables 2, 3, and 4. While this report is open for comment, it is recommended to focus comments on the general scope of use cases and their benefit logic rather than on individual assumptions or results.

Capgemini Canada Inc.

TABLE OF CONTENTS

BENEFIT ASSESSMENT OVERVIEW

Capgemini is pleased to provide Deliverable 1 – an overview of the benefits assessment and value drivers for your AMI 2.0 business case. This document outlines a number of use cases that have been examined and represents the primary business case value-drivers. As we move into Deliverable 2, data from the benefit assessment will be used to develop the "cost component" required to recognize identified benefits from Deliverable 1.

A summary of the use cases is included in Figure 1, in addition to the associated gross benefits. Within each use case there are one-to-many value drivers depending on the nature of the use case and its complexity. The financial model goes into extensive detail for each value driver by building value from the bottom-up. This provides transparency into each input and allows customization for each value driver. By building the value drivers in this fashion, it helps stakeholders understand how to defend the logic behind the benefit.

While the project continues to progress, scheduling and timing have prevented formal sign-off of various assumptions in the benefit assessment. We intend to follow-up with the appropriate business line stakeholders after the new year to complete this final verification. As such, the magnitude of the gross benefits are subject to change should adjustments be necessary.

One additional item to call out pertains to the Demand Response use case. This is clearly a use case that will be included in the AMI 2.0 business case; however we are in a HOL planning year. What this means is that available data is presently "dated and several years old". There is presently an effort to refresh a lot of various data sets that may include potential load reduction projections. For this reason, in addition to delays in receiving some of the potential load reduction data, we have excluded the Demand Response use case from this Benefit Assessment release. We anticipate the addition of this use case in the new year to an amended benefit assessment once all data has been collected and assumptions have been verified.

Figure 1: Core Use Cases

Core Use Cases	
AMI Sustainment	$ 41,287,046
Conservation Voltage Reduction	$24,508,110
Pre-Pay	$18,450,520
Remote Disconnect/Reconnect	$7,296,404
Outage Identification	$5,876,441
Customer Service Impact	$916,996
Service Restoration	$855,902
Predictive Maintenance	$502,984
Proactive Outage Notification	$271,308
Total Benefits:	**$ 99,965,711**

USE CASES

AMI Sustainment

Description

- To-date, Hydro Ottawa (HOL) operates and AMI 1.0 solution. The current system is approaching end of life and has limited capabilities related to power outage/restoration notifications and advanced use cases. The AMI sustainment use case is focused on the "do nothing" scenario. If HOL decides to maintain its current system, this use case includes all costs associated with maintaining and operating the existing AMI 1.0 system for the next 15 years. These costs are broken down into several categories that include meter hardware, collectors, gatekeepers, head end software, annual licensing, support and data collection costs.

  HOL further manages a meter compliance program for installed meters and are required to conduct accuracy testing which is mandated by Measurement Canada (MC). Installed meters are sampled on fixed frequencies (10, 8 and 6 years) to verify they remain compliant with MC regulations. This compliance program utilizes HOL resources that include labour, transportation, and meter sealing when meters are removed from the field and tested in a meter lab. If meters from a sample batch pass accuracy testing, they are typically resealed, inventoried, or redeployed in the field. All meters in the sampling batch and those meters part of the manufacturing batch, have their seal expiration dates extended if tests are successful.
- Equipment (meter and network) failures typically increase as AMI solutions age in addition to the technology becoming obsolete. Failures may occur in a variety of ways that include complete failure, accuracy issues and component failure resulting in erratic behaviour and communication issues. Replacing end-of-life meters and network equipment with next generation AMI equipment will reduce or eliminate truck rolls and replacement hardware costs for a significant number of years and improve reliability.
- With AMI 2.0, the existing meter compliance program will no longer be required for ten years once AMI installation begins and contingent on HOL obtaining an approval for temporary dispensation for meters with seals expiring in the AMI deployment window. As new AMI meters are installed, the mandatory MC testing period will reset to 10 years and the need to carry larger volumes of inventory is reduced where meter and network equipment failures be minimal.

Customer Experience Impact

There is very limited customer experience impact however an AMI project requires customer site visits to swap out AMI 1.0 meters with AMI 2.0 meters. The typical customer impact of these visits can be minimal, however there is an opportunity to evaluate how these customer interactions can improve the customer experience by creating more meaningful and personalized interactions.

Gross Benefit (2023): $41.3M

Value Drivers (VD)

1. **VD-1: Avoided cost of AMI 1.0 meter replacement -** Meters are presently replaced as a result of failure, upgrades, or meter compliance sampling. These costs are eliminated entirely once the new meters are installed. Continued installation of AMI 1.0 meters create challenges when evaluating a switch to AMI 2.0 where they may not be fully depreciated when removed from the field during installation of the next generation technology.
2. **VD-2: Avoided cost of complex meters –** These are meters read and managed by the MV-90 system. MV-90 typically communications with meters via costly phone lines, or cellular radios. These O&M costs will also be eliminated.
3. **VD-3: Reduced inventory overheads -** Installation of AMI 2.0 devices will eliminate AMI 1.0 inventory requirements. The new meters will essentially reset the MC sampling program resulting in less inventory in addition to standardizing meter inventory codes.
4. **VD-4: Network operating cost -** All related network operating costs for the legacy AMI system will be eliminated once AMI 2.0 meters have been deployed. This would include all phone line and cellular communications used between the AMI 1.0 HES and the collectors and gatekeepers.

5. **VD-5: Avoided cost of HES systems -** This assumes the HES used for the AMI 1.0 system and related periodic upgrade costs can be eliminated where the AMI 2.0 system will require a different HES.
6. **VD-6: O&M cost of existing meter to cash systems -** All related operating costs associated with the legacy HES will gradually be eliminated once all AMI 2.0 devices have been deployed. This includes annual licensing and support.
7. **VD-7: Reduced labour to run existing meter to cash systems -** All FTE costs associated with operating the HES, troubleshooting and support required to collect meter data and generate a customer bill.
8. **VD-8: Reduced truck rolls due to newer inventory and better insights into service conditions -** The AMI 2.0 system will be more reliable for a significant number of years compared to the AMI 1.0 devices. There are additional features in the AMI 2.0 devices that allow greater insights into customer service conditions enabling more effective remote troubleshooting resulting in fewer truck rolls.
9. **VD-9: Reduced third-party costs -** Use of third-party contractors for specific functions such as meter sealing will no longer be needed until the meter sampling program resumes in 10 years, or in limited amounts under special circumstances.
10. **VD-10: Reduced field labour cost -** AMI 2.0 devices have enhanced monitoring capabilities allowing for a more comprehensive ability to remotely troubleshoot a customer's service. Having remote diagnostic capabilities and insights will further reduce associated costs with field visits related to meter support, troubleshooting, investigations and customer complaints. Additionally, there should be fewer field visits to address potential meter issues since the meters will be newer and more reliable than existing AMI 1.0. devices.

Key Assumptions and Inputs for VD

All Value Driver assumptions were based on IR data, or assumptions which have been reviewed with HOL business line representatives.

- VD-1: Based on conversations with HOL, the annual metering-maintenance budget appears to cover the inventory and meter sampling program.
- VD-2: By transitioning management of MV-90 meters to the HES, meter communication costs are eliminated. These communication costs are traditionally phone line, or cellular.
- VD-3: The AMI 2.0 platform will reduce the number of inventoried meters required for meter failures and meter sampling program. Furthermore, standardization of meter service types will reduce the number of different meters required to handle and inventory.
- VD-4: Data is based off of IR and public filings for operating costs and data collection expenses related to phone line and cellular communications.
- VD-5: This assumes the HES is not compatible with the AMI 2.0 system. The HES for AMI 1.0 will be discontinued once AMI 2.0 devices are installed.
- VD-6: Annual operating, licensing and support costs that are associated with the HES will further be eliminated.
- VD-7: FTE required to operate the existing HES will no longer be required as AMI 1.0 is phased out
- VD-8: By installing new AMI 2.0 devices, meter failures are reduced and the meter sampling program clock is reset to 10 years.
- VD-9: Data is based on IR and conversations with HOL. Reduced sealing costs by third-parties will be eliminated for AMI 1.0.
- VD-10: Assumes a ramp down and ramp up rate based on AMI 2.0 installation progress and leverages data from IRs.

AMI Infrastructure Pre-requisites AMI meters have received Measurement Canada's Notice of Approval (NOA)	**Applications, Integrations and Data** AMI 1.0 HES, MDM, Troubleshooting tools, Communication Servicer (phone line, cellular)
Use Case Dependencies None, part of standard AMI infrastructure	**Business Impact, Time-to-Value** The value realization follows the AMI deployment schedule and removal of AMI 1.0 devices

Customer Service Impact

Description

- To-date, customers have traditionally had limited understanding and insights in how their power bill breaks down into individual end uses such as heating, laundry, cooking, high bills, etc. While having interval data available to them, energy usage visibility was limited to 60-minute intervals. AMI 2.0 devices can support far greater granularity with a new standard emerging consisting of 15-minute intervals. The objective of this use case is to enhance the customer experience while reducing the overall cost-to-serve. In this instance, we will be limiting the benefits to reduced labour costs as a result of lower average handling times in the customer contact centre.
- Customer energy insight platforms, ingest hourly and 15-minute interval energy data. This data can be used to illustrate how customers are using energy by leveraging machine learning and AI algorithms. Optionally, apps installed in AMI 2.0 meters also allow energy usage disaggregation to occur at the meter with potentially greater levels of accuracy. While energy insights are meant to empower customers, based on HOL's experience a previously deployed energy insight platform caused an increase in calls to the contact centre. While there is still value to such systems and HOL has indicated a desire to deploy similar technology in the future, we have excluded such platforms and features from this use case.
- With AMI 2.0, energy usage is recorded in more granular intervals providing even more valuable time-based insights about when energy is used. This information can be quite useful when assisting customer calls inquiring about high bills, usage patterns, energy spikes outside of occupied hours, etc. This granular data in addition to power quality notifications can reduce customer call time and enable HOL to operate in a proactive fashion to resolve issues before the customer is even aware there is an issue.

Customer Experience Impact

While the objective of this use case is to provide systems that can provide value to customers, a secondary objective is to reduce the cost-to-serve. While disaggregation systems have potential to reduce overall cost-to-serve, it is apparent that customer education must be included to ideally reduce contact center calls to support these systems. Regardless, the granular AMI 2.0 data and instrumentation data will help HOL be proactive with customers and resolve customer inquiries more quickly.

Gross Benefit (2023): $917K

Value Drivers (VD)

1. **VD-1: FTE efficiencies (reduction in cost-to-serve/AHT) –** Based on HOL's experience with disaggregation systems, the primary value driver is limited to 5% to overall average handling time focused on calls related to high bills, and energy savings utilizing 15-minute intervals. A 5% reduction in calls is also based on availability of more granular data.

Key Assumptions and Inputs for VD

- VD-1: Presently assumes an overall reduction in effort based on number of billable minutes.

AMI Infrastructure Pre-requisites Standard AMI Infrastructure, 15-minute (or 1, 5, 10 minute) Interval Data	**Applications, Integrations and Data** MDM, CRM, CIS
Use Case Dependencies This use case builds on the use cases: Energy Use Information and Time-varying rates.	**Business Impact, Time-to-Value** One complete day of recorded usage and ongoing.

Remote Disconnect / Reconnect

Description

- To-date, HOL has a hybrid approach to connect, disconnect and reconnect a customer's service. The disconnect/reconnect operation is typically performed via a series of two truck rolls, or remotely with upgraded AMI 1.0 equipment equipped with a remote disconnect switch (RDS). There are associated costs with these truck rolls in addition to potentially exposing field crews to personal danger in situations related to disconnect for non-pay (DNP). Furthermore, there are typically delays between when a DNP order is created and when the actual disconnect occurs.
- With RDS equipped AMI meters, HOL can remotely disconnect and reconnect all meters in a timely manner without involving a field crew. AMI 2.0 will provide a lower latency network than AMI 1.0 mesh systems which can be important to improve the customer experience. These devices may also provide additional real-time diagnostic and even load limiting features which can facilitate additional benefits and reduce the cost of load limiters if disconnections are periodically suspended during peak cooling, or heating periods.

Customer Experience Impact

The RDS will improve the overall customer experience by enabling pre-paid programs, reduce delays in customer requested disconnection/reconnection service for maintenance work in addition to improved reconnection time when DNP orders result in an actual disconnection. The RDS may also be used for safety purposes in power outages by defaulting to a disconnect state. By defaulting the RDS to a disconnect state, homes that are operating generators during a power outage could create hazardous conditions that could result in injuries to field crew members.

Gross Benefit (2023): $7.3M

Value Drivers (VD)

2. **VD-1: Reduced travel operating cost -** With RDS enabled AMI devices, disconnection/reconnections may be executed remotely. This reduces/eliminates field visits to customer sites that would have traditionally been made to disconnect/reconnect a service. The presence of the RDS reduces previously required travel and labour.
3. **VD-2: FTE efficiencies -** The RDS will allow disconnects and reconnects to be performed remote which eliminates previously required field visits. Cost savings are focused on reduced FTE hours.
4. **VD-3: Cost savings due to reduced write offs -** The RDS will allow quicker remote disconnects and reconnects. While this in turn does not eliminate write-offs, the time to disconnect will represent a savings and overall reduction in amounts written off.

Key Assumptions and Inputs for VD

- VD-1: Utilize IR information for labour, truck type, average cost, average transit time and wrench time.
- VD-2: Overall estimated reduction of 90% for reduction in standard labour hours and 90% reduction in overtime hours.
- VD-3: Assumed a 15% reduction in delay between DNP order issued and actual disconnection

AMI Infrastructure Pre-requisites Standard AMI Infrastructure with RDS equipped meters. Medium-to-low latency networks are preferred, however are not necessarily required.	**Applications, Integrations and Data** MDM, HES, Customer Care and Billing (optional);
Use Case Dependencies Enables Pre-payment	**Business Impact, Time-to-value** Immediate benefits with reduction in overall cost-to-serve, remote disconnect/reconnect in addition to potential benefits with a pre-payment program.

Pre-Payment

Description <u>To-date</u>, HOL experiences annual write-offs due to non-payment of customer bills and performs manual and automated service disconnect/reconnects. Customers that are late making bill payments will further trigger late payment processes that require FTE and system intervention in the form of reviews, emails, physical mail, phone calls, etc. Furthermore, use of security deposits has been a risk management method to guard against non-payment customers and act as a mechanism to recover unpaid customer balances that could be written off. <u>With Pre-Pay</u>, the concept of late payments will no longer exist. Since customers pay for electricity prior to consuming (similar to purchasing groceries), security deposits will no longer be required which further removes financial burdens from the customer. With remote disconnect functionality and a pre-pay management system, HOL will be able to offer a program to customers that can help them manage their energy use more efficiently, provide payment flexibility, eliminate/reduce security deposit requirements, avoid credit risk penalties, reduce write-offs and improve operational costs.
Customer Experience Impact Improves participation options to customers by offering an alternative to existing programs. Customers may not be required to make security deposits and they may purchase pre-pay power at increments of their choosing which are aligned with their budgets. Late payments, penalties, adverse credit rating impact will be eliminated and call volumes for pre-pay customers would be expected to decrease. The pre-pay management system would be responsible to notify customers when their balances are getting low, set up recurring or one-time energy purchases and show what their energy usage levels are. A pre-pay program should be viewed as an opt-in program for all customers and not necessarily limited to those who are simply late with payments.
Gross Benefit (2023): $18.4M
Value Drivers (VD) **Quantified benefits:** 1. **VD-1: Reduced travel operating costs –** With RDS enabled AMI devices, disconnection/reconnections may be executed remotely. This reduces/eliminates field visits to customer sites that would have traditionally been made to disconnect/reconnect a service. The presence of the RDS reduces previously required travel and labour. In a pre-pay program with an RDS capable meter, when customer balances are depleted, or hit a certain threshold the meter may be turned off automatically by the pre-pay management system and reconnected automatically once the customer purchases more energy. 2. **VD-2: FTE efficiencies:** The pre-paid management system monitors and manages disconnections and reconnections based on a customer's balance. This will result in FTE efficiencies where the prepaid management system plays an active role in notification, processing and taking action compared with manual processes. 3. **VD-3: Cost savings due to reduced write-offs:** By shifting to a prepaid paradigm, energy is purchased before it is consumed. Bad debts are unable to occur based on the inherent nature of the program. 4. **VD-4: Reduced cost of collections processing:** Under a pre-pay program, collection efforts are not required. HOL utilizes third-party collection services in addition to its own which will be reduced. 5. **VD-5: Reduction in contact centre FTE efforts due to reduced call volume and AHT –** Where pre-pay customers are predominantly self-managed, these customers will typically not need to contact the utility to make payments, setup payment plans, request reconnections, etc.
Key Assumptions and Inputs Requires AMI devices equipped with an RDS and a pre-pay management system.

AMI Infrastructure Pre-requisites RDS-Equipped AMI devices and a medium-low latency network.	**Applications, Integrations and Data** MDM, HES, Pre-pay system, Payment Processing System
Use Case Dependencies This use case relies on the remote disconnect/reconnect use case	**Business Impact, Time-to-Value** Immediate benefits with reduction in overall cost-to-serve, remote disconnect/reconnect, elimination of late payments, improve overall cashflow and reduced write-offs.
OCM Considerations [n/a] Creation and training of a broader pre-paid customer program, process changes and integrations.	**Project Resources** Program Manager and Customer Service Representatives. Marketing for program roll-out and education

Outage Identification

Description

- To-date, Hydro Ottawa relies on its OMS to locate outages and faults, but largely depends on customers to report an outage incident. Once a customer reports an outage, HOL typically takes up to twelve (12) minutes to qualify the outage. The AMI 1.0 system does not have power outage notification capability and HOL does not have visibility downstream from monitored equipment. AMI 2.0 has last gasp capability and all devices in a point-to-point system are able to report outages and restoration info automatically, or on demand. By leveraging real time outage notifications from AMI 2.0 devices, outage response time should improve in addition to identifying nested outages.
- Granular outage identification and real time notifications in addition to other types of power quality information will result in improved triaging in addition to many operational savings resulting in improvements to SAIDI. Further integration of AMI 2.0 data into an ADMS and ingestion of outage, momentary interruptions, voltage sags/swells and other forms of power quality data can help with FLISR and vegetation management operations further improving SAIDI.
- With power outage and restoration reporting from all meters, HOL will know exactly which customers are experiencing outages and those that are not. This will help HOL to accurately identify the full extent of an outage and reduce the time for fault identification / location / isolation. This information will further assist in the recall of field crews when addressing nested outages, intermittent power and inaccurate reports.
- In addition, this use case automatically generates accurate outage reports, including SIR (System Interruption Report), and eliminates dispatch of truck rolls for partial power as operations can remotely confirm power quality and status.

Customer Experience Impact

Outages and restoration activities are reported automatically by the AMI devices enabling faster identification, mobilizing the field response and reducing the time for isolation duration.

Gross Benefit (2023): $5.8M

Value Drivers (VD):

1. **VD-1: Travel operating cost benefits –** Outage identification and power quality data from AMI 2.0 devices can potentially reduce the number of truck rolls associated with unplanned outages and travel duration. Power quality information can provide indicators there are potential vegetation risks at a specific service address. This can help HOL prioritize tree trimming operations to reduce potential outages. Where all AMI devices are capable of providing real time outage information, field crews know exactly where outages have occurred reducing travel time when investigating outage causes. There are additional notification capabilities for commercial polyphase customers where customers may not be aware a phase is out which can cause equipment to malfunction or shut down like commercial refrigeration units. Service information received preceding an inevitable outage event can be used in a proactive way to prevent the outage.
2. **VD-2: FTE efficiencies** – By having granular and real time outage information from AMI 2.0 devices, time spent searching for the location and cause of different types of outages may be reduced. This benefit applies to both standard and overtime hours.
3. **VD-3: Savings due to avoided momentary interruptions and flickers –** There is a potential benefit by having visibility into momentary interruptions and flickers. This data has not been tracked by HOL and will not be included as a benefit. Having visibility into these events can help prevent unnecessary truck rolls or enable remote enhanced monitoring at a specific service to see if another issue might be the cause.
4. **VD-4: Back-office FTE cost savings for outage reporting SIR and SAIDI reporting –** Having real time outage information in addition to GIS data from outage notifications will help optimize the back-office efforts required to compile SIR, SAIDI and other forms of reporting.
5. **VD-5: Improved accuracy Interruption duration Index -** Real time outage notifications can improve the qualification and field crew response times. This ultimately results in an improved SAIDI and revenues.

Key Assumptions and Inputs for VD

- VD-1: The bulk of power outages will be identified upstream through distribution components that are monitored through SCADA, or ADMS (future). AMI can provide outage notifications at every service point enhancing the visibility and insights when outages occur thus reducing travel costs. - VD-2: Value is driven by reduced time to identify outage locations, scope and help triage the cause of the outage. - VD-3: While this is a quantifiable benefit, HOL does not track this info and it will be excluded.	
AMI Infrastructure Pre-requisites Standard AMI Infrastructure, Power Outage Reporting, Power Restoration, or Power Status Check	**Applications, Integrations and Data** OMS Outage Management System, or ADMS, ESB Enterprise Service Bus, CCB Customer Care Billing (optional)
Use Case Dependencies Deploy in tandem with Proactive Outage notification. This use case is the foundation for Service Restoration.	**Business Impact, Time-to-Value** Immediate benefits assuming integrations to OMS and other applications is complete.

Service Restoration

Description ▪ To-date, HOL's mesh AMI system does not have power restoration notification capability. While power status checks, or pinging meters may be performed, this information is typically not timely. Therefore, once power has been restored in an area, field crews must travel and verify customers downstream of an outage have their power restored. This is a manual process involving travel and FTE. ▪ With AMI 2.0, meters have power outage and restoration notification capability that is near real time. Timely access to this information can help field crews verify all service points down stream of an outage point have had their power restored without manual verification. This capability will eliminate or reduce manual verification time in addition to any instances where a field crew has left the area, only to return because of a customer(s) that may still be experiencing an outage.
Customer Experience Impact Outage duration will be reduced in addition to receiving details when the outage is resolved for those customers that have opted into these types of notifications.
Gross Benefit (2023): $855,902K
Value Drivers (VD) 1. **VD-1: Travel operating cost benefits –** Power restoration notifications will allow field crews to verify all homes that have power and reducing or eliminating manual site visits to verify customers restoration status. This value driver consists of reducing the travel costs of field crews looking for nested outages. 2. **VD-2: FTE efficiencies** – Similar to the reduction in travel operating costs, outage and restoration notifications from AMI 2.0 devices will reduce the overall efforts required to verify a customer service has been restored.
Key Assumptions and Inputs ▪ VD-1: Assumes a 5% improvement in restoration efforts related to vegetation related outages and 10% reduction in travel costs related to storm related outages. ▪ VD-2: Assumes significant number of FTE standard hours reduced for both vegetation and storm related outages with mixed FTE hour reduction for overtime hours.

AMI Infrastructure Pre-requisites Near-real time power outage and restoration messaging. processing of meter's last gasp and power status checks (PSC).	**Applications, Integrations and Data** OMS, or ADMS, HES, WFMS
Use Case Dependencies This use case builds on the Outage Identification use case.	**Business Impact, Time-to-Value** Immediate benefits once use case is implemented.

Proactive Outage Notification

Description

- To-date, HOL presently sends proactive outage notifications to customers who signed up for this service. The notification algorithm is informed by customer reported outages, or outages based on grid-level equipment status. HOL has indicated that it may take up to 12-minutes to qualify an outage once the first outage report has been received. Outages that are visible at the grid-level will typically result in customers downstream of that asset being proactively notified. There may be instances where customers that are experiencing an outage may not be proactively notified because the outage is not visible at the system level.
- With AMI 2.0 meters, HOL will be able to rely on meter outage notifications. This allows HOL to operate proactively before customers are aware of, or have time to report an outage. This will help reduce call volumes to live agents and the IVR through proactive notifications. Savings are achieved by being proactive and utilizing digital/low-cost communication channels such as text messages versus calls to live agents.

Customer Experience Impact

Outage is a key brand and customer satisfaction driver. Customers who receive timely and accurate outage information typically score their utility higher, because it allows customers to make informed decisions and minimizes the impact the outage has on them.

Gross Benefit (2023): $271K

Value Drivers (VD)

This value driver involves leveraging real time power outage and restoration information from AMI 2.0 devices to send proactive notifications to customers. Value is realized by leveraging low-cost communication channels in a proactive way to reduce inbound customer communications.

1. **VD-1: Reduction in outage related effort by live agents** – By sending timely and informative outage and restoration notifications to impacted customers, there is a reduced need for customers to make outage reports, or inquiries. This results in a reduction the overall customer cost-to-serve.

Key Assumptions and Inputs

HOL presently provides proactive notifications, so the benefits included here are quite conservative.

- VD-1: This value driver makes assumptions tied to notifications only being available to 50% of those customers that are signed up in the customer portal and an overall AHT reduction of 15%.

AMI Infrastructure Pre-requisites Near-real time processing of meter's last gasp and power restorations, or power status checks (PSC).	**Applications, Integrations and Data** OMS Outage Management System, Consumer Engagement Portal with preference mgmt. for automated notifications;
Use Case Dependencies Deploy in tandem with outage identification. Also, service restoration use case drives a reduction in outage duration which will also slightly contribute to a further reduction in call center effort.	**Business Impact, Time-to-Value** Immediate benefits once use case is implemented and outages are experienced.

Predictive Maintenance

Description	
▪ To-date, various systems are used to plan maintenance activities around vegetation management and potential unplanned outages. AMI 2.0 devices have the capability to provide instrumentation data in near real-time that can be used to identify various types of anomalies. Some of these anomalies may be attributed to vegetation contact with lines in addition to other forms of potentially hazardous service issues. ▪ With AMI 2.0, the capability to provide instrumentation data and service conditions will assist HOL in identifying potential issues before they actually become customer problems. In this instance, we are focusing on reducing outage-related field visits related to vegetation management and distribution transformer issues. By proactively addressing issues, HOL will not need to respond in a crisis-mode. ▪ High-resolution interval data, provides the energy, demand, voltage and current profiles of the service points connected to upstream equipment. This data can be further used to create a model that will identify 'signatures' of a failing equipment, leading to proactive, planned maintenance. This application monitors loading / events of distribution assets to predict maintenance work, pre-empt failure of overloaded assets, and shifts maintenance to proactive planned events. In addition, it identifies underloaded assets which are performing inefficiently and faulty assets which impact other assets.	
Customer Experience Impact With a Predictive Maintenance program, customers can be notified prior to planned maintenance and service interruptions will be minimized.	
Gross Benefit: (2023): $502K	
Value Drivers (VD) 1. **VD-1: Reduced travel operating cost –** This is a reduction in travel time and cost related to both vegetation related and unplanned equipment failure outages. 2. **VD-2: Reduced FTE costs due to reduced field crew efforts –** Similar to reduced travel costs, this is overall reduction of FTE efforts directly related to field visits.	
Key Assumptions and Inputs ▪ VD-1: Inputs were received from IRs and assume a percentage of vegetation work orders may be reduced from enhanced visibility into the distribution system. Inputs were also received for workorders addressing unplanned equipment failures and we assume 80% are attributed to distribution transformers resulting in an overall work order reduction of 20% ▪ VD-2: All data received from IRs and dependent on VD-1 reductions.	
AMI Infrastructure Pre-requisites Standard AMI Infrastructure with instrumentation recording capability	**Applications, Integrations and Data** HES, MDM, GIS
Use Case Dependencies This use case can be implemented in tandem with Virtual Meter functionality of Asset Load Monitoring	**Business Impact, Time-to-Value** Ability to see real-time asset loading immediately, or utilizing past data for predictive maintenance models that may require several months of interval data.

Conservation Voltage Reduction (CVR)

Description

- To-date, HOL has previously completed a Conversation Voltage Reduction proof-of-concept project within its service territory. The project was limited to a single substation over a relatively short period of time. The purpose of this use case is to reduce voltage (costs) at the substation while maintaining power quality and reliability to the end customer downstream. AMI 2.0 meters are used as sensors throughout a feeder and send frequent instrumentation data to the CVR control system. If voltages downstream reach a certain threshold, it will result in customer impact issues, so voltages need to be increased at the substation to compensate for the line loss and prevent any impact to the customer.
- Leveraging existing infrastructure, by using AMI 2.0 devices results in a significant cost avoidance for line sensors and installation costs. Typical line sensors have a lifespan of approximately 10 years, requiring the asset to be refreshed at the end of that period.
- CVR benefits, will drive annual energy savings for both HOL and its end customers in addition to reducing demand at the substation. Typical savings are 1 – 3% of substation capacity and can act as a form of continued demand reduction when CVR is enabled.

Customer Experience Impact

Overall reduced energy usage and savings to the customer. Leveraging AMI 2.0 devices to maintain quality of service will ideally result in no customer impact in the form of interruptions.

Gross Benefit (2023): $24.5M

Value Drivers (VD)

1. **VD-1: Value of avoided line sensor cost –** AMI 2.0 devices that are capable of measuring voltage and other instrumentation quantities may be used as line sensors to monitor service voltages downstream from the substation. This benefit pertains to the hardware and communication costs of a typical line sensor.
2. **VD-2: Value of avoided line sensor installation costs –** Traditional line sensors require installation and use of a bucket truck. This benefit eliminates the need for installation, travel, wrench time and a service vehicle.
3. **VD-3: Value of energy savings across service territory** – As a result of reduced voltage at the substation, less energy is transmitted to customers. Customers are not impacted by this voltage drop but enjoy the benefit of reduced energy usage (lower bills). This is a reciprocal benefit to HOL whereby they reduce the total amount of energy required to maintain the customers quality of service.
4. **VD-4: Value of demand savings throughout service territory** – The reduction in energy usage results in an average demand reduction at the substation between 1-3%. This value represents a benefit as an avoided capacity cost at each substation but has not been included in this evaluation at this time.

Key Assumptions and Inputs for VD

We are leveraging information from the CVR pilot that is documented in the "Impact Evaluation of Hydro Ottawa's Conservation Voltage Reduction Pilot", dated December 13, 2018.

- VD-1: Line sensor cost was based on another Canadian client in a PUC rate filing of $855/sensor.
- VD-2: Line sensor installation costs were based on another Canadian client in a PUC filing of an all-in cost of $1,200 per sensor.
- VD-3: Value of energy savings came from the CVR pilot report (1.27 GWh) and reduced to 85%. This was multiplied by the average 2022 RPP Supply Cost to calculate a reduced savings. This benefit was further applied to an estimated 8-substations that have a similar capacity as the substation used in the CVR pilot.

AMI Infrastructure Pre-requisites	**Applications, Integrations and Data**
Standard AMI Infrastructure, Instrumentation Profiling Capability, Low Latency Network	CVR Management System, SCADA, HES.

Use Case Dependencies	Business Impact, Time-to-Value
This use case is dependent on AMI 2.0 meters being deployed, CVR pre-requisites including software and hardware is in place.	Value is realized over time when CVR is enabled during peak periods and continues over time.

Fleet Operations Assessment – Final Report

HYDRO OTTAWA, ONTARIO, CANADA

June 28, 2022

mcg
consulting solutions

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1 Executive Summary

Hydro Ottawa is at a challenging time when it comes to their fleet program. Replacement underfunding has created a backlog, their Fleet Management Information System is no longer supported by the vendor and must be replaced, and federal, provincial and local regulations are mandating stricter environmental controls. MCG Consulting Solutions was asked to compare Hydro Ottawa's fleet with industry best practices and provide a summary of current research into sustainable options for the fleet. To accomplish this, MCG worked closely with the company to create an accurate fleet profile, a best practice checklist, a Sustainable Fleet Research Report and this final report.

In general, Hydro Ottawa's fleet management team is deeply knowledgeable and professional in their approach. They have a robust policy framework and effective maintenance processes in place. They fully understand the challenges they are facing and need support and suggestions to address them.

The main functional areas of review and the findings in each area appear below.

- **Governance:** Governance looks at the organization and policy framework of a fleet organization; both of which are solid. Governance could improve through the re-enactment of a Fleet Advisory Committee whereby user representatives would meet regularly to discuss fleet replacement and sustainability. Another improvement would be to conduct annual Customer Satisfaction Surveys to be more proactive about identifying and addressing customer issues.
- **Utilization**: Utilization management is vital to ensure a fleet is the right-size, right-type and using the right fuels. Technology is the key in understanding not only kilometers driven but also asset criticality and the number of trips per asset. This functional area could be improved by using technology and implementing a formal policy for annual utilization reviews. The company could also benefit from comparing the costs of ride sharing and reimbursement to having an administrative pool of vehicles. Where pooling is a desirable strategy (i.e., for medium and heavy-duty vehicles), the pool should be centrally managed although geographically dispersed. Finally, fleet users need to be required to identify lightly used assets and vehicles suited for transfer or elimination.

- **Replacement Planning:** Fleet replacement should be scheduled to minimize the Total Cost of Ownership (TCO) of fleet assets. This means determining optimum lifecycles where the combined capital operating costs of fleet assets are minimized. Vehicle purchase costs should be minimized by the use of cooperative purchasing where possible, proceeds on resale should be returned to the capital replacement fund, and organizations should have a detailed replacement plan with levelled funding requirements.

- **Maintenance:** Effective maintenance programs depend on adequate staffing, a mix of in-house and outsourcing strategies and a proactive plan. There are several areas of improvement in the maintenance function. The staffing analysis showed a shortfall of one technician and job descriptions need updating. A new FMIS would facilitate preventative maintenance planning and compliance and assist in the management of warranties for vehicles and parts.

- **Technology:** Fleet Management is an extremely data-driven function and best-in-class fleet need automated tools to ensure efficient operations. The most important recommendation from this report is that the company needs a new Fleet Management Information System (FMIS) with connectivity to their fuel and telematics systems and the ability to report on Key Performance Indicators. The FMIS would facilitate implementation of most of the other recommendations in this report.

- **Sustainability:** Although this was not an electric vehicle conversion study, research findings on the opportunities and challenges of electrification were provided. Hydro Ottawa intends to meet local and federal Greenhouse Gas emissions targets but does not yet have a plan for the fleet to ensure targets are met. This plan needs to be developed by the Net Zero Committee with vehicle and charging structure availability in mind. Conversion to an electric fleet must be accompanied with other strategies to reduce vehicle miles travelled, eliminate idling and adopt a mobility mindset to replace the use of conventionally fueled vehicles wherever possible.

The analysis for each of these areas is provided in detail in the following chapters.

2 Introduction

Hydro Ottawa Holding Inc. is wholly owned by the City of Ottawa. It is a private company overseen by an Independent Board which consists of a President and Chief Executive Officer and ten members appointed by City Council.

Hydro Ottawa is supported by a fleet of approximately 274 vehicles and equipment. The current fleet management system is FleetWave by Chevin, but the Corporation is considering a move to a new system. 80% of repairs are done inhouse in a central facility with eight bays and five mechanics. Fleet is funded through an Internal Service Fund and charges customers for the provision of fleet and maintenance management services.

Hydro Ottawa engaged MCG Consulting Solutions to conduct a fleet review and sustainability research. Three questions that the organization is interested in resolving are:

- What are the latest industry trends in in fleet utilization, replacement and maintenance, and how does Hydro Ottawa compare?

- Are current information management and technologies effective in supporting fleet operations?

- What factors will impact the ability of the organization to meet the goal of net-zero in 2030?

1. Fleet Profile

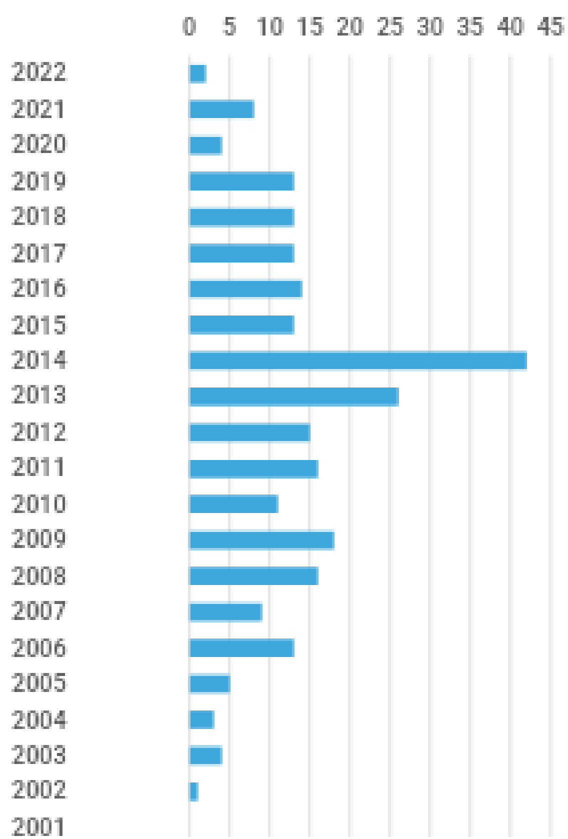
Hydro Ottawa has a fleet of 274 vehicles. The distribution of assets by vehicle type is as shown:

Classification	Count
Light Trucks	**81**
1/2 Ton Pickup	56
3/4 Ton Pickup	20
1 Ton Pickup	5
Heavy Trucks	**64**
Heavy Truck	5

Classification	Count
Heavy Aerial	59
Vans	**77**
Van	21
1/2 Ton Van	8
3/4 Ton Van	24
1 Ton Van	3
Step Van	21
Equipment	**24**
Equipment MD	10
Equipment HD	4
Forklift	7
Forklift HD	3
Support Vehicles	**5**
Sedan	3
SUV	2
Trailers	**23**
Total	**274**

The next tables show the active vehicles and equipment by age and model year. The listing to the left simply shows the number of existing assets from each model year. The highs and lows in annual procurement numbers will also be discussed in future deliverables.

Year	Count
2022	2
2021	8
2020	4
2019	13
2018	13
2017	13
2016	14
2015	13
2014	42
2013	26
2012	15
2011	16
2010	11
2009	18
2008	16
2007	9



2006	13
2005	5
2004	3
2003	4
2002	1
2001	0
2000 and Older	15

Hydro Ottawa values sustainability and is invested in meeting 2030 zero-emissions goals. The current state of alternative fuel vehicles (AFVs) if the fleet is shown:

Fuel Commodity	Count
Diesel	94
Electric	6
Gas	148
Propane	3
None (trailers)	23
Total	**274**

As an overall assessment, the fleet and maintenance services provided to Hydro Ottawa by Fleet Services exhibit a number of best practices. The organization has a strong foundation with qualified staff, thorough policies and a replacement program based on optimum lifecycles. Our audit findings are aimed at bringing other areas of fleet and maintenance management to this standard.

In compliance with the Request for Proposal, data analysis and staff interviews were conducted to make recommendations in the following areas:

- Governance
- Utilization
- Replacement planning
- Maintenance staffing
- Fleet Information Technology
- Sustainability

Each of the topics is addressed in the summary best practices table and further details follow in subsequent chapters on each subject.

3 Governance

Fleet governance includes the organization, reporting structures and policy framework. Fleet operations are normally more efficient when they are centralized as management functions do not have to be replicated for separate organizations. A common Fleet Management Information System (FMIS) can ensure that there is a single repository for all fleet data. Best practice fleets communicate regularly with their customers and have a robust policy framework to facilitate decision making.

The best practices in the governance area appear in the table below. The best practice in each area is stated, in column one and assessed in the middle column. The right column describes the practice at the Company. A ✓ indicates that the Company complies with best practice and a ~ indicates partial compliance with room for improvement. An X in the column means that the practice is not met. Criteria with ~ and X will be discussed further in the final report.

Criteria		Rating	Comment
1	The fleet program is centralized to capture economies of scale.	✓	Fleet and maintenance management are centralized. The Fleet Services organization reports to the Manager of Fleet and Facilities.
2	There is a Fleet Advisory Committee with representatives from all customers who meet regularly to discuss fleet issues including vehicle replacement and safety.	~	There are Terms of Reference for a Fleet Advisory Committee but meetings were discontinued prior to COVID.
3	A Fleet Policy Manual is in place that defines program objectives, responsibilities, and service standards.	✓	POL-Fi-012.00 Fleet details the overarching policies available. There are formal policies for utilization, acquisition, fuel and disposal.
4	A Driver's Handbook outlines driver responsibilities and drivers sign to confirm compliance.	✓	The Company has an online toolkit for drivers, covering all topics that would be found in a Driver's Handbook.
5	Service level agreements (SLAs) are in place to ensure that the fleet organization and its customers are working in a collaborative manner.	✓	There are SLAs in place that cover a range of suitable topics including responsibilities of all parties.

Criteria		Rating	Comment
6	Annual surveys are conducted to assess customer satisfaction.	x	Annual customer service surveys are not completed.

1. Fleet Advisory Committee (FAC) (BP 2)

An FAC is a valuable tool to ensure that fleet customers are heard, and the fleet organization's priorities and plans are communicated. Specific functions include:

- **Replacement planning**. Review the annual replacement plan and discuss any changes.
- **Sustainable conversion**. Discuss opportunities for electric vehicle conversion.
- **Safety**. Review accident statistics and primary causes.
- **Maintenance concerns**. Discuss issues of concern to all customers.

Most importantly, the use of a FAC ensures that fleet customers designate a representative who can talk knowledgeably about fleet on behalf of their operational area. That representative should be familiar with the inventory, vehicle utilization, condition, safety concerns, budget and sustainable goals.

Hydro Ottawa had used a FAC in the past for many of these functions. It had been discontinued prior to COVID and has not been reinstated. As Hydro Ottawa is facing some significant challenges associated with delayed replacement and greenhouse gas emissions targets, reinstating this FAC will be an effective way to discuss solutions with all stakeholders.

2. Customer Surveys (BP 6)

An annual customer survey is an efficient way to gather information that can improve fleet service levels. A simple five-point scale can be used to gauge satisfaction with key fleet functions. The results can be used to measure progress over time. An example of the results of a customer survey appears below:

Criteria/Customer	A	B	C	D	E	F	G	H	I	J	K	L	
Cust Service	4	4	3	4	4	4	4	3	4	4	5	4	4.00
Facility	5	3	4	4	4	4	4	2	4	4	3	3.5	3.75
Quality	3.5	3	3.5	2	4	4	4	4	4	4	5	3	3.66

Communication	4	2	2.5	2.5	4	4	4	3	4	3.5	5	4	3.61
PM	4	3	5	3	2.5	3	4	4	2.5	3.5	5	2	3.57
Parts	4.5	3	2.5	3	4.5	3	4	3	4.5	3	4	3	3.50
Fuel	4	5	2	4	1	5	4	1	1	4	5	4	3.54
Availability	5	3	1	2	4.5	4	4	3	4.5	3	3.5	2	3.34
Acquisition	4.5	4	3	3	N/A	5	4	3	N/A	4	3	N/A	3.70
Time to repair	5	3	1.5	1	4	4	3	1	4	4	4	2	3.09
Technicians	5	3	1	2	2	3	3	3	2	4	4	3	2.93
Overall Average	4.4	3.3	2.6	2.8	3.5	3.9	3.8	2.7	3.5	3.7	4.2	3.1	**3.5**

The reinstatement of a Fleet Counsel is an opportune time to commence customer satisfaction surveys.

Recommendations:

1. **Revitalize the Fleet Advisory Committee and hold bi-annual meetings.**

2. **Conduct annual customer satisfaction surveys to measure fleet's performance over time.**

4 Utilization

Utilization reviews call for organizations to have a mobility mindset. When a transportation requirement is identified, the default should not be to immediately purchase an additional resource without consideration of alternatives. Management and users should first ask whether that requirement can be met more efficiently by other means such as renting, public transportation, employee reimbursement, loaner pools or leasing (if permitted by the Rate Board). Vehicle ownership should be the last resort. Where ownership is the best option, care should be taken in matching the asset to the requirement in a way that promotes efficiency and sustainability.

Across the industry, vehicle utilization over the past two years has been impacted by responses to address COVID. In some cases, vehicles were parked because staff was working from home, or had left the position and not been replaced. In other cases, utilization increased as employees could not travel together due to social distancing requirements so each person had to take a vehicle. As operations return to normal, companies should do a formal utilization review to gauge the sufficiency of their fleet to meet operational requirements.

The best practices regarding fleet utilization appear in the table below.

Criteria		Rating	Comment
1	Asset utilization policies and guidelines are clearly defined to ensure that vehicles and equipment are allocated properly based on job requirements.	✓	The fleet Utilization Policy, POL-Fi-012, covers basic guidelines and responsibilities for fleet utilization.
2	Processes are in place to capture utilization data from available sources and to validate and analyze the data. Annual utilization reviews are conducted and vehicles are replaced, eliminated, pooled or rotated as needed.	~	Geotab is available to capture utilization data. There is no policy outlining the conduct of annual utilization reviews.
3	Motor Pool vehicles are available for occasional needs. Motor Pools are located and managed to provide efficient service.	~	The Company maintains spares for operational units. There are also two pooled vehicles for administrative use but additional opportunities to share assets exist.

Criteria		Rating	Comment
4	Vehicles that are replaced are disposed of immediately.	✓	Rideau Auction (virtual) is used to remarket assets in a timely fashion.
5	Fleet users are proactive in identifying vehicles with low utilization.	x	Management has access to the dashboards and they can review certain metrics with staff. Utilization is not formally reviewed.

1. Annual Utilization Reviews (BP 2)

Vehicle utilization should be reviewed on an annual basis. Vehicles with utilization well below the average for their vehicle class should be pooled or eliminated as appropriate to ensure that the size and composition of the fleet are optimized. The practice of conducting an annual review will also create an annual opportunity to consider technology improvements and vehicle availability to further the Company's conversion to an electric fleet.

The approach used to assess fleet utilization should include the following steps:

- Review vehicle utilization data in Geotab.
- Identify averages of usage by vehicle classification.
- Establish utilization thresholds (for example, 70% of the average usage for that class).
- Interview users of low-usage assets, understanding that asset criticality (emergency response) may justify retention.

Interviews with fleet users are key as the odometer reading may not fully reflect utilization. A work truck, for example, may drive only a short distance to a job site but remain there all day. It is fully utilized even though it only travelled a short distance. Asset criticality must also be considered in studying emergency fleet utilization. A specialized response truck may be used only once a month, however, if it is the only asset of its type and is critical to operations, it cannot be eliminated.

After analysis and interviews with vehicle users, one of the following recommendations for each asset should be made:

Retain	Keep current unit in service and replace according to a multi-year replacement plan based on optimum lifecycles.

Replace	Asset is overdue for replacement and should be replaced immediately.
Right-Type	The current asset is not the best or most economical for the job. It should be replaced with a different asset at the end of the current lifecycle.
Right-Fuel	Asset is a good candidate for conversion to an alternative fuel.
Eliminate	Utilization does not justify retention of the asset. The asset should be sent to auction and not replaced.
Re-Examine Post-Covid	Review once normal operations resume.
Other	Other recommendations may include borrow, pool, rent or additional analysis.

The process for the annual utilization review should be included in the Fleet Asset Utilization Policy.

2. Motor Pool (BP 3)

There can be three types of pools of vehicles and equipment.

- Administrative pool
- Equipment pool (spares)
- Garage loaners

An administrative pool consists of light-duty vehicles available to meet occasional transportation needs. They should be centralized in a location that is convenient to the majority of users and a reservation system should be available to manage their use. Hydro Ottawa has two electric vehicles available for administrative purposes. Many organizations are comparing the cost of an administrative pool to either ride sharing or reimbursement for use of personal vehicles to evaluate the efficiency of maintaining a pool. The City of Washington, DC found that ride sharing was 50% less expensive than the costs of maintaining pool vehicles. Reimbursement rates have recently risen due to the cost of fuel to 61 cents/km but reimbursement programs are still an affordable option for infrequent business travel.

Equipment pools normally consist of spares for critical assets. They are often 'retired' front line assets that are retained in this role. Hydro Ottawa has tried to maintain a pool of spares at each of the five areas consisting of two bucket trucks, two diggers and two trailers, but has been unable to keep enough equipment. These pools are not centralized as different groups prefer to have control over their own assets and may stock their vehicles differently. Replacement delays have resulted in many of the spares being returned to front line service. Whenever a vehicle is replaced, fleet will evaluate the condition of all vehicles in that class and remove the one in the worst overall condition. As these resources become scarcer, the need for centralized management and sharing between groups becomes increasingly important. A model that is managed centrally but dispersed locally would realize the benefits of centralization while remaining convenient for users.

Garage loaners are an efficient way to ensure employees are not idle when their vehicle is in the shop. Hydro Ottawa had loaners prior to COVID but no longer has vehicles available for this purpose.

Reimbursement is an appropriate strategy for occasional, administrative requirements. Employees, however, should be asked to confirm that their personal insurance policy covers such use of their vehicles.

3. User Involvement (BP 5)

POL-Fi-012 Utilization of Fleet Assets covers the responsibilities of fleet personnel and custodians regarding monitoring and reporting on fleet utilization. Also, fleet shares the Geotab dashboard which has very detailed utilization data with all users. Custodians are not always proactive about addressing lightly used assets. In a recent utilization exercise, the Fleet and Facilities Manager sent out 50 notifications requesting explanations for lightly used assets and received only four replies.

Recommendations:

3. **Add the process for annual utilization reviews to the Utilization of Fleet Assets Policy.**

4. **Compare the costs of ride sharing and reimbursement to having a pool of vehicles for administrative purposes and adopt the most efficient strategy.**

5. **Create a centrally managed pool for equipment with decentralized access.**

6. **Ask custodians to provide justification for lightly used assets that can be seen on the Geotab dashboard.**

5 Replacement

Establishing optimal lifecycles and a corresponding multi-year replacement plan are fundamentals of fleet management. The theory of effective capital asset management is well established in the fleet industry and is based on these principles.

- The failure to replace vehicles on time costs an organization more money, both in hard dollars and in indirect costs, than replacing them according to schedule.
- An old fleet has a negative impact on staff productivity, as unreliable vehicles are frequently in the shop and not available for work.
- If a fleet is old, users seek to keep extra vehicles to act as backups and spares, so they can survive the increased unreliability of front-line vehicles. As a result, there are often more vehicles in service than are needed.
- The older vehicles in a fleet use more fuel and emit more pollution than newer vehicle, because standards for emissions and fuel economy were lower in the past than they are now.
- Older vehicles are not as safe as new ones as they lack many of the advanced safety features that are standard with new cars (such as cameras, sensors, lane departure warning, collision avoidance systems, side curtain air bags, etc.).

Despite these observations, it must be acknowledged that these are unprecedented times and vehicle replacement is very challenging. Vehicles that required a one-year order timeframe are currently requiring 2-3 years. The lack of vehicle availability will result in a backlog of orders and the need to replace vehicles quickly once supply chain issues are resolved.

The following table shows how Hydro Ottawa compares to best practices in the area of fleet replacement.

	Replacement	Rating	Comment
1	Vehicles are procured to meet specific job requirements and customers have input on specs.	✓	The Company has generic specs for vehicles and then works with customers to ensure vehicles meet their requirements.

2	Non-technical requirements such as parts lists, repair manuals, diagnostic tools, and training are included in vehicle specifications.	✓	Parts lists and manuals are requested in the RFP.
3	Cooperative agreements are used in order to take advantage of volume pricing.	x	Cooperative purchasing options are not being used at this time.
4	Vehicle upfitting processes minimize the use of in-house resources and put newly acquired vehicles into service as quickly as possible.	✓	Equipment is acquired nearly ready to use. The shop will install some equipment in-house.
5	Vehicle decommissioning practices ensure that vehicles are disposed of in the most efficient and cost-effective manner possible. Vehicles determined to no longer be needed are physically removed from service to control fleet size.	✓	Policies reinforce that vehicles are turned in once replaced. If those vehicles are in good condition, they are retained as spares and an older asset is disposed of.
6	Funds from vehicle disposal are returned to the equipment replacement fund.	x	Funds from vehicle remarketing do not go back to the equipment replacement fund.
7	Replacement cycles have been determined for all vehicle classes.	~	There are published replacement cycles for all classes of vehicles; however, they have not been adhered to. In many cases, vehicles are retained for much longer than stated replacement cycles due to insufficient capital funding allocations and regulatory approvals.
8	Replacement cycles are based on age, usage, condition, or some combination of these criteria and are reasonable and appropriate.	✓	Replacement cycles are based on usage, age and condition.
9	A multi-year replacement plan exists and is updated regularly.	✓	The Company has a detailed replacement plan that is regularly updated based on changing circumstances. Orders for replacement vehicles have been submitted out to 2024.

10	Funding adequately supports the replacement plan.	x	The adopted budget has been insufficient in the past four years, resulting in delayed replacement and a backlog of vehicles overdue for replacement as a result of delayed orders from the 2016-2020 and 2020-2025 rate applications.
11	Customers are involved in decisions regarding replacement of their vehicles.	✓	Customers are involved in prioritizing assets for replacement.
12	Sustainability is considered in the replacement decision.	✓	Sustainable options are considered when replacing light-duty vehicles.

1. Cooperative Purchasing (BP 3)

Cooperative purchasing practices such as "piggybacking" on contacts already established by another government entity, is a proven way to streamline the vehicle acquisition process, secure the availability of vehicles even as a smaller customer, and obtain advantageous pricing. Hydro Ottawa does not currently use cooperative purchasing, although they have begun examining the possibility of doing so. The Company should continue to pursue this strategy, partnering with City of Ottawa or other cities to join their purchasing arrangements.

2. Remarketing Funds (BP 6)

When vehicles are disposed of (either auctioned or sold for scrap), the proceeds from these sales should be cycled back into this vehicle replacement fund. This will incentivize the owner to quickly dispose of old vehicles, and it will reinforce the linkage between vehicle disposition and the total cost of ownership.

3. Replacement Cycles (BP 7)

Vehicles should be replaced when the Total Cost of Ownership (TCO) is minimized. This is usually just before the maintenance costs associated with an older vehicle start to spike. Hydro Ottawa has published replacement cycles for all vehicle types. The table below shows these policy guidelines in terms of age, kilometers and engine hours.

The guidelines have not been followed due to the unavailability of sufficient budget resources and the shortage of vehicles available for purchase. In fact, the order cycle for bucket trucks has gone from 12 to 36 months. The following table shows the average age of vehicles by unit type as well as how many vehicles of each type are past the policy replacement lifecycle based upon age.

Unit Type	Category	Age	Km	Hours	Ave Age	Past Policy
Automobile	Light Duty	10	150,000	4,000	10.2	3
Vans - Compact	Light Duty	8	150,000	5,000	7.5	11
Vans - Cargo	Light Duty	8	150,000	6,000	7.9	10
Vans - Step/Cube	Medium Duty	12	150,000	8,000	8.8	13
Trucks - Pickup (Compact)	Light Duty	10	100,000	5,000	-	-
Trucks - Pickup (Conventional)	Light Duty	10	150,000	6,000	7.0	11
Trucks - Dump	Medium Duty	12	125,000	6,000	10.0	2
Trucks - Stake	Medium Duty	15	150,000	8,000	2.3	0
Trucks - Knuckle Boom	Heavy Duty	15	200,000	10,000	14.5	1
Trucks - Buckets	Heavy Duty	12	200,000	10,000	10.2	18
Trucks - Line/RBD	Heavy Duty	12	200,000	10,000	9.5	5
Forklifts	Other	15		10,000	17.7	4
Trailers	Other	15			13.7	9
TOTAL						87

As the table shows, there are 87 units in the Hydro Ottawa fleet which have an age exceeding the policy replacement lifecycle. This figure does not include the heavy and medium-duty equipment categories, for which a replacement policy is not established. It also does not account for units on order and to be delivered later in 2022l About 38% of the vehicles in the categories shown above are older than the policy replacement lifecycle.

To note is that orders have been placed for replacement vehicles out to 2024, but delivery times for these vehicles are unknown in most cases.

4. Replacement Budget (BP 10)

Companies benefit from a multi-year replacement plan with levelled funding requirements. Historically, a level funding approach has not been the case for Hydro Ottawa. In 2005, five utilities merged to form the company. In support of the new organization, 100 assets were purchased. This created a large spike in procurement that has been difficult to level. The proposed capital budget requests for 2021 to 2025 reflect this inconsistency in funding requirements.

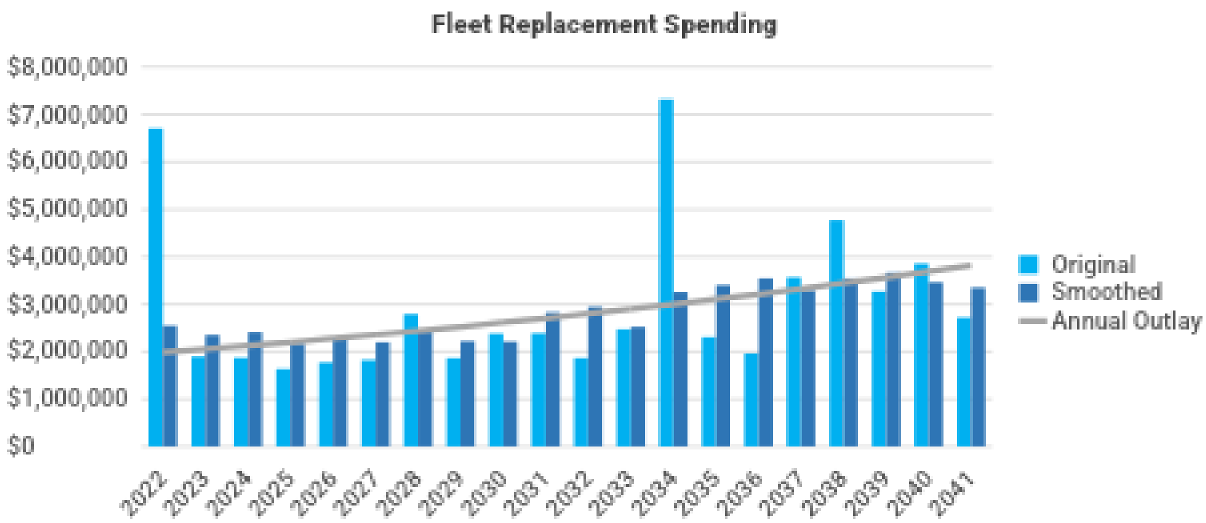
Table 5 – Proposed 2021-2025 Fleet Capital Expenditures by Vehicle Category ($'000s)

Vehicle Category	2021		2022		2023		2024		2025		Total	
	# of units	$	# of units	$	# of units	$	# of units	$	# of units	$	# of units	$
Light Duty	26	$1,319	17	$1,130	17	$932	17	$910	0	$0	77	$4,291
Medium Duty	9	$1,671	5	$797	0	$0	0	$0	0	$0	14	$2,468
Heavy Duty	8	$3,191	8	$2,599	3	$1,173	2	$771	2	$2,008	23	$9,742
Other	1	$164	0	$0	1	$115	0	$0	0	$0	2	$279
TOTAL	**44**	**$6,345**	**30**	**$4,526**	**21**	**$2,220**	**19**	**$1,681**	**2**	**$2,008**	**116**	**$16,780**

Hydro Ottawa needs a levelled multi-year replacement plan where funding would be more consistent year-to-year. Using the data provided by Hydro Ottawa, the funding model from the Matrix forecasting tool provides an estimate of required funding. Hydro Ottawa needs approximately $2 million per year (increasing with inflation hereafter) to afford replacement of its fleet. To update all vehicles that warrant replacement based upon the adopted replacement criteria during one year would require about $6.5 million, meaning that a replacement backlog of $4.5 million exists.

Rather than spend this additional $4.5 million in Year 1, which would be fiscally infeasible and result in exaggerated peaks and valleys of spending in future years, a smoothed approach can be taken to get fleet replacement on schedule. The following table and chart illustrate a schedule which would bring 93% of units to current within six years, and the entire fleet within ten years:

	Original	Smoothed	Annual Outlay
2022	$6,704,903	$2,547,253	$1,987,106
2023	$1,895,524	$2,350,741	$2,056,655
2024	$1,869,210	$2,410,841	$2,128,638
2025	$1,639,174	$2,172,548	$2,203,140
2026	$1,776,551	$2,302,702	$2,280,250
2027	$1,825,157	$2,197,023	$2,360,059
2028	$2,796,371	$2,412,078	$2,442,661
2029	$1,862,754	$2,220,773	$2,528,154
2030	$2,379,365	$2,210,383	$2,616,639
2031	$2,387,280	$2,829,960	$2,708,222
2032	$1,862,917	$2,948,225	$2,803,009
2033	$2,477,023	$2,522,063	$2,901,115
2034	$7,327,064	$3,256,526	$3,002,654
2035	$2,311,278	$3,402,973	$3,107,746
2036	$1,965,585	$3,544,868	$3,216,518
2037	$3,566,024	$3,295,255	$3,329,096
2038	$4,773,229	$3,545,625	$3,445,614
2039	$3,271,580	$3,665,885	$3,566,211
2040	$3,854,820	$3,468,015	$3,691,028
2041	$2,718,193	$3,350,930	$3,820,214



We have not completed a replacement plan as part of this study but have used available data to illustrate the backlog and approach to replace all units within optimum lifecycles and minimize the Total Cost of Ownership of the fleet.

Recommendations:

7. **Pursue cooperative purchasing methods for vehicle acquisition to streamline the process, secure vehicle availability, and obtain the best pricing available in a challenging market.**

8. **Cycle funds from vehicle auctions or sales back into the vehicle replacement fund.**

9. **Observe published replacement cycles to reduce the average age of the fleet and minimize TCO.**

10. **Create a detailed replacement plan with levelled funding requirements and update the plan regularly as the situation changes.**

6 Maintenance

Fleet maintenance and repair processes have a significant impact on vehicle availability, reliability, safety, economy, and environmental integrity. The principal components of fleet maintenance are technician labour, facilities and equipment, parts, and commercial (i.e., sublet or outsourced) services. The objective of fleet maintenance managers is to integrate these components in order to maximize operating performance while minimizing costs.

The indirect costs of fleet maintenance activities are also important and can far exceed the direct costs. For example, mechanical failures that idle employees or disrupt service activities can result in productivity losses or more severe problems whose costs can often be much higher than those of repairing a vehicle.

The following table shows how Hydro Ottawa compares to best practices in the area of fleet maintenance.

Maintenance		Rating	Comments
1	Staffing levels are consistent with the size and type of vehicles in the fleet. There are an adequate number of heavy duty and light duty mechanics, and operations are centralized where reasonable.	x	Operations are centralized and mechanics are properly trained and certified. Vehicle Equivalency Unit (VEU) analysis shows the organization requires the equivalent of six mechanics (approved staffing will increase from four to five in June 2022).
2	Ratio of supervisory and support positions to technicians is reasonable.	✓	The ratios are reasonable: the Supervisor oversees a total of eight positions, but one of those assists in providing oversight to the four (soon five) line-level mechanics.
3	Job descriptions, covering a reasonable range of functions and responsibilities are available and up to date.	~	The organization has job descriptions at an appropriate level of detail. Most are at least four years old and may not fully reflect the responsibilities of each position.
4	A comprehensive PM program is in place that complies with manufacturer recommendations. Customers receive notification of scheduled service dates and compliance levels are 90% or better.	~	The PM schedule for each vehicle is based on manufacturer recommendations. Customers are called or emailed to schedule PM's. Compliance rates are not directly tracked, in part because the software is not used to facilitate them. Certain safety inspections are mandated by law and are always followed.
5	Outsourcing versus insourcing processes determine the best option (capability, cost, downtime, etc.) for undertaking a repair. Fleet uses outsourcing to manage peak workloads.	✓	Outsourcing decisions are based on how busy the shop is, how complex and time consuming the repair will be, and whether it is under warranty or recall or not. The Company outsources heavy duty tires, upholstery and body work and approximately 50% of aerial inspections.

6	Shop business hours have been set for customer convenience.	✓	Shop hours are from 7am – 4pm and align with the organization's working hours.
7	Customers are always contacted when repairs are complete.	✓	Customers receive a call or email when their vehicle repairs are finished.
8	Customers are given regular status updates about vehicles in the shop.	✓	Customers are notified of delays.
9	Field service is available for roadside breakdowns and construction equipment.	✓	Mechanics make frequent road calls and arrange for towing as required to bring vehicles in for repair.
10	Warranty recoveries are actively pursued for both repairs and parts.	~	Warranty work is sent to the dealer when it makes business sense to do so (for example when the downtime of sending the vehicle to the dealer will be excessive, the warranty repair may be done in-house).
11	A formal skills assessment and training plan has been developed to keep employees current with changes in the fleet industry.	~	Mechanics are required by the Company to have three certifications: automotive technician, truck/heavy coach technician, and aerial certification. Staff is also required to obtain and maintain air conditioning certificates. There is no program for additional training.
12	Trip inspections are completed before and after each use of a vehicle.	✓	Most vehicles are assigned and drivers complete vehicle inspections daily.
13	Completed trip inspection reports are kept on hand as legislated.	✓	Inspections are recorded and digitally retained in Geotab.
14	Where defects are noted on the trip inspection report, they are signed off by a mechanic prior to the vehicle being used.	✓	Drivers call the shop when defects are noted. If the vehicle cannot be driven or the issue represents a safety concern, the repair will be completed before it can be used.
15	Staff vacancies are minimal, and efforts are being made to fill them.	✓	There is currently one vacancy due to the creation of a new position. Vacancies and turnover have not been of concern.

1. Shop Staffing (BP 1,2,17)

The number of technicians and required for a shop to operate effectively is primarily driven by the size and composition of the fleet it serves. Because most fleet operations service a wide variety of vehicles and equipment, it is necessary to establish a relative measure that allows for the evaluation and comparison of staffing needs and costs.

Vehicle Equivalency Units

A process known as **Vehicle Equivalent Unit (VEU)** analysis is used to equate the level of effort required to maintain all types of vehicles to a sedan, which is given a baseline VEU of 1.0. Work with other fleet organizations has shown that a VEU of 1.0 is equal to 10-15 annual maintenance labour hours, depending upon factors unique to each organization. All other types of vehicles are allocated a VEU value based on their relationship to a sedan. For example, a half-ton pickup truck has a VEU of 1.5. It requires about 1.5 times the annual maintenance hours of a passenger car, or between 15 and 22.5 hours per year.

A VEU was assigned for each make and model of vehicle and the 274 assets in the fleet total 842 VEU's. The following table summarizes the VEU calculations:

Vehicle Type	Count	VEU per Unit	Total VEU
1 Ton Pickup	5	2	10
1 Ton Van	3	1.5	4.5
1/2 Ton Pickup	56	1.5	84
1/2 Ton Van	8	1.25	10
3/4 Ton Pickup	20	1.75	35
3/4 Ton Van	24	1.5	36
Equipment HD	4	5	20
Equipment MD	10	3	30
Forklift	7	3	21
Forklift HD	3	5	15
Heavy Aerial	59	8	472
Heavy Truck	5	5	25
Sedan	3	1	3
Step Van	21	2	42
SUV	2	1	2
Trailer	23	0.5	11.5
Van	21	1	21
Total	**274**		**842**

Labour Hours/VEU

The next step is to determine the number of labour hours required to maintain one VEU. The baseline figure is 10 hours per year, but adverse or challenging conditions can increase this. while unusually good conditions can drive labour demand down. In determining the number of hours per VEU for an organization, we consider factors that are unique to each fleet. These factors include fleet age and condition, usage levels, degree of outsourcing, and overall operating environment. For Hydro Ottawa, we determined that the labour factor required to properly maintain the fleet is 12.5 hours per VEU. Our calculation for this is shown in the following table:

Factor	Value	Explanation
Baseline hours required per VEU	10.0	Standard starting point for mixed vocational fleets
Adjustment for fleet age	1.0	The average fleet age is 9.5 years which means fleet is replaced every 19 years. Best practice is between 12 and 16.
Adjustment for utilization levels	0.0	Utilization and territory served are not uncharacteristic for an electrical utility.
Adjustment for operating environment	0.5	Subzero temperatures often result in an adverse operating environment.
Adjustment for facility and tools	0.0	The facility and tools do not create delay or hardship
Adjustment for parts support	0.5	The shop's parts support function is limited.
Adjustment for mechanic skills and training	0.5	Mechanics hold the necessary certifications but are not systematically trained.
Adjusted hours per VEU	**12.5**	**Adjusted hours per VEU.**

With 12.5 labour hours per VEU needed, the annual workload is calculated to be 10,525 hours (842 VEU's X 12.5 hours per VEU).

Mechanic Productivity

While a fleet mechanic's salary is based on 2,080 hours per year (52 weeks x 40 hours per week), only approximately 1,456 labour hours per year (70% of annual hours) are available to perform actual maintenance work (the remaining payroll hours are lost to vacation, sick time, holidays and indirect time such as training and meetings). Therefore, a fleet mechanic for Hydro Ottawa can be assigned a total of about 116.5 VEUs per year (1,456 hours available per year divided by 12.5 hours per VEU). When the

10,525 mechanic hours required to maintain the fleet are divided by the 1,456 annual labour hours available per mechanic, the result is a need for 7.2 mechanics.

Current Staffing

The following table summarizes the positions currently authorized and the percentages of their time allocated to working on vehicles and equipment. There are a total of 5.1 technician FTE's.

Position	Authorized Positions	% of Time Spent on Vehicles	Mechanic FTE's
Fleet Supervisor	1.0	0%	**0**
Fleet Maintenance Advisor	1.0	5%	**0.1**
Vehicle Technician	5.0	100%	**5.0**
Tool & Equipment Mechanic	1.0	0%	**0**
Garage Attendant	1.0	0%	**0**
Total	**9.0**		**5.1**

These positions are adequate to meet 5.1 of the 7.2 required mechanic FTE's for the fleet. This leaves a shortfall of 2.1 FTEs or 3,058 hours per year to effectively maintain the fleet. Organizations fill this type of shortfall through a combination of outsourcing, overtime and increased staffing. A best practice is to outsource between 10-15% of maintenance operations. For Hydro Ottawa, this would represent between 1,050 to 1,580 hours/year. In addition to outsourcing, we would recommend an increase of one technician FTE for a total of six mechanics. The company is planning to increase their number of bays which will allow the six mechanics to have a high level of productivity.

It is important to note the relationship between having adequate spare vehicles and loaners and the ability to run an efficient shop. Users will be reluctant to bring work trucks in for regular servicing if they cannot have a replacement vehicle. The staffing level recommendations are predicated on adherence to the formal Preventive Maintenance schedule.

2. Job Descriptions (BP 3)

Job descriptions are core human resources tools which allow an organization to define the scope of each position, the requirements and prerequisites for the position, its expected duties and responsibilities, and its relationship to other positions in the organization. They should be updated regularly, typically every three to five years.

Hydro Ottawa has job descriptions for its fleet positions, and they are written at an appropriate level of detail. Most are at least four years old, however, and should be updated on a regular cycle rather than only when a position is to be advertised for hiring.

3. Preventive Maintenance (BP 4)

A well-designed and executed PM program is the cornerstone of effective fleet maintenance. The objective of a PM program is to minimize equipment failure by maintaining a constant awareness of the condition of equipment and correcting defects before they become serious problems. A PM program minimizes unscheduled repairs by causing most maintenance and repair activities to occur through scheduled inspections. An effective PM program pays dividends not only in improved equipment safety and reliability, but also financially by extending the life of equipment, minimizing the high cost of breakdowns, and reducing lost employee productivity resulting from equipment downtime.

Due to its importance, PMs on all classes of vehicles need to be scheduled and monitored. A Fleet Management Information System should be used to create a PM schedule and notify all fleet users of appointments. PM compliance should be tracked and should exceed 90%.

The PM schedule for each of Hydro Ottawa's vehicles is based on manufacturer recommendations. Customers receive calls or emails to schedule preventive maintenance services. Because certain safety inspections are mandated by law, these intervals are always followed. There is no tracking of interim PM inspections, however, in large part because the FMIS is not used to facilitate them.

The PM compliance rate is a key performance metric for a fleet operation, providing a measure of the consistency with which the shop conducts preventive maintenance. Hydro Ottawa should begin managing its PM schedule and reminders in the FMIS once a suitable system can be obtained or the proper functionality realized with the current system. With this accomplished, they should begin tracking and reporting on the PM compliance rate.

4. Warranty Work (BP 10)

Vehicles that are under warranty should be sent to the dealer or manufacturer for warranty repair. Where this is impractical due to time, distance, or vehicle downtime, many fleets make arrangements with the dealer or manufacturer to do the work themselves and recover the costs of the work from the dealer or manufacturer.

When parts that have a warranty are used for repair, their use should be tracked and appropriate action taken if they fail within the warranty period. Warranty management can save an organization money and is facilitated by a Fleet Management Information System.

Hydro Ottawa sends repairs to the manufacturer for a warranty-covered repair when it makes business sense to do so based on the repair's cost, timing, and how essential the vehicle is. The shop is not currently managing warranties for vehicle repair or parts usage with its FMIS, because the system does not have the capability to reliably track and update the status of warranties. When the shop has an FMIS with the ability to do this, they should begin using the system for that purpose in order to realize a more thorough and less labour-intensive approach to warranties.

5. Technician Training (BP 11)

Fleet organizations are increasingly recognizing that adopting programs designed to ensure that technicians are well trained and technically proficient is a basic business necessity. Vehicles and fleet equipment are becoming more complicated and increasingly expensive. Training and professional certification provide an organization with assurance that equipment will be properly maintained and, that the value of the organization's equipment investments will be preserved. Training can also act as a retention tool in areas where technicians are in high demand, such as the Ottawa area.

In the past, fleet organizations relied almost entirely on training that was provided by vehicle and equipment manufacturers free of charge. While these programs are still available, organizations can no longer make them the centerpiece of their training efforts. This is due to the increasing demand for these programs from dealerships and private fleets, which has severely reduced the number of seats available to municipal technicians. Moreover, manufacturer-training programs have become increasingly complex with strict prerequisites that make it nearly impossible for an organization to rely on these programs to provide technicians with well-rounded training.

Consequently, many fleet organizations today are having to develop training programs that tap a variety of sources to provide technicians with the technical knowledge and updated skill sets that are required to maintain modern fleet equipment. In our view, investing in technician training today is a business necessity and should be a high priority for Hydro Ottawa.

Hydro Ottawa currently promotes training where mechanics are required by law to have three certifications: automotive technician, truck/heavy coach technician, and aerial certification. Staff is also required to obtain and maintain air conditioning certificates, and participate in NAPA training.

In order to support the maintenance of mechanics' skill sets, the organization should offer incentives such as time off and reimbursement for attending classes, and hourly incentives for ASE certifications. Along with the certificates required by the Province, these measures will ensure that technicians are prepared to provide the highly skilled and technically sound level of service necessary for maintaining the Hydro Ottawa fleet.

Recommendations:

11. **Meet the staffing deficit by hiring one additional mechanic, ensuring sufficient spares to replace vehicles while in the shop and outsourcing the remaining work.**

12. **Update fleet job descriptions on a rotating cycle of 3-5 years to ensure that they remain current as references for operational and personnel-related matters.**

13. **Manage PMs with the FMIS and track and report on the PM compliance rate, once reliable FMIS functionality for this purpose has been attained.**

14. **Manage warranties for repairs and parts with the FMIS, once reliable FMIS functionality for this purpose has been attained.**

15. **Provide allowances and incentives for mechanic training beyond ASE certifications.**

7 Fleet Information Technology

Comprehensive, accurate, and readily accessible records regarding fleet operations are essential to optimize performance and manage costs. In the past, fleet maintenance records were kept on paper orders, vendor invoices, and handwritten notes. However, as with all business activities, fleet maintenance shops have evolved to use management information systems to document operations and produce management reports. Having all maintenance and other data available in a computerized system and accessible by all fleet program stakeholders provides an effective tool for managing shop operations, an efficient way to retrieve and report key information, and a basis for timely management decisions.

The following table shows how Hydro Ottawa compares to best practices in the area of fleet technology and information management.

	Fleet Information Technology	Rating	Comment
1	A FMIS is in place that uses modern technology and provides up to date functionality for asset management, maintenance management, and cost reporting.	~	The Company has FleetWave but its accuracy and reliability have resulted in the staff adopting more manual processes. Also, there is no data analyst position to fully analyze the data to support business decisions.
2	Access to the fleet system is readily available to all staff, including parts clerks and technicians.	✓	All staff have access to FleetWave.
3	All members of staff have been appropriately trained in the use of the fleet system.	✓	All staff have been trained at different levels depending on their duties.
4	A fuel management system is in place.	x	FleetWave has a fuel management module, but it is not currently functional or linked to the city’s system. Fuel data is obtained through a manual process.
5	The fuel system tracks both the vehicle being fueled and the driver.	✓	The city fuel system tracks and can produce reports on every operator (with their own card for access to pumps) and every vehicle. Hydro Ottawa can get access but it is a manual process to integrate them in their databank.

	Fleet Information Technology	Rating	Comment
6	A telematics system is in place to improve routing and scheduling of services, identify driver training issues, and provide timely fleet data.	✓	Geotab is used to track location, trip history, engine information and driver behaviours such as braking, turning and speeding. There is no data analyst to process this information.
7	Information produced by systems are routinely used to make management decisions and reports are provided to customers.	~	The data (repair costs, work orders, parts turnover, mechanic utilization rates) which would be generated from a functioning FMIS is not available.
8	A formal performance measurement system is in place to track the effectiveness of service outcomes, and performance levels compare reasonably well to industry benchmarks.	~	Vehicle downtime is tracked through Geotab. Other performance metrics such as average repair time, average PM time, PM compliance rate, parts turnover rate and fuel shrinkage are not tracked. The lack of data analyst impacts the ability to process valuable data.

1. Fleet Management Information System (BP 1,7,8)

Hydro Ottawa has the FleetWave system by Chevin as their FMIS. Although the system originally met all their needs, the lack of support has rendered the system unusable. The company is therefore actively looking for a new system.

Hydro Ottawa should implement a modern fleet management system with a parts management module, built-in reporting capabilities and adequate technical support. This system should be used to maintain detailed, regularly updated profiles of every vehicle and piece of equipment in the fleet, and it should serve as the master database for any other systems. This system should be used to create, update, and finalize all work orders, and it should be used to generate regular reports for the Fleet and Facilities Manager, customers, and senior management.

Any FMIS acquired for the future should have the following capabilities:

- Complete vehicle equipment life-cycle management including
  - Budgeting and forecasting
  - Acquisition and upfitting capital costs
  - Capital improvements
  - Disposal management
- Comprehensive work order functionality

  - Repair status
  - Repair type
  - Repair labor hours & costs by asset
  - Repair parts expense by asset
- Shop repair scheduling and workflow assessments
- Preventive maintenance scheduling
- Regulatory safety inspection scheduling
- Labor tracking and management
- Productivity monitoring (KPIs)
- Inventory control and parts room management
- Cost reporting and billing
- Motor pool management
- Warranty and claims tracking

There are many reputable vendors who market solutions that can readily meet the company's needs. A nationally recognized system with excellent customer support such as AssetWorks M5, RTA, Faster or Fleetio all meet these criteria.

In addition to a capable system, the Company needs dedicated support for fleet analytics. The current challenges of delayed replacement, sourcing scarce vehicles and planning to meet emissions reduction targets heighten the need for support in this area.

2. Fuel System (BP 5)

Ideally, fuel systems provide secure fueling and connect directly to fleet management systems for data transparency and accuracy. Systems should authenticate that the driver and vehicle receiving fuel are authorized to do so and capture odometer readings automatically to avoid errors caused by manual entry. Exception reports and fuel usage reports should be automatically generated and readily available.

POL-Fi-012 Fueling of Fleet Assets Policy covers all aspects of fueling for the company. Hydro Ottawa obtains fuel principally from the City of Ottawa. The City's fuel system is Gasboy. Every driver has a unique identification code, and every truck has a FOB. The fuel system is not connected to the FleetWave system but the Company gets monthly reports from the City on fuel use. When city fuel facilities are not convenient, drivers use a local provider, Drummond's. The local provider bills Hydro Ottawa monthly for fuel used.

Once the company acquires a working fleet management system, an interface should be built to the fuel system to facilitate data capture and reporting.

3. Data Tracking and Use of Key Performance Indicators (BP 7,8)

Performance measurement is a valuable management tool that can be used to increase efficiency and accountability within an organization. The use of year-to-year historical data and industry benchmarks to measure performance can provide management with the data necessary to recognize and diagnose potential problem areas as well as opportunities for improvement. Performance measures also provide the organization with the information necessary to communicate the value of the services it provides. It is not possible for an organization to optimize its performance without establishing concrete, measurable, and challenging goals.

Hydro Ottawa should use its new fleet management system and reporting capability to track a number of performance measures. These are listed and discussed below:

- **Average Fleet Age:** This measure tracks the average age of the fleet in comparison to average replacement cycles. Major classes of vehicles and data for different customer groups should be tracked separately. Trends should be presented for multiple years and associated with other Key Performance Indicators (KPIs) as the age of the fleet has a fundamental impact on program performance.

- **Fleet Availability**: This measure tracks the percentage of the fleet that is available for work each day. The calculation is simply the total number of vehicles and pieces of equipment in the fleet divided by the number of vehicles out of service for repair (i.e. in the shop, waiting in the deadline to come into the shop, or at a vendor). The target of performance for this KPI is 95%.

- **Service Turnaround Time**: This measure tracks the percentage of repairs that are completed within 24 and 48 hours. A good target of performance for this KPI is 70% of repairs and services completed in 24 hours and 90% in 48 hours.

- **Scheduled Repairs:** This measure tracks the percentage of workorders resulting from scheduled activities (such as preventative maintenance (PM), inspections, work discovered during PMs and inspections, recalls, etc.) versus unscheduled activities (such as breakdowns and road calls). The standard of performance for this KPI is at least 60% scheduled.

- **Downtime:** This measure tracks segments of downtime while vehicles are down for repair. The entire lifecycle of a work order should be tracked including waiting for a mechanic or shop bay, waiting for customer approval, under repair, waiting for parts, at a vendor, waiting for validation and closure, waiting for customer pickup, etc. Tracking of this measure enables a fleet organization to understand what activities are causing downtime and delays so they can be managed.

- **PM Compliance**: This KPI measures the percentage of PMs and scheduled inspections that are completed before they are overdue. The target of performance for this KPI is 90%.

- **Billable Hours:** This KPI tracks how productive mechanics are in terms of the annual number of hours billed to work orders. The target for this KPI is 70% of annual regular payroll hours (1,456 of 2,080 hours per year).

The Company should begin tracking the KPIs listed above and reporting them to management each month.

Recommendations:

16. Acquire a commercial off the shelf FMIS that has the capabilities needed by the company and reliable technical support.

17. Engage a fleet analyst to monitor and analyze fleet data to support business decisions.

18. Integrate fuel data with the FMIS.

19. Produce regular reports on fleet performance that include the KPIs listed above.

8 Sustainability

In April 2021, Canada set a national emissions reductions target of 40-45% greenhouse gas reductions below 2005 levels by 2030. With the country's largest population, Ontario remains Canada's second largest GHG emitter and continues to lag behind proactive provinces such as Quebec and British Columbia in tackling climate change.

The City of Ottawa's 2020 Climate Change Master Plan contains goals for GHG emission reduction. The 2030 target is a 50% reduction in emissions, to be followed by reaching 100% elimination by 2040. As of 2018, more than two-thirds of Ottawa's GHG emissions were due to its fleet, suggesting that fleet-related changes would need to represent the bulk of actions taken to meet targets.

Sustainable fleets are those that take every opportunity to lower GHG emissions and provide necessary support to operations in the greenest way possible. The clearest way to reduce emissions is not to burn fossil fuels. This can be achieved by using alternative mobility options such as walking, biking or using public transport. Changing work processes by telecommuting, remote meetings and overall reduction of the need to travel can also impact emissions. Work-related functions still have to take place but reducing idling and converting to alternative fuels, including electricity, can help.

The following table shows how Hydro Ottawa compares to best practices in the area of sustainability.

	Sustainability	Rating	Comment
1	The organization has a Sustainable Plan with goals to meet the Net-Zero targets of the Federal government.	~	Hydro Ottawa has a 5-year strategic direction document which includes sustainability goals. Among these are a commitment to achieve net zero status by 2030. This goal is not currently supported with a plan to achieve it.
2	The organization measures GHG emissions.	✓	Greenhouse gas emissions are a key metric for gauging progress toward net zero operations, and Hydro Ottawa reports on its GHG emissions as part of its strategic plan.
3	The organization tracks and seeks to lower fuel usage.	~	Fuel usage is tracked. A manual process is required to produce reports. The organization has a policy on reducing idling for light-duty vehicles.

	Sustainability	Rating	Comment
4	Alternative fuels are considered when vehicles are being replaced.	✓	Alternative fuel vehicles are the first choice when purchasing new assets and is listed as the Company's preference in specifications.
5	Future infrastructure needs are being planned to accommodate sustainable fleet vehicles.	✓	Hydro Ottawa has plans to order 40 EV charging stations subsidized by the Federal Government. The project is pending funding approval.

1. Sustainable Fleet Plan (BP 1)

Fleets should have a sustainable fleet plan that is nested in the overall strategy of the organizations. The fleet plan must have a clear path to meet the GHG targets set in the overall strategy.

Hydro Ottawa continues to invest in green fleet vehicles and technology, where it is available for commercial fleets, and to replace vehicles, as per the established fleet replacement schedule, with the following:

- Hybrid or more energy efficient vehicles, where available.
- Hybrid technology to operate hydraulics for aerial devices, where it is effective.
- Battery technology to eliminate idling for heating and lighting, while servicing underground, overhead cabling.
- Electric vehicles, where appropriate.

Hydro Ottawa is committed to the acquisition of vehicles with hybrid technology where there is an operational and financial business case for doing so. The impediments to this happening are vehicle availability, charging infrastructure and capacity for emergency response. The first two issues were dealt with in depth in the Sustainability Report.

In terms of ability to support EV customers during a disaster-caused outage, there are developing solutions. The grid below shows a full mix of supplemental power solutions to power electric vehicles in an outage.[1]

[1] Strategies for EV charging resiliency during natural disasters (esource.com)

Vendor	Product	Approximate number of cars that can receive a 40-mile charge	Product size or platform
Tesla	Megapack Mobile Supercharger	54 to 154	Fits on a semi-truck flatbed
Dannar	4.00	6 to 25	About the size of a high-profile sport utility vehicle
Lightning Systems	Lightning Mobile	9	3,700 pounds; fits in the back of a cargo van or midsize cargo trailer
Freewire Technologies	Mobi	4	Slightly larger than a shopping cart
Beam (formerly Envision Solar)	EV Arc 2020	1 to 2	Fits on a midsize trailer
SparkCharge	Roadie	Less than 1	Each module is about the size of a suitcase; up to five modules can be connected

Ultimately, EV charging resilience depends on a combination of these options, tailored to the needs of the organization. The current state of alternative fuel vehicles (AFVs) if the fleet is shown:

Fuel Commodity	Count
Diesel	94
Electric	6
Gas	148
Propane	3
None (trailers)	23
Total	**274**

In practical terms, the company has four RAV4s (fully electric) on order to replace four internal combustion engine (ICE) vans and has the following plan for the 2021-2026 timeframe:

2021-26 Planned Acquisitions

	Fully EV	Hybrid	ICE	Total
Heavy Duty	0	0 to 5	18 to 23	23

	2021-26 Planned Acquisitions			
Medium Duty	0	10 to 14	0 to 4	14
Light Duty	0	20 to 25	52 to 57	77
Totals	0	30 to 44	70 to 84	114

This will not be sufficient to meet 2030 GHG reduction needs.

2. Fuel Use and Idling (BP 3)

Organizations are not going to be able to convert their fleets to electric vehicles quickly enough to meet GHG reduction targets. They must combine conversion plans with efforts to reduce Vehicle Miles Travelled (VMTs) and idling.

POL-HEA-001Idling Control for Fleet Vehicles provides detailed instructions for idling reduction. Idling is allowed to warm up a diesel engine (three minutes) or a gasoline engine (two minutes) or when temperatures exceed established parameters (below 5 degrees or above 27 degrees).

In comparison, the City of Ottawa idling policy states that:

- Vehicles shall never be left idling when unattended.
- Engine warm-up periods will not exceed one minute (provided required airbrake pressure and/or other critical settings have been reached).
- Vehicles will be shut off whenever idling time is expected to exceed one minute.

The Hydro Ottawa policy is not strict enough and compliance is questionable. The company has data on idling by vehicle and can demonstrate

- One hour of idling requires 3.5 liters of fuel.
- There are units that consume 8,200 liters of fuel through idling in one week.
- Some units idle 30+ hours per week.

Addressing this problem requires a combination of education and incentives. First, the policy should be tightened to reduce the parameters where idling is permitted. Regulations should state that any time there is a site trailer present, employees are to use the trailer, instead of an idling vehicle to complete administrative tasks. Second, policies need to be effectively communicated to gain employee buy-in and interest in emissions reduction. Third, data should be made public so employees can see their idling history and progress towards idle reduction.

Combining these education efforts with incentives can create friendly competition and reward employees who do the right thing. Incentives may be offered for all who reach certain targets or the best work team or employee in a quarter. They can take the form of preferred parking, public recognition, a gift card, or bonus. In one case, a fleet offered to share fuel savings with drivers 50/50 and were extremely successful in reducing idling.

Recommended steps to an effective idling reduction program are:

- Create the baseline for the fleet to enable accurate measurement of results.
- Measure idling across groups and individual drivers per week.
- Set goals and publish them throughout the company.
- Offer incentives for goals to show that the program is beneficial to both the driver and the organization.
- Provide weekly reports that are delivered automatically.
- Use productivity alerts to help managers improve behavior.
- Alert supervisors to idling incidents.

Recommendations:

20. Set realistic GHG emission reduction targets and understand what volume of conventional fuel reduction is necessary to meet the targets.

21. Develop a strict idle elimination program with education and incentives.

Hydro Ottawa Limited

Inflation Factor

August 26, 2024

Utilis Consulting Inc.

Table of Contents

Introduction

- For Price Cap and Annual IR, the OEB's IRM model accounts for the inflation factor change by escalating rates by Inflation Factor (I) less Stretch Factor (X).

Price Cap Index (PCI) = I - X

- Under this approach, all rates are increased by the same value of inflation, regardless of variations in inflationary pressures for different components of the revenue requirement.

- Some utilities, notably Hydro One and now Toronto Hydro, have used Revenue Cap structures rather than Price Cap; escalating revenues rather than rates themselves. Rather than increase rates themselves, the formula increases the revenue requirement, which is then used to design rates based on billing determinants. A Revenue Cap interacts with inflation in the same manner as a Price Cap.

Ontario (OEB) Inflation Factor

EB-2010-0379--Renewed Regulatory Framework (RRF) for Electricity

- On October 18, 2012, the OEB issued its RRF Report adopting a more Ontario industry-specific inflation factor for 4th Generation IR rather than the Canadian economy-wide index used in 3rd Generation IR.

- The OEB's 2-factor Input Price Index (IPI) excluded a specific capital sub-index and comprised of:
    - A labour sub-index derived from the Average Weekly Earnings (AWE) of workers in Ontario
    - A non-labour sub-index derived from Canada's GDP IPI FDD*.

- The weights of the component are 30% for labour and 70% for non-labour sub-index.

* Gross Domestic Product Implicit Price Index Final Domestic Demand

Findings: OEB Precedents

- Most utilities on CIR modified the price cap/revenue cap index by using a custom capital factor (Toronto Hydro 2015; Hydro One 2018):

$$PCI/RCI = I - X + C$$

- The C Factor was added to recover revenue related to new capital investments above the forecasted amount.

- The OEB accepted the capital factor but imposed measures to ensure efficiency and reduce over-funding of capital related RR (CRRR):
  - Added an additional 0.15% to the stretch factor.
  - Added a calculation to rate framework to remove the excess CRRR that would otherwise be implemented through the standard Price Cap formula of I – X.

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Findings: OEB Precedents (Cont’d)

- Formula to remove I – X escalation applicable to CRRR can be expressed in an expanded formula, as:

PCI/RCI = I – X + C – (CRRR/Total RR)*(I - X)

- The effect of this is that whatever forecast of inflation is included in the CRRR used to establish the C-Factor will not be updated for actual inflation during the rate term.

Findings: OEB Precedents (Cont'd)

- No electricity distributor has varied from the RRFE Inflation Factor since its creation.
- Non-distributors that varied from the Inflation Factor are as follows:

Entity	Indices	Weightings
EB-2016-0152--Ontario Power Generation 2017-2021	Ontario AWE and GDP-IPI-FDD	12% labour and 88% non-labour
EB-2017-0306/0307--Union Gas/Enbridge Gas 2019-2028	Quarterly GDP IPI FDD*	-
EB-2019-0082--Hydro One 2020-2022 Transmission / EB-2018-0218--Hydro One Sault Ste. Marie 2019 / EB-2018-0275--Niagara Reinforcement Limited Partnership 2020-2024 Transmission	Ontario AWE and GDP-IPI-FDD	14% labour and 86% non-labour
EB-2022-0200--Enbridge Gas Phase 1 2024	Ontario Quarterly Average Hourly Earnings (AHE) And Quarterly GDP IPI FDD	25% labour and 75% non-labour

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* This inflation factor had been adopted by the gas utilities in the past, and the applicants' provided details that the GDP IPI FDD and the two-factor inflation factor applied to electricity distributors have not been materially different since 1993.

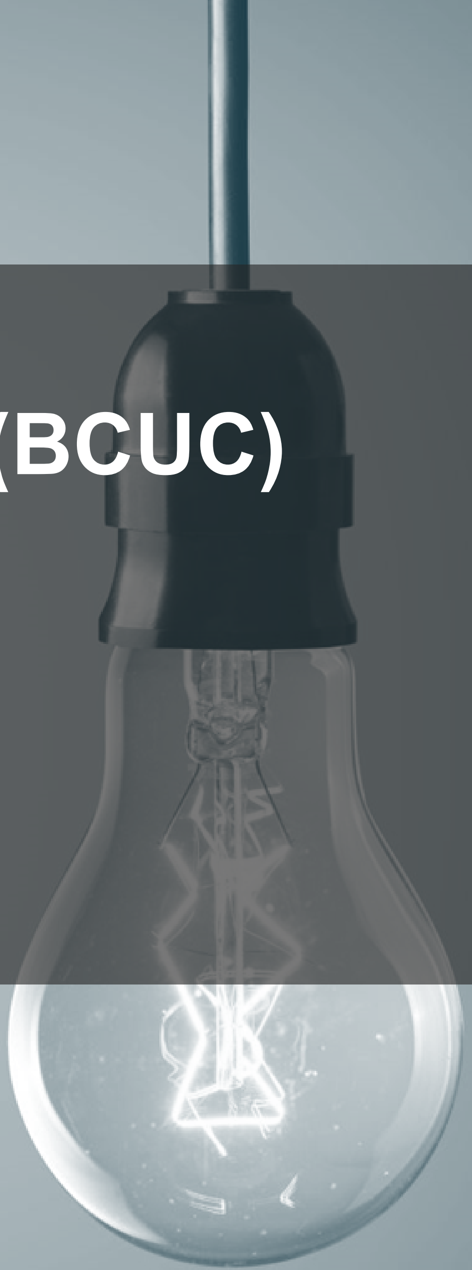
Findings: Toronto Hydro Inflation Factor (EB-2023-0195)

- Toronto Hydro proposed a custom inflation factor which aligned with the OEB methodology but included an alternative to replace the Ontario AWE inflation index with a custom Toronto Hourly Salary and Wages Index, derived using Conference Board of Canada index.

- Toronto Hydro withdrew this proposal in interrogatory responses (1B-Staff-93), citing data errors in the original evidence.

- In responding to Toronto Hydro's proposal, PEG advocated for a shift to the Fixed Weighted Index (FWI), citing the AUC's decision to adopt this index.

Alberta (AUC) and British Columbia (BCUC) Inflation Factor



Findings: AUC Precedents

- The I factor approved for the Performance-Based Regulation 3 (PBR3) term included same indices with different weights: 60% for labour and 40% for non-labour.

$$I_t = 60\%\ x\ FWI_t + 40\%\ x\ CPI_t$$

Where,

I_t	Inflation factor for the year.
FWI_t	Alberta fixed weighted index[70] for the January to December period. (A placeholder value for the July to June period from the preceding year will initially be used.)
CPI_t	Alberta consumer price index[71] for the January to December period. (A placeholder value for the July to June period from the preceding year will initially be used.)

- Shifted from Alberta AWE to FWI as it is less volatile and tracks utility labour inputs prices more closely.

- The AUC agreed that it should not presume that inflation would average out over the PBR3 term. Hence, true-up approach should be used to reflect uncertain inflation environment.

Findings: BCUC Precedents

- FortisBC's I-Factor consist of labour (BC AWE) and non-labour (BC All-Items index for CPI) indices.

$$I = X \; x \; AWE{:}BC_{t-1} + Y \; x \; CPI{:}BC_{t-1}$$

Where:

- I = Inflation Factor
- AWE:BC = labour index
- CPI:BC = non - labour index
- t - 1 = most recent July to June value
- X = the previous year's labour ratio; and
- Y = the previous year's non-labour ratio.

- No weights were assigned. It will be assigned separately to each utility.

- The Panel found that it is more reliable and accurate to set the labour/non-labour ratio annually by basing it on the most recently completed year.

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Integrating an Inflation Factor into a Rate Framework

Inflation Factor and Rate Framework

- In Toronto Hydro's 2025 CIR application, it changed the relationship between Revenue Growth Factor (RGF) (formerly C-Factor) and inflation. RGF will fund the forecasted incremental capital and investment needs in the years, 2026-2029.

- The proposed Custom RCI calculation includes (I – X + RGF):
  - A forecast of inflation within the costs, consistent with prior C-Factor treatment.
  - Instead of removing impacts of I – X on CRRR during IRM, it removes inflation upfront allowing for full weight of inflation factor (less X) in IRM applications.

	2025	2026	2027	2028	2029
Base Revenue Requirement (BRR)	972	1,027	1,074	1,176	1,219
Difference	-	55	47	101	44
RGF before Inflation Adjustment	**-**	**5.61%**	**4.62%**	**9.43%**	**3.71%**
Forecast Inflation Factor (%)	-	(2.00%)	(2.00%)	(2.00%)	(2.00%)
RGF after Inflation Adjustment	**-**	**3.61%**	**2.62%**	**7.43%**	**1.71%**

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Inflation Factor and Rate Framework (Cont'd)

- As per the Settlement Proposal, the Parties agreed to a five-year Custom IR Framework based on the proposed Custom Revenue Cap Index (CRCI):
  - The CRRR portion of RGF will be reduced by an incremental 0.3% capital stretch factor. This value will be built into the RGF, and not applied mathematically in IRM applications.
  - The OM&A portion of RGF will not be based on a 5-year forecast of OM&A as proposed. Instead, the OM&A forecasts used to establish the RGF will be based on the Test Year, increased for inflation and a 0.41% growth factor each year. The growth factor is meant to represent incremental costs driven by customer and peak demand growth.

Conclusion

Conclusion

- The non-distributors followed the OEB's 2-factor IPI methodology but modified weights of non-labour and labour components to better reflect their cost structures.
    - The modification decreased the labour component, placing more emphasis on non-labour inflation.

- When approving the framework, the OEB made sure that:
    - The annual growth rate was aligned to the OEB's annual inflation factor.
    - The rate framework promoted efficiencies incase of modifications to the indices.
    - The OEB emphasized the inflation factor should be based on an external and publicly available index for transparency

Conclusion (Cont'd)

- Other jurisdictions revisit the framework more regularly and catered more to the requirements of the utilities.

- Economic consultants to OEB Staff, PEG, are advocating to replace AWE with FWI specifically for labour costs, which is consistent with the changes made in AUC's PBR3.

- The Toronto Hydro RGF proposal is still awaiting decision and, if approved, may change the dynamics of how inflation is incorporated into the rate framework, making it more reflective of rising inflationary pressures.

Hydro Ottawa Limited

OM&A Benchmarking – 2015 - 2023

Updated:
November 2024
Utilis Consulting Inc.

Table of Contents

Introduction

- Hydro Ottawa Limited (Hydro Ottawa) has requested Utilis Consulting (Utilis) provide regulatory consulting services to produce benchmarking evidence specific to its Operating Maintenance and Administration (OM&A) proposals (OM&A Benchmarking) that support its 2028 Cost of Service application (COS Application)
- The first phase of the OM&A Benchmarking project is for Utilis to provide Hydro Ottawa an understanding of how it is performing relative to peer Ontario electricity distributors (Benchmarking Universe). Hydro Ottawa and Utilis plan to use the learnings from this first phase to target opportunities that support the COS Application
- Utilis has produced this presentation to accompany the Benchmarking Universe enclosed in the Benchmarking Excel Booklet. The presentation provides data on how Hydro Ottawa:
    - Ranks relative to a data set of 54 other distributors across 29 metrics or ratios
    - Compares against a group of distributors with similar customer counts, rural vs. urban landscape and load distribution across 29 metrics or ratios
    - Ranks relative to a data set of 54 distributors in Reliability metrics (SAIDI and SAIFI)

Basis for Benchmarking Universe

- Cohorts have been established to produce relevant and fair comparisons for like utilities:
  - As an example, the number of customers Cohort (Customer Cohort) is established by selecting the distributors whose customer numbers are comparable to Hydro Ottawa. For the Customer Cohort, Utilis produced a range of metrics and ratios that provides insights on how Hydro Ottawa performed relative to distributors in the group
- Benchmarking Universe Characteristics:
  - **Baseline Cohort Chosen: Number of Customers**
  - **Total # of Distributors in Cohort: 6**
  - **Total # of Distributors: 54**
  - **Data Source: OEB Open Source Data**
- Additional Cohort Groups (refer to Appendix)
  - **Urban/Rural Ratios – (eg: square footage of rural divided by total territory square footage)**
    - **Total # of Distributors in Cohort: 6**
  - **Load distribution between Residential, GS<50 and GS>50**
    - **Total # of Distributors in Cohort: 9**
    - **Selected distributors with similar load distribution, using a deadband of +1%**
  - **[Next Step: Discuss other potential Cohort Groups]**

Baseline Cohort – Number of Customers

Alectra Utilities Corporation	1,082,646
Toronto Hydro-Electric System Limited	792,732
Hydro Ottawa Limited	364,334
Elexicon Energy Inc.	176,725
London Hydro Inc.	167,081
Enova Power Corp.	162,022

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Basis for Benchmarking Universe

- Utilis generated the following metrics and ratios to compare Hydro Ottawa with its cohort and the broader industry.

Utilis Consolidated Scorecard Metric	OMA / Circuit KM	(Contract Services) / Total CapEx
OMA/FTE	Operating Expense / Circuit KM	Operating Expense Ratio
Operating Expense / FTE	Maintenance Expense / Circuit KM	FTE / $1M of CapEx
Maintenance Expense / FTE	Admin. Expenses / Circuit KM	FTE / $1M of CapEx Additions
Admin. Expense / FTE	OMA / MWh	FTE / 1,000 Customer
OMA / Customer	Operating Expense / MWh	FTE / Circuit KM
Operating Expense / Customer	Maintenance Expense / MWh	FTE / GWh
Maintenance Expense / Customer	Admin. Expenses / MWh	FTE / Summer Peak Load (MWh)
Admin. Expense / Customer	MWh / Customer	FTE / Winter Peak Load (MWh)
Circuit km / 1,000 Customers	OMA / CapEx	

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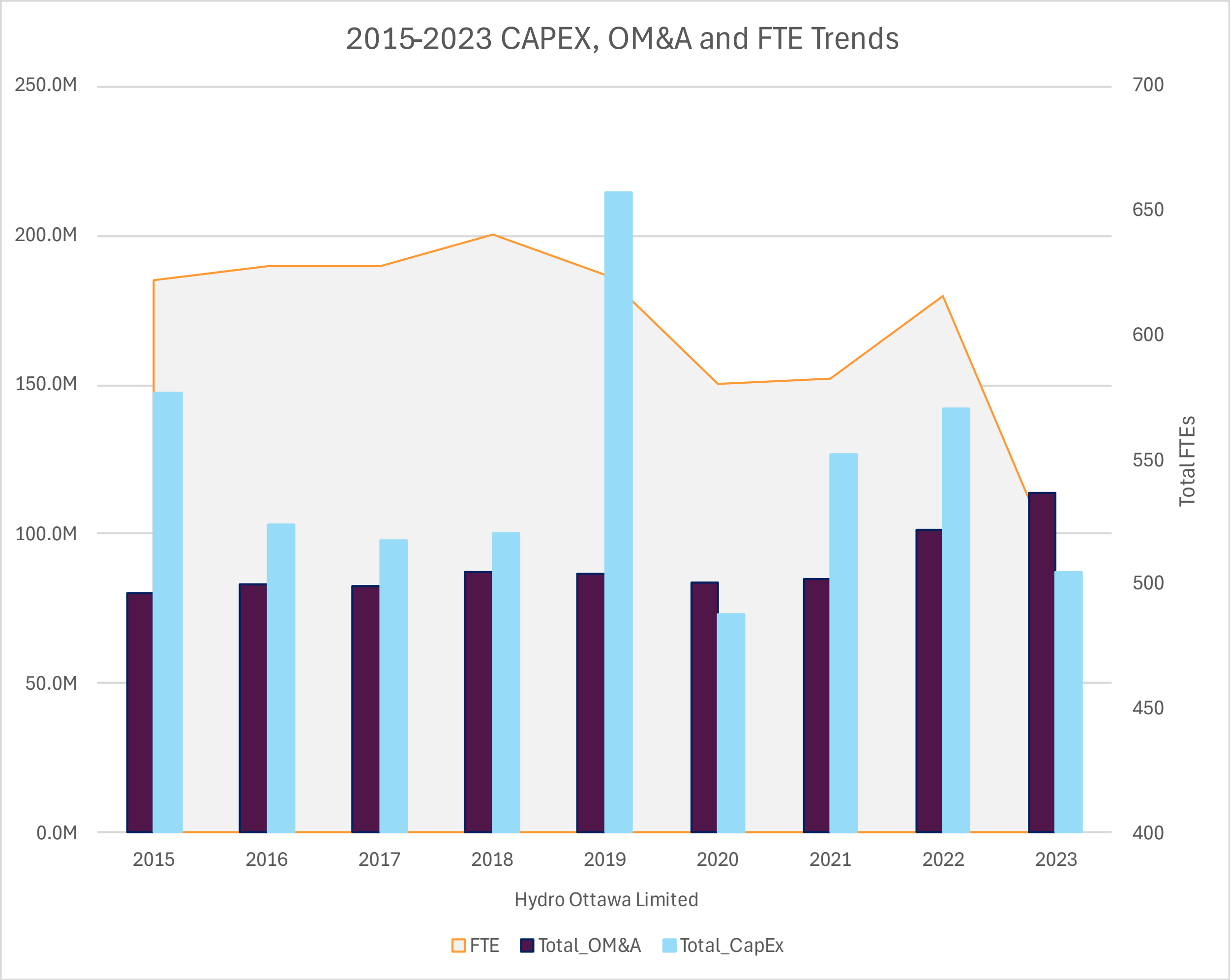
Benchmarking Universe

Hydro Ottawa
Performance 2015 - 2023

Summary Findings

- FTEs decreased significantly between 2022 and 2023.
- FTEs were at 615.7 in 2022 and 509.01 in 2023
- OM&A costs rose from $83.8M in 2020 to $114.1M in 2023
- CapEx spend has varied year-over-year, peaking at $214.8M in 2019.There was a significant decline but post-2020 is showing some recovery.



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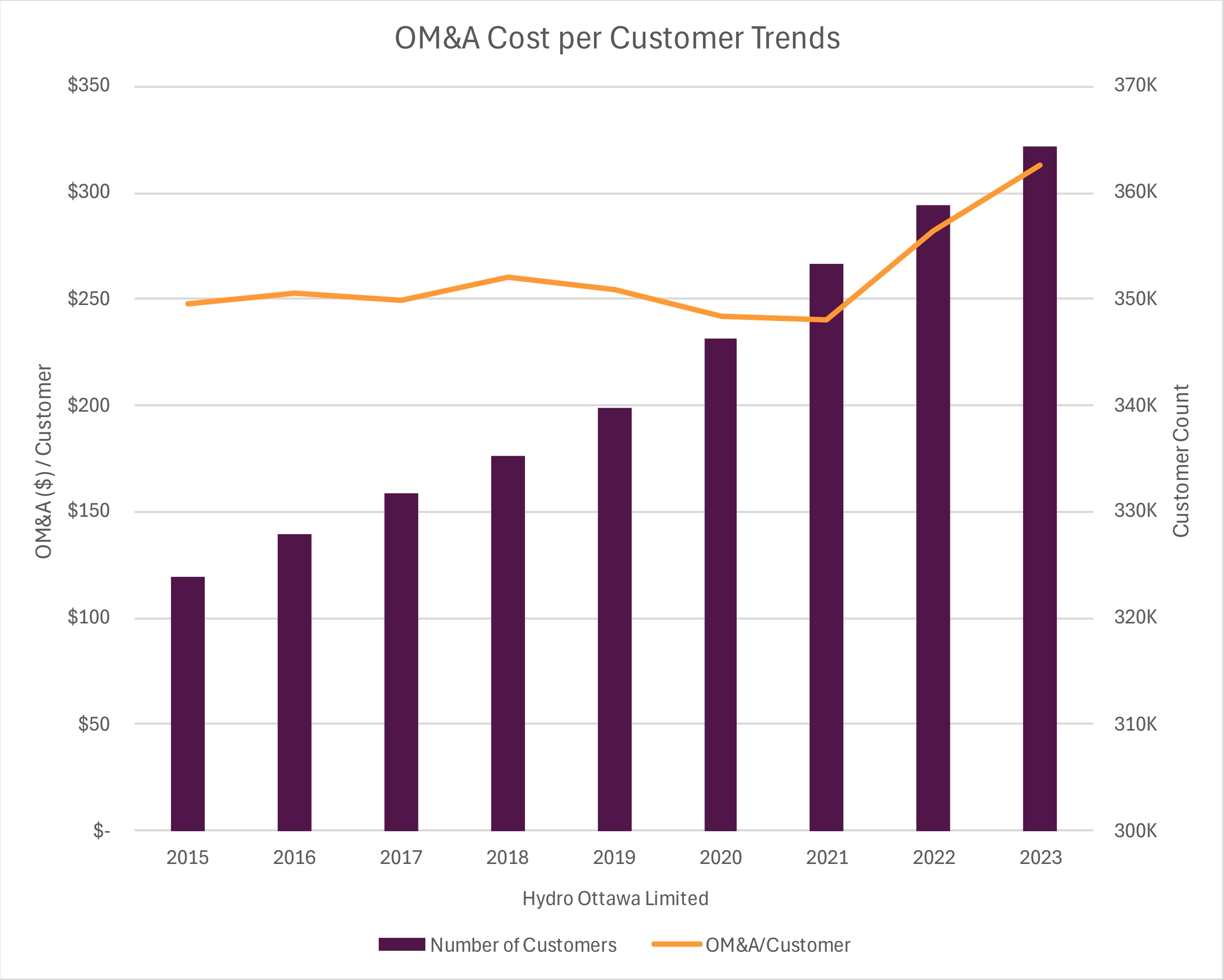
Summary Findings

- OM&A cost per customer has been variable from 2015 to 2021, sharply increasing in 2022 and 2023
- OM&A/Customer started at $248 in 2015 and ending at $313 in 2022. A CAGR of 2.95%
- The number of customers increased by approximately 34.9K from 324K in 2015 to 364K in 2023. A CAGR of 1.48%



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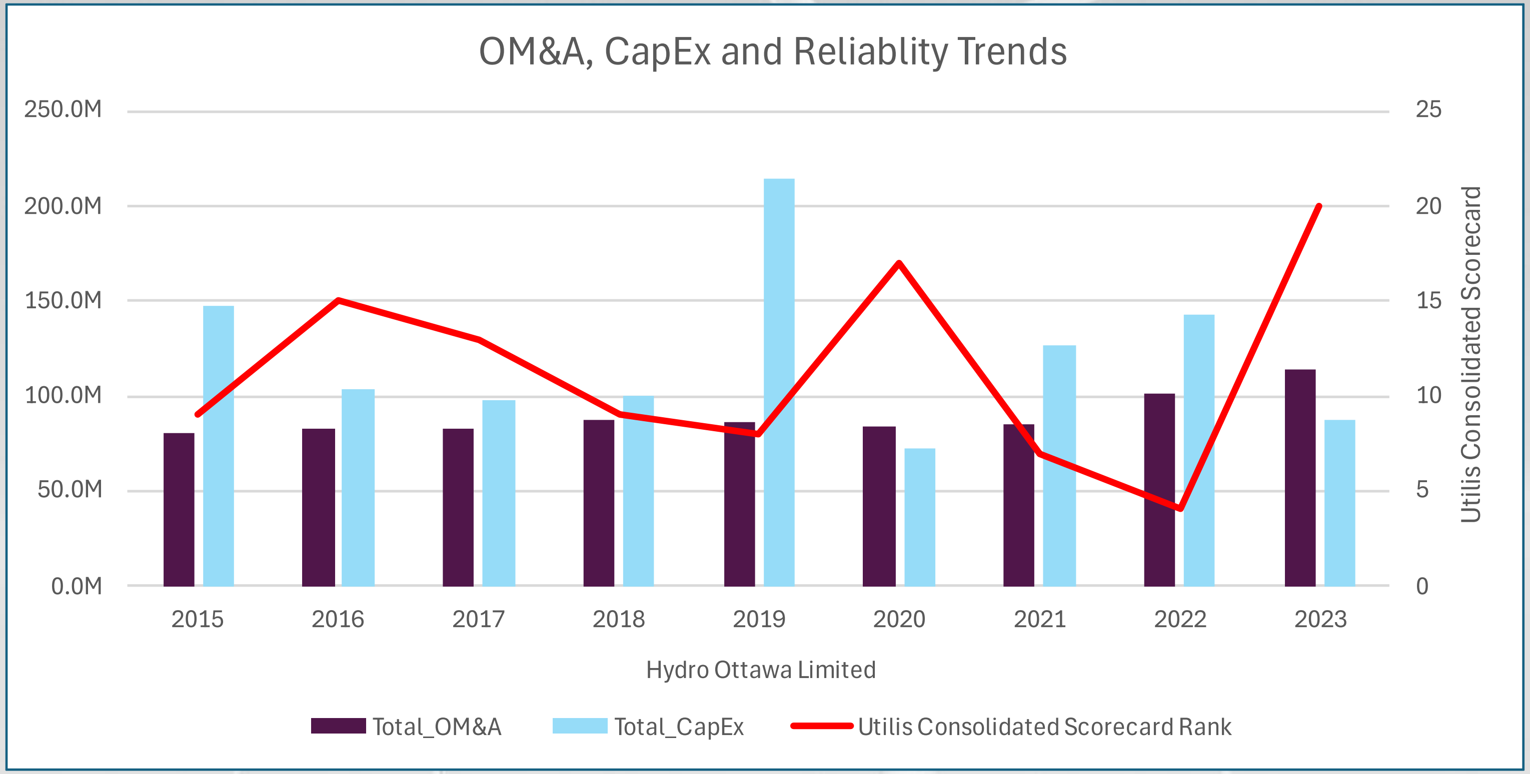
Summary Findings

- Hydro Ottawa's ranking[1] across 10 OEB Scorecard metrics improved substantively in 2021 and 2022



1: Utilis developed the "Utilis Consolidated Scorecard" that ranks each distributor against the 54 other distributors in the data set. The best ranking is 1 and worst ranking is 54. **Additional details provided in Appendix**

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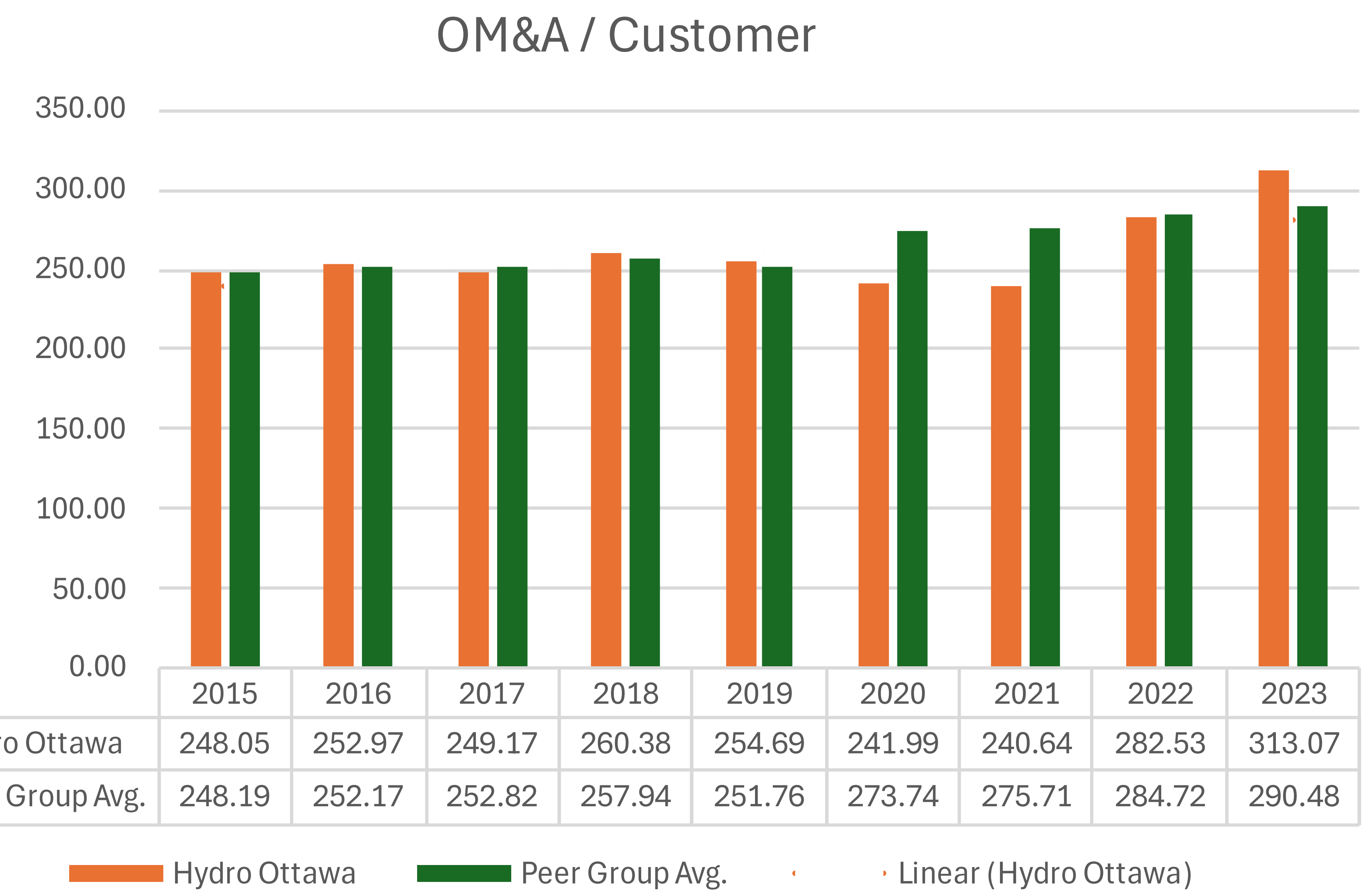
Benchmarking Universe

Hydro Ottawa
Performance Relative to
Customer Cohort

Hydro Ottawa Performance Relative to Customer Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	248.05	252.97	249.17	260.38	254.69	241.99	240.64	282.53	313.07
Peer Group Avg.	248.19	252.17	252.82	257.94	251.76	273.74	275.71	284.72	290.48

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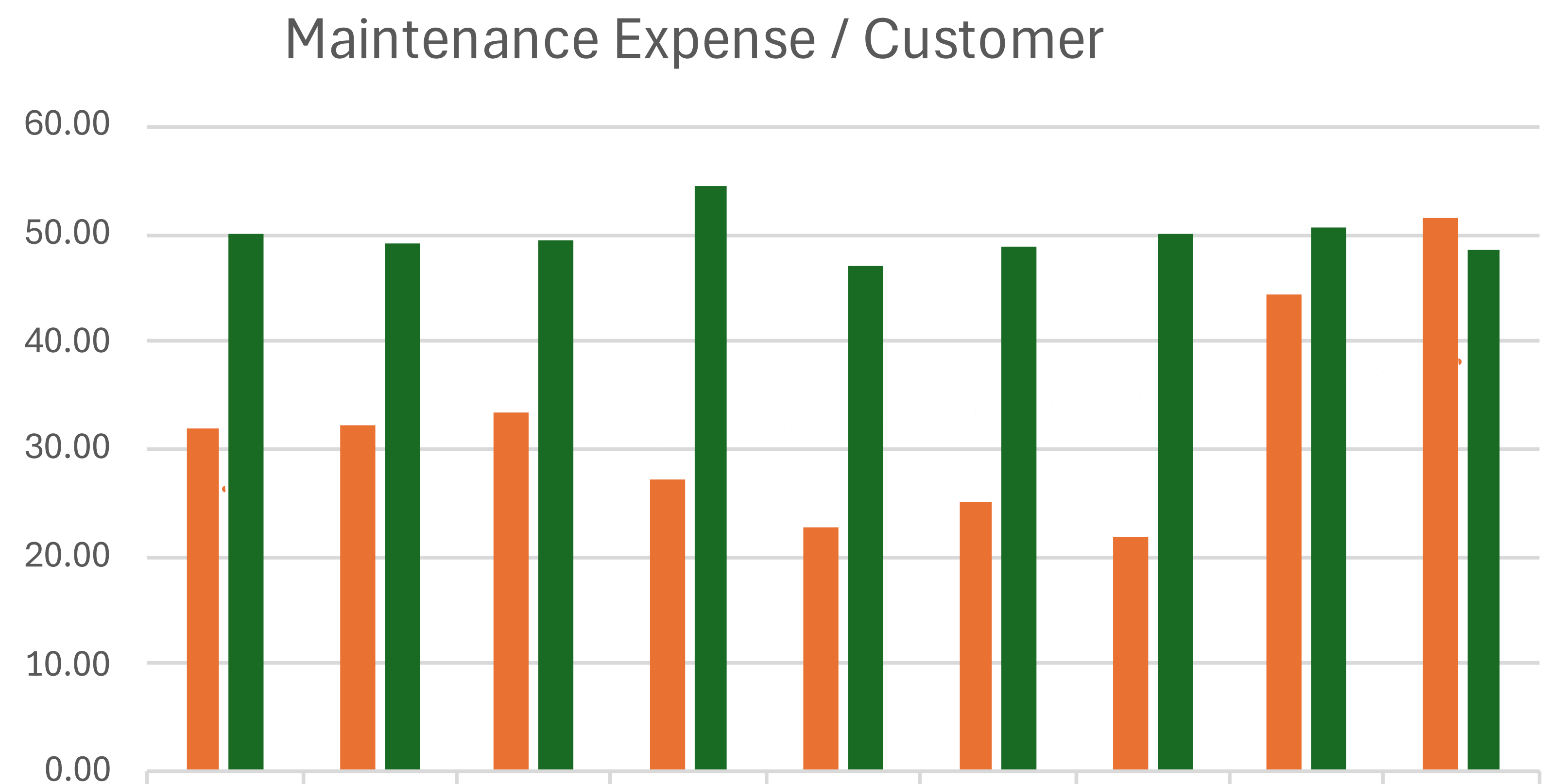
Hydro Ottawa Performance Relative to Customer Cohort

	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	51.08	53.35	54.25	62.26	61.40	66.70	60.02	67.43	74.23
Peer Group Avg.	64.04	66.34	64.07	67.07	67.45	67.43	68.14	73.48	69.66

Hydro Ottawa Performance Relative to Customer Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	31.84	32.22	33.37	27.21	22.64	25.01	21.76	44.53	51.60
Peer Group Avg.	50.08	49.12	49.40	54.49	46.92	48.73	50.05	50.75	48.41

Hydro Ottawa Peer Group Avg. Linear (Hydro Ottawa)

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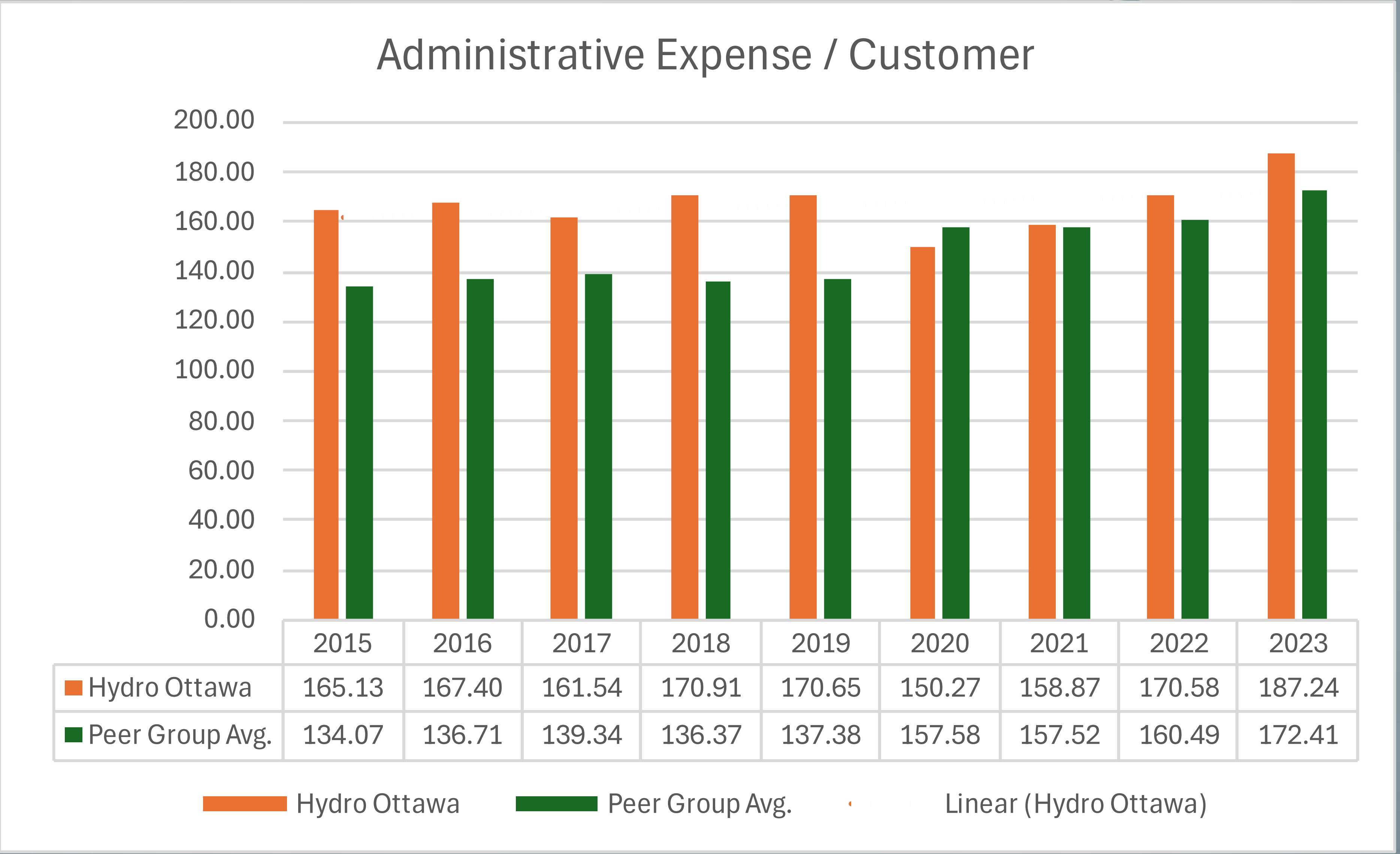
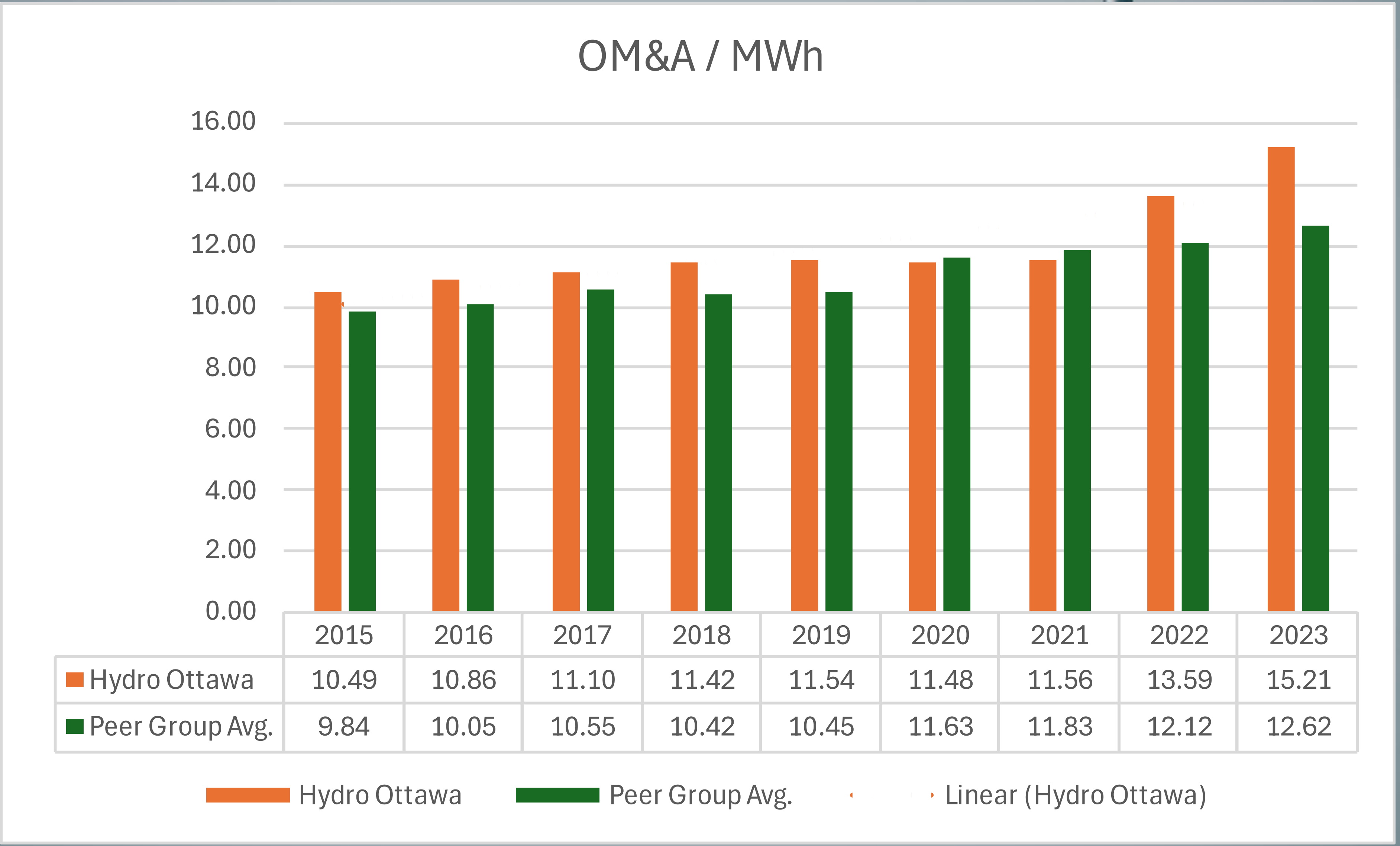
Hydro Ottawa Performance Relative to Customer Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	165.13	167.40	161.54	170.91	170.65	150.27	158.87	170.58	187.24
Peer Group Avg.	134.07	136.71	139.34	136.37	137.38	157.58	157.52	160.49	172.41

Hydro Ottawa Performance Relative to Customer Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	10.49	10.86	11.10	11.42	11.54	11.48	11.56	13.59	15.21
Peer Group Avg.	9.84	10.05	10.55	10.42	10.45	11.63	11.83	12.12	12.62

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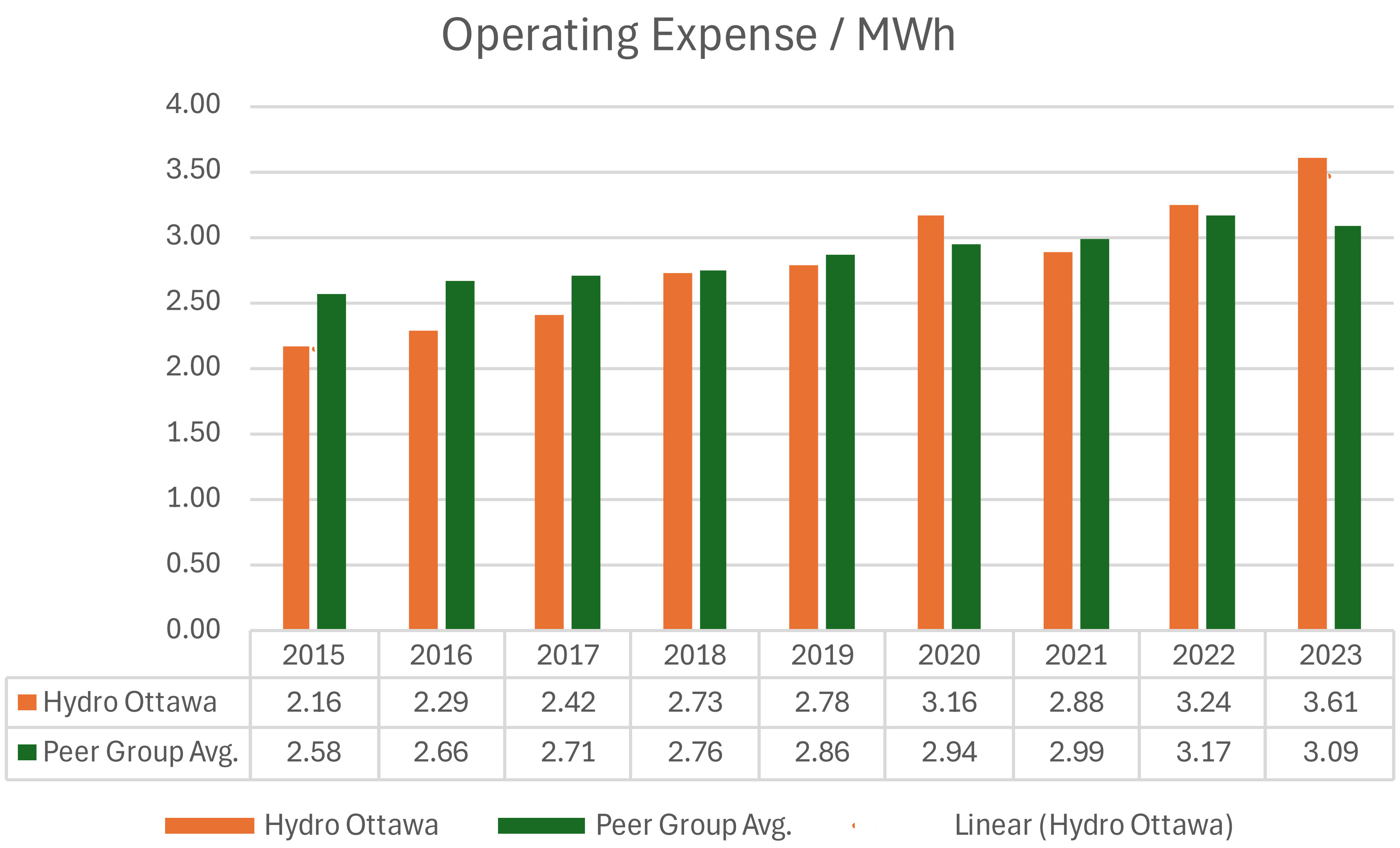
Hydro Ottawa Performance Relative to Customer Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	2.16	2.29	2.42	2.73	2.78	3.16	2.88	3.24	3.61
Peer Group Avg.	2.58	2.66	2.71	2.76	2.86	2.94	2.99	3.17	3.09

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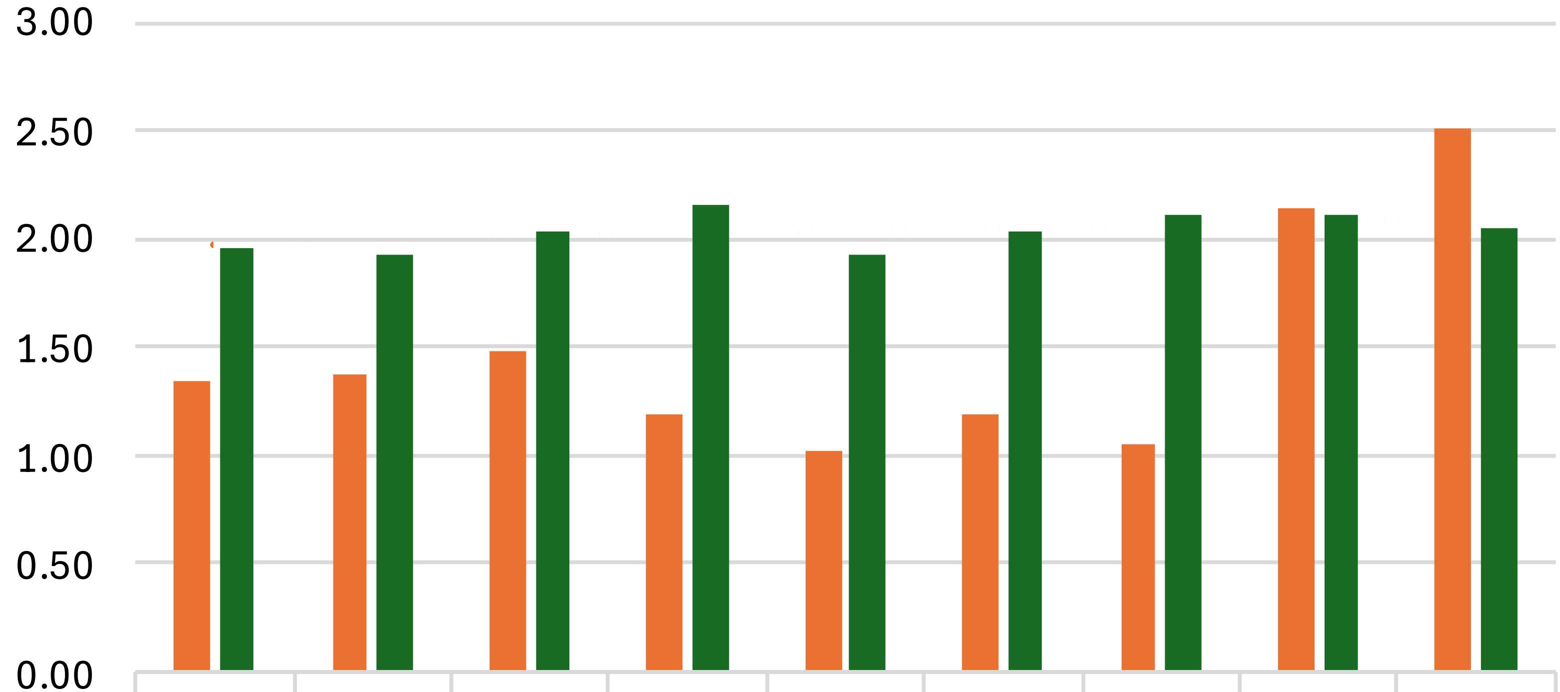
Hydro Ottawa Performance Relative to Customer Cohort

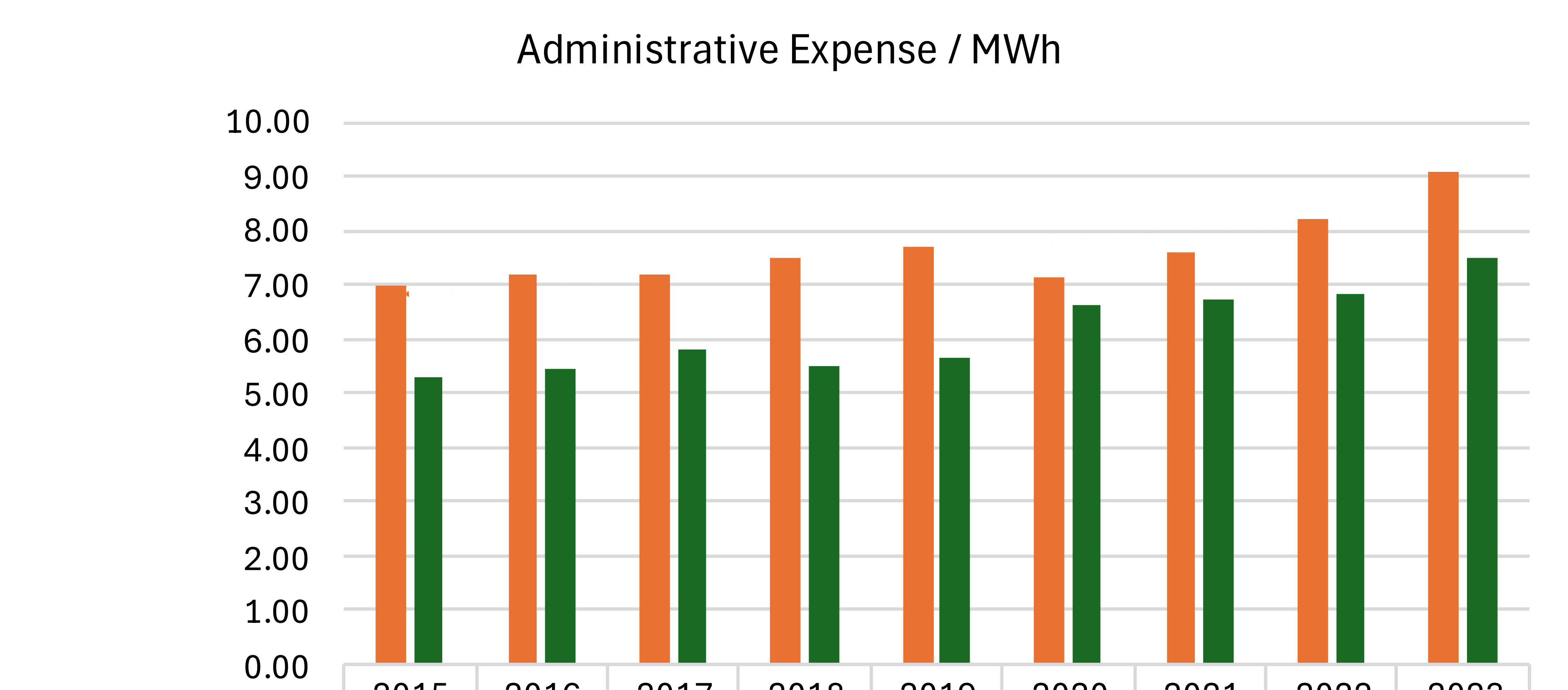
Maintenance Expense / MWh



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	1.35	1.38	1.49	1.19	1.03	1.19	1.05	2.14	2.51
Peer Group Avg.	1.95	1.93	2.03	2.16	1.93	2.04	2.11	2.11	2.05

Hydro Ottawa Peer Group Avg. Linear (Peer Group Avg.)

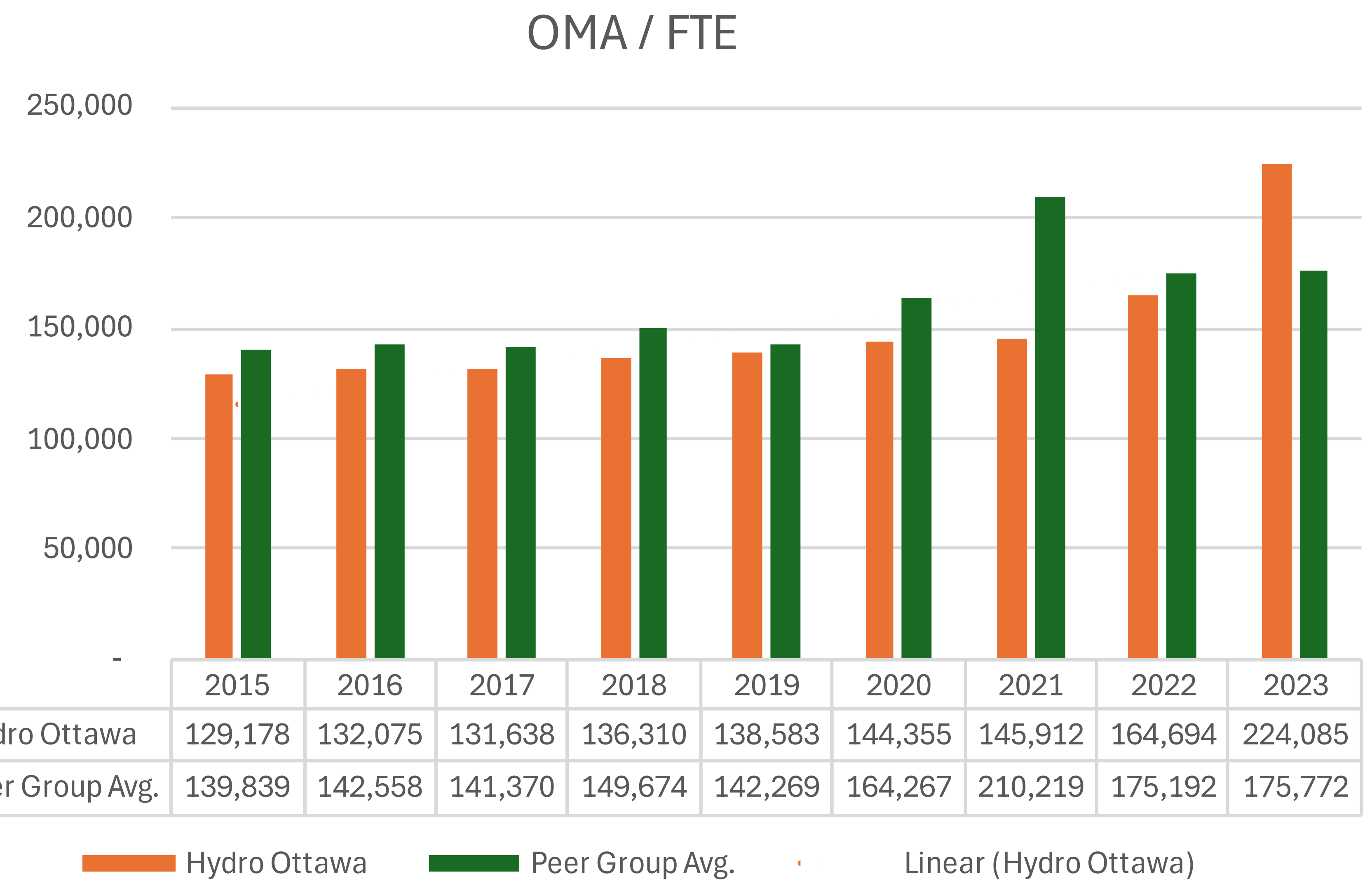
Hydro Ottawa Performance Relative to Customer Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	6.98	7.19	7.20	7.50	7.73	7.13	7.63	8.20	9.09
Peer Group Avg.	5.31	5.45	5.81	5.50	5.65	6.64	6.74	6.83	7.48

Hydro Ottawa Peer Group Avg. Linear (Hydro Ottawa)

Hydro Ottawa Performance Relative to Customer Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	129,178	132,075	131,638	136,310	138,583	144,355	145,912	164,694	224,085
Peer Group Avg.	139,839	142,558	141,370	149,674	142,269	164,267	210,219	175,192	175,772

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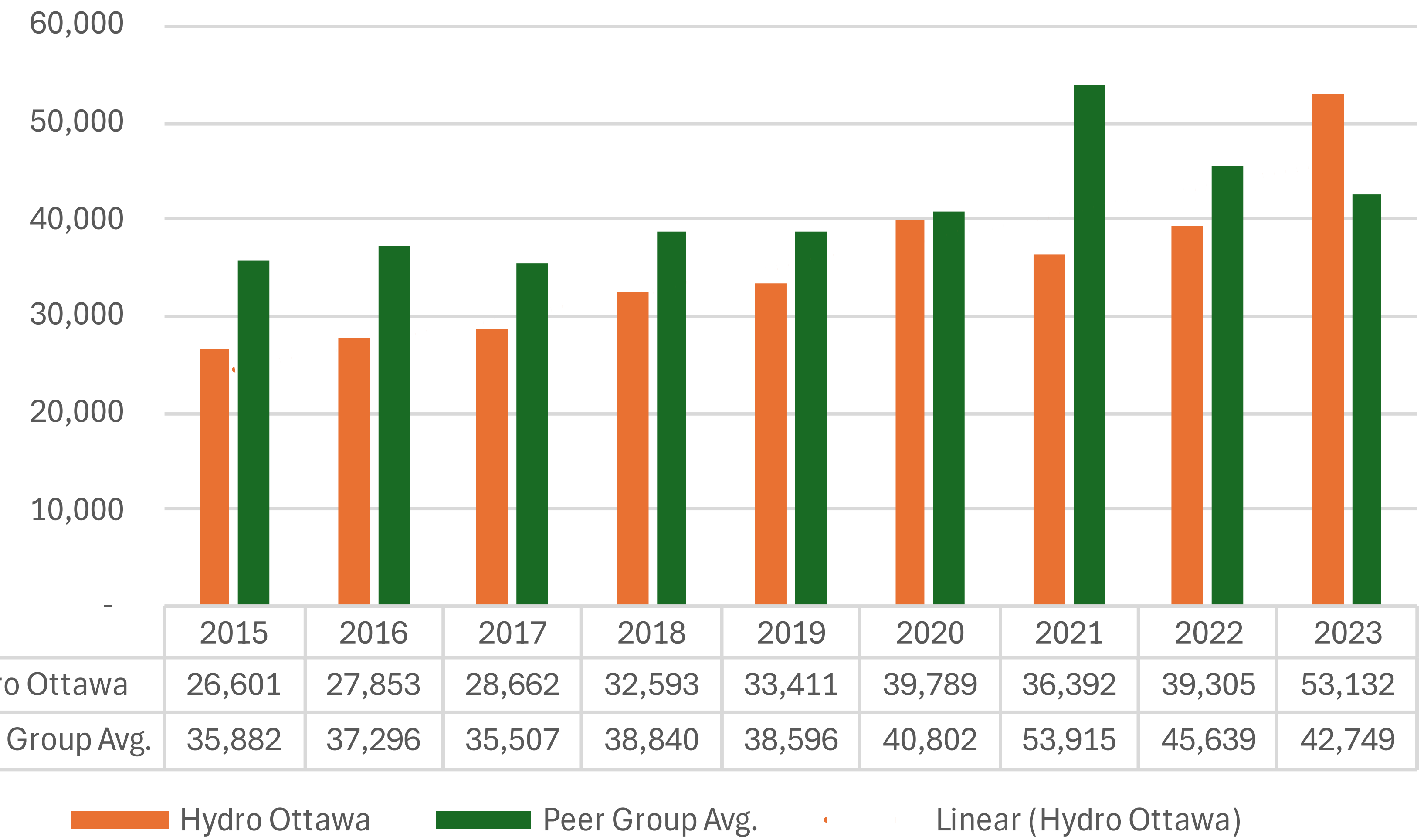
Hydro Ottawa Performance Relative to Customer Cohort

Operating Expense / FTE



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	26,601	27,853	28,662	32,593	33,411	39,789	36,392	39,305	53,132
Peer Group Avg.	35,882	37,296	35,507	38,840	38,596	40,802	53,915	45,639	42,749

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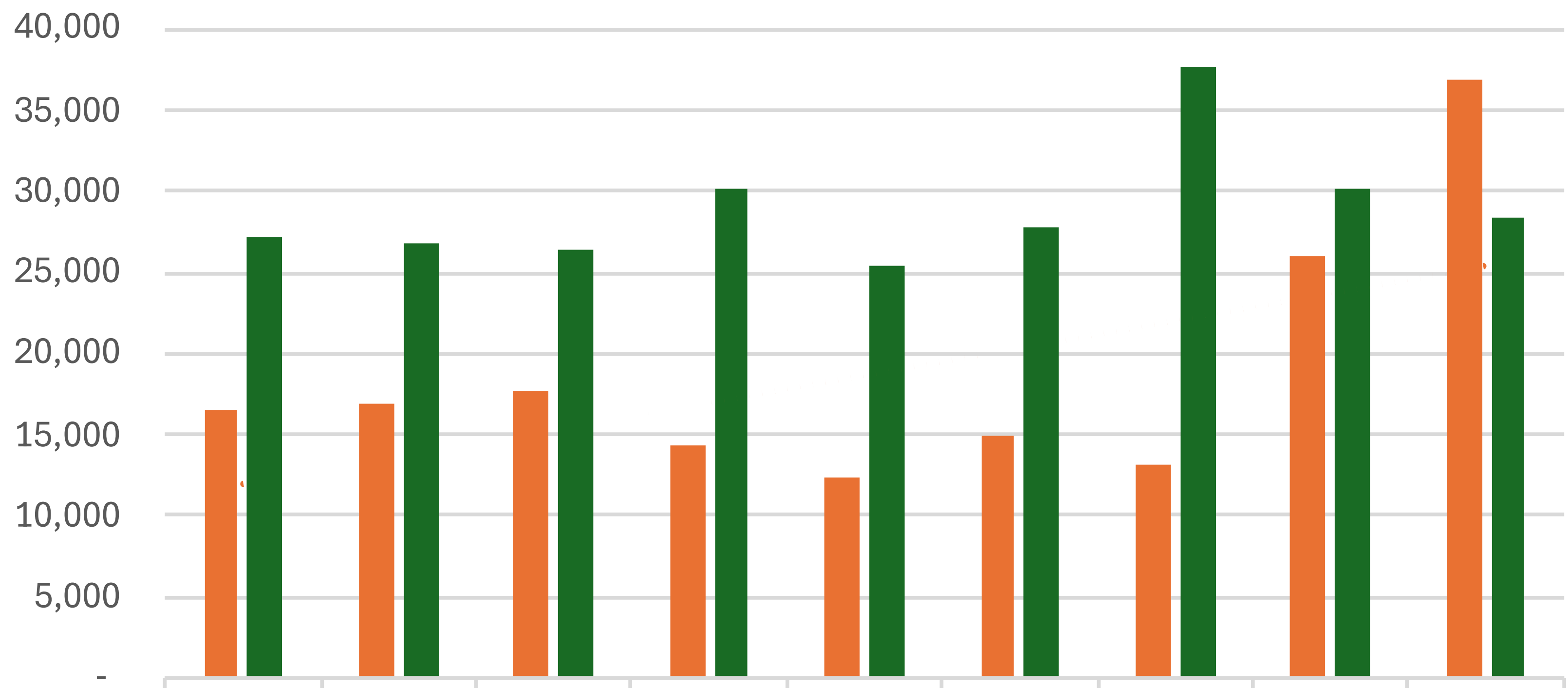
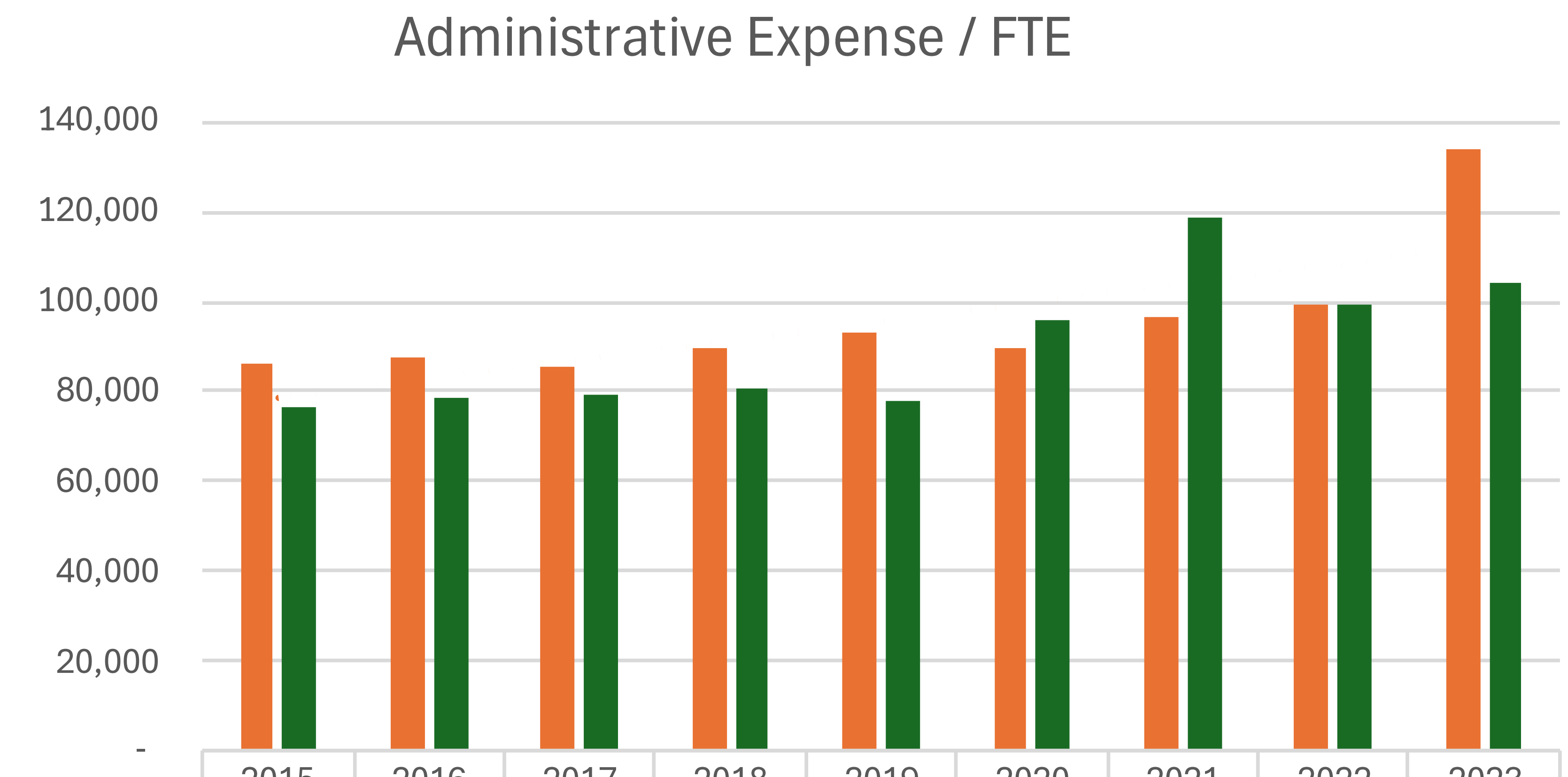
Hydro Ottawa Performance Relative to Customer Cohort

Maintenance Expense / FTE



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	16,581	16,821	17,630	14,246	12,320	14,922	13,192	25,957	36,934
Peer Group Avg.	27,140	26,720	26,426	30,262	25,457	27,817	37,725	30,253	28,457

Hydro Ottawa Performance Relative to Customer Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	85,995	87,401	85,345	89,471	92,852	89,644	96,329	99,432	134,020
Peer Group Avg.	76,817	78,542	79,436	80,572	78,215	95,648	118,580	99,300	104,567

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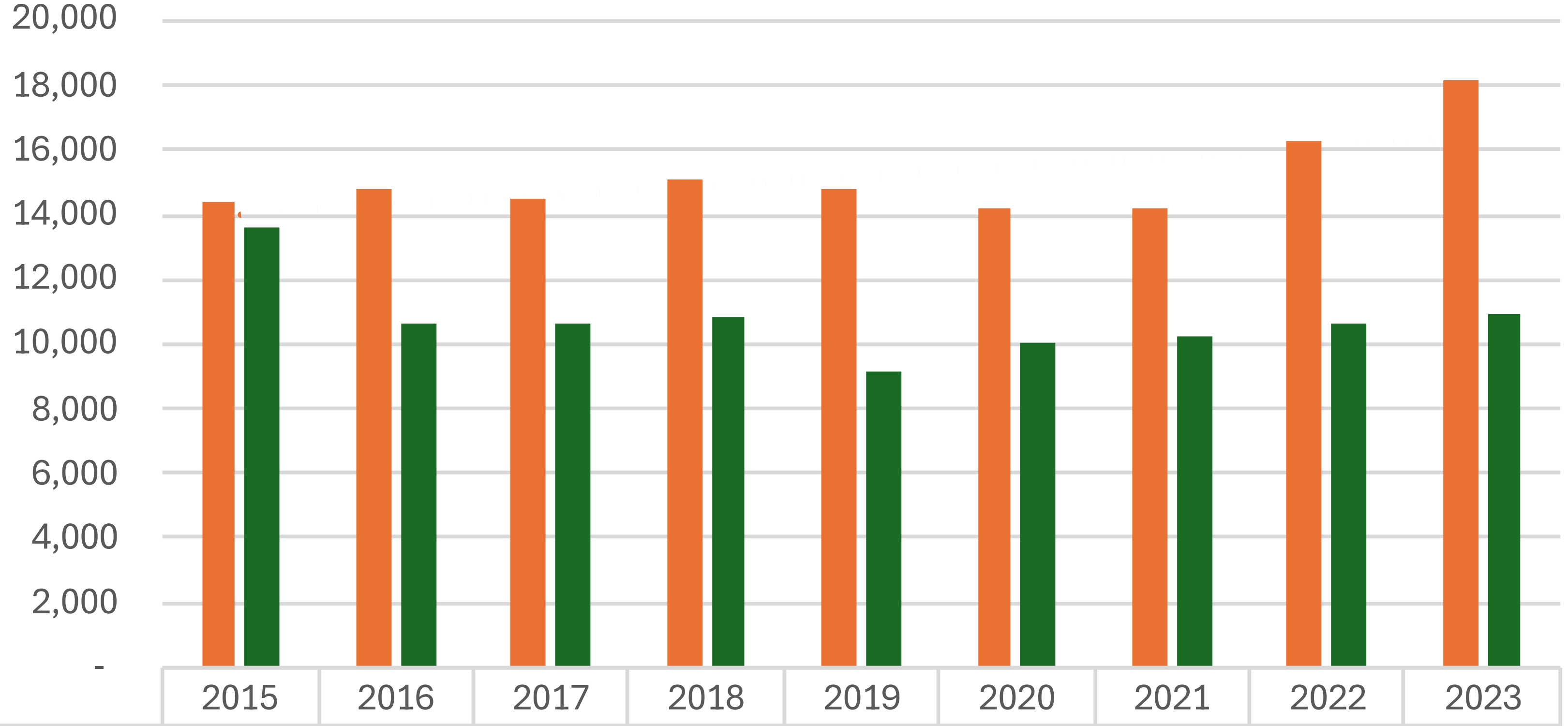
Hydro Ottawa Performance Relative to Customer Cohort

OMA / Circuit KM



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	14,420	14,790	14,473	15,140	14,828	14,174	14,171	16,287	18,157
Peer Group Avg.	13,589	10,633	10,674	10,791	9,115	9,996	10,196	10,646	10,898

Hydro Ottawa   Peer Group Avg.   Linear (Hydro Ottawa)

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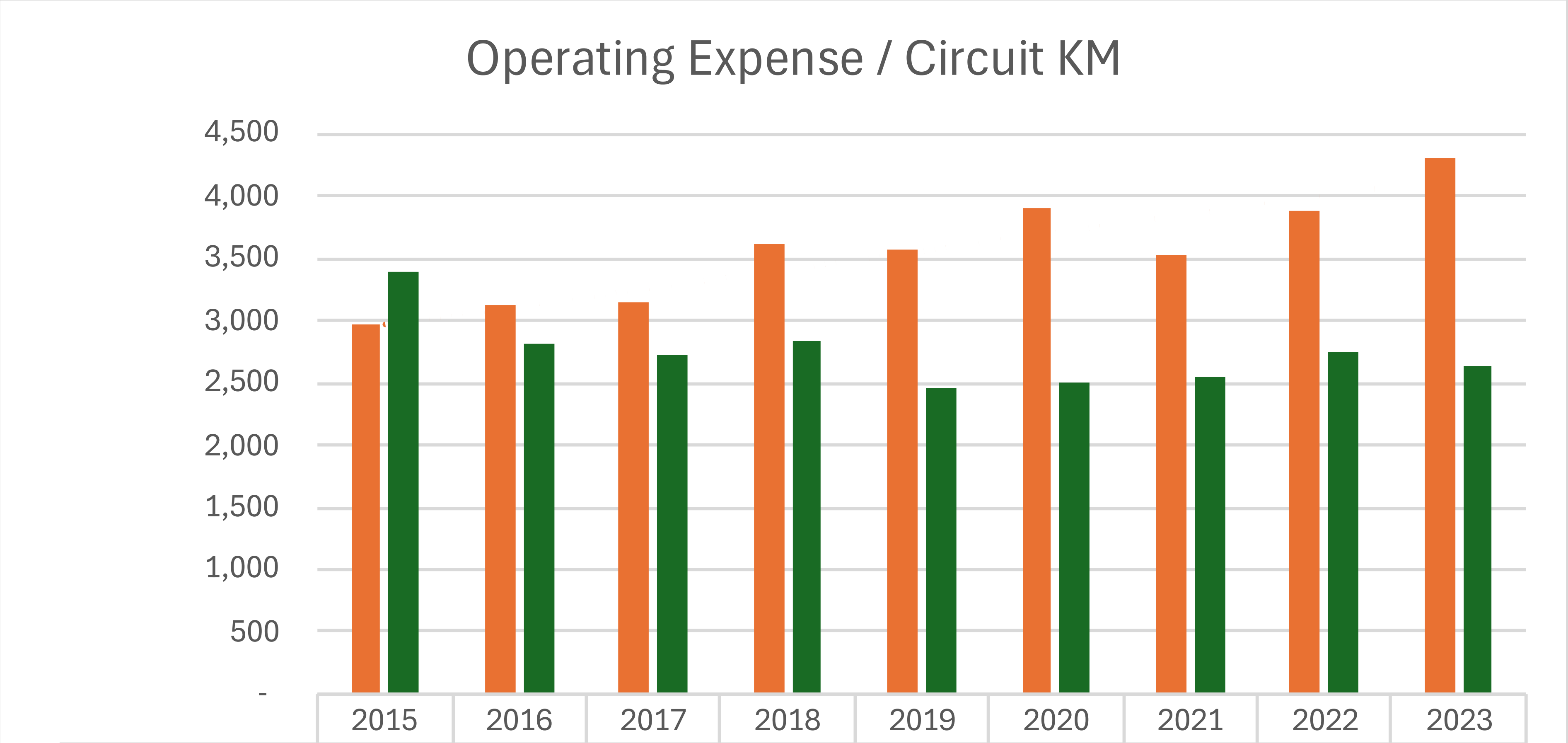
Hydro Ottawa Performance Relative to Customer Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	2,969	3,119	3,151	3,620	3,575	3,907	3,534	3,887	4,305
Peer Group Avg.	3,387	2,824	2,734	2,842	2,464	2,510	2,553	2,756	2,649

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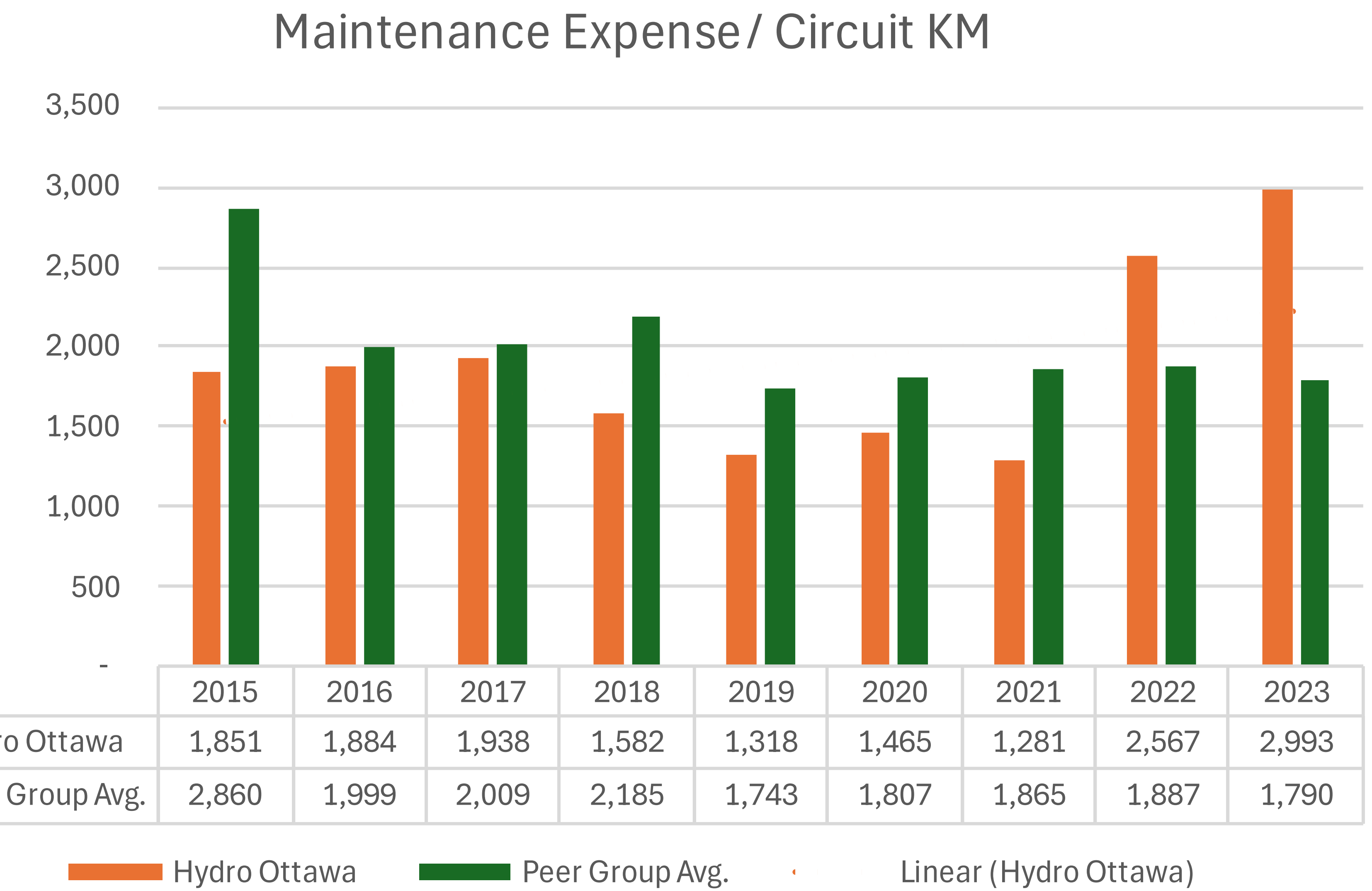
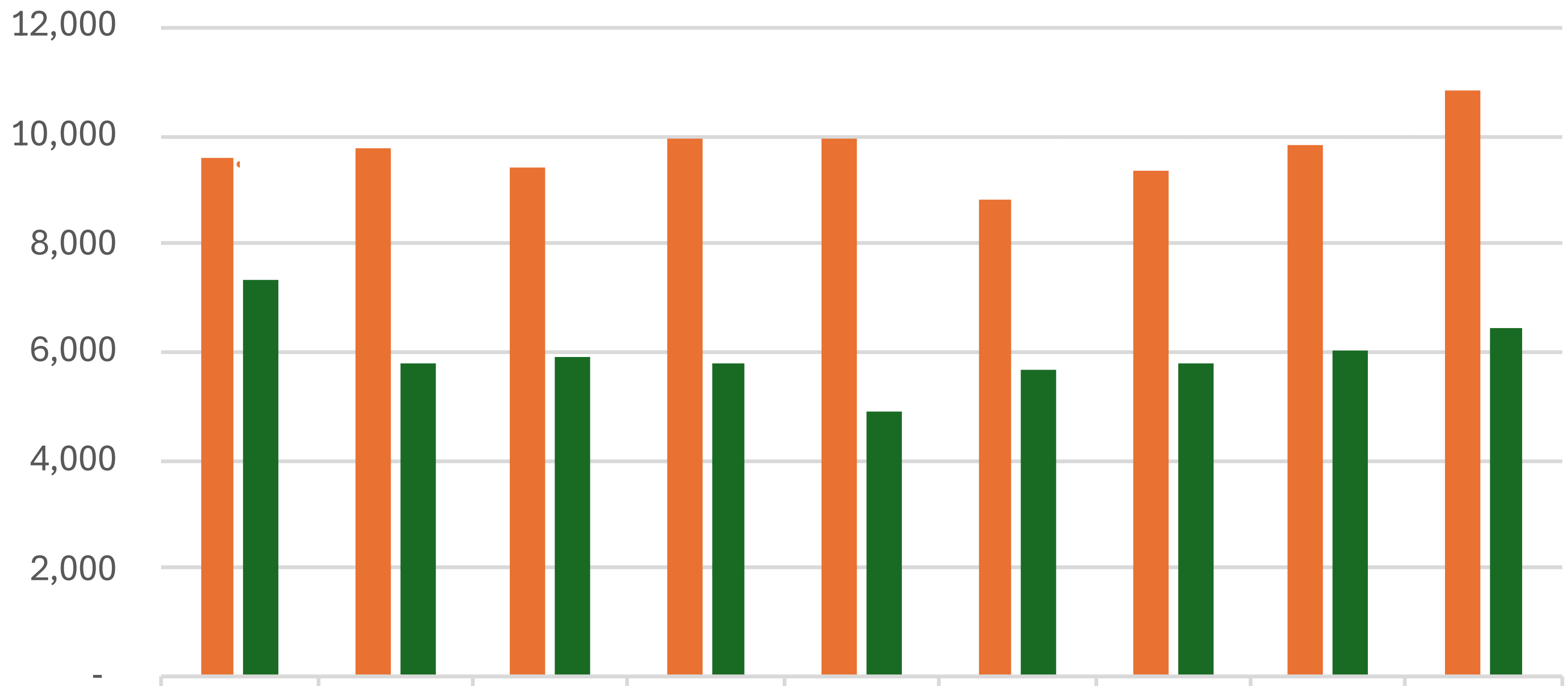
Hydro Ottawa Performance Relative to Customer Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	1,851	1,884	1,938	1,582	1,318	1,465	1,281	2,567	2,993
Peer Group Avg.	2,860	1,999	2,009	2,185	1,743	1,807	1,865	1,887	1,790

Hydro Ottawa Performance Relative to Customer Cohort

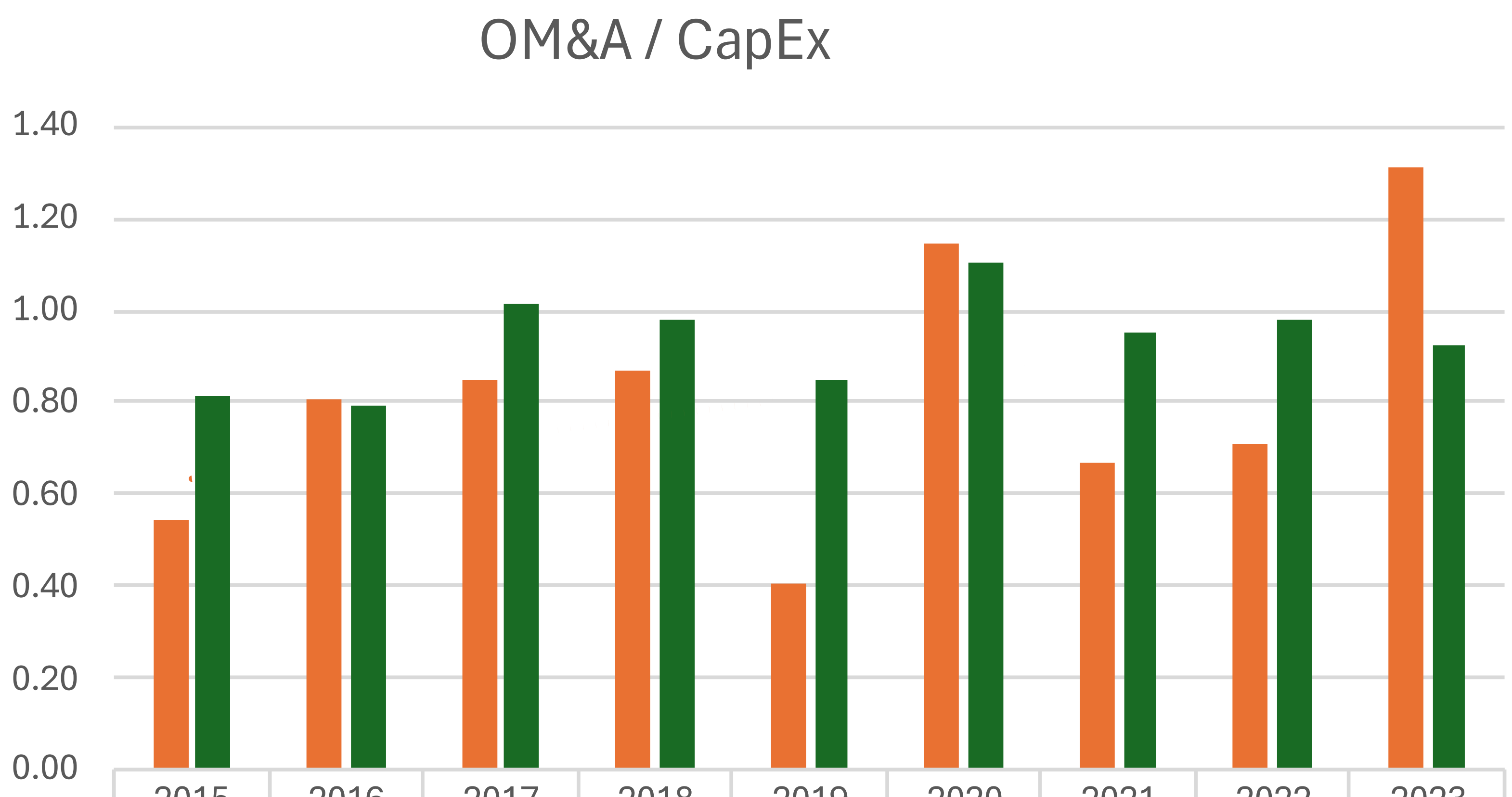
Administrative Expenses / Circuit KM



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	9,600	9,787	9,383	9,938	9,935	8,802	9,355	9,833	10,859
Peer Group Avg.	7,343	5,810	5,931	5,764	4,908	5,679	5,777	6,004	6,459

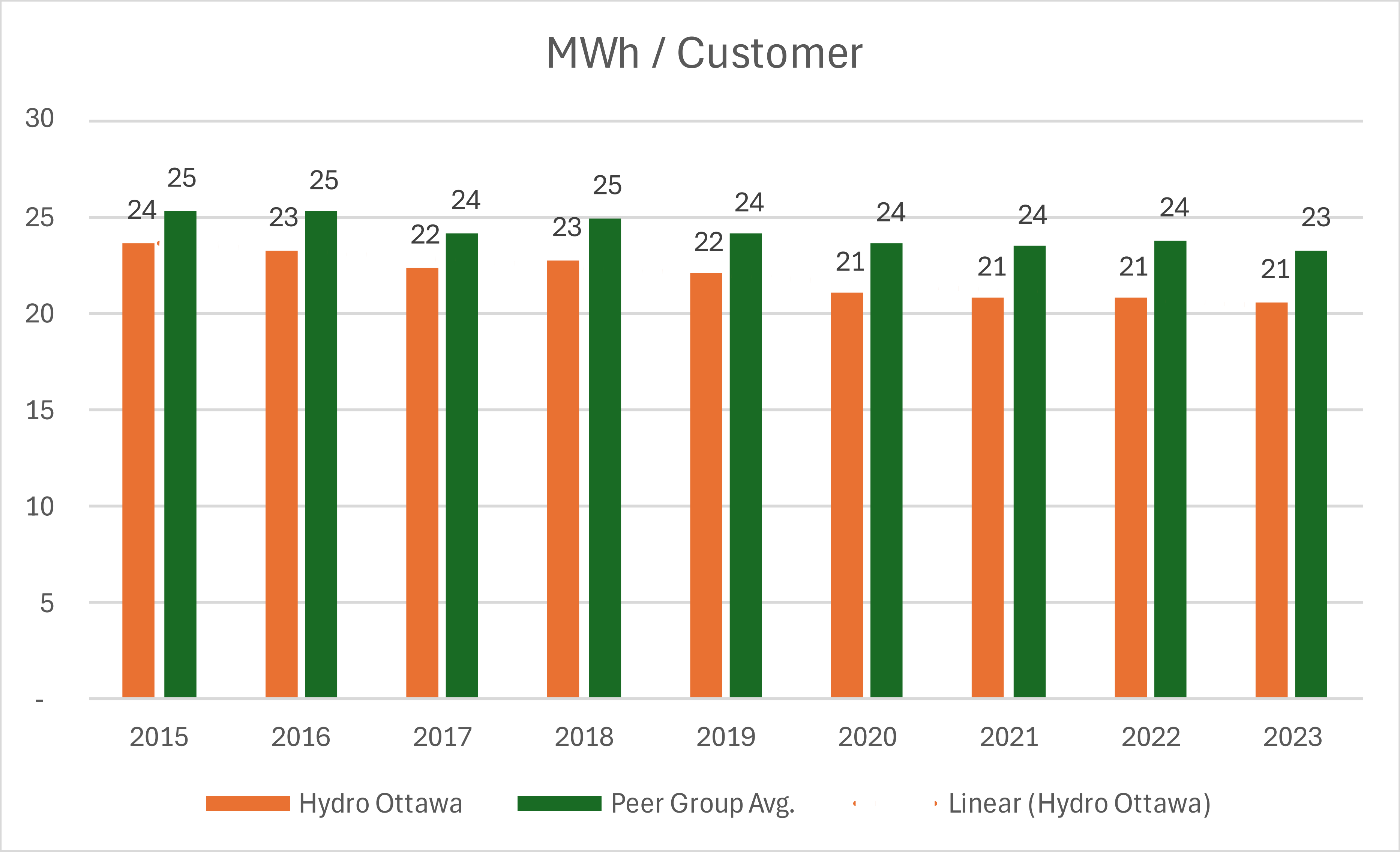
Hydro Ottawa Peer Group Avg. Linear (Hydro Ottawa)

Hydro Ottawa Performance Relative to Customer Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	0.55	0.80	0.85	0.87	0.40	1.15	0.67	0.71	1.31
Peer Group Avg.	0.81	0.79	1.02	0.98	0.85	1.11	0.95	0.98	0.93

Hydro Ottawa Performance Relative to Customer Cohort



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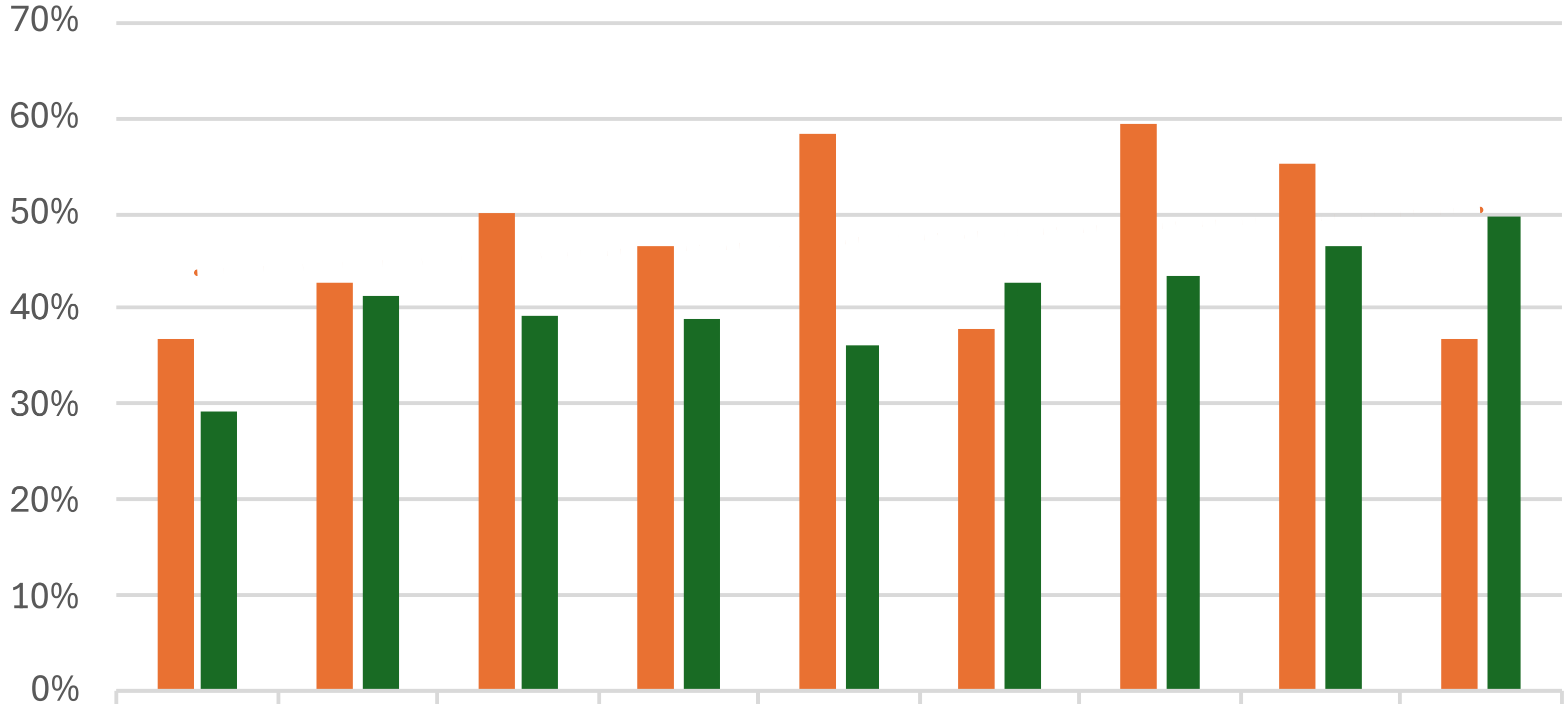
Hydro Ottawa Performance Relative to Customer Cohort

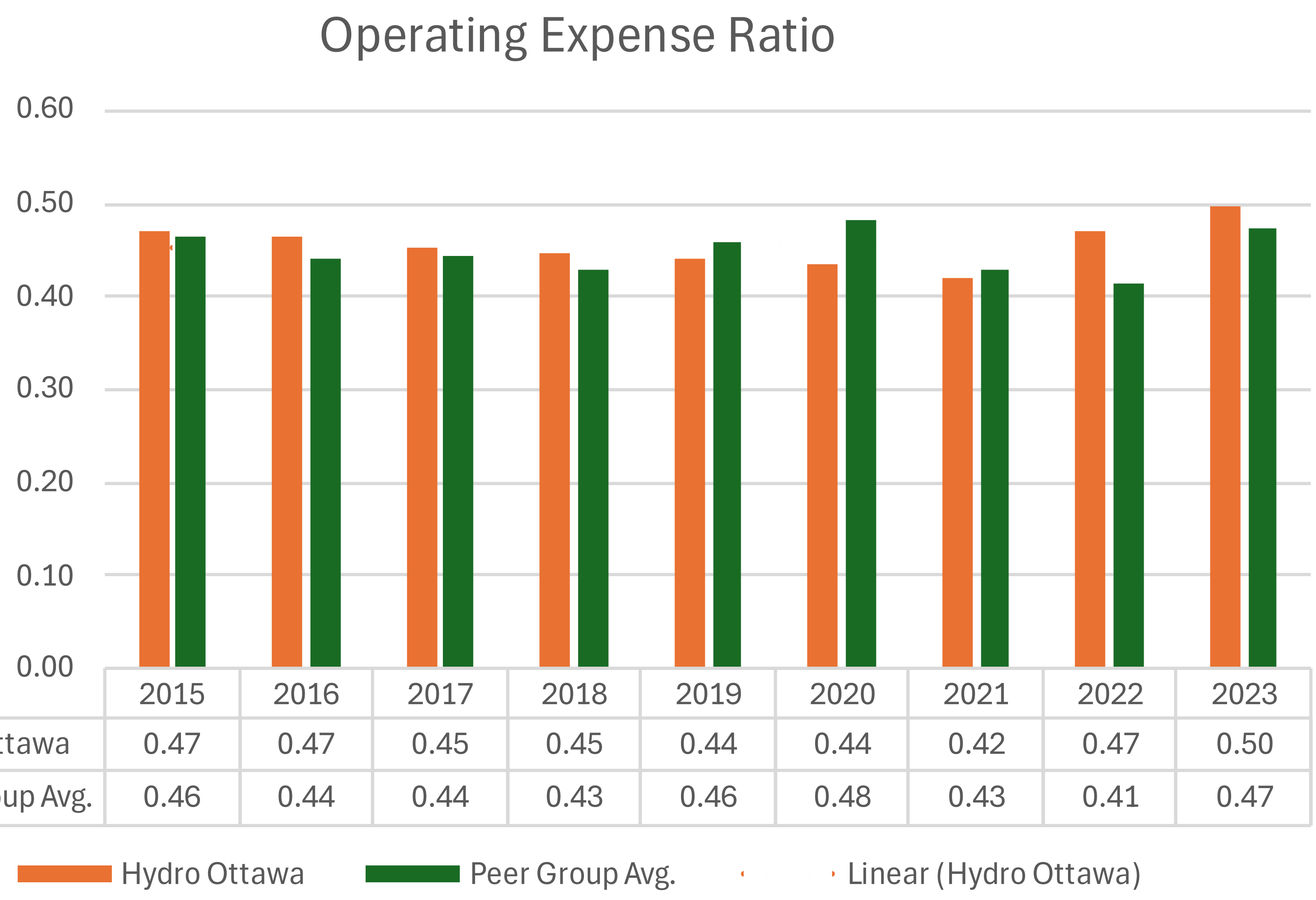
(Contract Services) / Total CapEx



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	37%	43%	50%	47%	58%	38%	59%	55%	37%
Peer Group Avg.	29%	41%	39%	39%	36%	43%	43%	47%	50%

Hydro Ottawa   Peer Group Avg.   Linear (Hydro Ottawa)

Hydro Ottawa Performance Relative to Customer Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	0.47	0.47	0.45	0.45	0.44	0.44	0.42	0.47	0.50
Peer Group Avg.	0.46	0.44	0.44	0.43	0.46	0.48	0.43	0.41	0.47

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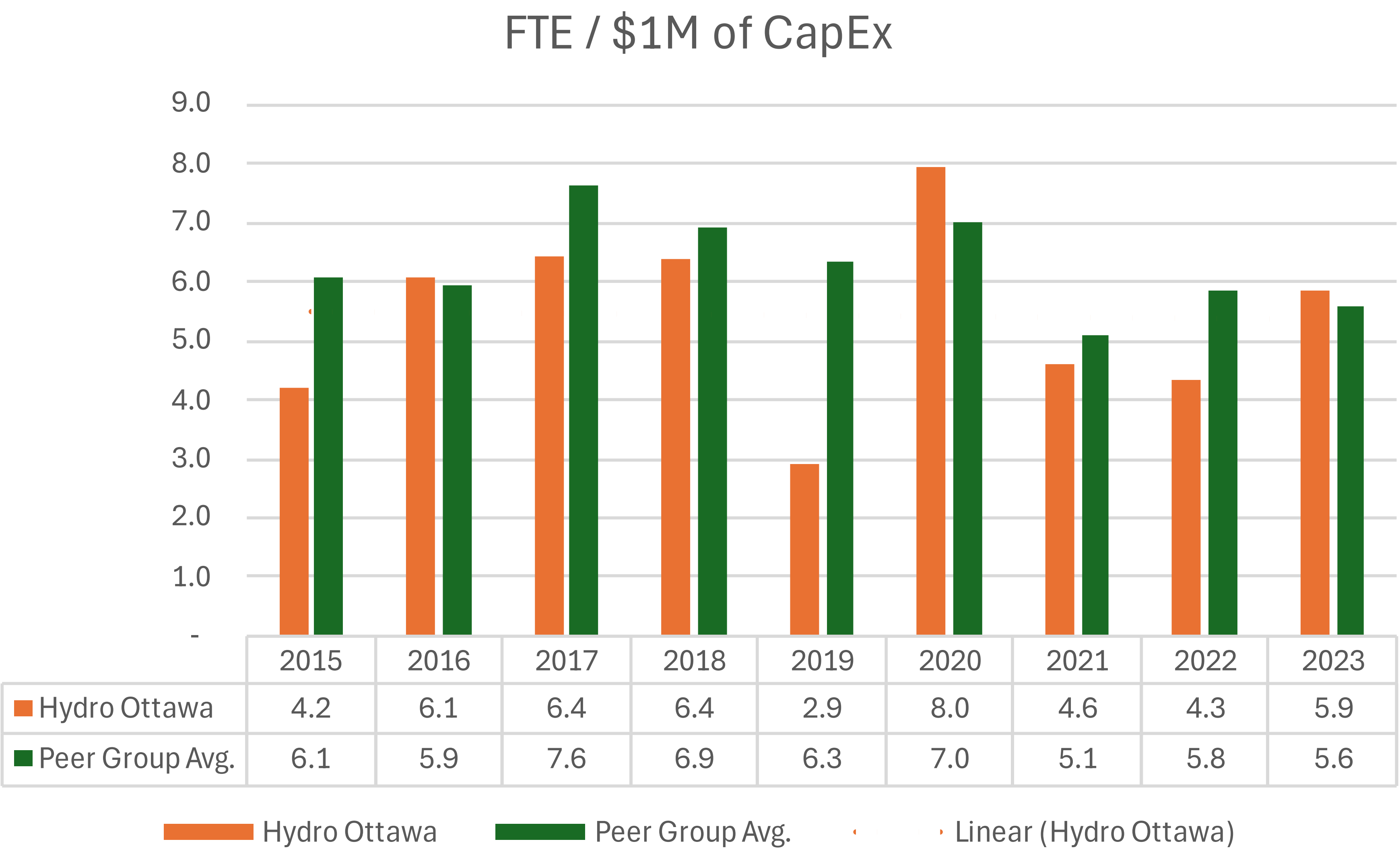
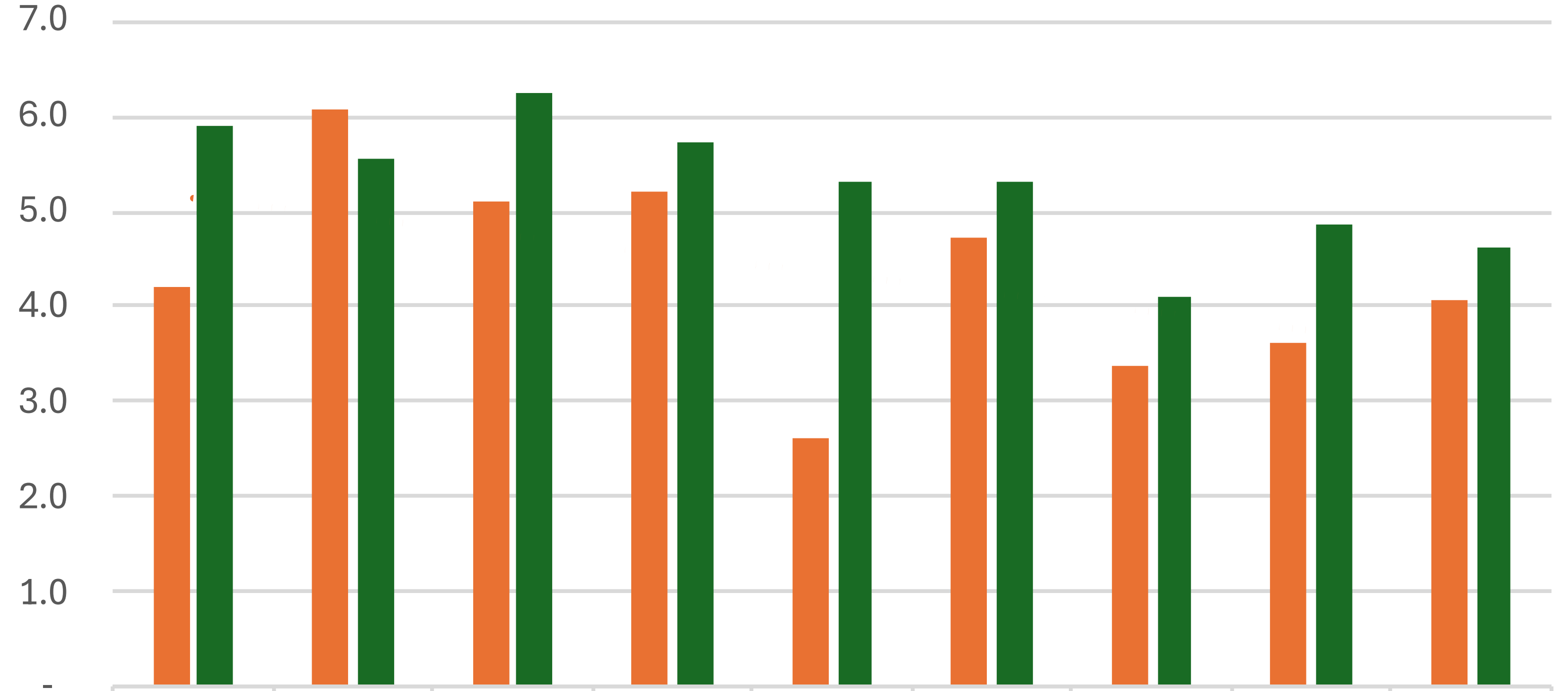
Hydro Ottawa Performance Relative to Customer Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	4.2	6.1	6.4	6.4	2.9	8.0	4.6	4.3	5.9
Peer Group Avg.	6.1	5.9	7.6	6.9	6.3	7.0	5.1	5.8	5.6

Hydro Ottawa Performance Relative to Customer Cohort

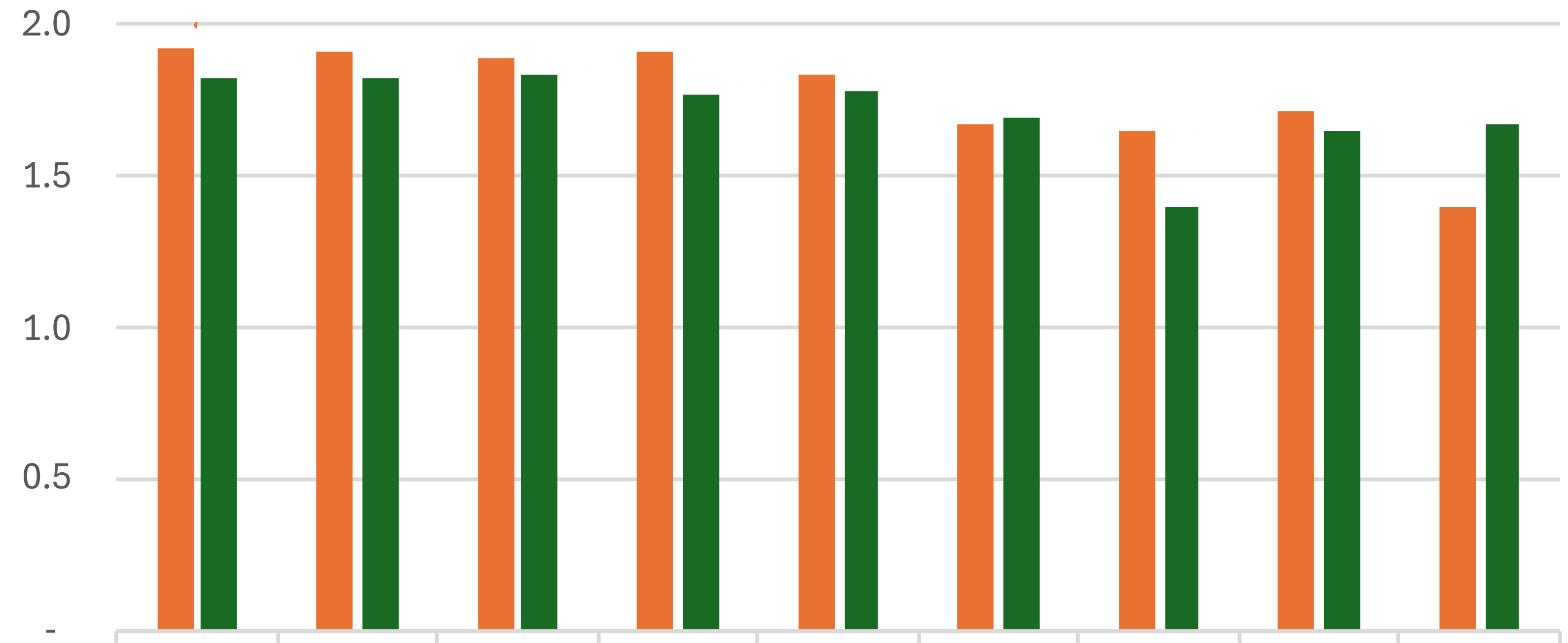
FTE / $1M of CapEx Additions



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	4.2	6.1	5.1	5.2	2.6	4.7	3.4	3.6	4.1
Peer Group Avg.	5.9	5.5	6.3	5.7	5.3	5.3	4.1	4.9	4.6

Hydro Ottawa Performance Relative to Customer Cohort

FTE / 1,000 Customer



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	1.9	1.9	1.9	1.9	1.8	1.7	1.6	1.7	1.4
Peer Group Avg.	1.8	1.8	1.8	1.8	1.8	1.7	1.4	1.6	1.7

Hydro Ottawa   Peer Group Avg.   Linear (Hydro Ottawa)

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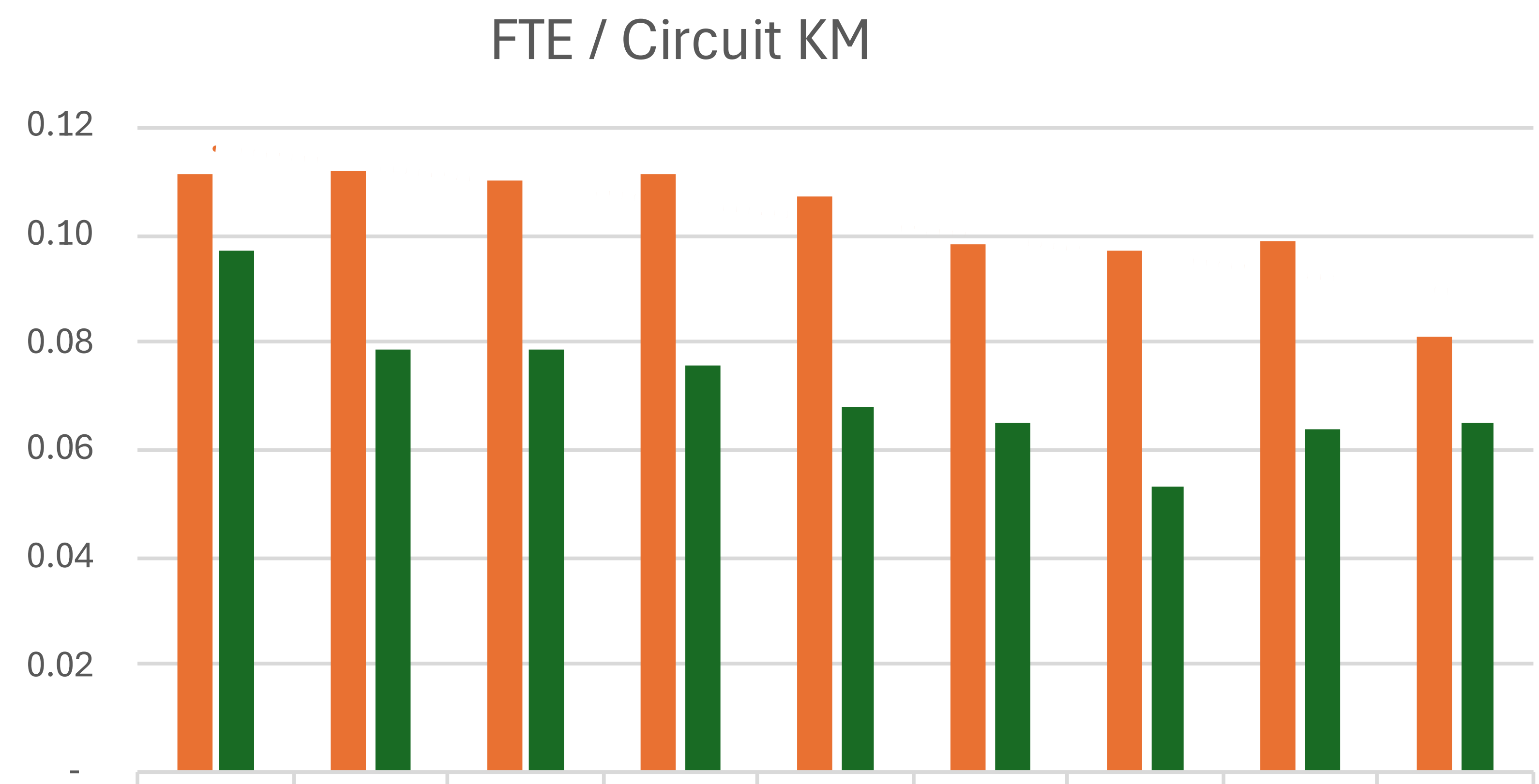
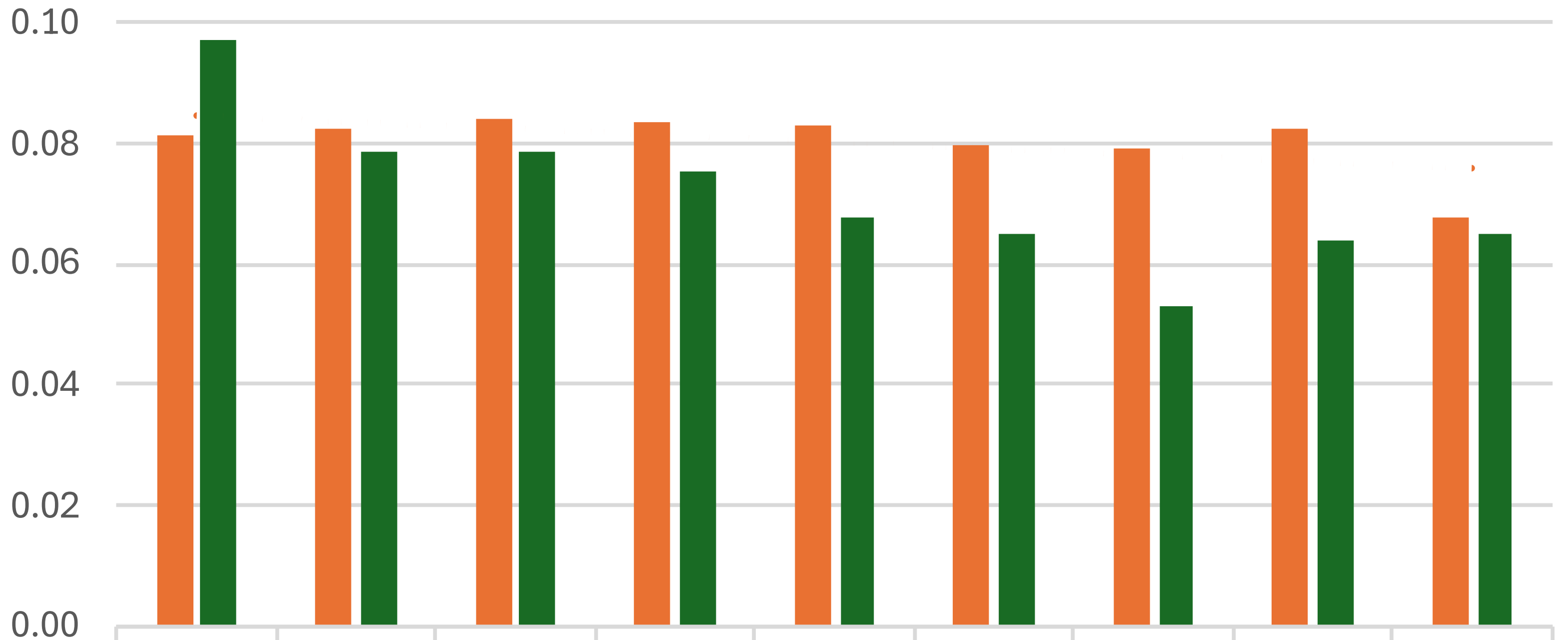
Hydro Ottawa Performance Relative to Customer Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	0.11	0.11	0.11	0.11	0.11	0.10	0.10	0.10	0.08
Peer Group Avg.	0.10	0.08	0.08	0.08	0.07	0.06	0.05	0.06	0.06

Hydro Ottawa Performance Relative to Customer Cohort

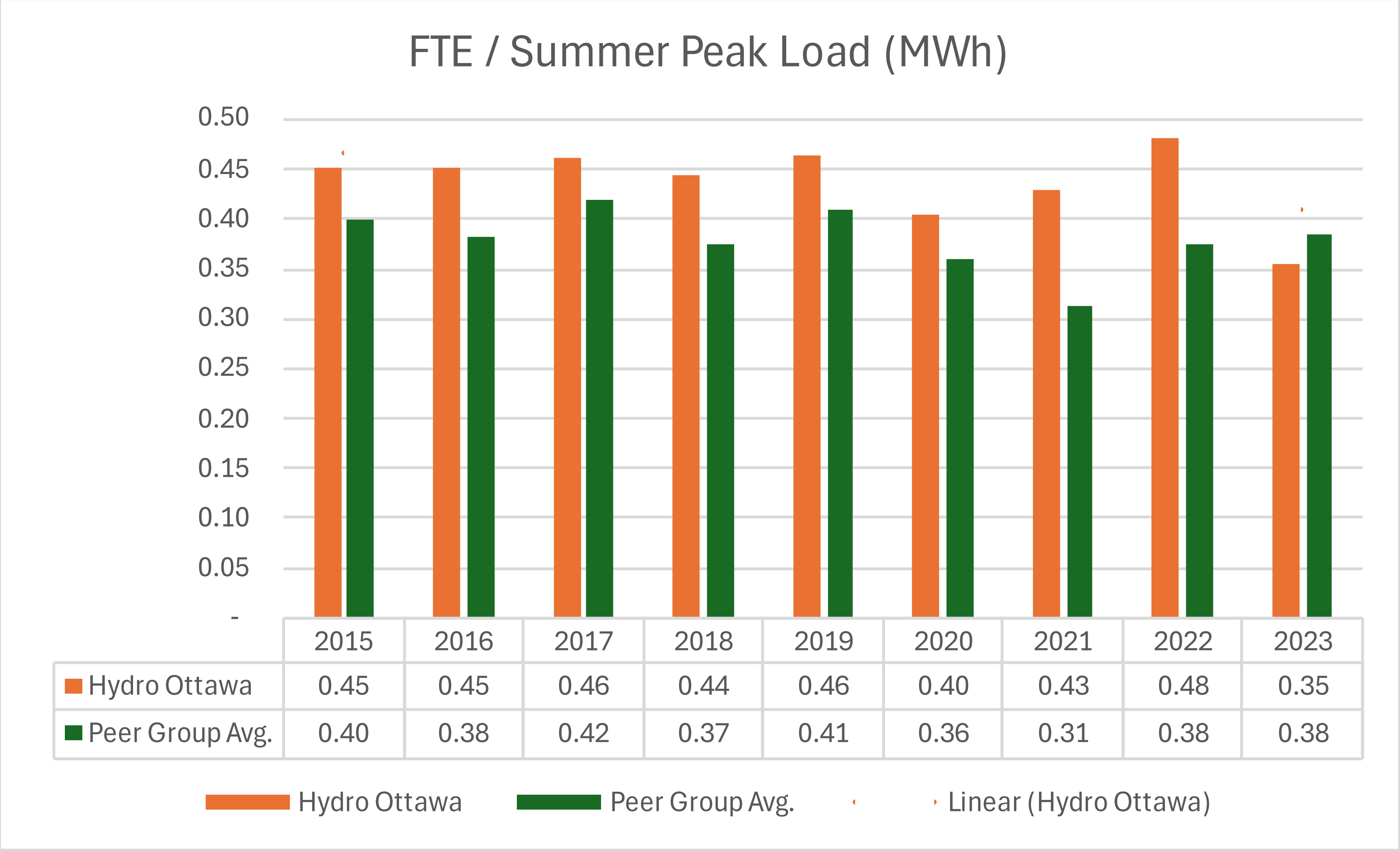
FTE / GWh



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.07
Peer Group Avg.	0.10	0.08	0.08	0.08	0.07	0.06	0.05	0.06	0.06

Hydro Ottawa   Peer Group Avg.   Linear (Hydro Ottawa)

Hydro Ottawa Performance Relative to Customer Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	0.45	0.45	0.46	0.44	0.46	0.40	0.43	0.48	0.35
Peer Group Avg.	0.40	0.38	0.42	0.37	0.41	0.36	0.31	0.38	0.38

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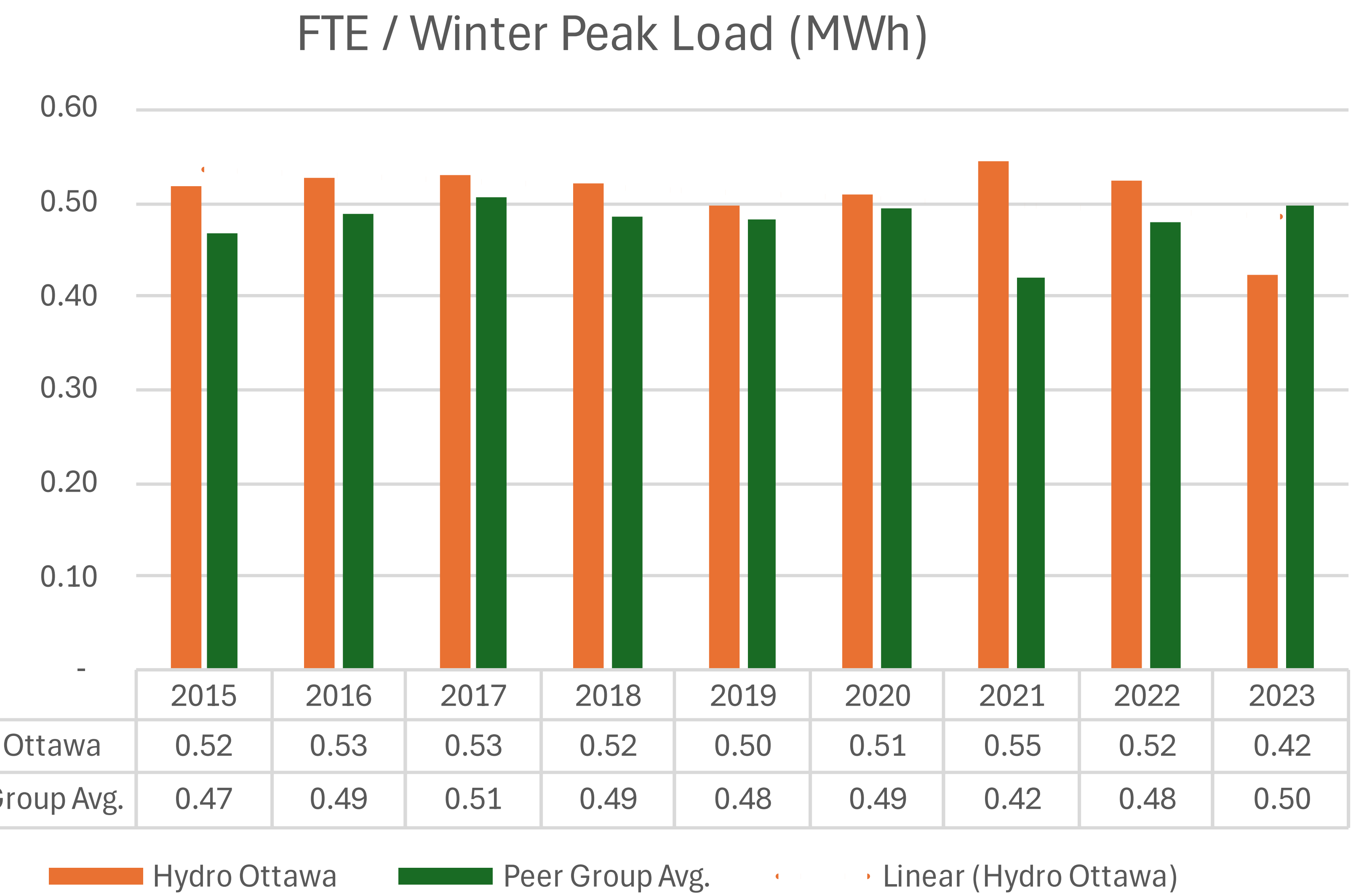
Hydro Ottawa Performance Relative to Customer Cohort



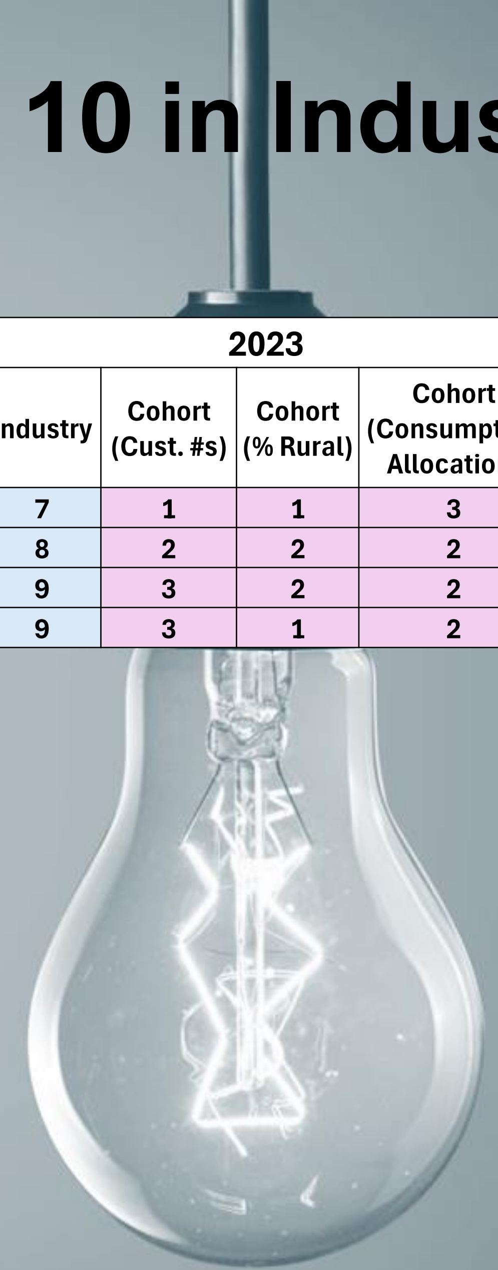
	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	0.52	0.53	0.53	0.52	0.50	0.51	0.55	0.52	0.42
Peer Group Avg.	0.47	0.49	0.51	0.49	0.48	0.49	0.42	0.48	0.50

Benchmarking Universe

Hydro Ottawa Ranking Relative to Distributor Data Set

Hydro Ottawa Ranking is Top 10 in Industry

Metric	2015	2016	2017	2018	2019	2020	2021	2022	2023 Industry	2023 Cohort (Cust. #s)	2023 Cohort (% Rural)	2023 Cohort (Consumption Allocation)
Circuit km / 1,000 Customers	11	11	8	8	8	7	7	7	**7**	**1**	**1**	**3**
FTE / 1,000 Customer	26	27	26	26	25	21	23	24	**8**	**2**	**2**	**2**
FTE / Summer Peak Load (MWh)	21	23	21	24	24	22	25	30	**9**	**3**	**2**	**2**
FTE / Winter Peak Load (MWh)	26	25	25	29	27	25	28	26	**9**	**3**	**1**	**2**



Hydro Ottawa Ranking is 11 to 20 in Industry

									2023			
Metric	2015	2016	2017	2018	2019	2020	2021	2022	Industry	Cohort (Cust. #s)	Cohort (% Rural)	Cohort (Consumption Allocation)
FTE / $1M of CapEx Additions	6	15	5	9	2	6	4	3	**11**	**3**	**2**	**1**
FTE / $1M of CapEx	6	12	7	7	2	15	5	2	**12**	**3**	**1**	**1**
FTE / GWh	23	23	23	25	24	24	24	24	**12**	**3**	**2**	**2**
Administrative Expense / Customer	26	24	17	23	22	11	13	12	**15**	**5**	**5**	**3**
Administrative Expenses / MWh	16	17	15	17	20	15	17	17	**19**	**6**	**5**	**6**
Reliability	9	15	13	9	8	17	7	4	**20**	**4**	**3**	**5**
OMA / Customer	13	13	13	16	14	7	5	13	**20**	**5**	**4**	**5**
OMA / CapEx	4	6	5	4	2	10	3	3	**20**	**5**	**3**	**3**

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Hydro Ottawa Ranking 21 to 30 in Industry

									2023			
Metric	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**Industry**	**Cohort (Cust. #s)**	**Cohort (% Rural)**	**Cohort (Consumption Allocation)**
OMA / MWh	10	14	10	14	13	11	9	17	**21**	**6**	**4**	**7**
MWh / Customer	35	34	35	33	34	31	26	27	**27**	**3**	**3**	**3**
Maintenance Expense / MWh	12	12	12	8	7	8	4	21	**28**	**4**	**3**	**9**
(Contract Services) / Total CapEx	34	35	35	43	46	33	44	42	**28**	**2**	**3**	**7**
Maintenance Expense / Customer	11	13	12	8	8	8	7	21	**30**	**4**	**3**	**9**

Hydro Ottawa Ranking 31 to 54 in Industry

									2023			
Metric	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**Industry**	**Cohort (Cust. #s)**	**Cohort (% Rural)**	**Cohort (Consumption Allocation)**
Operating Expense / Customer	22	21	20	31	26	29	24	30	**31**	**4**	**4**	**5**
Operating Expense / MWh	19	21	21	27	26	28	21	27	**31**	**5**	**3**	**6**
FTE / Circuit KM	37	37	39	42	42	40	41	43	**33**	**4**	**4**	**5**
Maintenance Expense / FTE	12	12	14	11	6	9	8	23	**36**	**5**	**4**	**7**
Administrative Expense / FTE	18	16	15	16	18	12	17	13	**38**	**6**	**6**	**7**
OMA/FTE	11	10	9	11	13	13	11	16	**40**	**6**	**4**	**7**
Maintenance Expense / Circuit KM	23	24	25	20	22	24	22	34	**40**	**6**	**4**	**8**
Administrative Expenses / Circuit KM	37	35	36	37	36	36	39	40	**41**	**6**	**6**	**6**
Operating Expense / FTE	23	29	26	31	33	34	31	34	**42**	**5**	**5**	**8**
OMA / Circuit KM	34	34	36	37	35	37	38	42	**43**	**6**	**6**	**7**
Operating Expense Ratio	48	49	49	48	48	50	50	44	**44**	**3**	**6**	**8**
Operating Expense / Circuit KM	37	38	41	43	44	46	46	49	**50**	**6**	**6**	**8**

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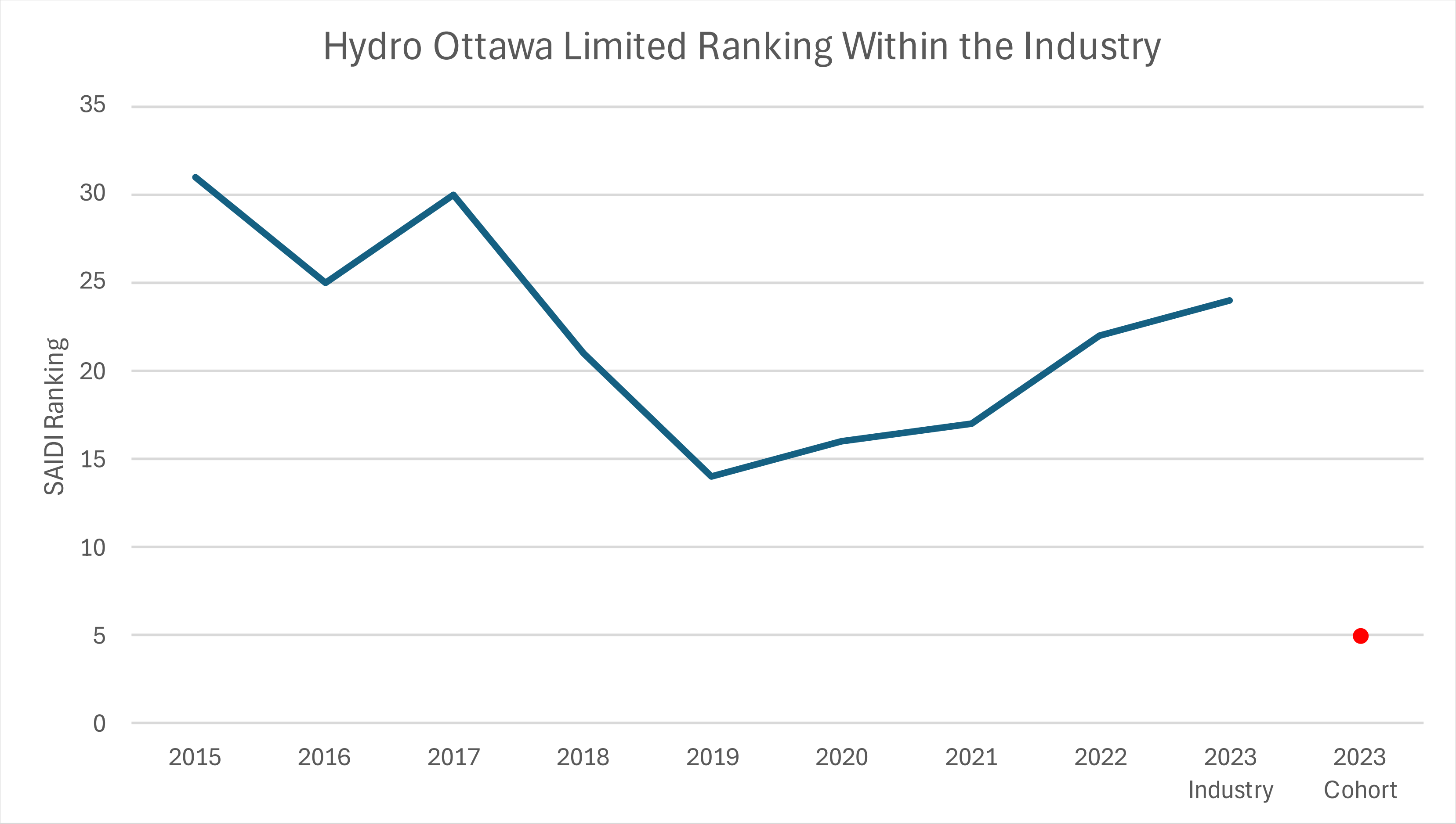
Benchmarking Universe

Hydro Ottawa Reliability Ranking Relative to Distributor Data Set

Hydro Ottawa Reliability Ranking: SAIDI

	2015	2016	2017	2018	2019	2020	2021	2022	2023 Industry	2023 Cohort
SAIDI - Average Number of Times that Power to a Customer is Interrupted	31	25	30	21	14	16	17	22	24	5



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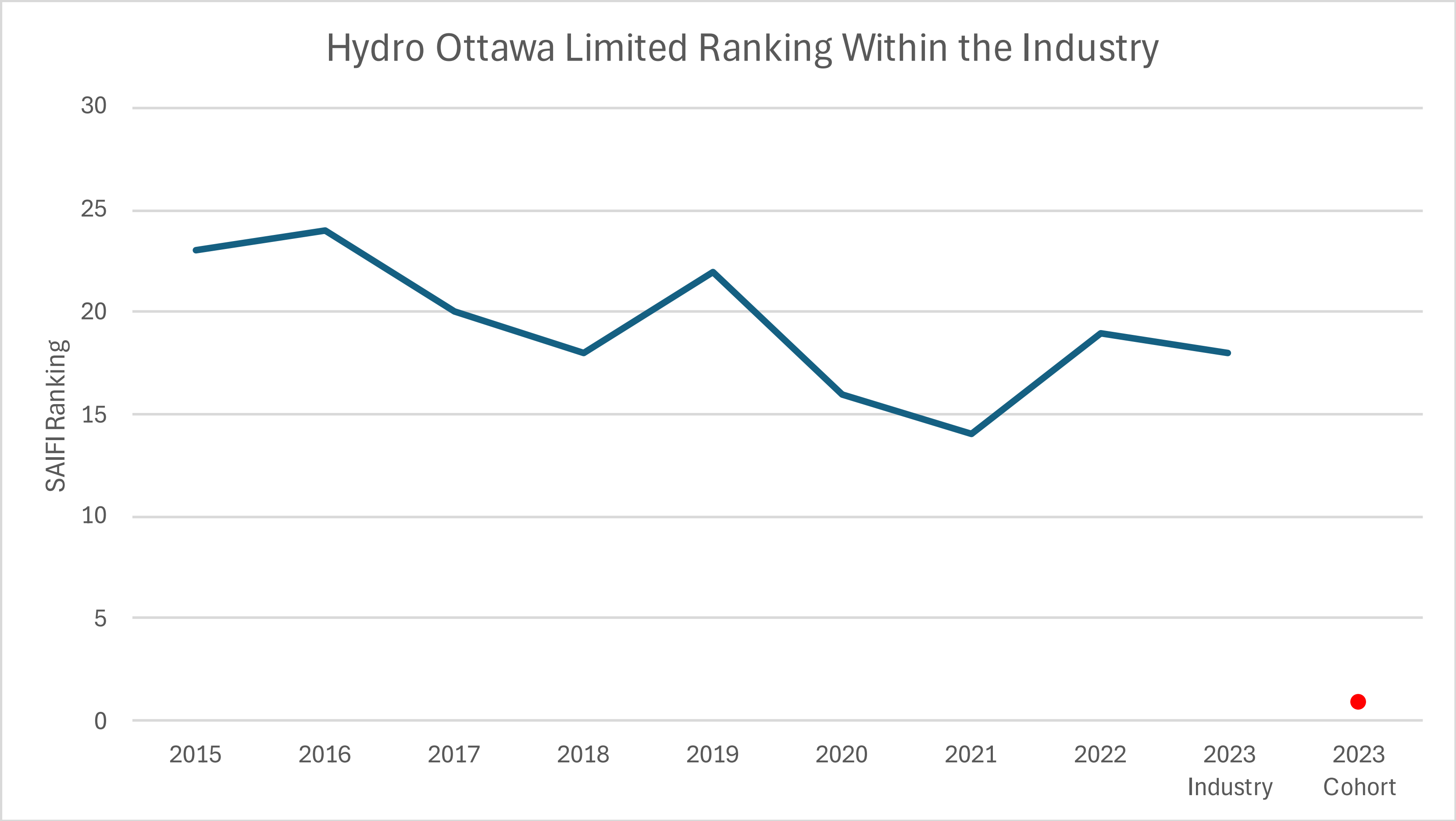
Hydro Ottawa Reliability Ranking: SAIFI

	2015	2016	2017	2018	2019	2020	2021	2022	2023 Industry	2023 Cohort
SAIFI - Average Number of Hours that Power to a Customer is Interrupted	23	24	20	18	22	16	14	19	18	1



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Appendix

Database of Distributors used in Benchmarking Analysis

Hydro Ottawa Limited	Greater Sudbury Hydro Inc.	Orangeville Hydro Limited
Algoma Power Inc.	Grimsby Power Incorporated	Oshawa PUC Networks Inc.
Atikokan Hydro Inc.	Halton Hills Hydro Inc.	Ottawa River Power Corporation
Bluewater Power Distribution Corporation	Hearst Power Distribution Company Limited	PUC Distribution Inc.
Burlington Hydro Inc.	Hydro 2000 Inc.	Renfrew Hydro Inc.
Canadian Niagara Power Inc.	Hydro Hawkesbury Inc.	Rideau St. Lawrence Distribution Inc.
Centre Wellington Hydro Ltd.	Hydro One Networks Inc.	Sioux Lookout Hydro Inc.
Chapleau Public Utilities Corporation	Hydro Ottawa Limited	Synergy North Corporation
Cooperative Hydro Embrun Inc.	InnPower Corporation	Tillsonburg Hydro Inc.
E.L.K. Energy Inc.	Kingston Hydro Corporation	Toronto Hydro-Electric System Limited
ENWIN Utilities Ltd.	Lakefront Utilities Inc.	Wasaga Distribution Inc.
EPCOR Electricity Distribution Ontario Inc.	Lakeland Power Distribution Ltd.	Welland Hydro-Electric System Corp.
ERTH Power Corporation	London Hydro Inc.	Wellington North Power Inc.
Elexicon Energy Inc.	Milton Hydro Distribution Inc.	Westario Power Inc.
Enova Power Corp.	Newmarket-Tay Power Distribution Ltd.	
Entegrus Powerlines Inc.	Niagara Peninsula Energy Inc.	
Essex Powerlines Corporation	Niagara-on-the-Lake Hydro Inc.	
Festival Hydro Inc.	North Bay Hydro Distribution Limited	
Fort Frances Power Corporation	Northern Ontario Wires Inc.	
GrandBridge Energy Inc.	Oakville Hydro Electricity Distribution Inc.	

Additional Cohort Groups for Consideration

Rural Ratio

Elexicon Energy Inc.	59.57%
Hydro Ottawa Limited	59.32%
London Hydro Inc.	57.99%
Bluewater Power Distribution Corporation	54.17%
Burlington Hydro Inc.	47.87%
Welland Hydro-Electric System Corp.	44.44%

Load Distribution Ratio

	% Residential kWh	% GS<50 kWh	% GS>50 kWh
Niagara Peninsula Energy Inc.	37.2%	10.8%	52.0%
Enova Power Corp.	37.0%	14.3%	48.7%
Hydro Ottawa Limited	36.6%	11.0%	52.5%
ENWIN Utilities Ltd.	36.4%	14.8%	48.8%
Niagara-on-the-Lake Hydro Inc.	36.4%	21.5%	42.2%
Renfrew Hydro Inc.	36.1%	13.3%	50.6%
Kingston Hydro Corporation	35.8%	16.2%	48.0%
Orangeville Hydro Limited	35.6%	13.3%	51.1%
Hydro Hawkesbury Inc.	35.6%	11.7%	52.6%

Utilis Consolidated Scorecard Methodology

1. Identified 10 OEB Scorecard Measures (Measure)
2. Calculated distributor % achievement of OEB Target (% Achieved)
   - If a distributor achieved target, they would receive 100%
3. Applied 10% weighting for each Measure
4. Summed distributor's % Achieved for 10 Measures to produce Annual Service Quality score
5. Ranked each distributors Annual Service Quality score against the data set of 54 distributors for each year from 2015 to 2023

OEB Scorecard Measures
LV Connections %
HV Connections %
Telephone Access. %
Appt. Met %
Written Responses to Enquires %
Emerg. Urban Response %
Emerg. Rural Response %
Telephone Call Abandon %
Appt. Sched. %
Resched. Missed Appt. %

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Hydro Ottawa Limited

OM&A Benchmarking – 2015 – 2023

Load Distribution Cohort

Updated:
November 2024
Utilis Consulting Inc.

Basis for Benchmarking Universe

- **Benchmarking Universe Characteristics:**
- Baseline Cohort Chosen: Load distribution between Residential, GS<50 and GS>50
- Total # of Distributors in Cohort: 9
- Total # of Distributors: 54
- Data Source: OEB Open Source Data
- Selected distributors with similar load distribution, using a deadband of +/- 1.0%

Load Distribution Peer Group

	% Residential kWh	% GS<50 kWh	% GS>50 kWh
Niagara Peninsula Energy Inc.	37.2%	10.8%	52.0%
Enova Power Corp.	37.0%	14.3%	48.7%
Hydro Ottawa Limited	36.6%	11.0%	52.5%
ENWIN Utilities Ltd.	36.4%	14.8%	48.8%
Niagara-on-the-Lake Hydro Inc.	36.4%	21.5%	42.2%
Renfrew Hydro Inc.	36.1%	13.3%	50.6%
Kingston Hydro Corporation	35.8%	16.2%	48.0%
Orangeville Hydro Limited	35.6%	13.3%	51.1%
Hydro Hawkesbury Inc.	35.6%	11.7%	52.6%

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Basis for Benchmarking Universe

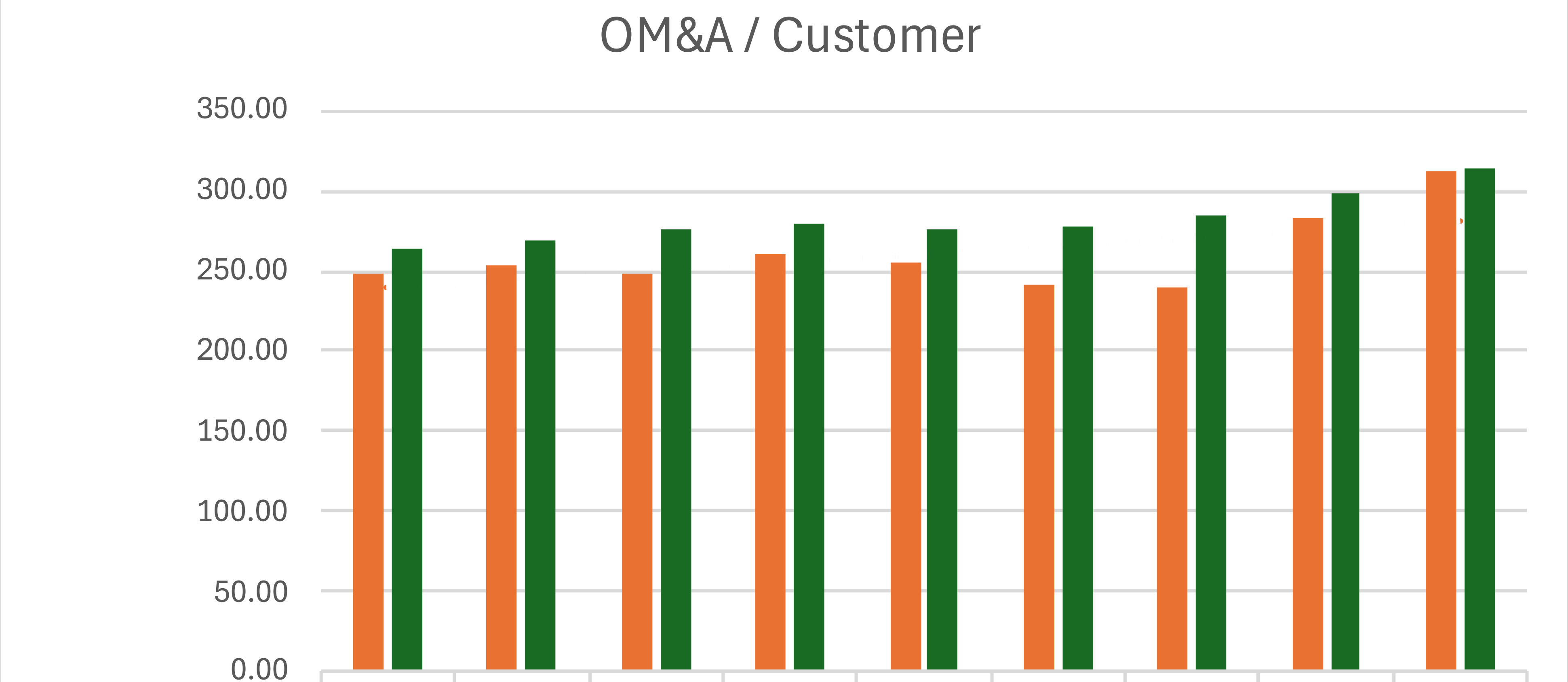
- Utilis generated the following metrics and ratios to compare Hydro Ottawa with its cohort

Utilis Consolidated Scorecard Metric	OMA / Circuit KM	(Contract Services) / Total CapEx
OMA/FTE	Operating Expense / Circuit KM	Operating Expense Ratio
Operating Expense / FTE	Maintenance Expense / Circuit KM	FTE / $1M of CapEx
Maintenance Expense / FTE	Admin. Expenses / Circuit KM	FTE / $1M of CapEx Additions
Admin. Expense / FTE	OMA / MWh	FTE / 1,000 % Rural
OMA / % Rural	Operating Expense / MWh	FTE / Circuit KM
Operating Expense / % Rural	Maintenance Expense / MWh	FTE / GWh
Maintenance Expense / % Rural	Admin. Expenses / MWh	FTE / Summer Peak Load (MWh)
Admin. Expense / % Rural	MWh / % Rural	FTE / Winter Peak Load (MWh)
Circuit km / 1,000 % Rurals	OMA / CapEx	

Benchmarking Universe

Hydro Ottawa Performance Relative to Load Distribution Cohort

Hydro Ottawa Performance Relative to Load Distribution Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	248.05	252.97	249.17	260.38	254.69	241.99	240.64	282.53	313.07
Peer Group Avg.	264.70	269.07	275.75	280.15	276.15	278.66	285.09	298.97	314.65

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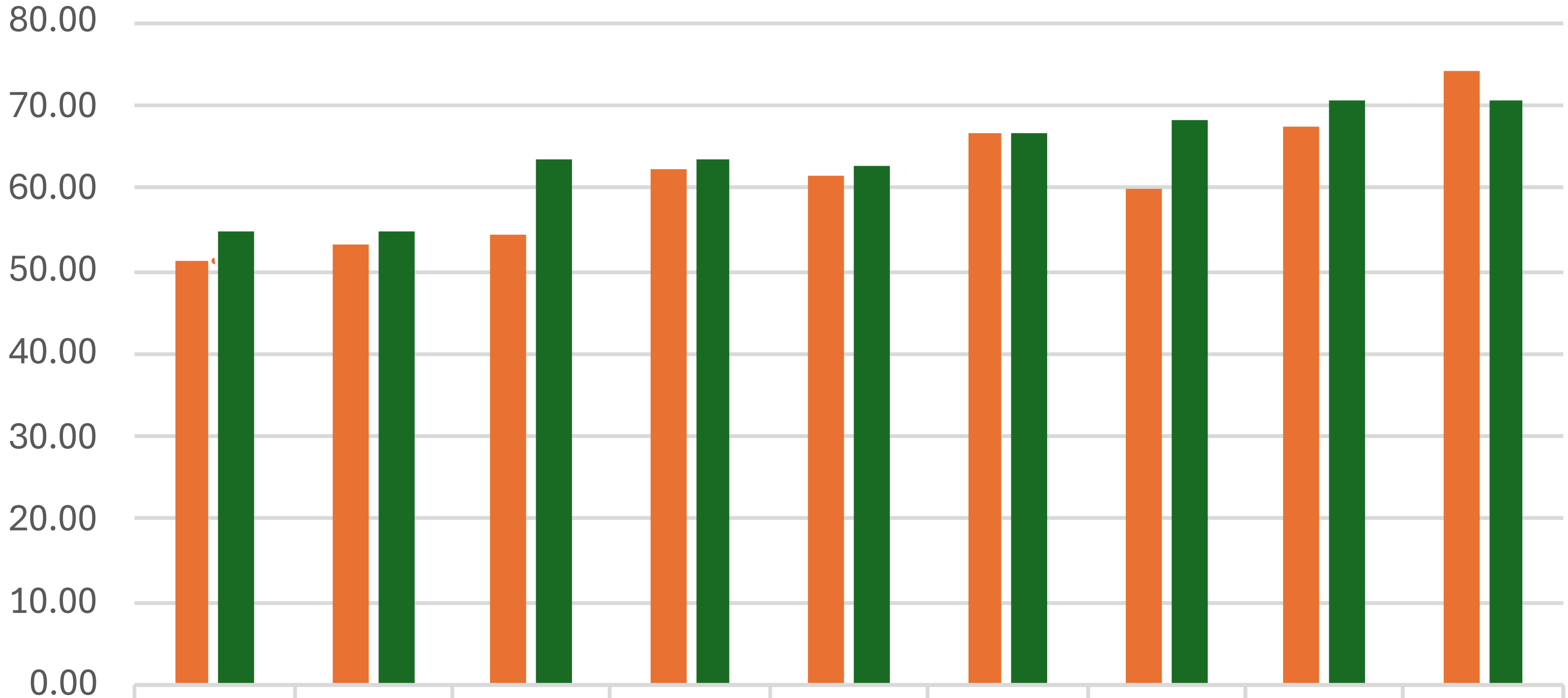
Hydro Ottawa Performance Relative to Load Distribution Cohort

Operating Expense / Customer

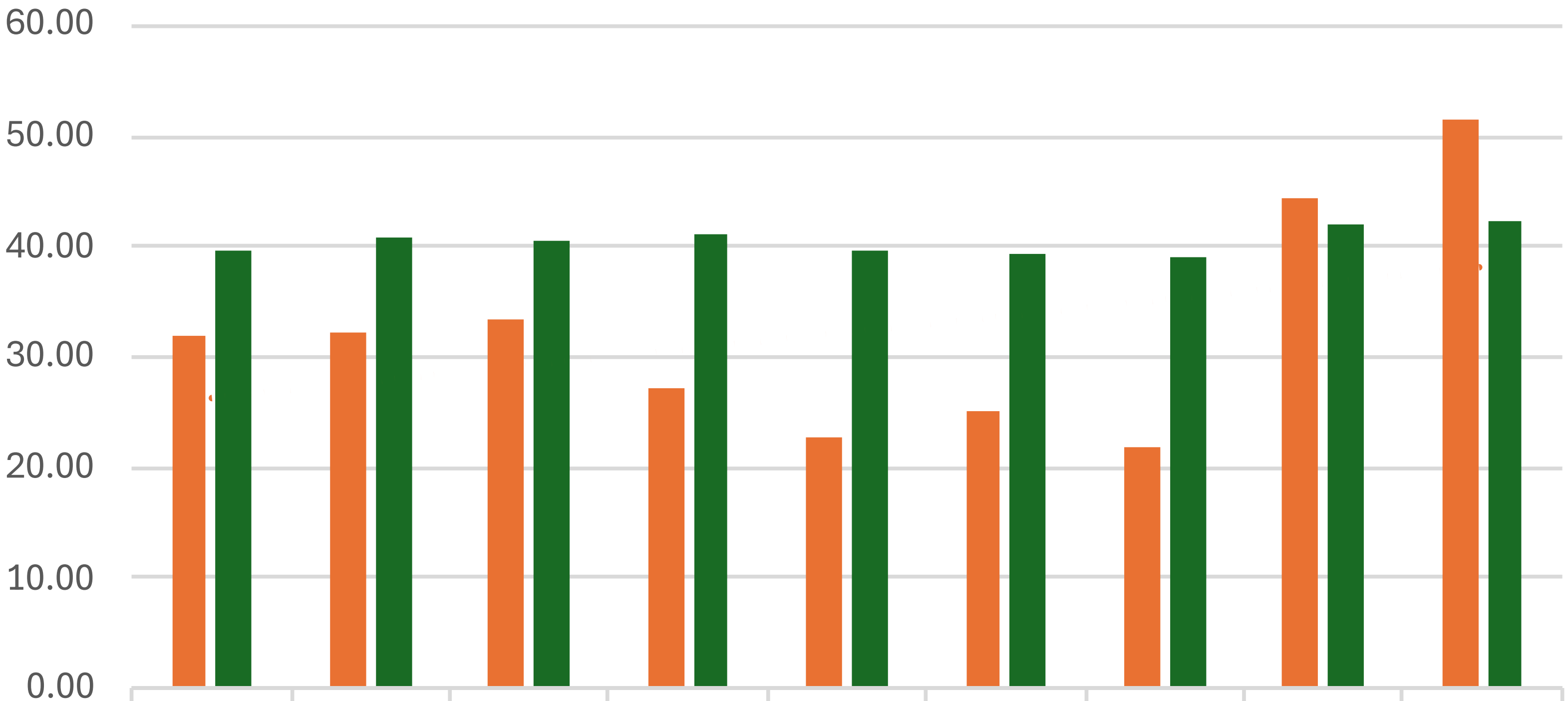


	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	51.08	53.35	54.25	62.26	61.40	66.70	60.02	67.43	74.23
Peer Group Avg.	54.87	54.73	63.38	63.42	62.87	66.52	68.10	70.75	70.67

Hydro Ottawa   Peer Group Avg.   Linear (Hydro Ottawa)

Hydro Ottawa Performance Relative to Load Distribution Cohort

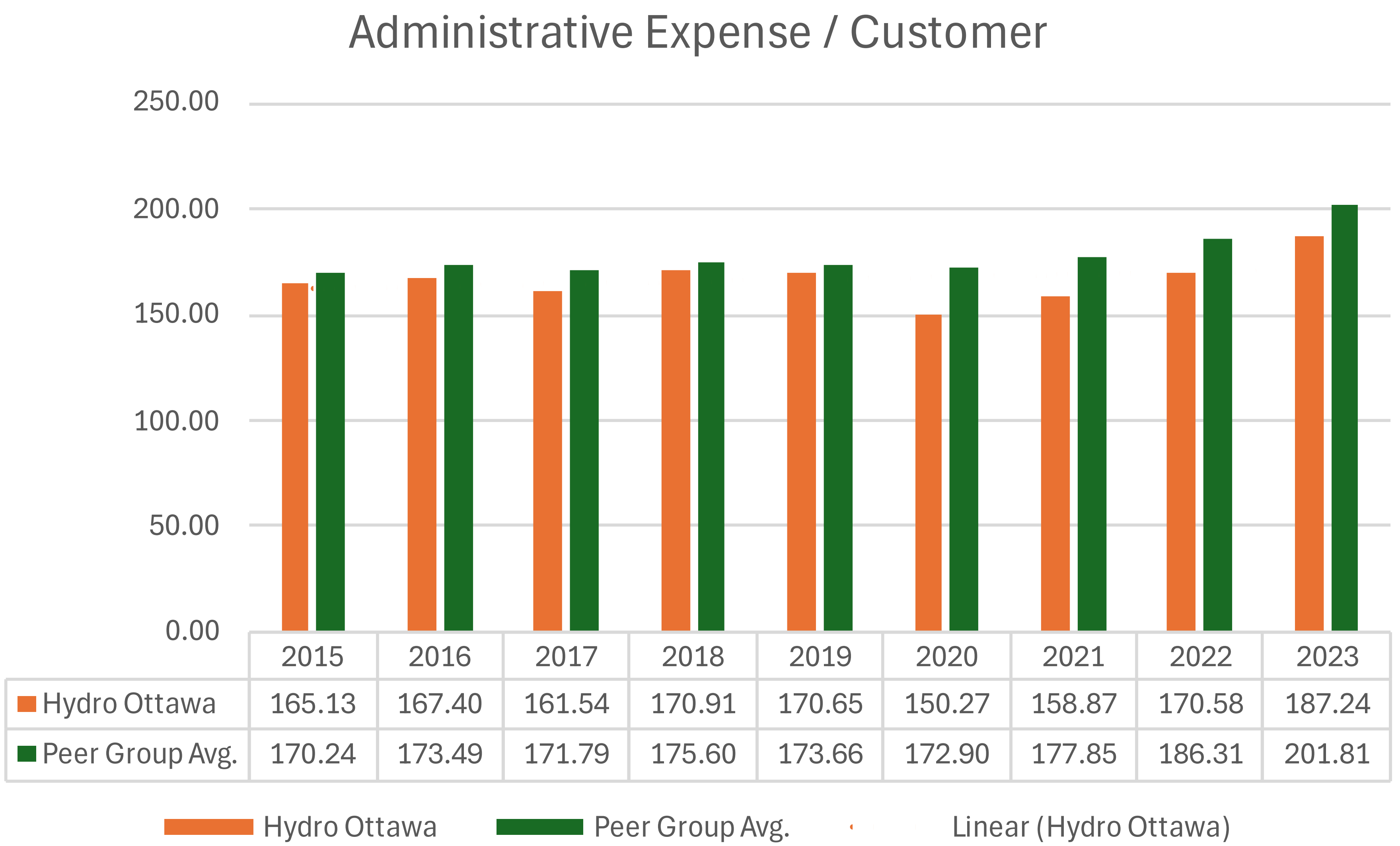
Maintenance Expense / Customer



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	31.84	32.22	33.37	27.21	22.64	25.01	21.76	44.53	51.60
Peer Group Avg.	39.59	40.86	40.58	41.13	39.62	39.24	39.14	41.91	42.17

Hydro Ottawa　Peer Group Avg.　Linear (Hydro Ottawa)

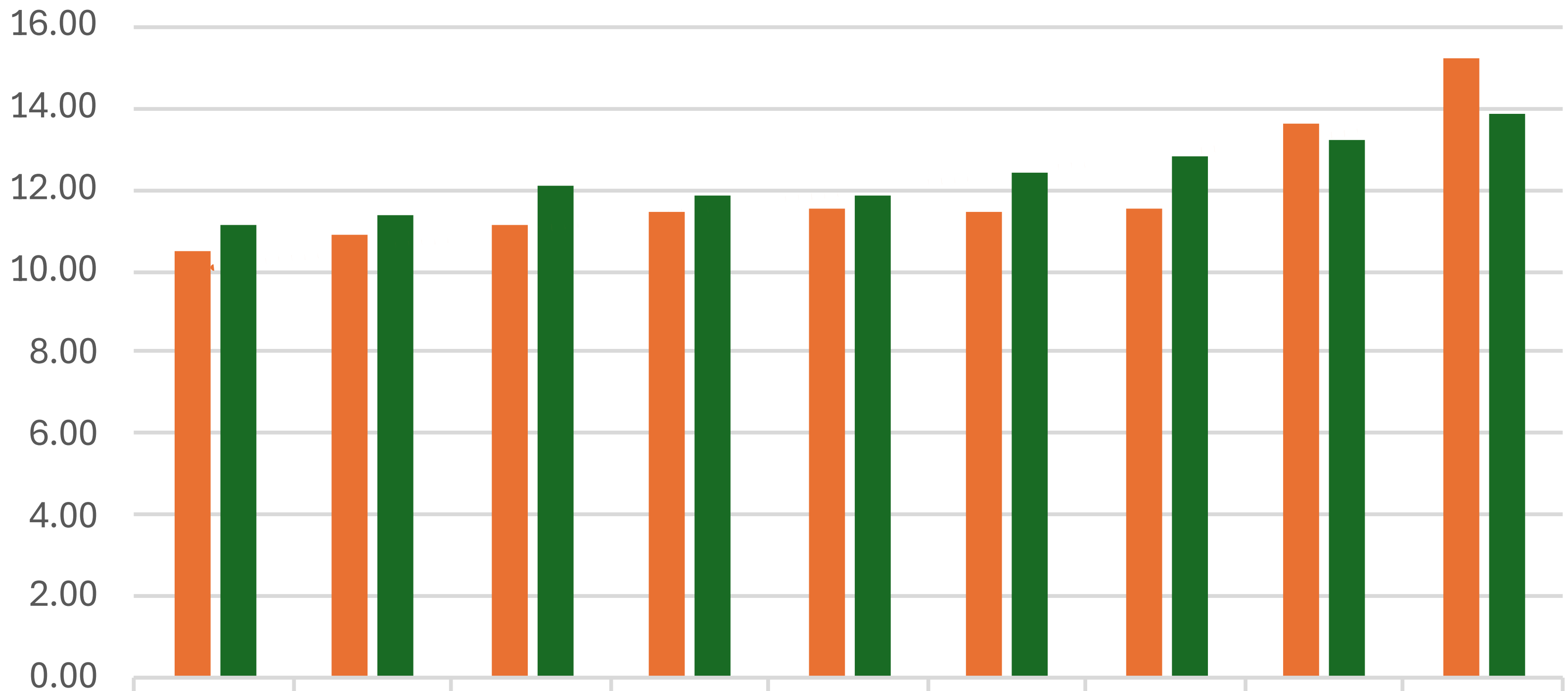
Hydro Ottawa Performance Relative to Load Distribution Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	165.13	167.40	161.54	170.91	170.65	150.27	158.87	170.58	187.24
Peer Group Avg.	170.24	173.49	171.79	175.60	173.66	172.90	177.85	186.31	201.81

Hydro Ottawa Performance Relative to Load Distribution Cohort

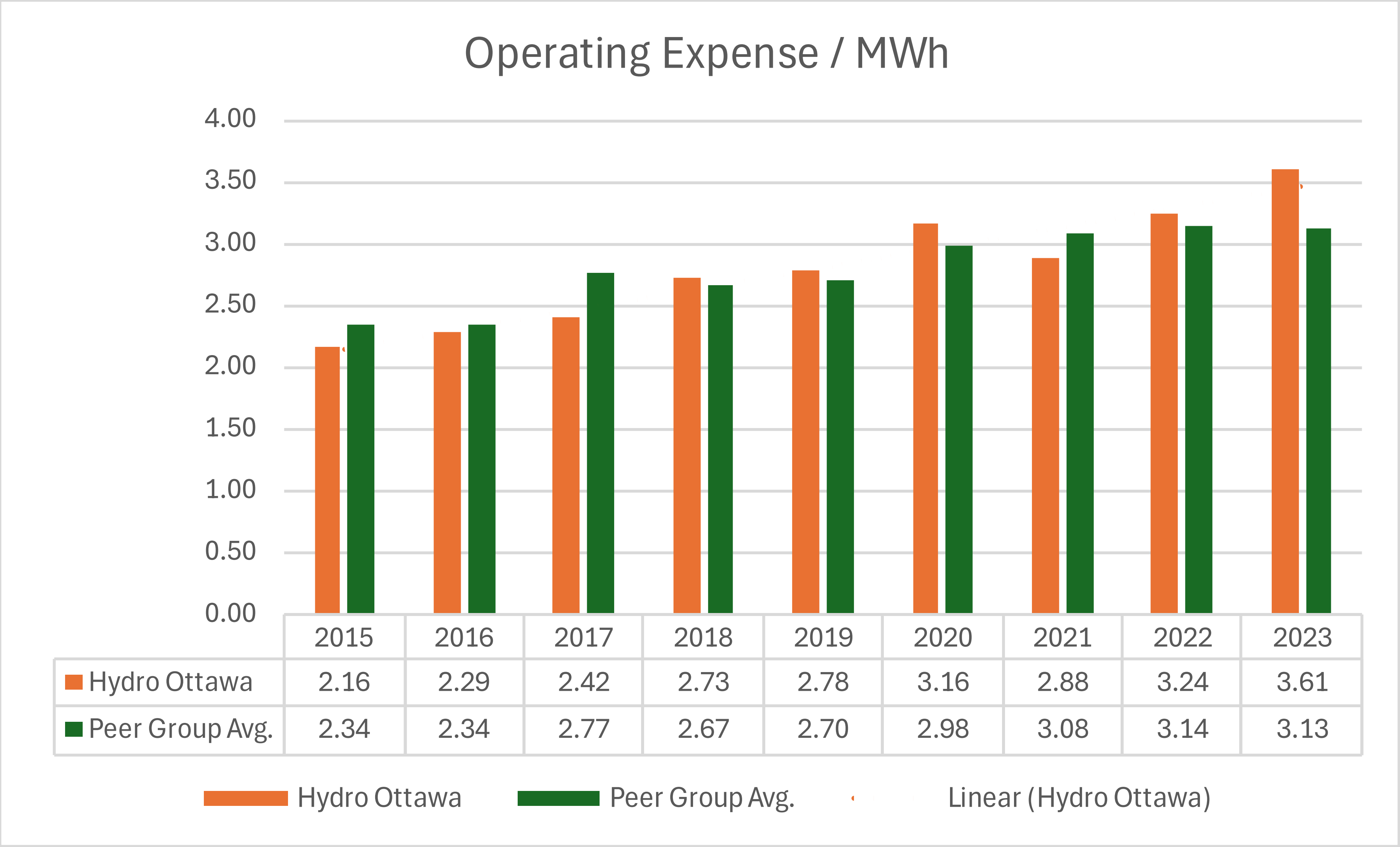
OM&A / MWh



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	10.49	10.86	11.10	11.42	11.54	11.48	11.56	13.59	15.21
Peer Group Avg.	11.13	11.36	12.07	11.82	11.87	12.43	12.85	13.24	13.85

Hydro Ottawa Peer Group Avg. Linear (Hydro Ottawa)

Hydro Ottawa Performance Relative to Load Distribution Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	2.16	2.29	2.42	2.73	2.78	3.16	2.88	3.24	3.61
Peer Group Avg.	2.34	2.34	2.77	2.67	2.70	2.98	3.08	3.14	3.13

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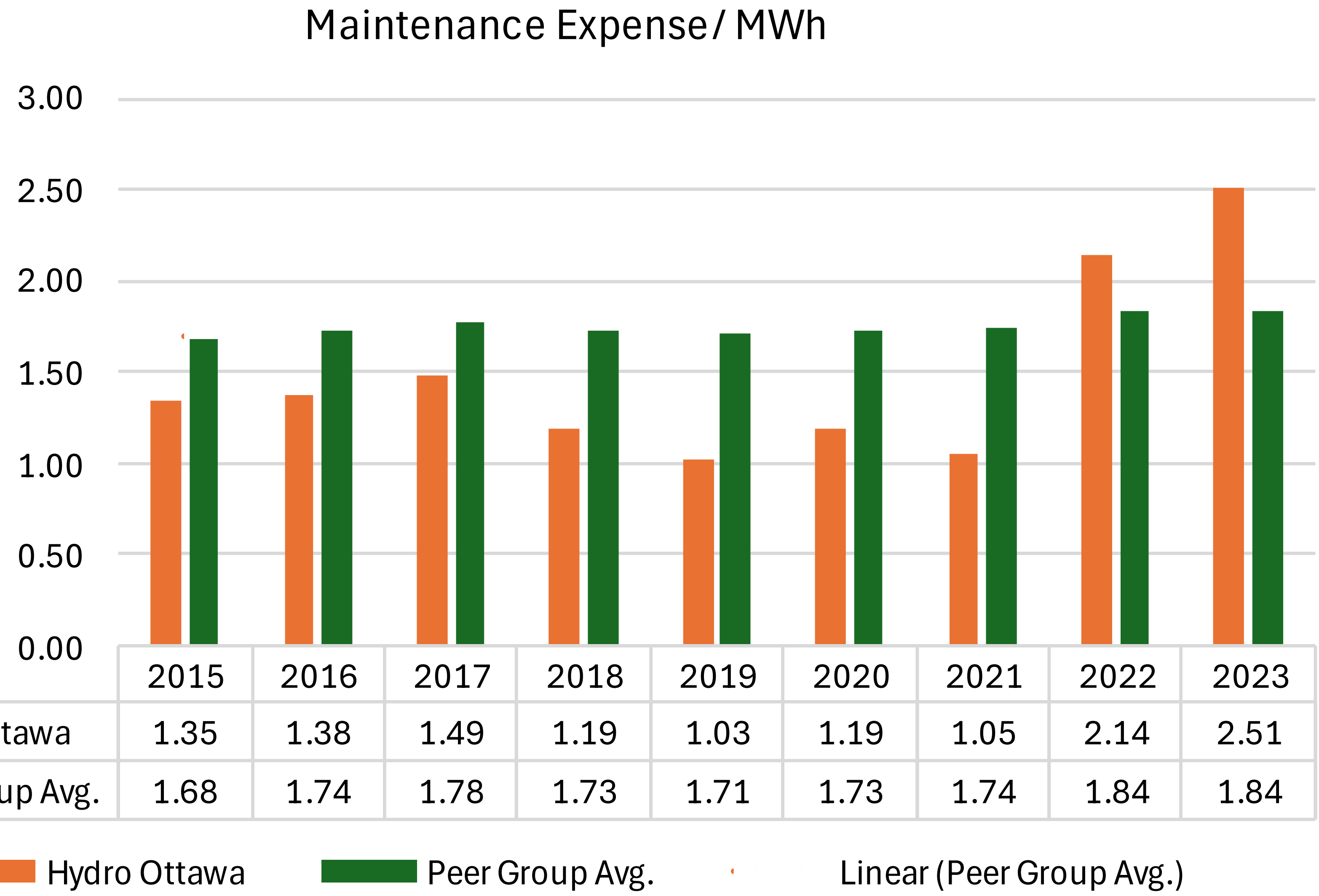
Hydro Ottawa Performance Relative to Load Distribution Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	1.35	1.38	1.49	1.19	1.03	1.19	1.05	2.14	2.51
Peer Group Avg.	1.68	1.74	1.78	1.73	1.71	1.73	1.74	1.84	1.84

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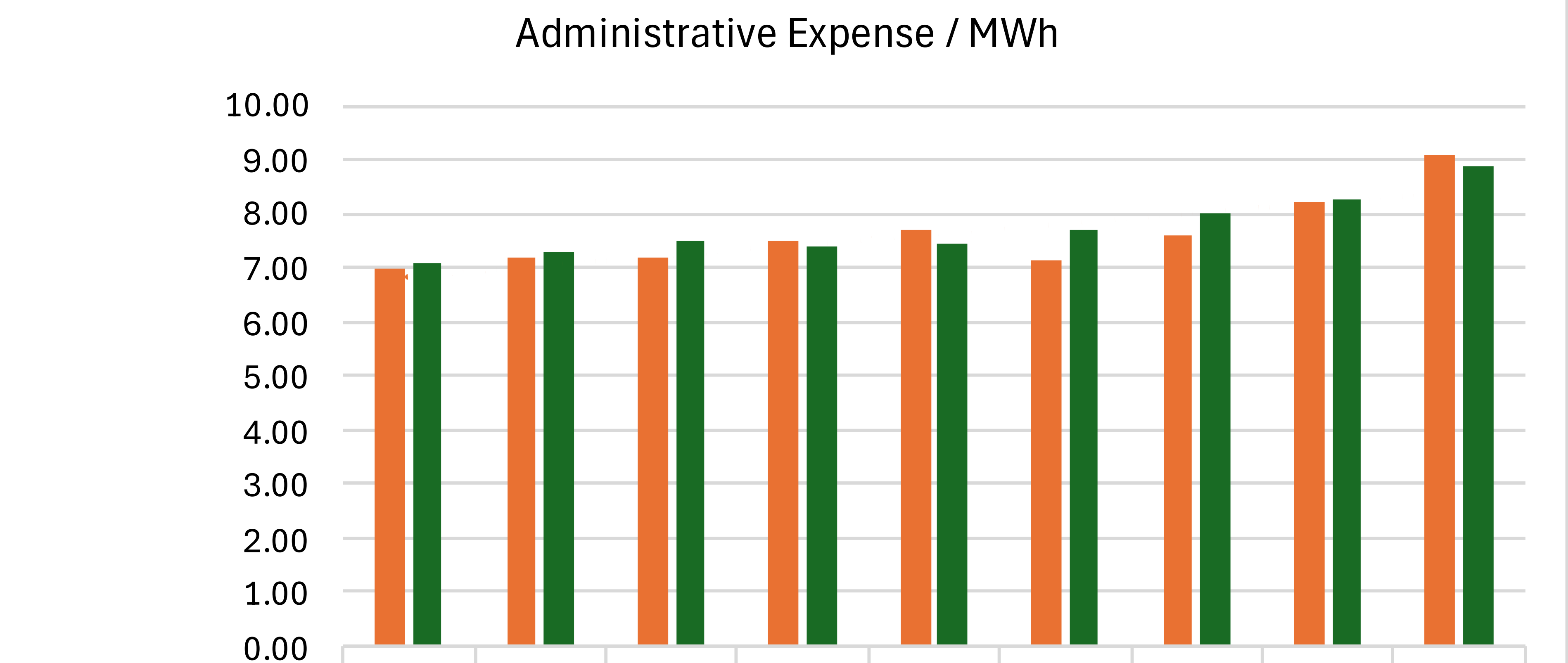
Hydro Ottawa Performance Relative to Load Distribution Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	6.98	7.19	7.20	7.50	7.73	7.13	7.63	8.20	9.09
Peer Group Avg.	7.10	7.28	7.53	7.42	7.46	7.71	8.03	8.26	8.88

Hydro Ottawa Peer Group Avg. Linear (Hydro Ottawa)

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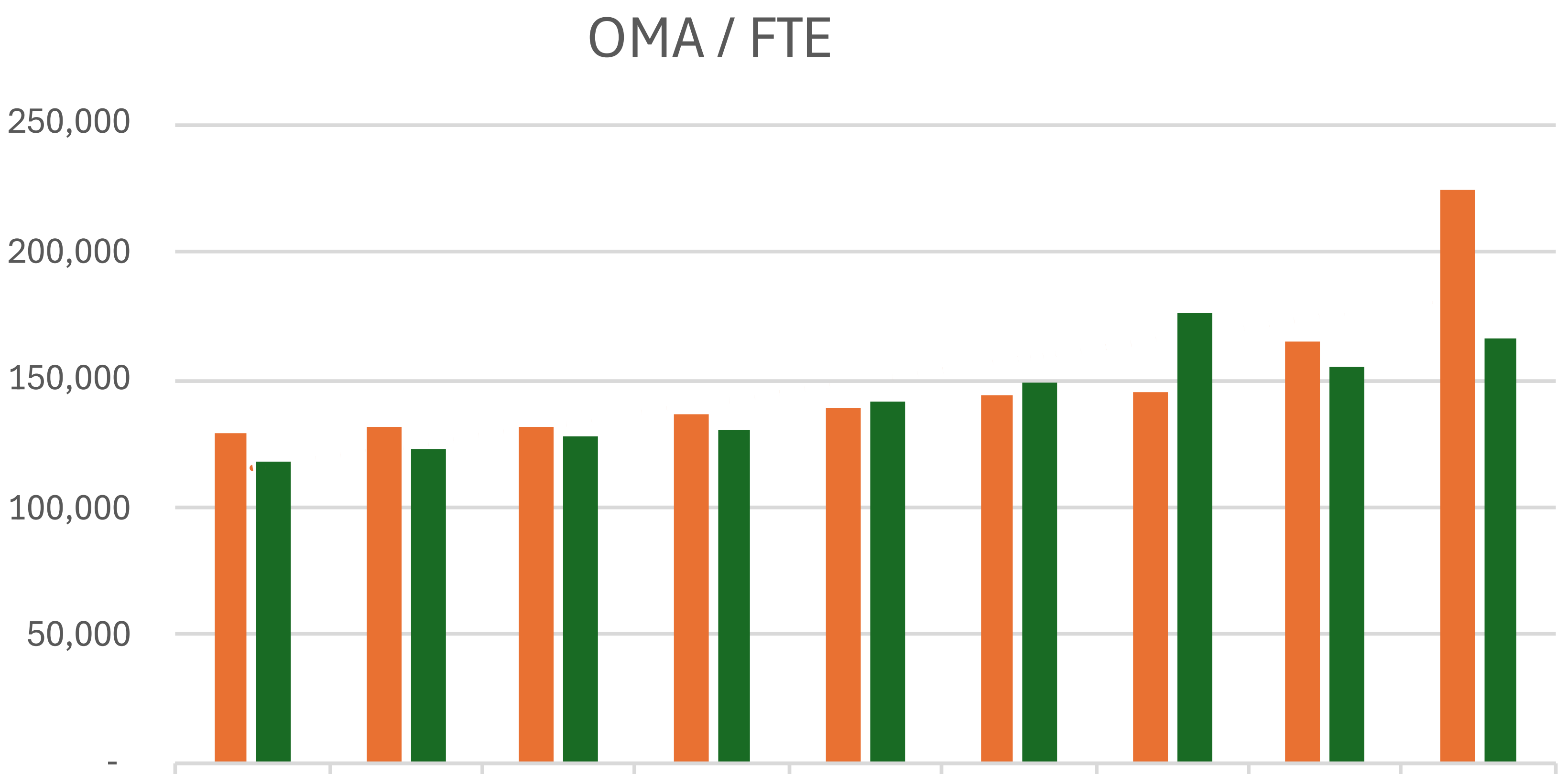
Hydro Ottawa Performance Relative to Load Distribution Cohort

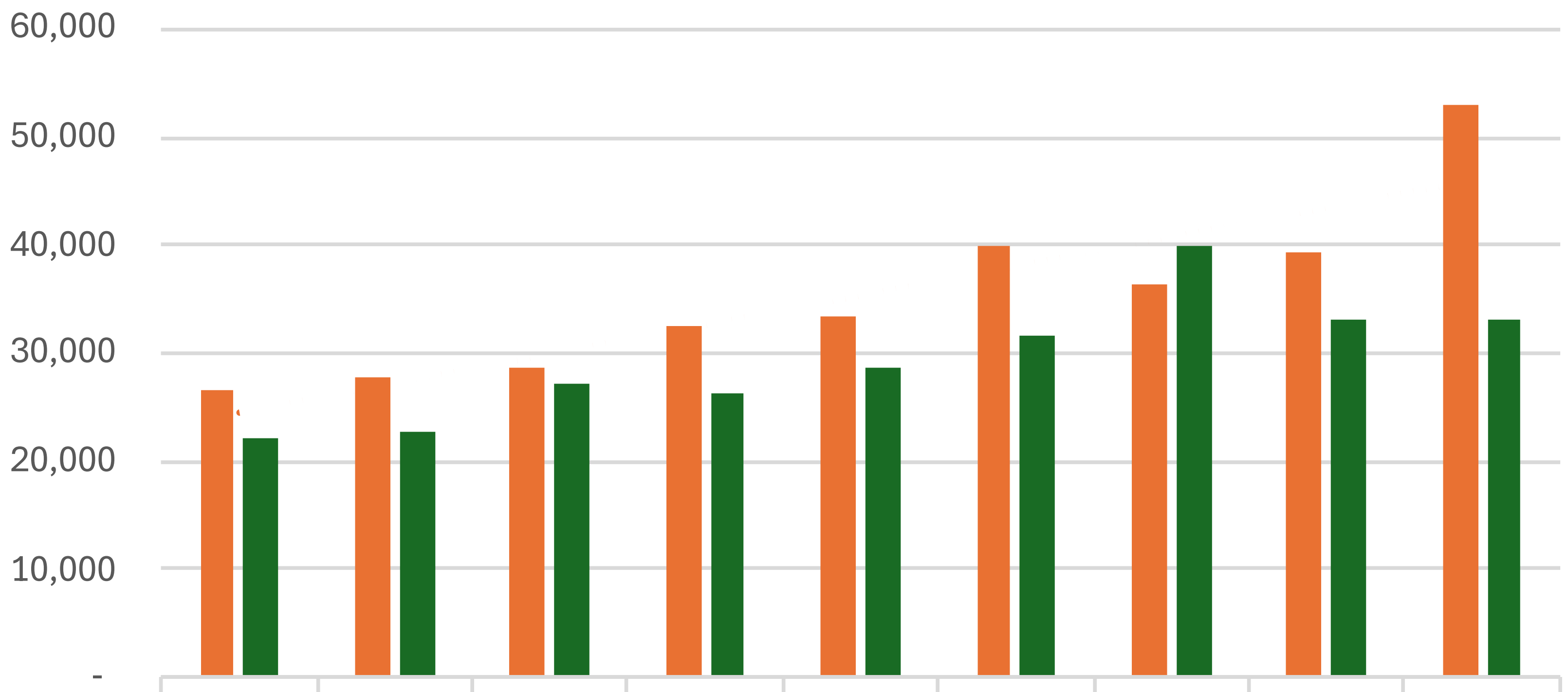


	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	129,178	132,075	131,638	136,310	138,583	144,355	145,912	164,694	224,085
Peer Group Avg.	118,091	123,549	127,371	130,638	141,925	149,030	175,770	155,520	166,165

Hydro Ottawa   Peer Group Avg.   Linear (Hydro Ottawa)

Hydro Ottawa Performance Relative to Load Distribution Cohort

Operating Expense / FTE

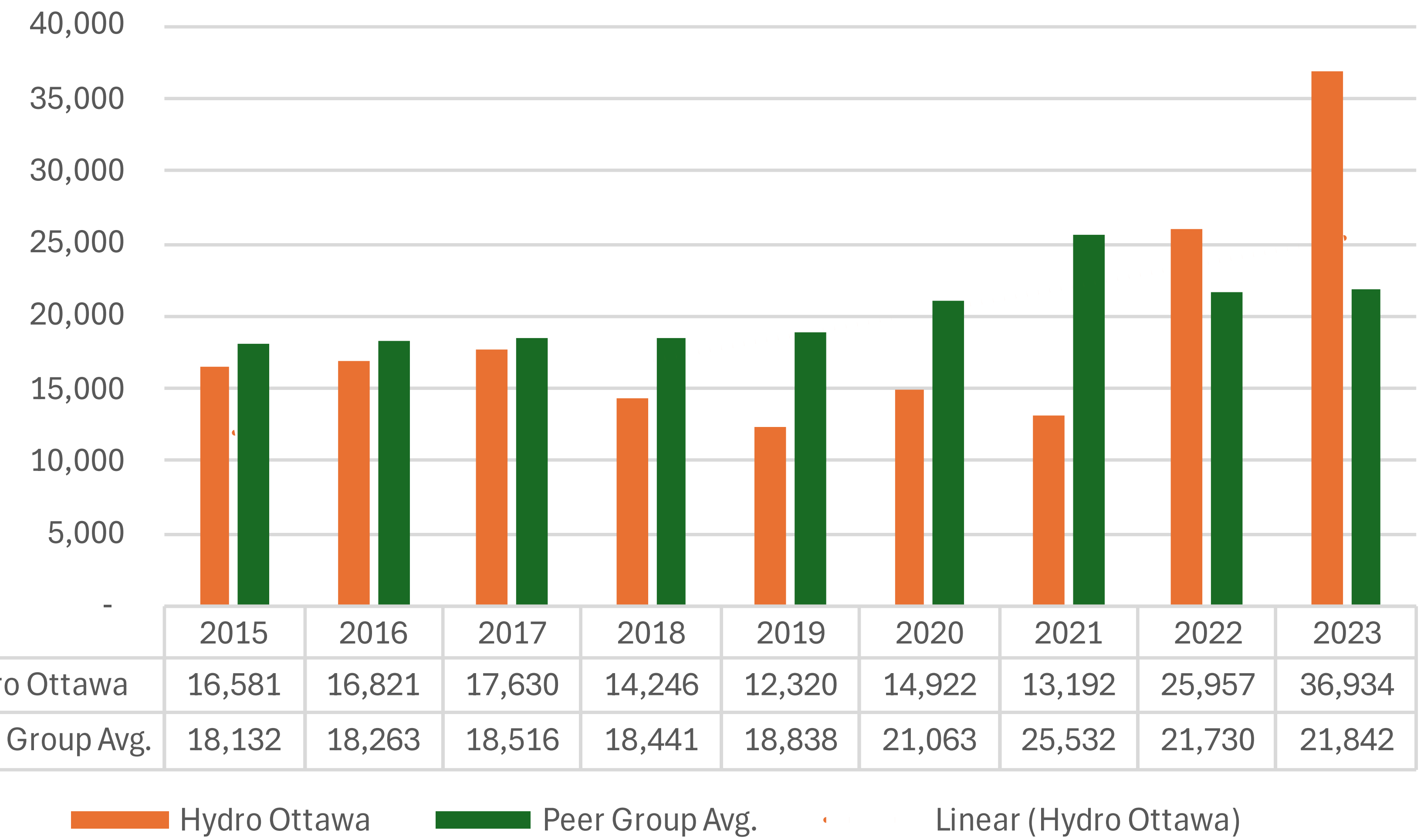


	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	26,601	27,853	28,662	32,593	33,411	39,789	36,392	39,305	53,132
Peer Group Avg.	22,016	22,606	27,106	26,167	28,597	31,686	39,816	32,950	33,118

Hydro Ottawa   Peer Group Avg.   Linear (Hydro Ottawa)

Hydro Ottawa Performance Relative to Load Distribution Cohort

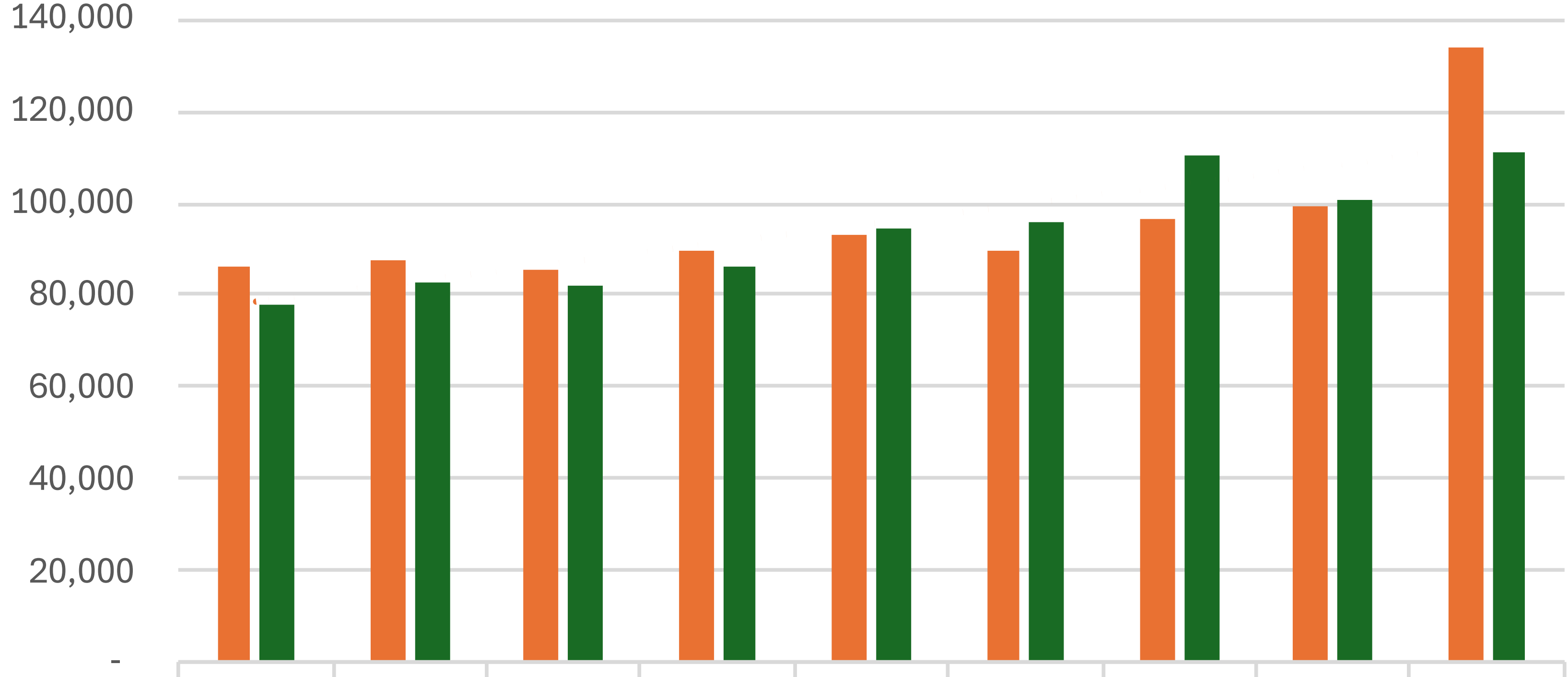
Maintenance Expense / FTE



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	16,581	16,821	17,630	14,246	12,320	14,922	13,192	25,957	36,934
Peer Group Avg.	18,132	18,263	18,516	18,441	18,838	21,063	25,532	21,730	21,842

Hydro Ottawa Performance Relative to Load Distribution Cohort

Administrative Expense / FTE



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	85,995	87,401	85,345	89,471	92,852	89,644	96,329	99,432	134,020
Peer Group Avg.	77,943	82,680	81,749	86,030	94,490	96,281	110,423	100,840	111,205

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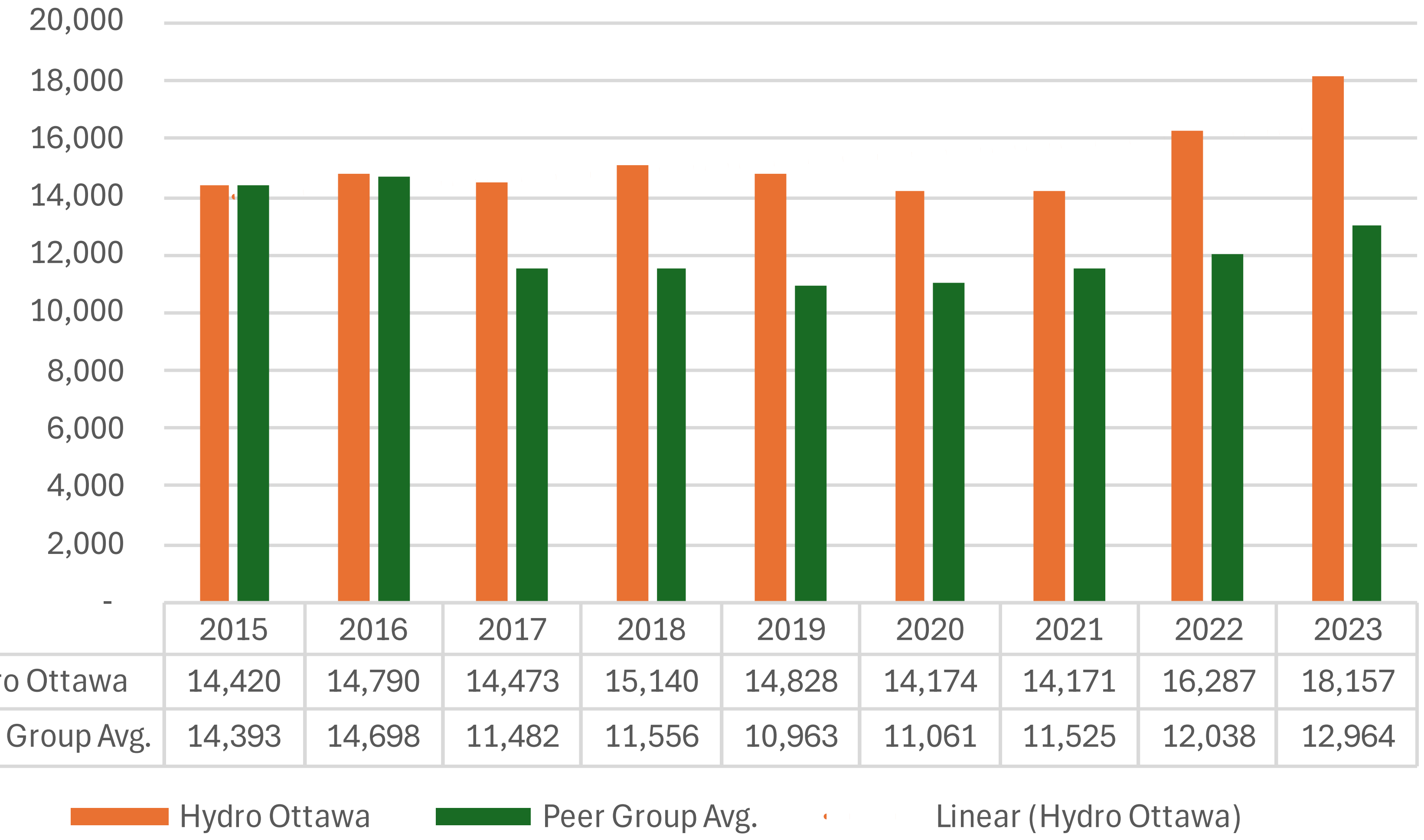
Hydro Ottawa Performance Relative to Load Distribution Cohort

OMA / Circuit KM



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	14,420	14,790	14,473	15,140	14,828	14,174	14,171	16,287	18,157
Peer Group Avg.	14,393	14,698	11,482	11,556	10,963	11,061	11,525	12,038	12,964

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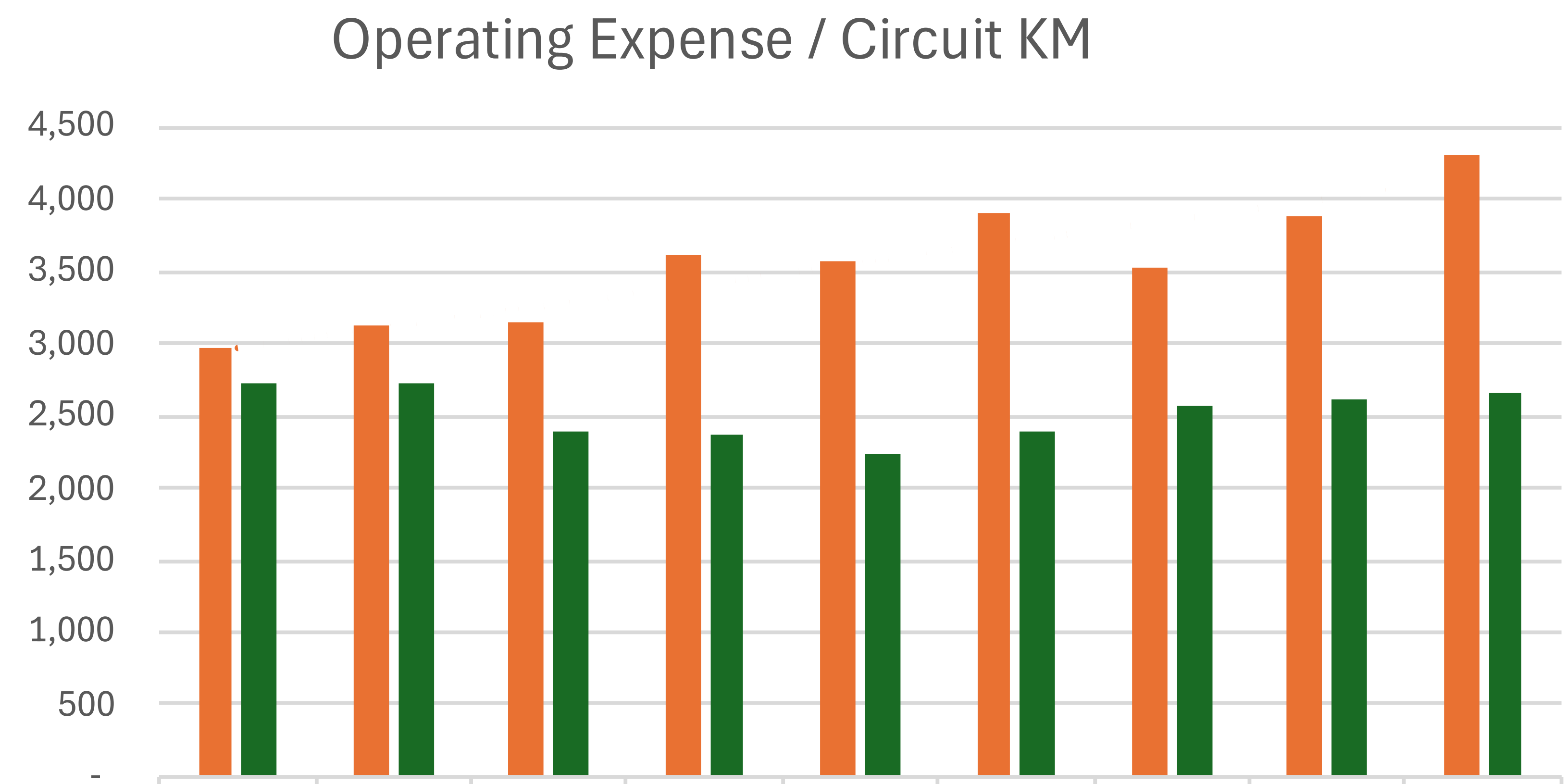
Hydro Ottawa Performance Relative to Load Distribution Cohort

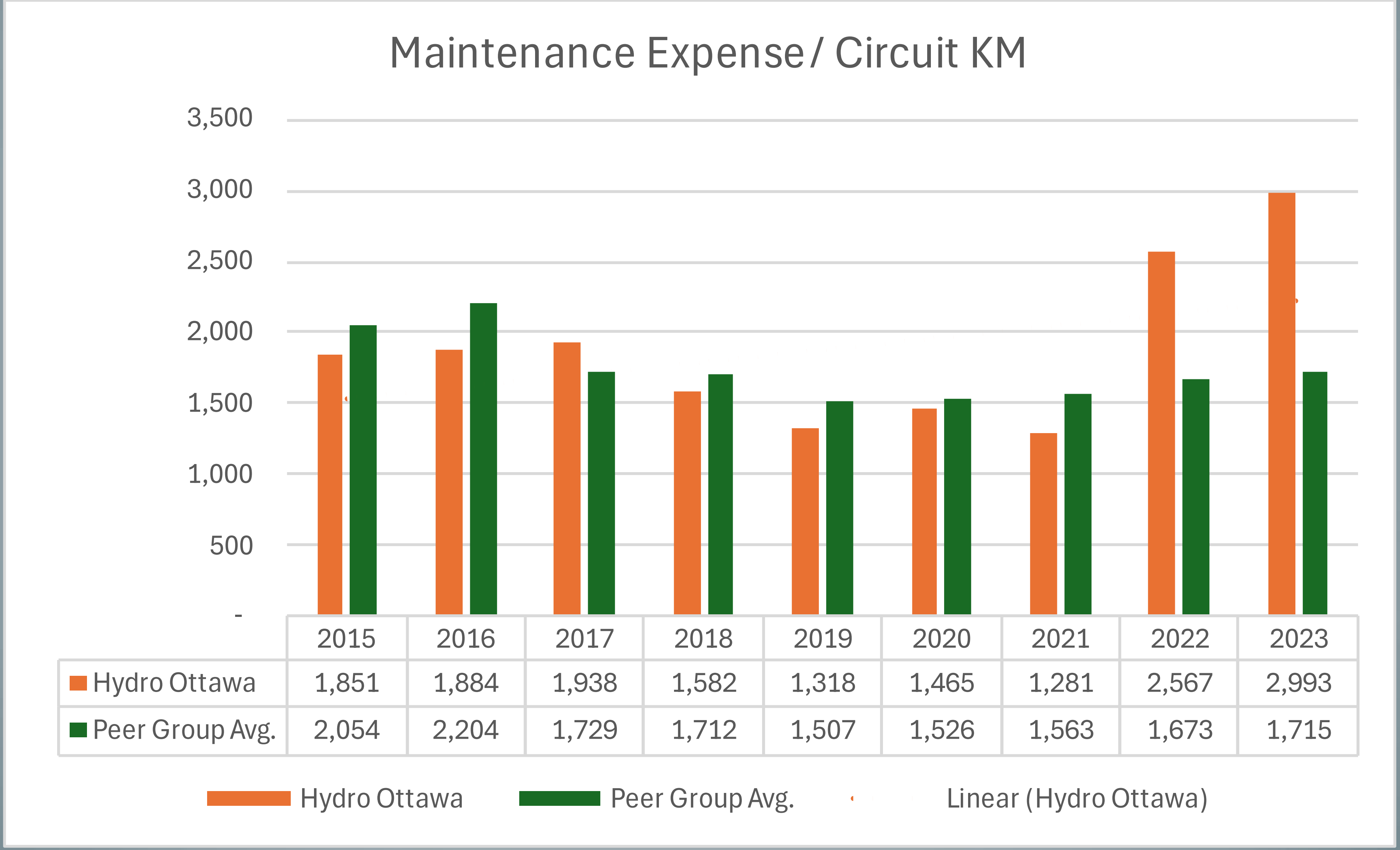


	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	2,969	3,119	3,151	3,620	3,575	3,907	3,534	3,887	4,305
Peer Group Avg.	2,724	2,732	2,393	2,360	2,243	2,389	2,566	2,615	2,670

Hydro Ottawa   Peer Group Avg.   Linear (Hydro Ottawa)

Utilis

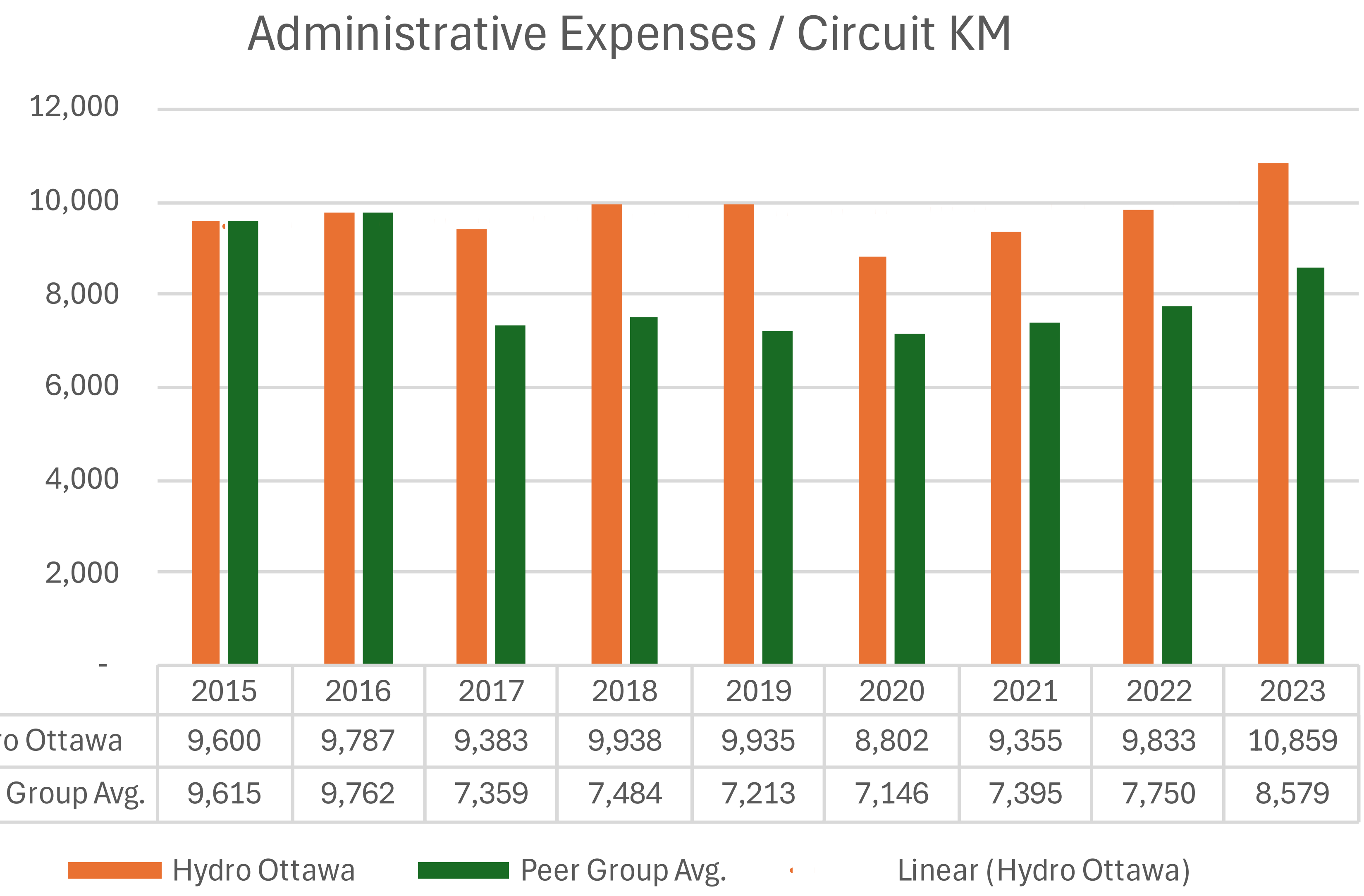
Hydro Ottawa Performance Relative to Load Distribution Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	1,851	1,884	1,938	1,582	1,318	1,465	1,281	2,567	2,993
Peer Group Avg.	2,054	2,204	1,729	1,712	1,507	1,526	1,563	1,673	1,715

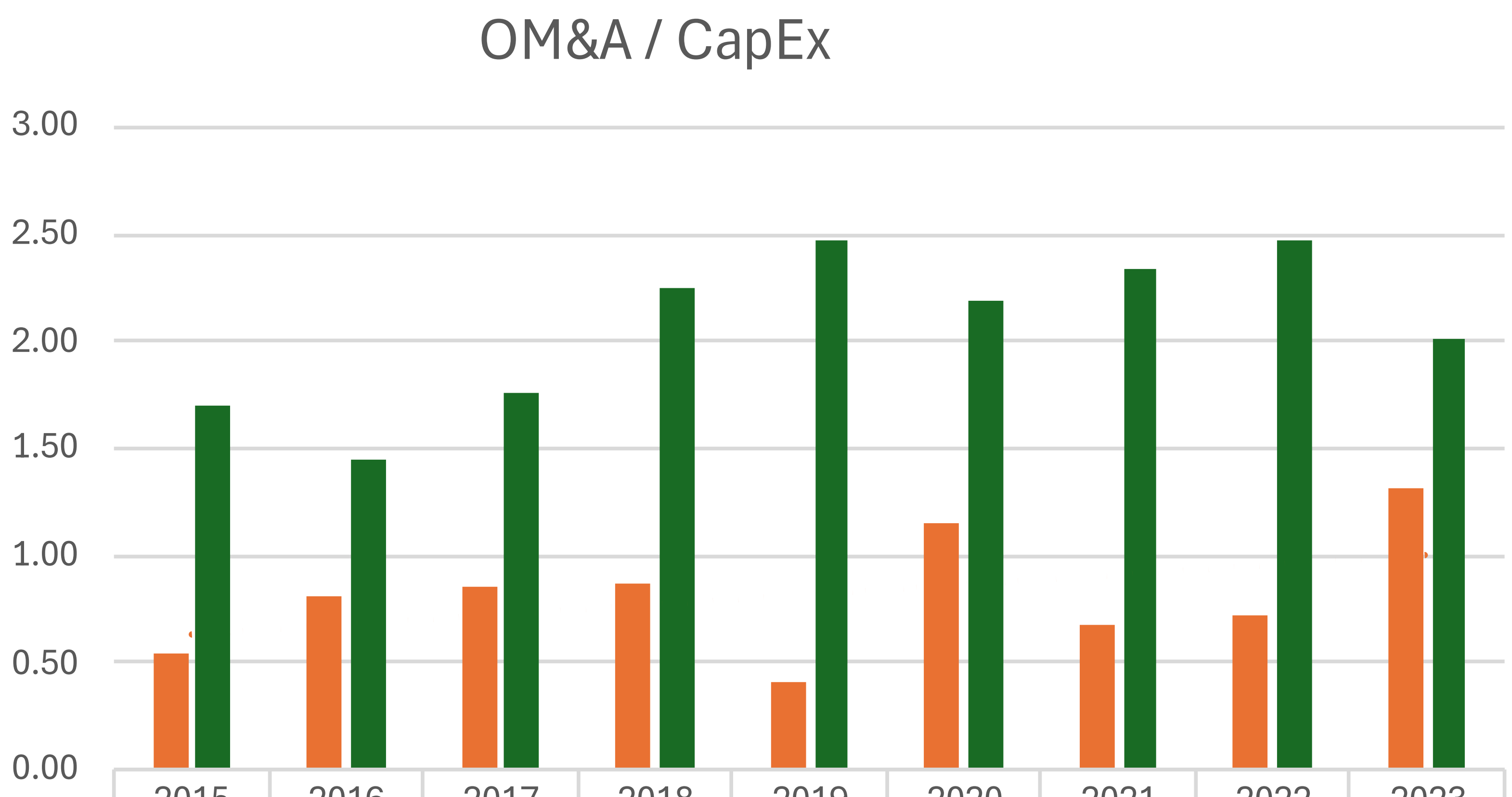
Utilis

Hydro Ottawa Performance Relative to Load Distribution Cohort



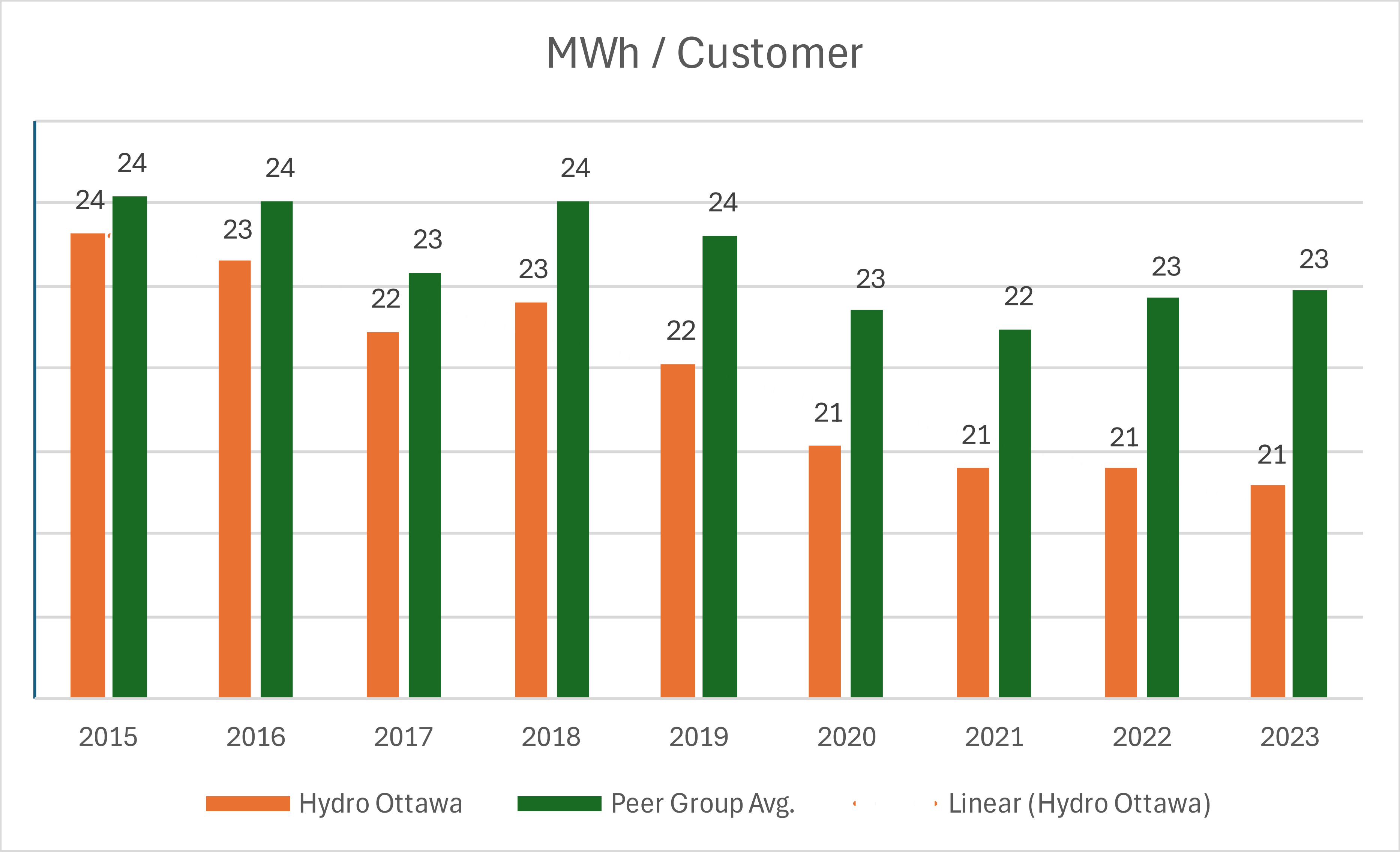
	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	9,600	9,787	9,383	9,938	9,935	8,802	9,355	9,833	10,859
Peer Group Avg.	9,615	9,762	7,359	7,484	7,213	7,146	7,395	7,750	8,579

Hydro Ottawa Performance Relative to Load Distribution Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	0.55	0.80	0.85	0.87	0.40	1.15	0.67	0.71	1.31
Peer Group Avg.	1.70	1.44	1.76	2.25	2.48	2.19	2.33	2.47	2.01

Hydro Ottawa Performance Relative to Load Distribution Cohort



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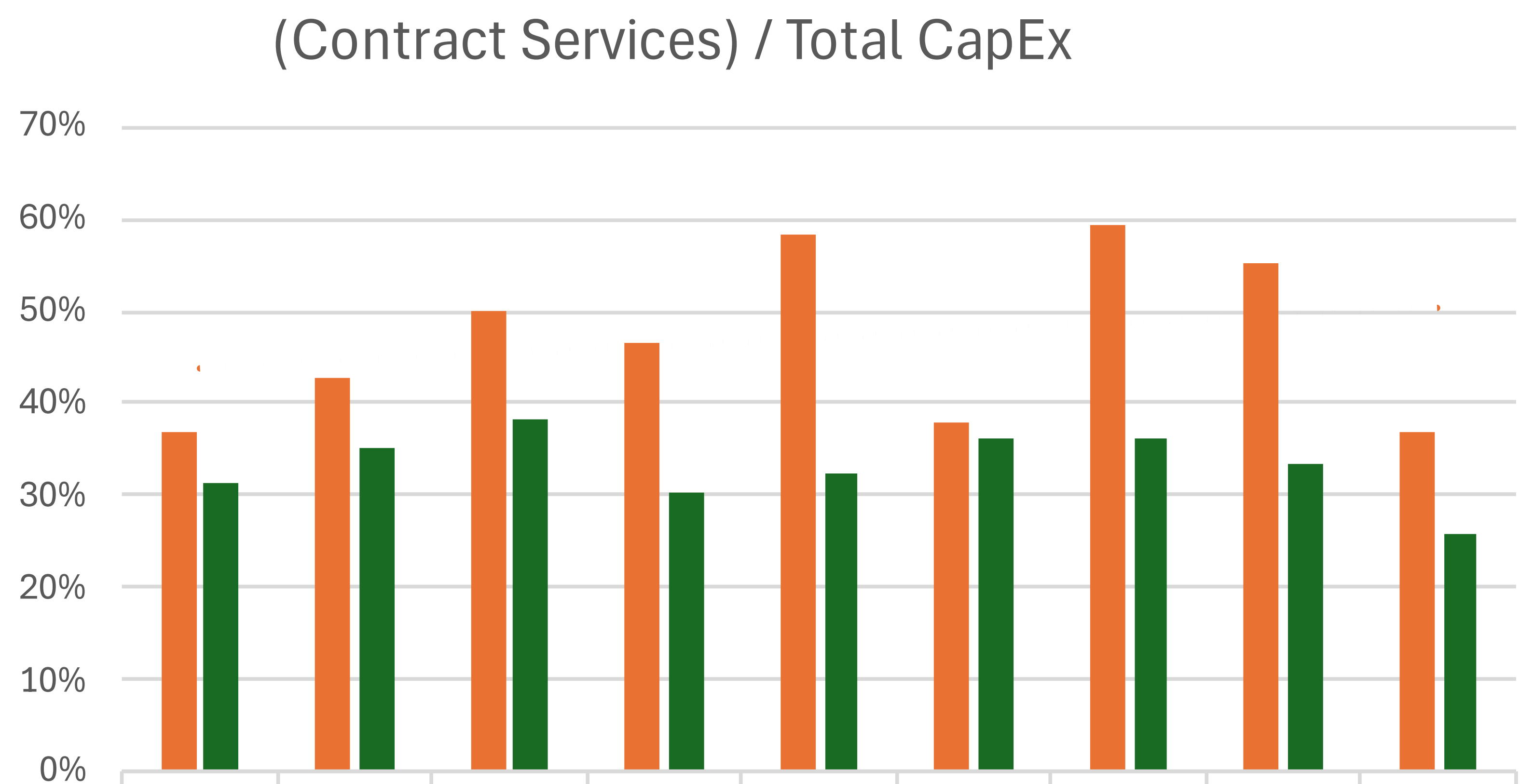
Hydro Ottawa Performance Relative to Load Distribution Cohort

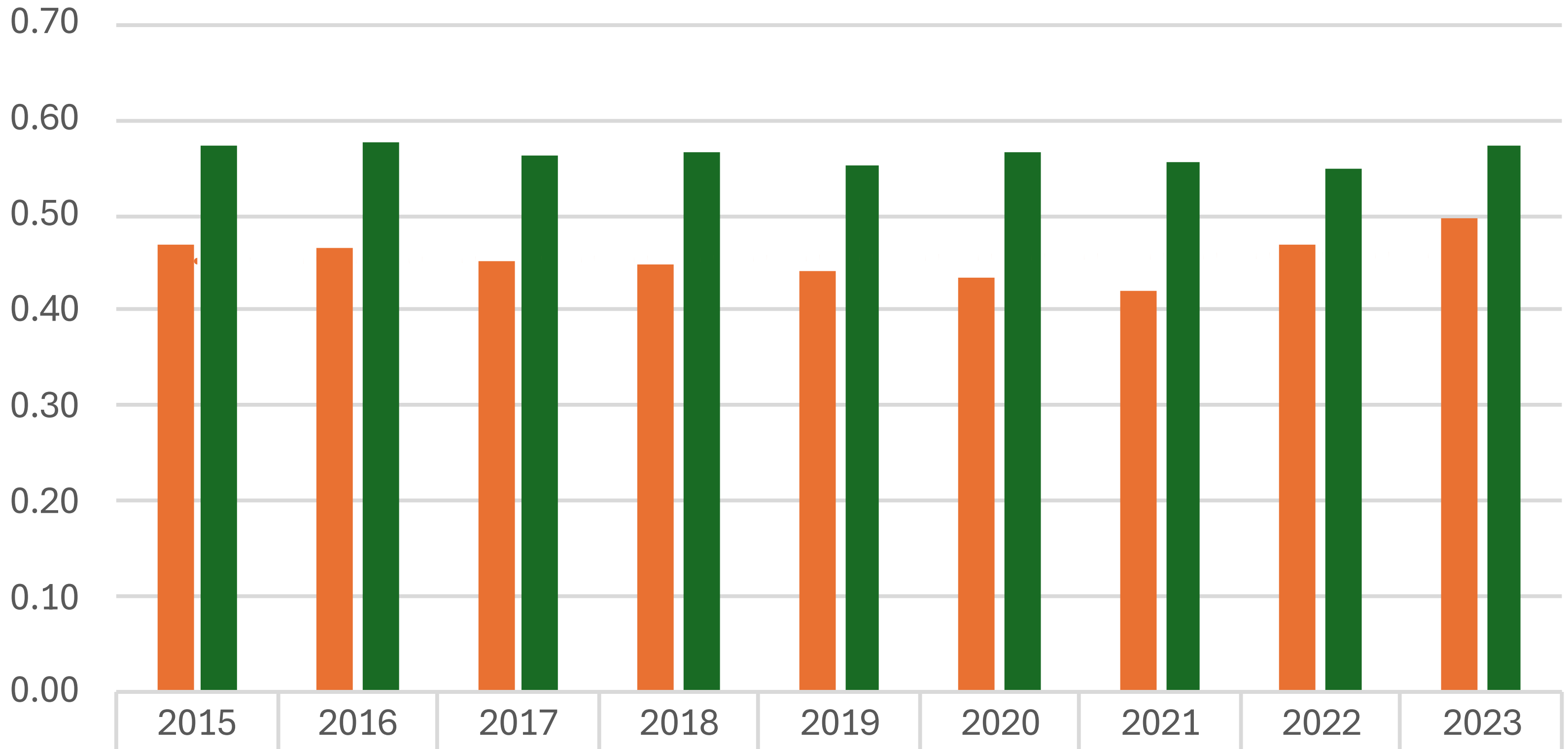


	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	37%	43%	50%	47%	58%	38%	59%	55%	37%
Peer Group Avg.	31%	35%	38%	30%	32%	36%	36%	33%	26%

Utilis

Hydro Ottawa Performance Relative to Load Distribution Cohort

Operating Expense Ratio

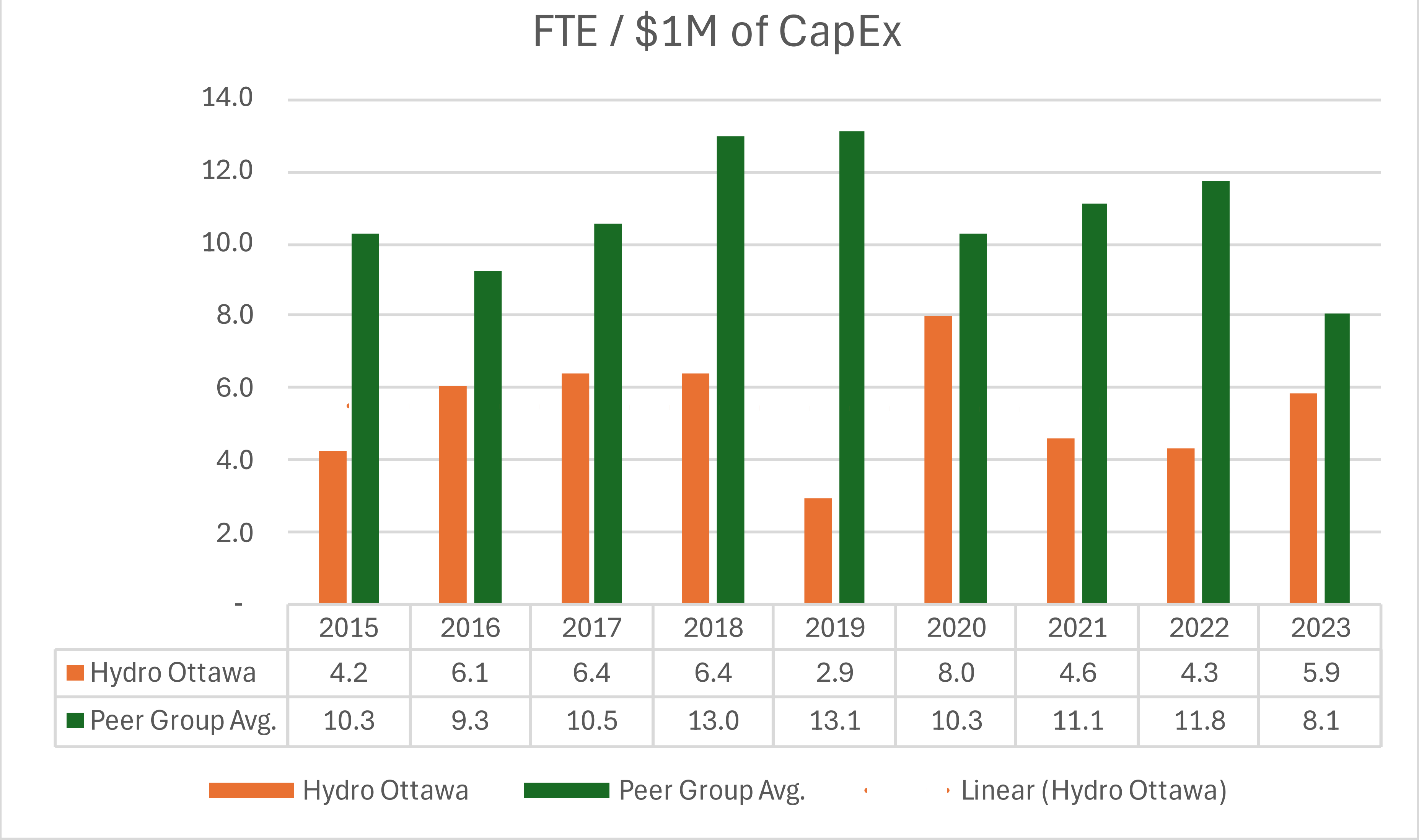


	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	0.47	0.47	0.45	0.45	0.44	0.44	0.42	0.47	0.50
Peer Group Avg.	0.57	0.58	0.56	0.57	0.55	0.57	0.56	0.55	0.57

Hydro Ottawa   Peer Group Avg.   Linear (Hydro Ottawa)

Utilis

Hydro Ottawa Performance Relative to Load Distribution Cohort

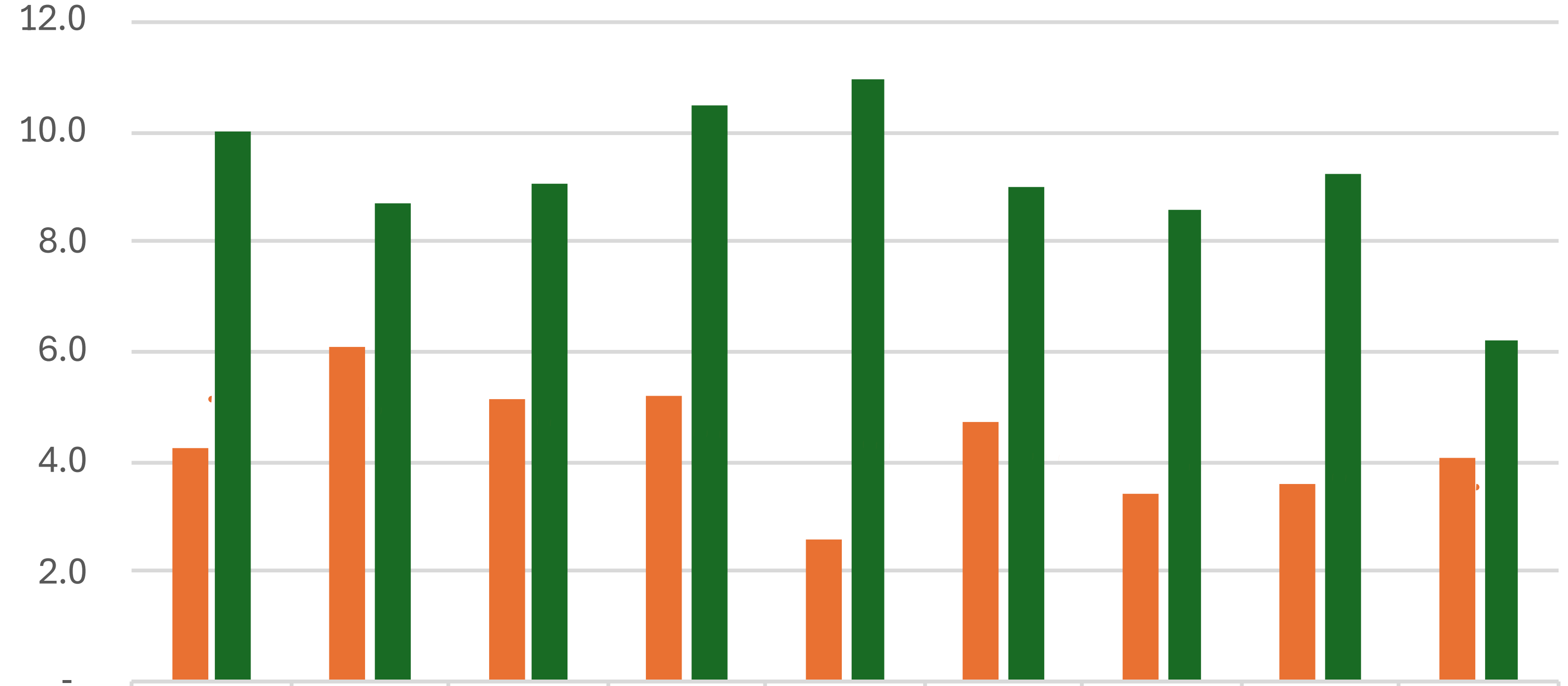


	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	4.2	6.1	6.4	6.4	2.9	8.0	4.6	4.3	5.9
Peer Group Avg.	10.3	9.3	10.5	13.0	13.1	10.3	11.1	11.8	8.1

Utilis

Hydro Ottawa Performance Relative to Load Distribution Cohort

FTE / $1M of CapEx Additions



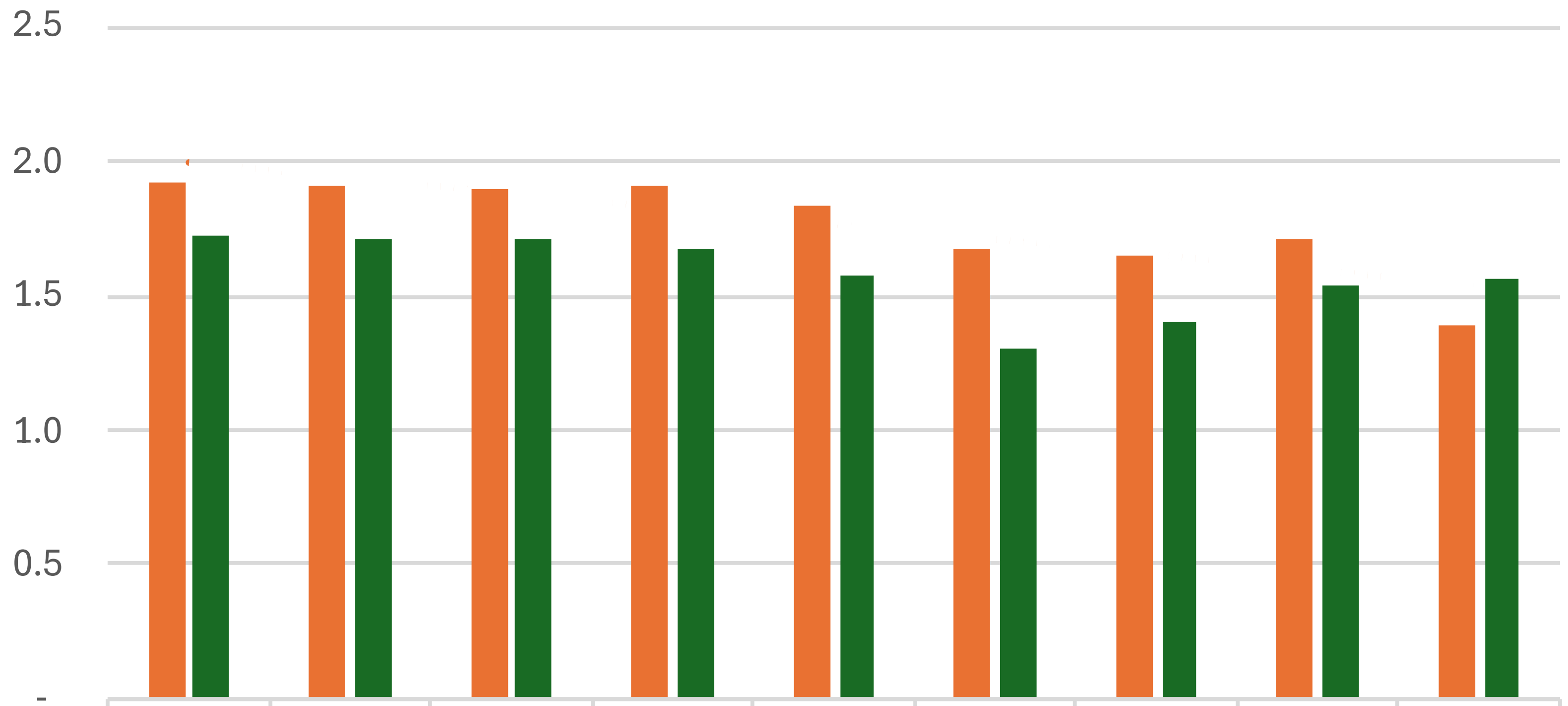
	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	4.2	6.1	5.1	5.2	2.6	4.7	3.4	3.6	4.1
Peer Group Avg.	10.0	8.7	9.1	10.5	11.0	9.0	8.6	9.3	6.2

Hydro Ottawa   Peer Group Avg.   Linear (Hydro Ottawa)

Utilis

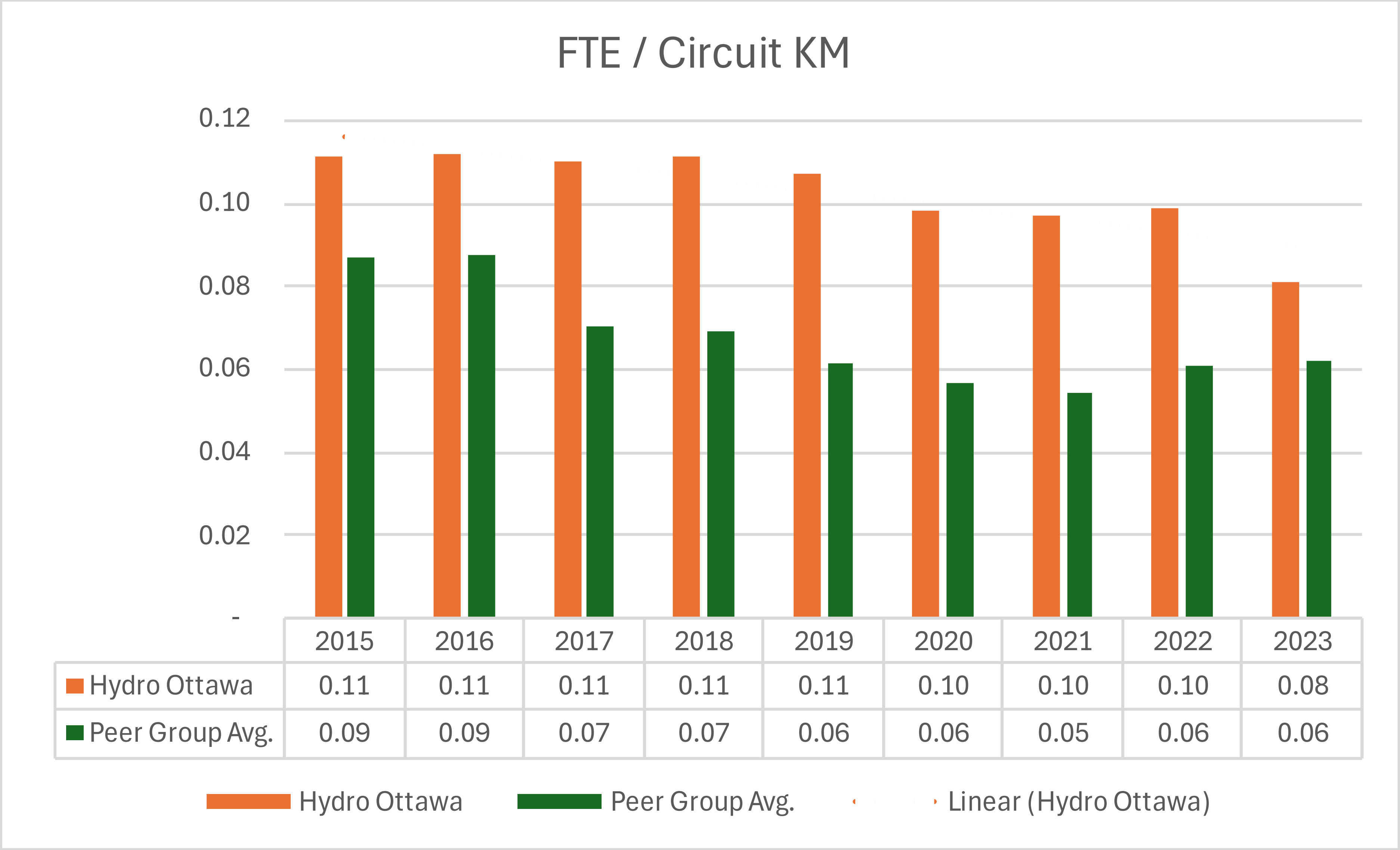
Hydro Ottawa Performance Relative to Load Distribution Cohort

FTE / 1,000 Customer



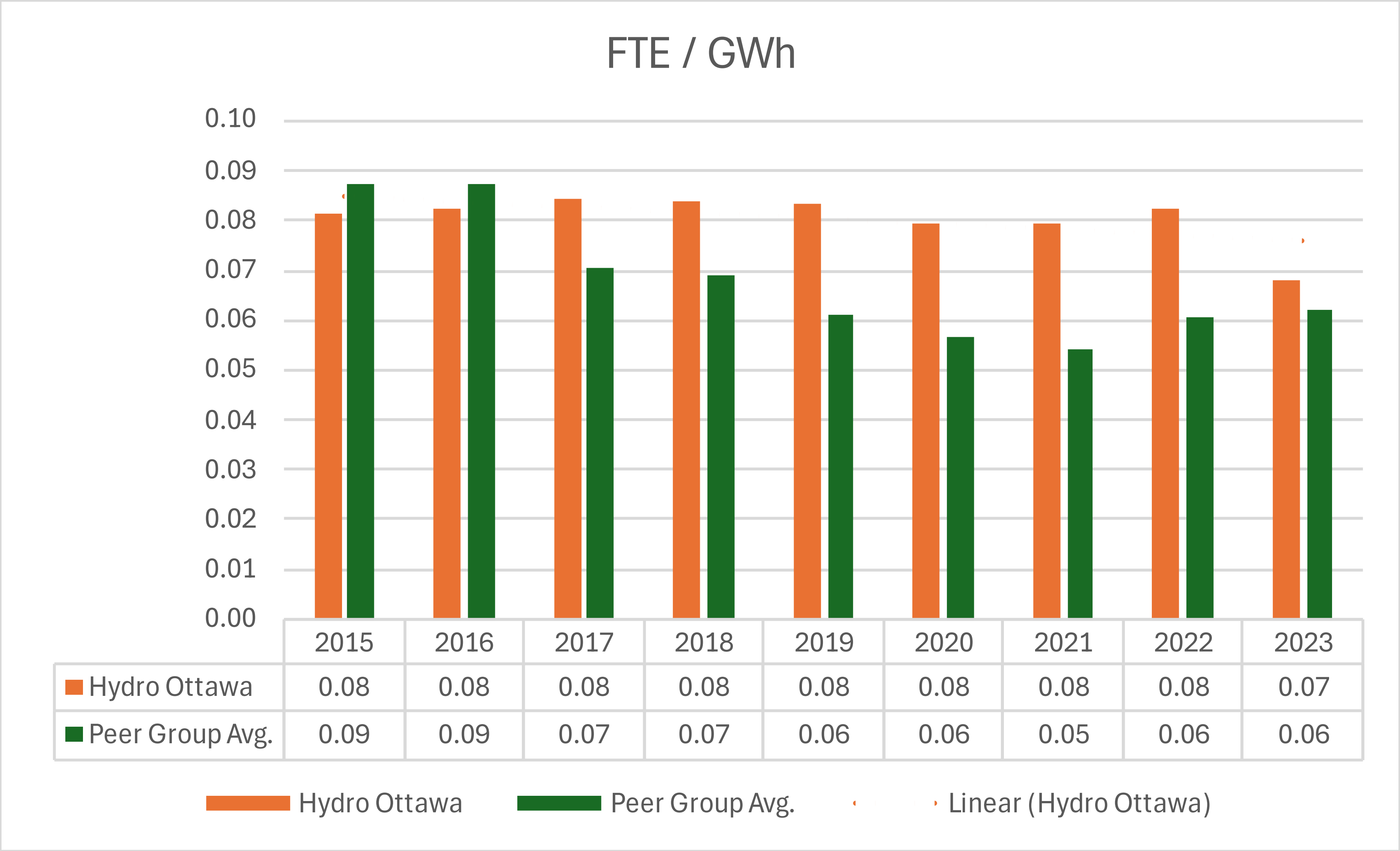
	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	1.9	1.9	1.9	1.9	1.8	1.7	1.6	1.7	1.4
Peer Group Avg.	1.7	1.7	1.7	1.7	1.6	1.3	1.4	1.5	1.6

Hydro Ottawa Performance Relative to Load Distribution Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	0.11	0.11	0.11	0.11	0.11	0.10	0.10	0.10	0.08
Peer Group Avg.	0.09	0.09	0.07	0.07	0.06	0.06	0.05	0.06	0.06

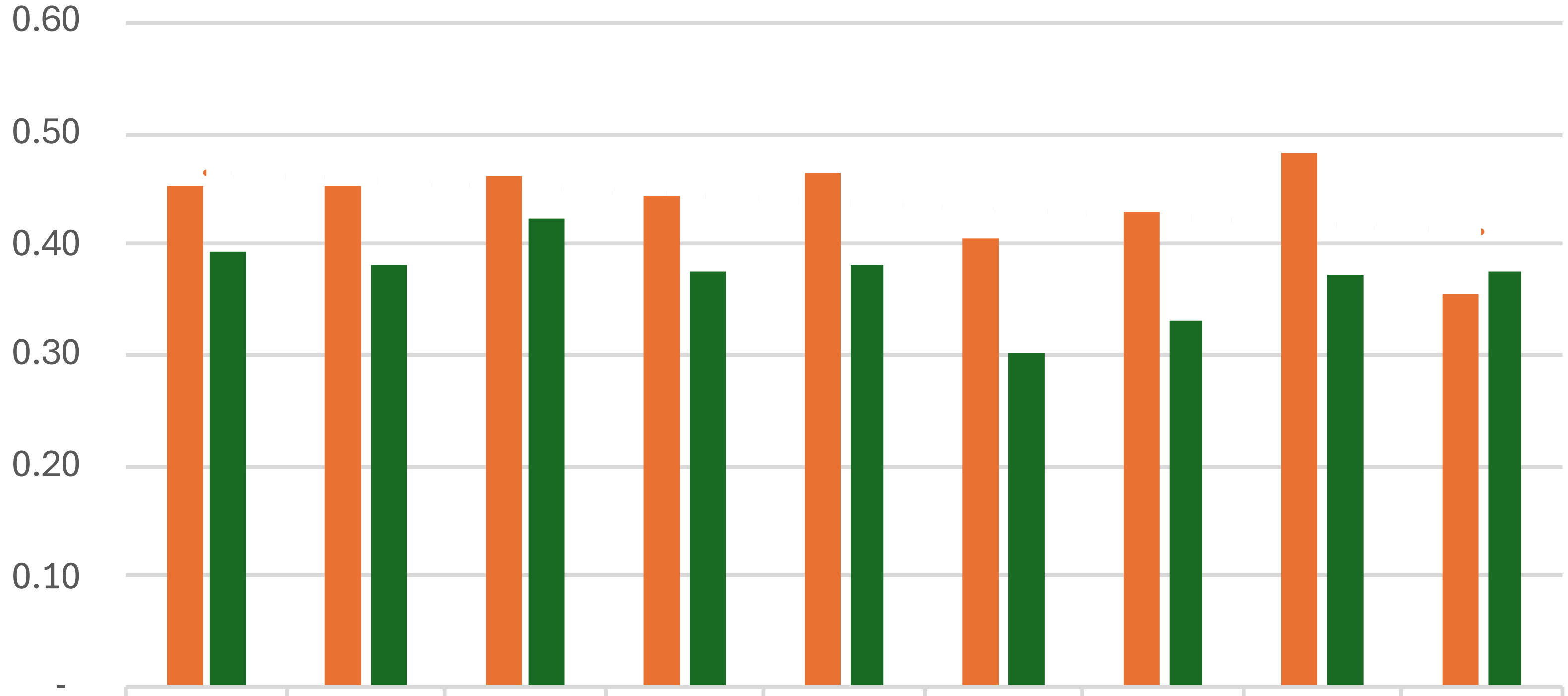
Hydro Ottawa Performance Relative to Load Distribution Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.07
Peer Group Avg.	0.09	0.09	0.07	0.07	0.06	0.06	0.05	0.06	0.06

Hydro Ottawa Performance Relative to Load Distribution Cohort

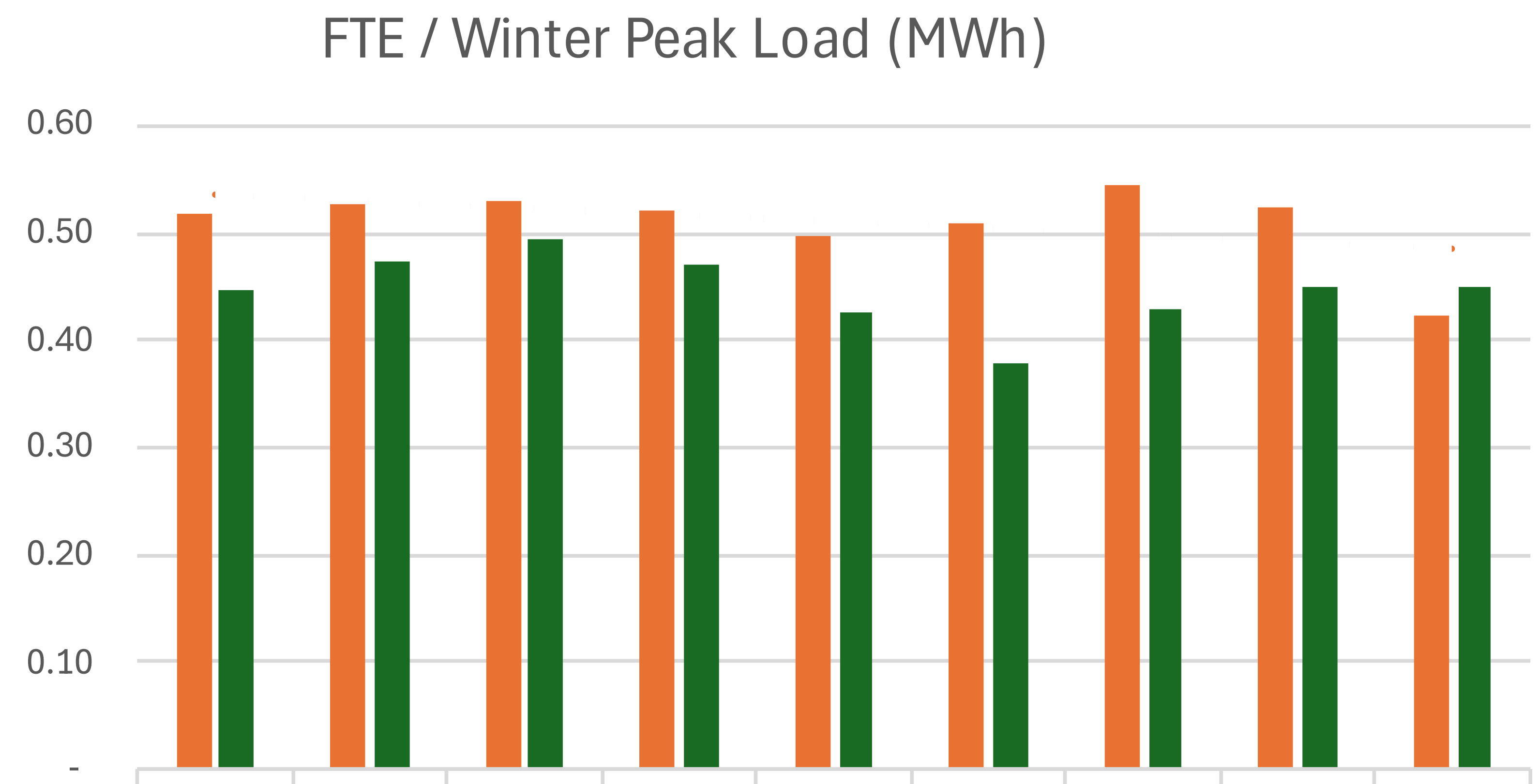
FTE / Summer Peak Load (MWh)



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	0.45	0.45	0.46	0.44	0.46	0.40	0.43	0.48	0.35
Peer Group Avg.	0.39	0.38	0.42	0.38	0.38	0.30	0.33	0.37	0.37

Hydro Ottawa Peer Group Avg. Linear (Hydro Ottawa)

Hydro Ottawa Performance Relative to Load Distribution Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	0.52	0.53	0.53	0.52	0.50	0.51	0.55	0.52	0.42
Peer Group Avg.	0.45	0.47	0.50	0.47	0.43	0.38	0.43	0.45	0.45

Hydro Ottawa Peer Group Avg. Linear (Hydro Ottawa)

Hydro Ottawa Limited

OM&A Benchmarking – 2015 – 2023

% Rural Cohort

Updated:
November 2024
Utilis Consulting Inc.

Basis for Benchmarking Universe

- Benchmarking Universe Characteristics:
  - **Baseline Cohort Chosen: % Rural**
  - **Total # of Distributors in Cohort: 6**
  - **Total # of Distributors: 54**
  - **Data Source: OEB Open Source Data**
  - **% Rural = square footage of rural territory divided by square footage of total territory**
- % Rural Cohort – Peer Group

Elexicon Energy Inc.	59.57%
Hydro Ottawa Limited	59.32%
London Hydro Inc.	57.99%
Bluewater Power Distribution Corporation	54.17%
Burlington Hydro Inc.	47.87%
Welland Hydro-Electric System Corp.	44.44%

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Basis for Benchmarking Universe

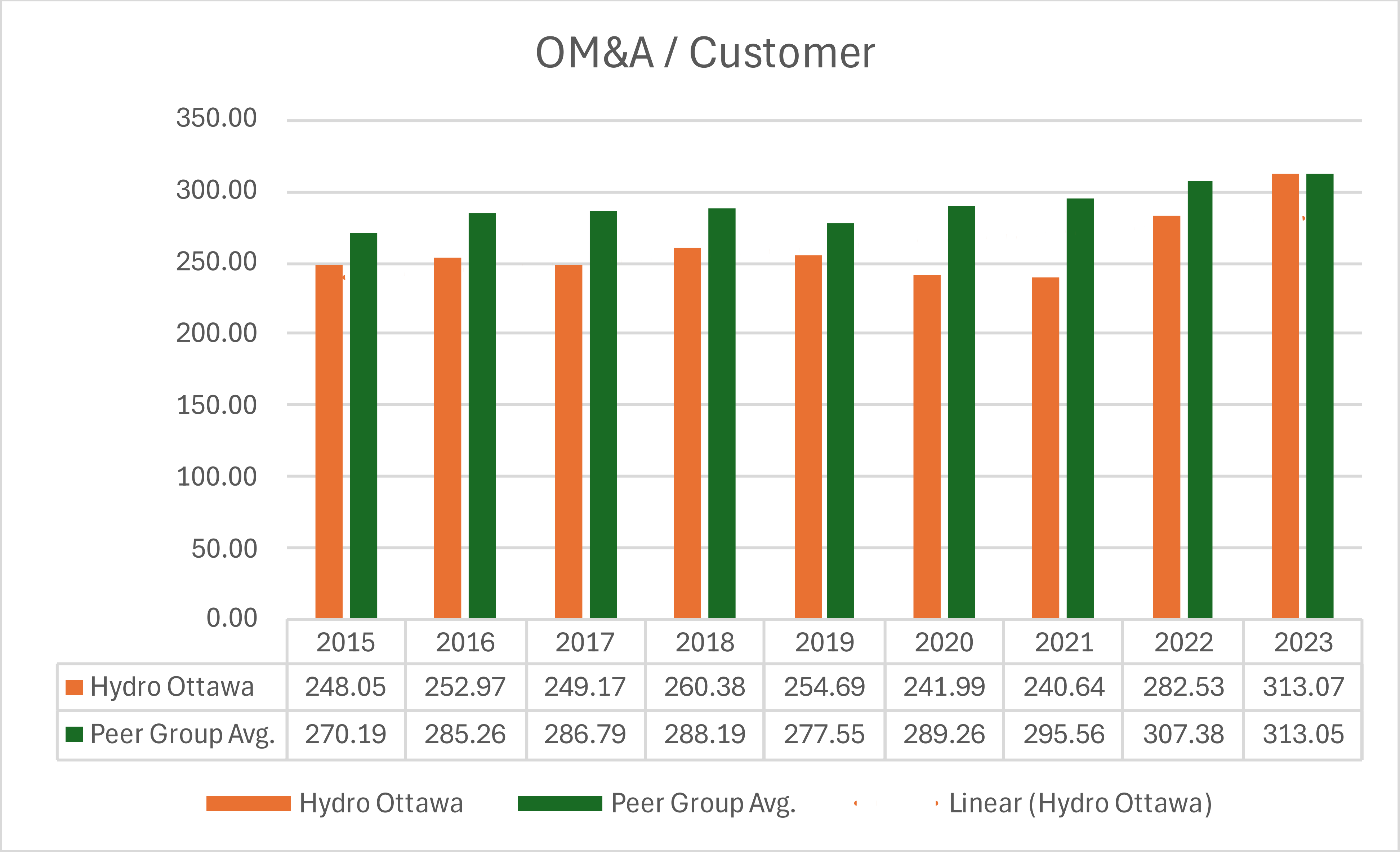
- Utilis generated the following metrics and ratios to compare Hydro Ottawa with its cohort

Utilis Consolidated Scorecard Metric	OMA / Circuit KM	(Contract Services) / Total CapEx
OMA/FTE	Operating Expense / Circuit KM	Operating Expense Ratio
Operating Expense / FTE	Maintenance Expense / Circuit KM	FTE / $1M of CapEx
Maintenance Expense / FTE	Admin. Expenses / Circuit KM	FTE / $1M of CapEx Additions
Admin. Expense / FTE	OMA / MWh	FTE / 1,000 % Rural
OMA / % Rural	Operating Expense / MWh	FTE / Circuit KM
Operating Expense / % Rural	Maintenance Expense / MWh	FTE / GWh
Maintenance Expense / % Rural	Admin. Expenses / MWh	FTE / Summer Peak Load (MWh)
Admin. Expense / % Rural	MWh / % Rural	FTE / Winter Peak Load (MWh)
Circuit km / 1,000 % Rurals	OMA / CapEx	

Benchmarking Universe

Hydro Ottawa Performance Relative to % Rural Cohort

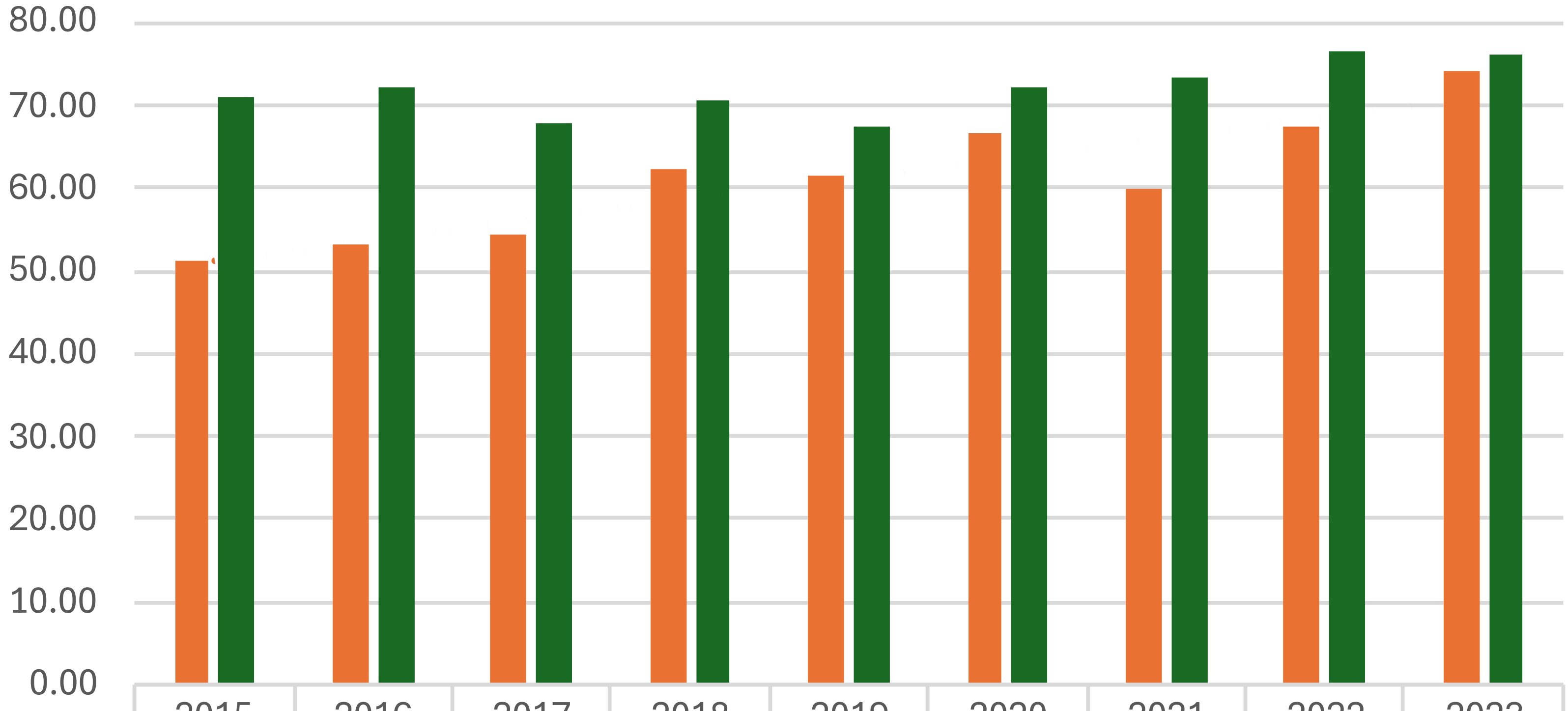
Hydro Ottawa Performance Relative to % Rural Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	248.05	252.97	249.17	260.38	254.69	241.99	240.64	282.53	313.07
Peer Group Avg.	270.19	285.26	286.79	288.19	277.55	289.26	295.56	307.38	313.05

Hydro Ottawa Performance Relative to % Rural Cohort

Operating Expense / Customer

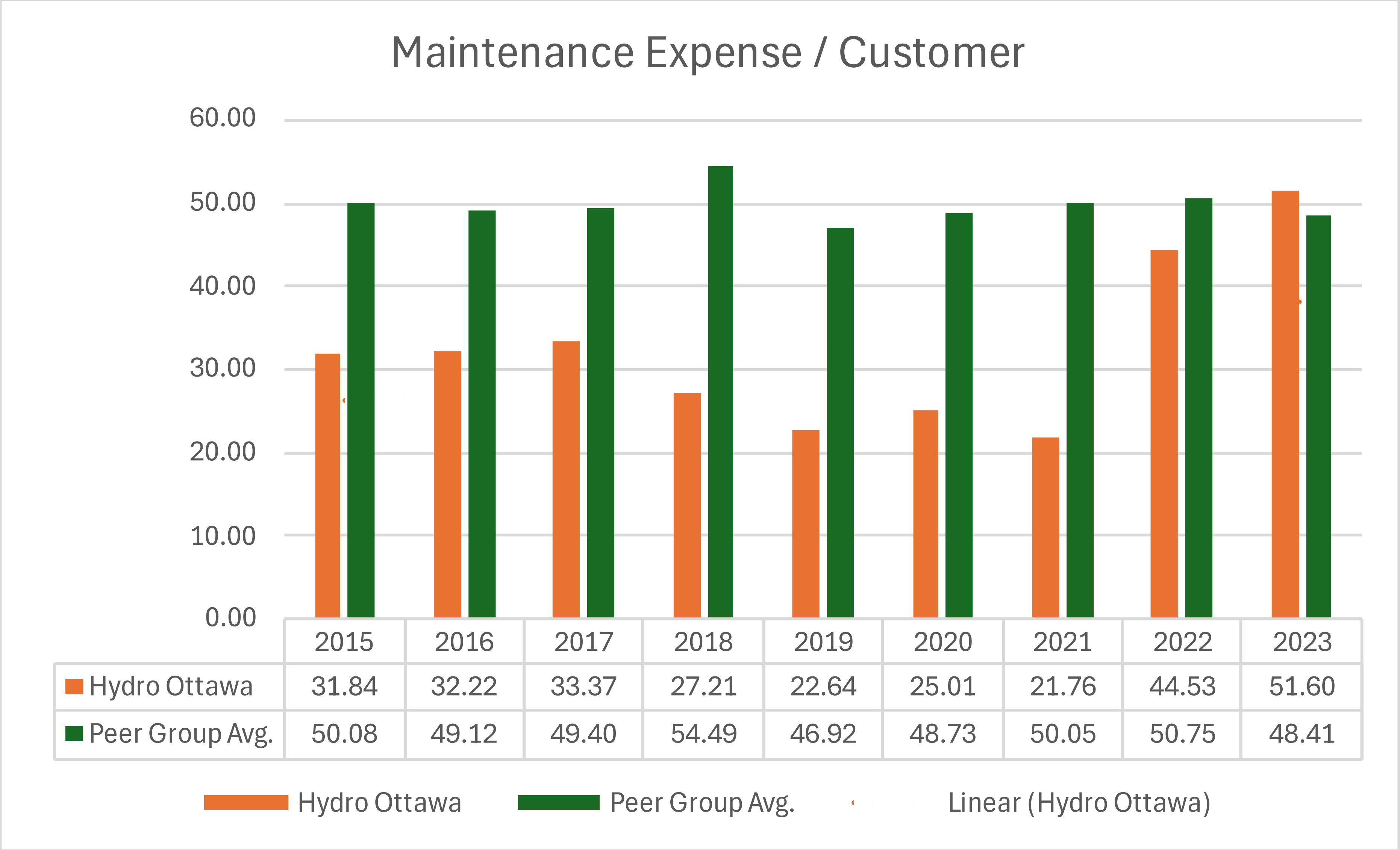


	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	51.08	53.35	54.25	62.26	61.40	66.70	60.02	67.43	74.23
Peer Group Avg.	71.02	72.06	68.08	70.75	67.54	72.43	73.56	76.42	76.18

Hydro Ottawa   Peer Group Avg.   Linear (Hydro Ottawa)

Utilis

Hydro Ottawa Performance Relative to % Rural Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	31.84	32.22	33.37	27.21	22.64	25.01	21.76	44.53	51.60
Peer Group Avg.	50.08	49.12	49.40	54.49	46.92	48.73	50.05	50.75	48.41

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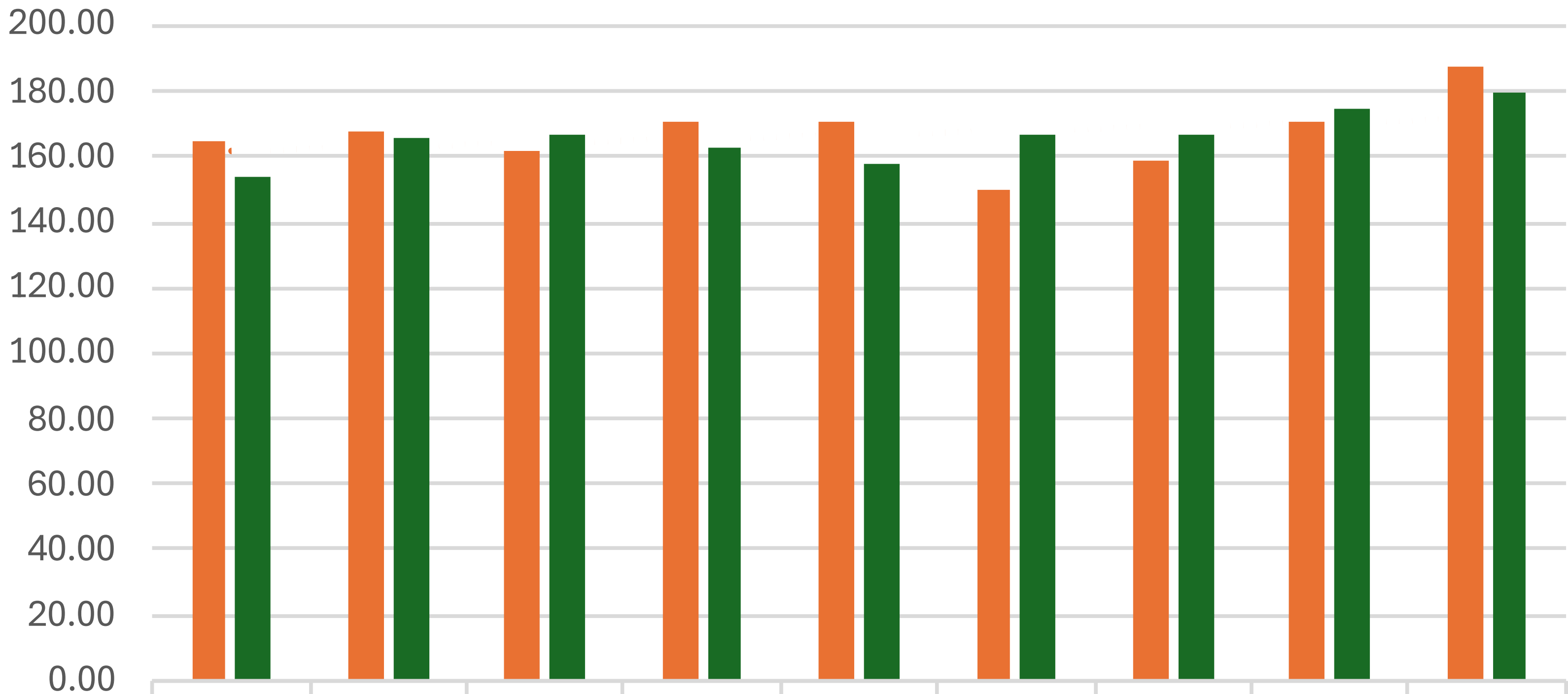
Hydro Ottawa Performance Relative to % Rural Cohort

Administrative Expense / Customer

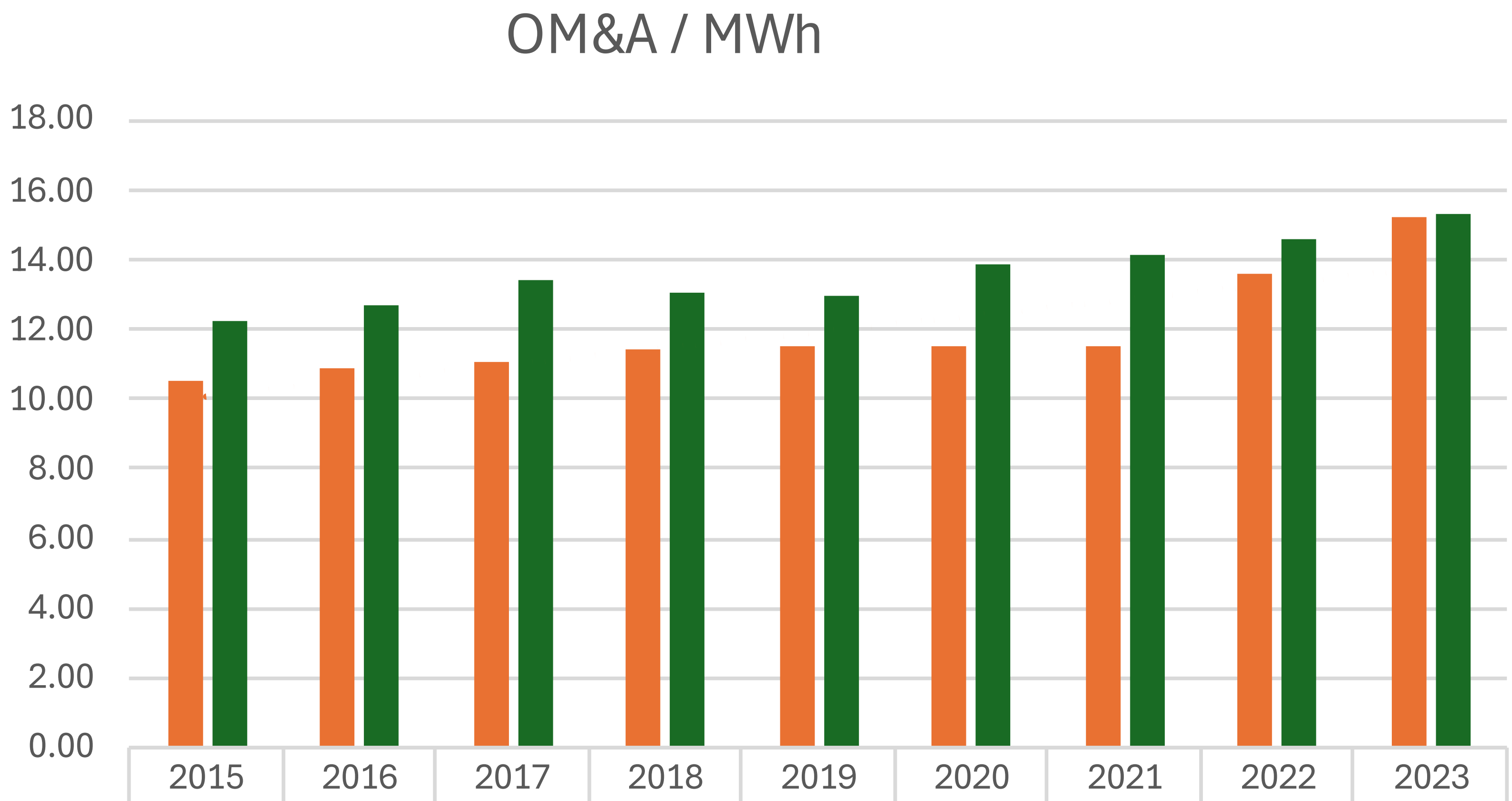


	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	165.13	167.40	161.54	170.91	170.65	150.27	158.87	170.58	187.24
Peer Group Avg.	153.57	166.15	166.67	162.69	158.28	166.39	166.74	175.08	179.26

Hydro Ottawa Peer Group Avg. Linear (Hydro Ottawa)

Utilis

Hydro Ottawa Performance Relative to % Rural Cohort



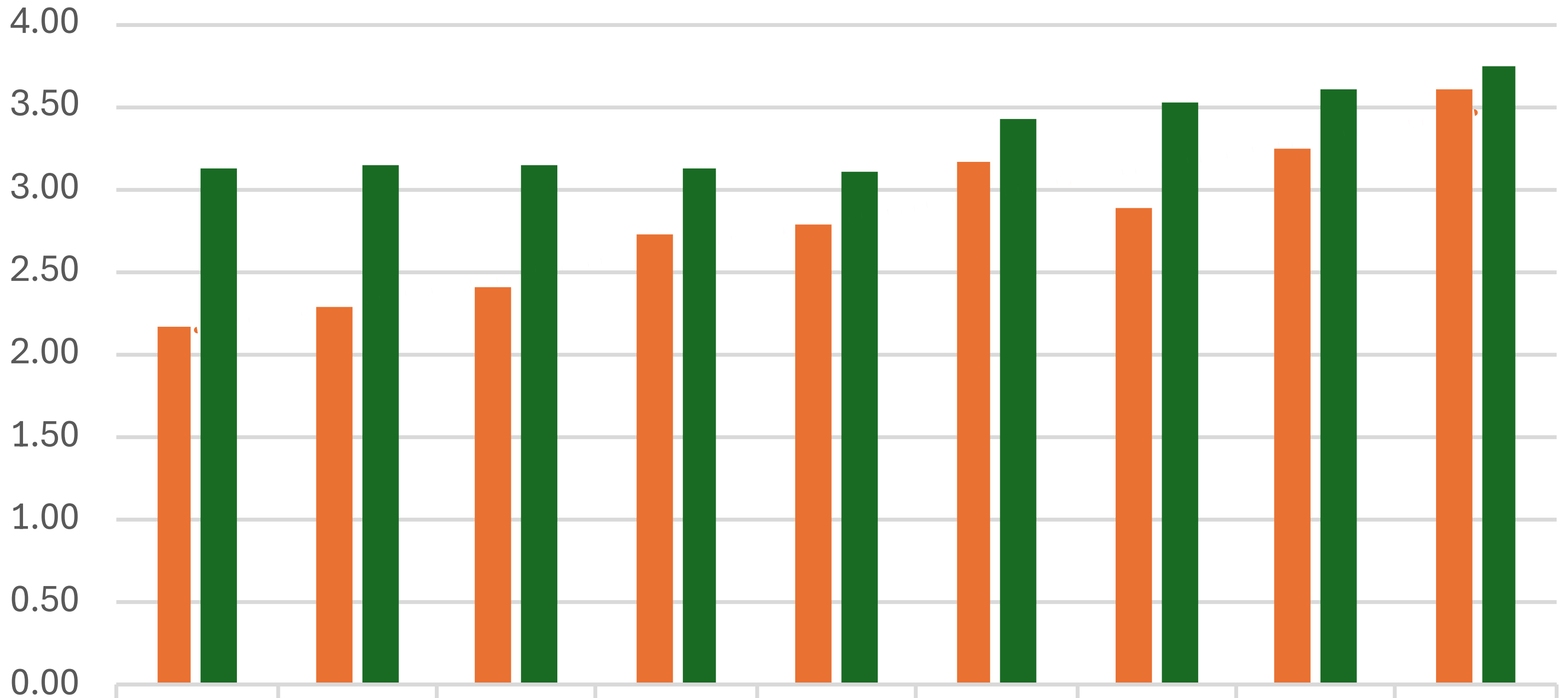
	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	10.49	10.86	11.10	11.42	11.54	11.48	11.56	13.59	15.21
Peer Group Avg.	12.21	12.74	13.40	13.03	13.01	13.84	14.15	14.61	15.30

Hydro Ottawa   Peer Group Avg.   Linear (Hydro Ottawa)

Utilis

Hydro Ottawa Performance Relative to % Rural Cohort

Operating Expense / MWh

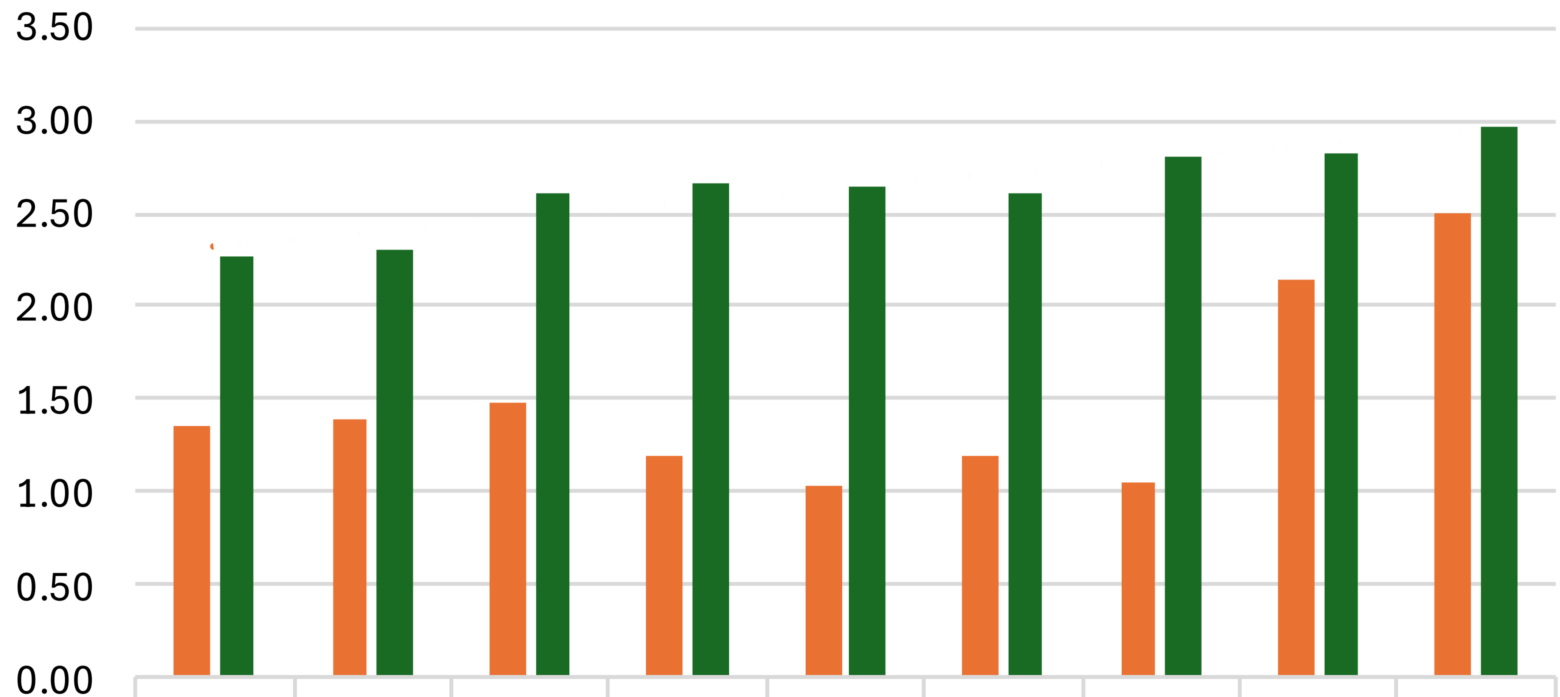


	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	2.16	2.29	2.42	2.73	2.78	3.16	2.88	3.24	3.61
Peer Group Avg.	3.12	3.16	3.16	3.13	3.11	3.42	3.53	3.62	3.74

Hydro Ottawa Peer Group Avg. Linear (Hydro Ottawa)

Hydro Ottawa Performance Relative to % Rural Cohort

Maintenance Expense / MWh

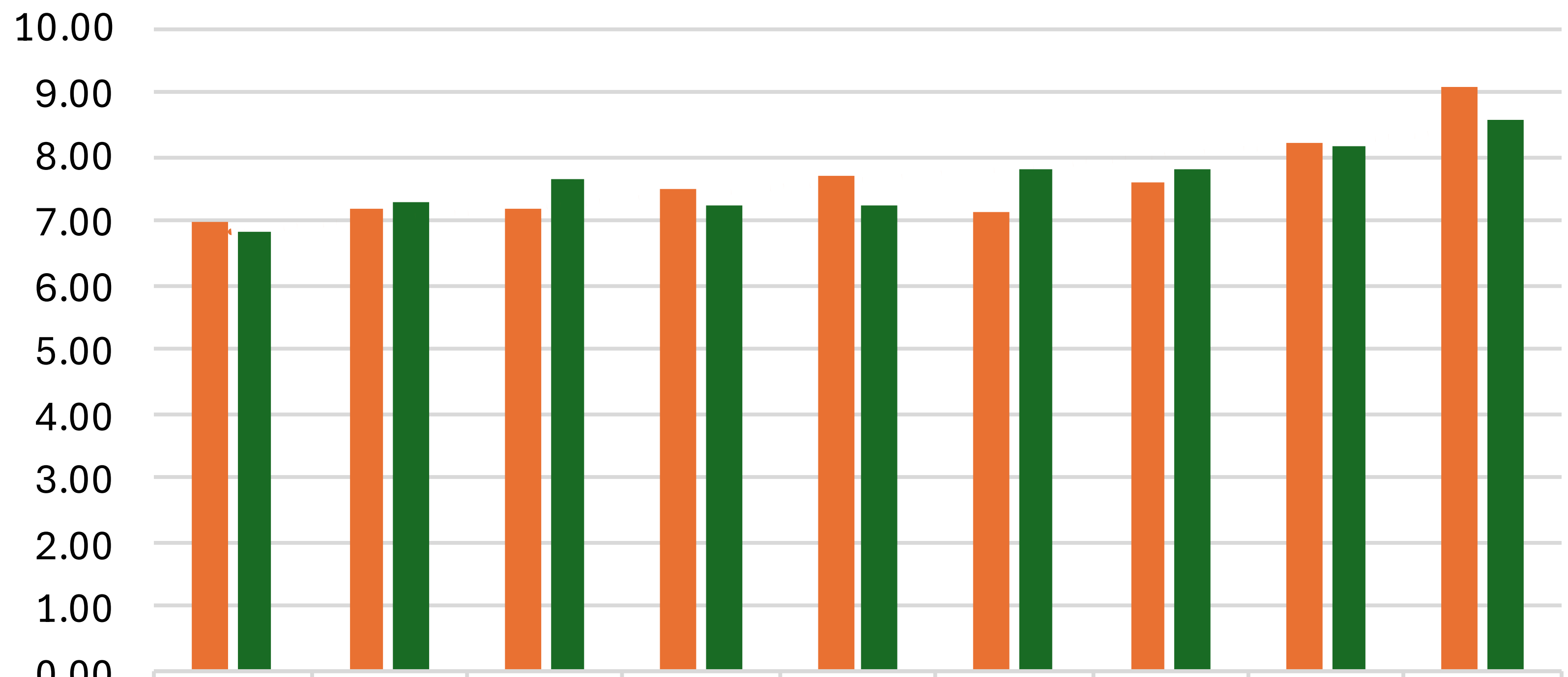


	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	1.35	1.38	1.49	1.19	1.03	1.19	1.05	2.14	2.51
Peer Group Avg.	2.26	2.30	2.61	2.66	2.65	2.61	2.80	2.83	2.97

Hydro Ottawa Peer Group Avg. Linear (Peer Group Avg.)

Hydro Ottawa Performance Relative to % Rural Cohort

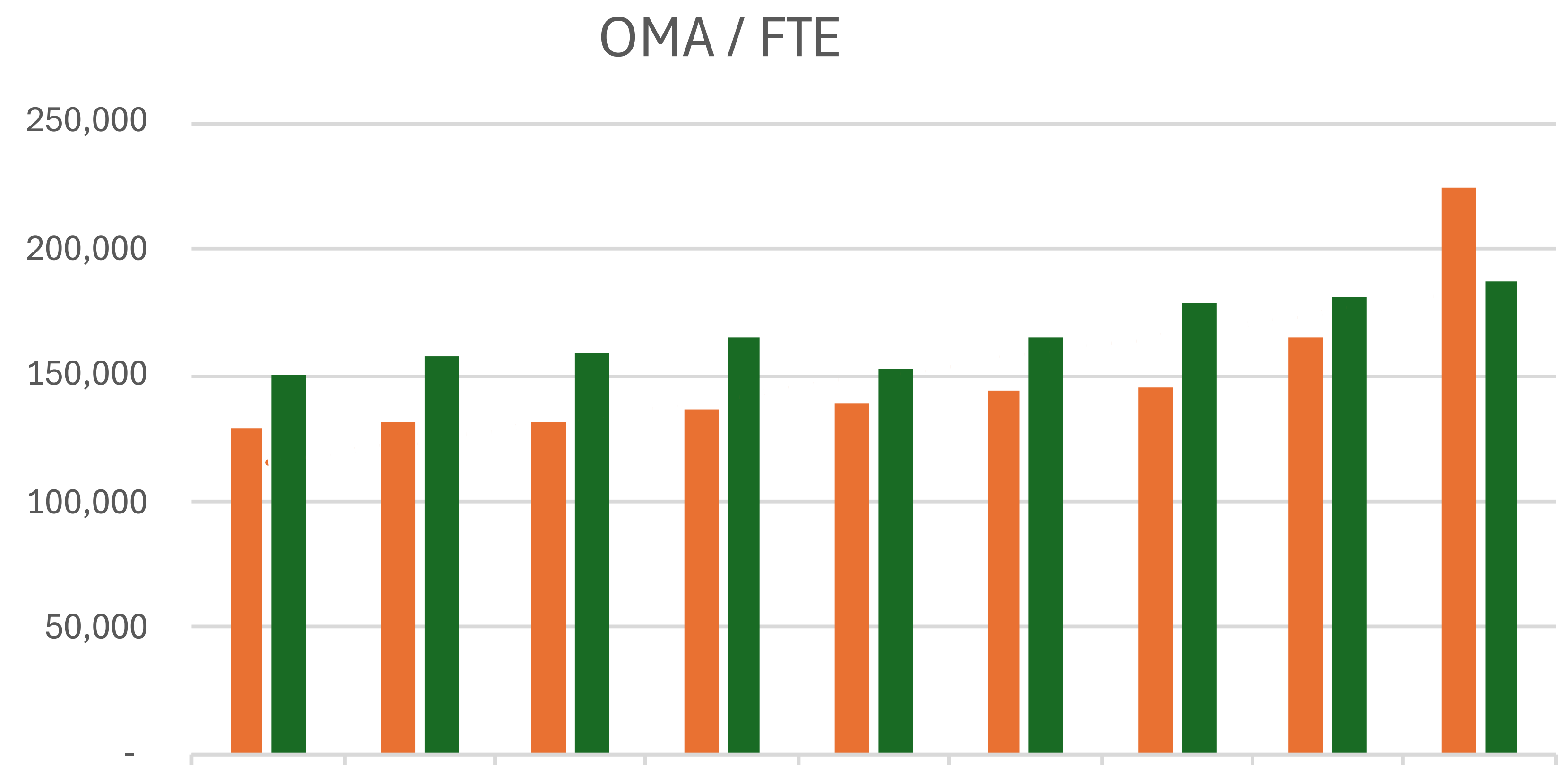
Administrative Expense / MWh



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	6.98	7.19	7.20	7.50	7.73	7.13	7.63	8.20	9.09
Peer Group Avg.	6.82	7.28	7.63	7.23	7.26	7.80	7.83	8.17	8.59

Hydro Ottawa   Peer Group Avg.   Linear (Hydro Ottawa)

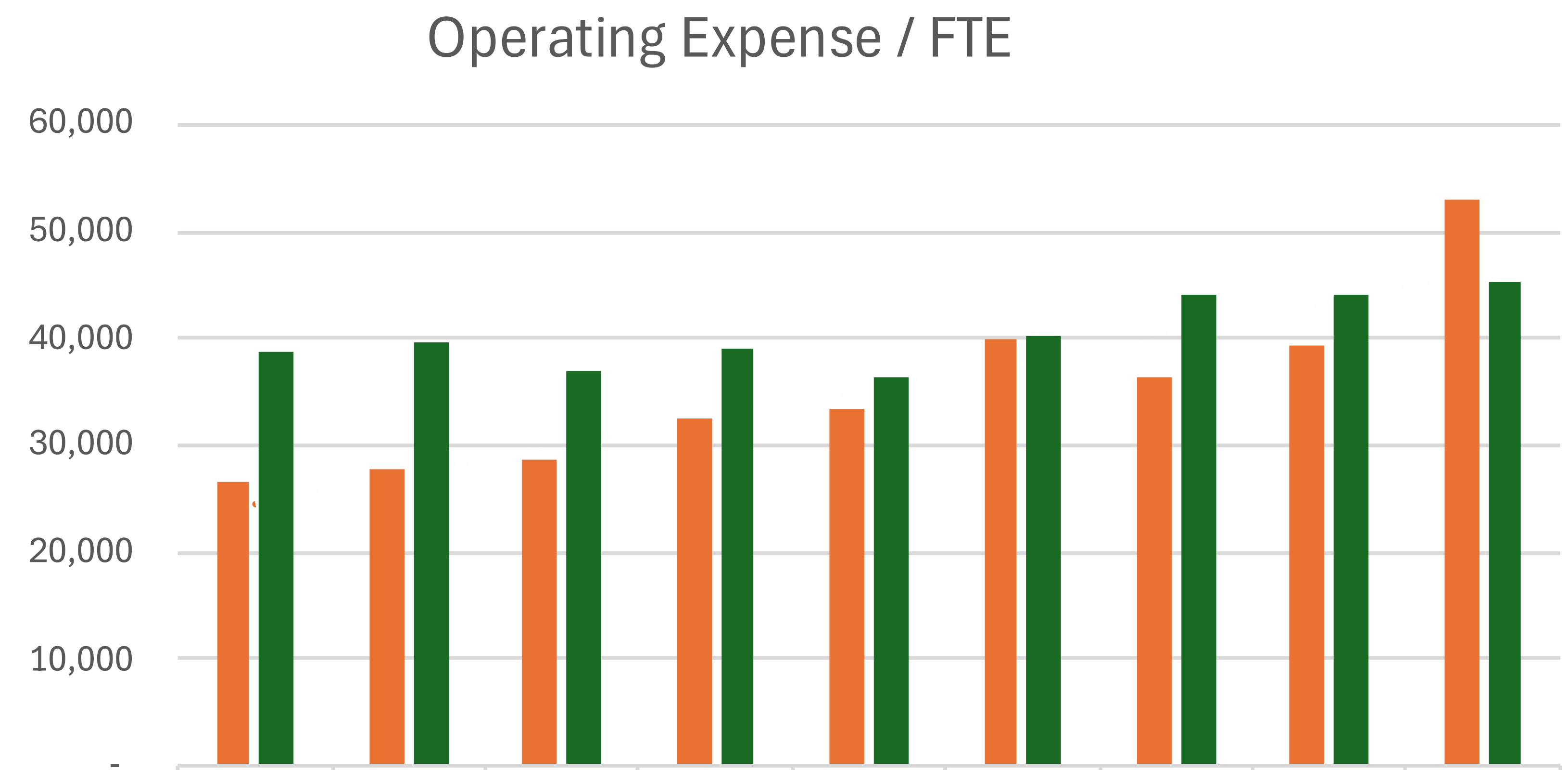
Hydro Ottawa Performance Relative to % Rural Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	129,178	132,075	131,638	136,310	138,583	144,355	145,912	164,694	224,085
Peer Group Avg.	149,891	157,945	159,061	164,613	152,834	164,980	179,279	180,841	187,028

Hydro Ottawa Peer Group Avg. Linear (Hydro Ottawa)

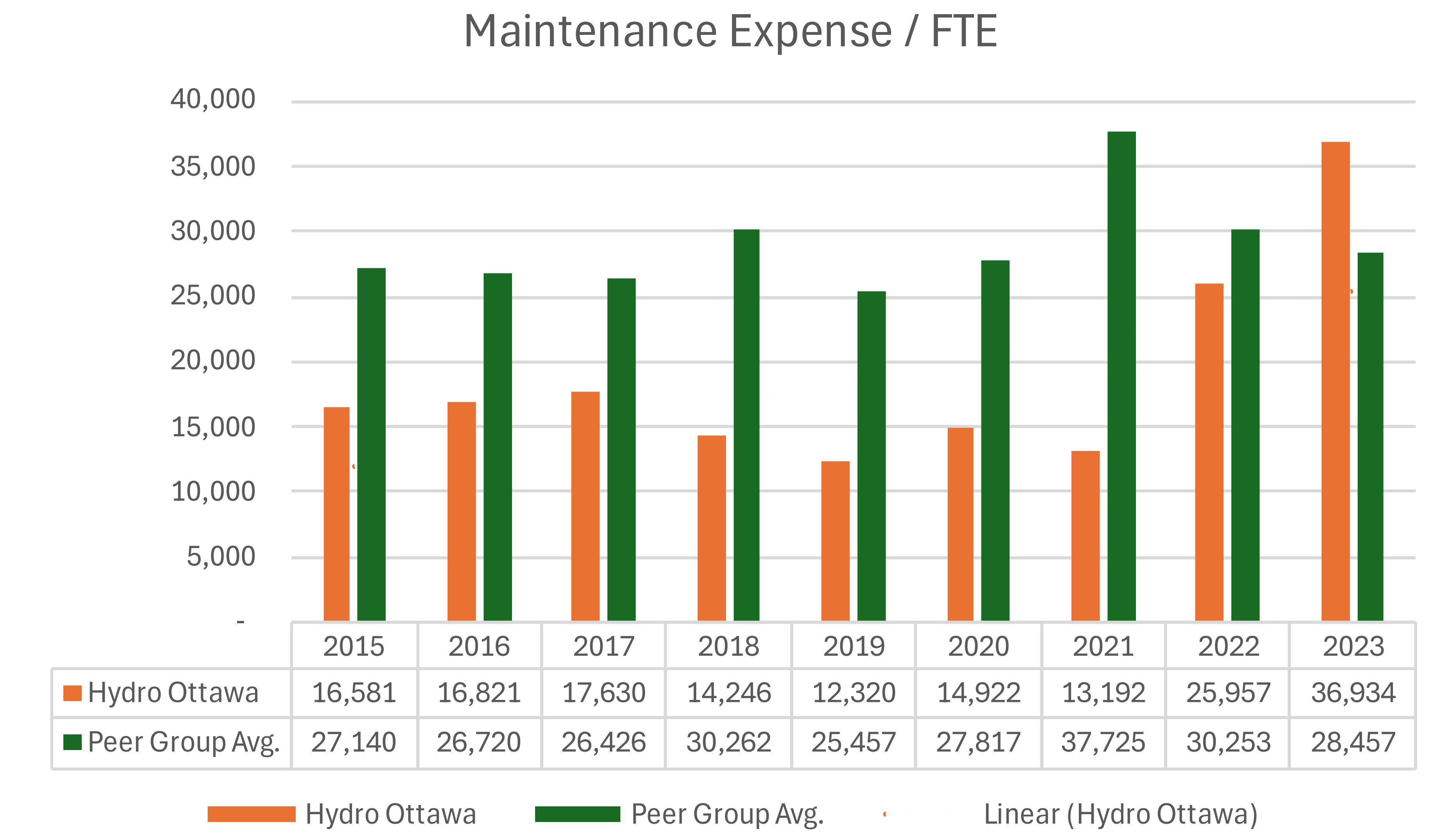
Hydro Ottawa Performance Relative to % Rural Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	26,601	27,853	28,662	32,593	33,411	39,789	36,392	39,305	53,132
Peer Group Avg.	38,804	39,569	36,923	38,994	36,414	40,299	44,009	44,095	45,203

Utilis

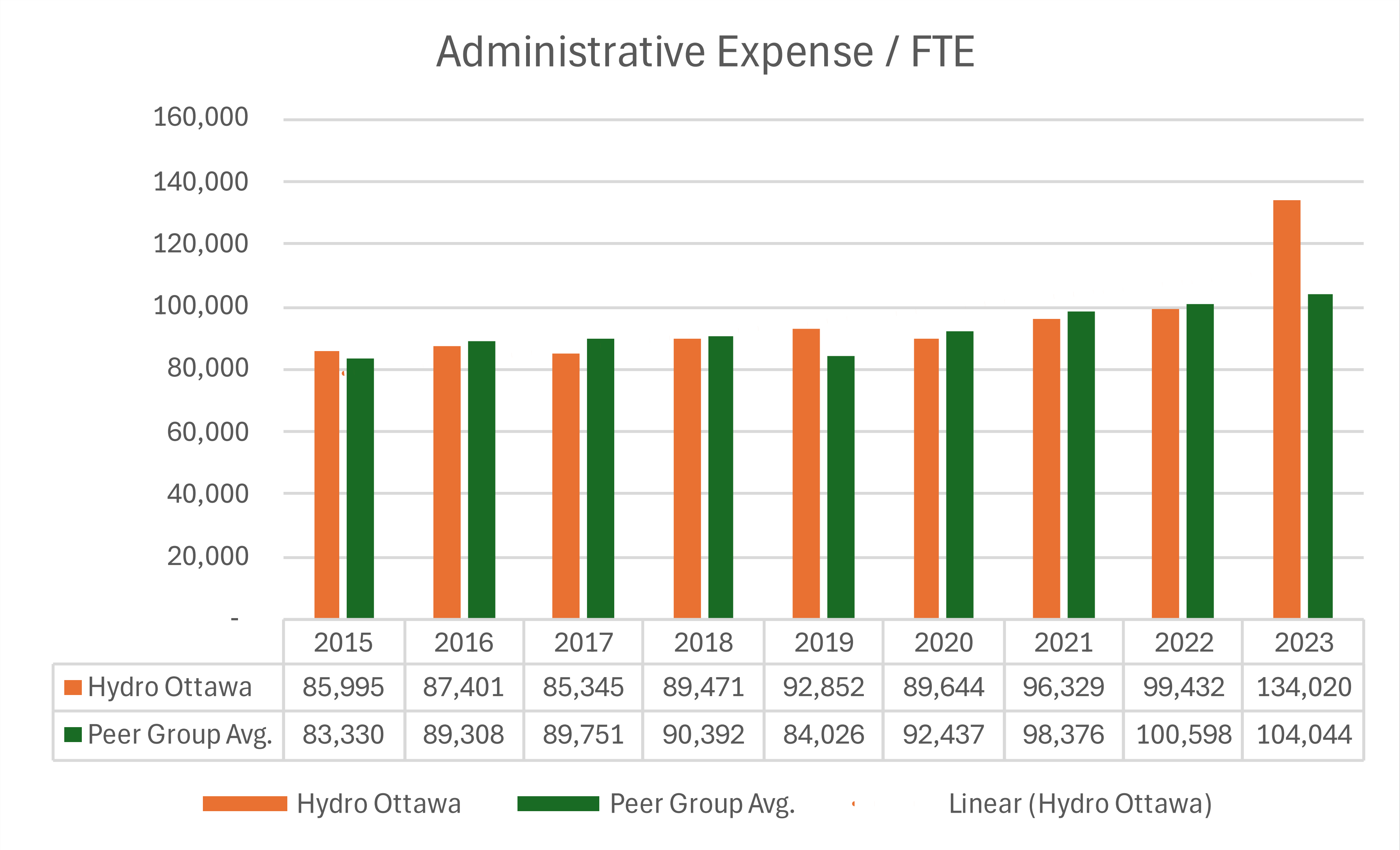
Hydro Ottawa Performance Relative to % Rural Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	16,581	16,821	17,630	14,246	12,320	14,922	13,192	25,957	36,934
Peer Group Avg.	27,140	26,720	26,426	30,262	25,457	27,817	37,725	30,253	28,457

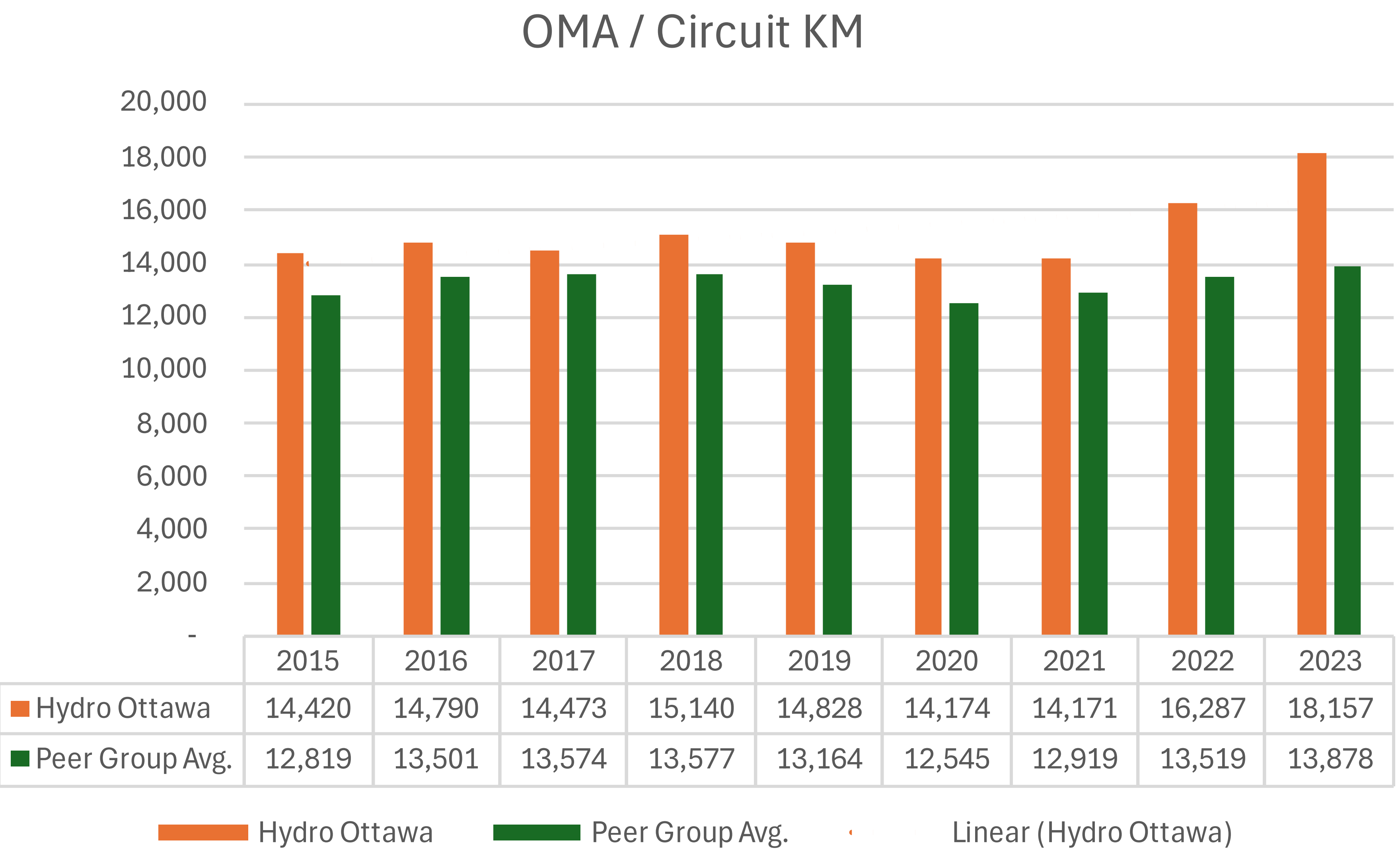
Utilis

Hydro Ottawa Performance Relative to % Rural Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	85,995	87,401	85,345	89,471	92,852	89,644	96,329	99,432	134,020
Peer Group Avg.	83,330	89,308	89,751	90,392	84,026	92,437	98,376	100,598	104,044

Hydro Ottawa Performance Relative to % Rural Cohort

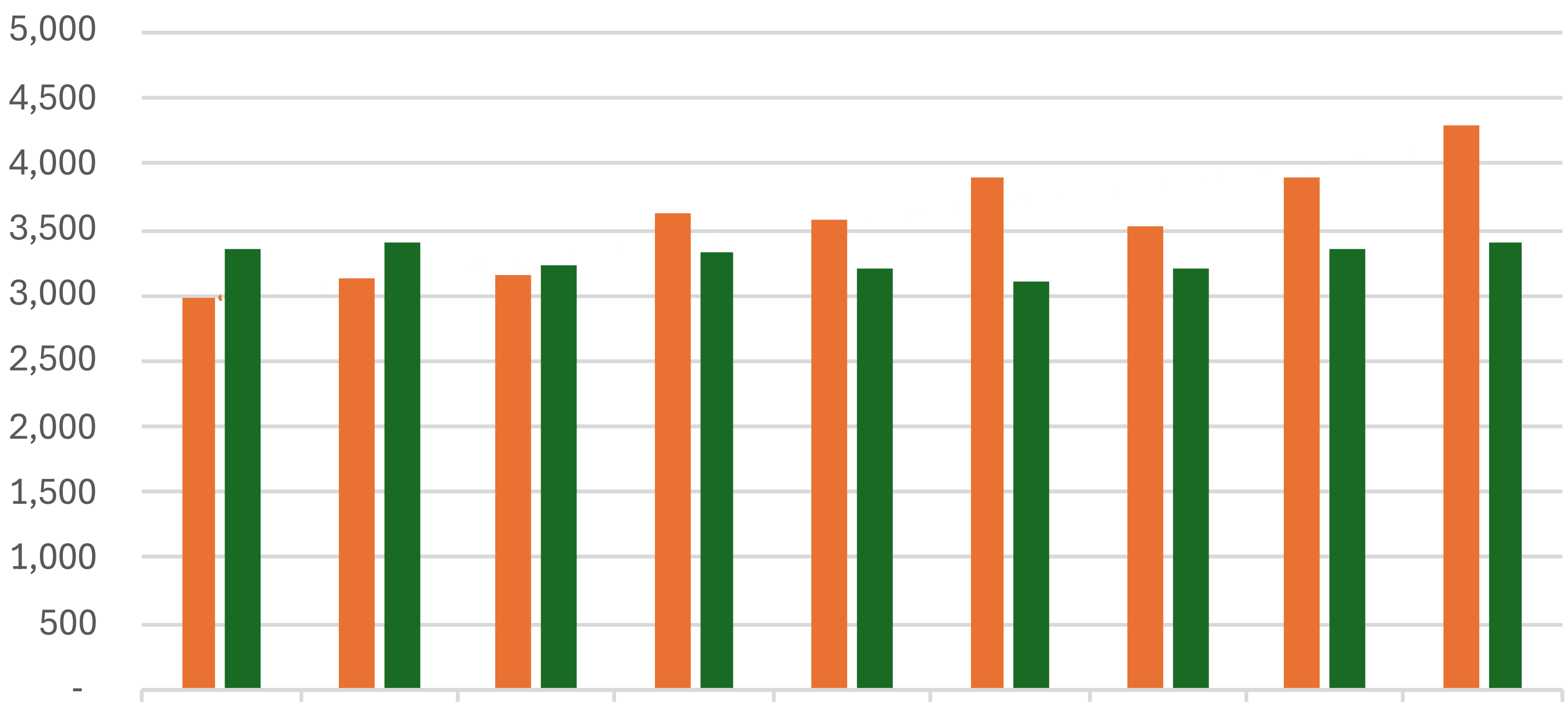


	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	14,420	14,790	14,473	15,140	14,828	14,174	14,171	16,287	18,157
Peer Group Avg.	12,819	13,501	13,574	13,577	13,164	12,545	12,919	13,519	13,878

Utilis

Hydro Ottawa Performance Relative to % Rural Cohort

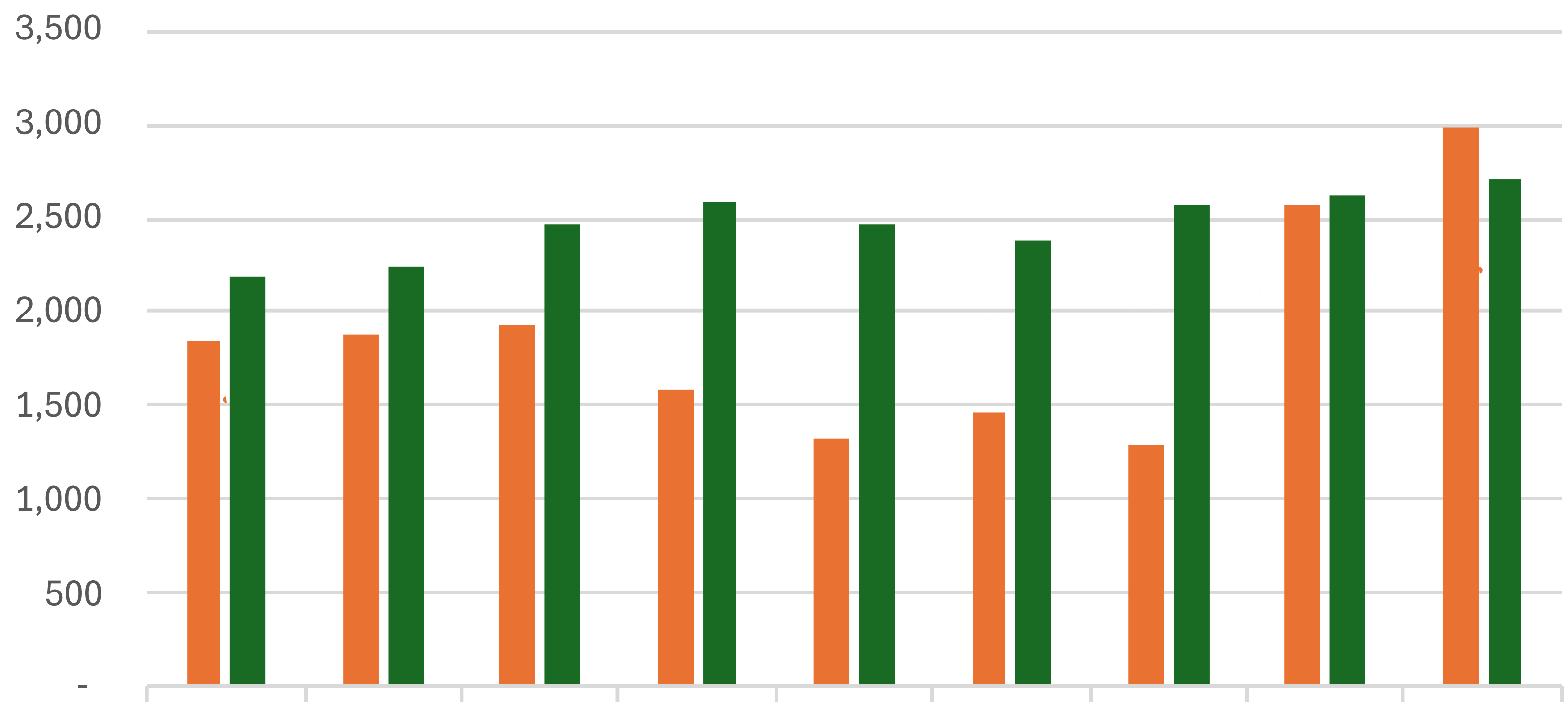
Operating Expense / Circuit KM



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	2,969	3,119	3,151	3,620	3,575	3,907	3,534	3,887	4,305
Peer Group Avg.	3,355	3,404	3,231	3,334	3,205	3,109	3,210	3,343	3,391

Hydro Ottawa Performance Relative to % Rural Cohort

Maintenance Expense / Circuit KM

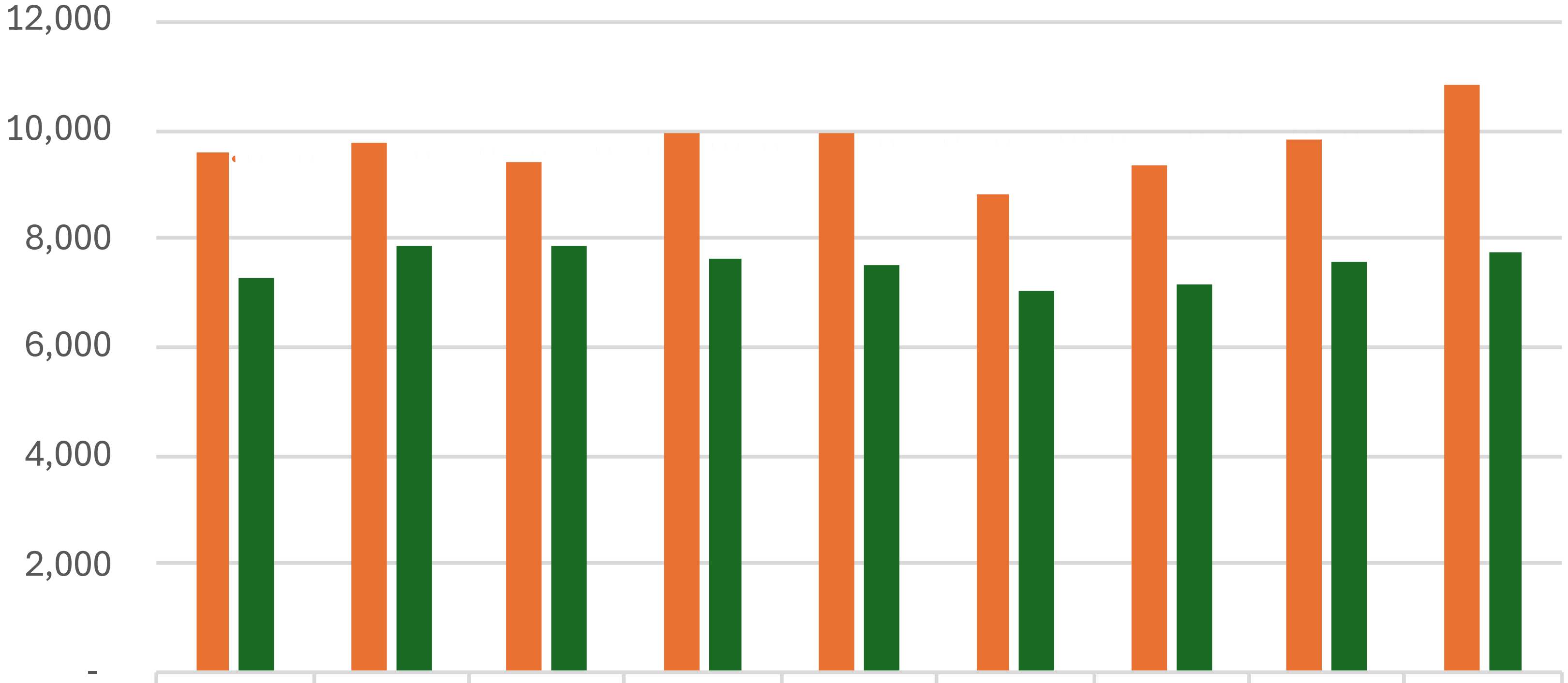


	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	1,851	1,884	1,938	1,582	1,318	1,465	1,281	2,567	2,993
Peer Group Avg.	2,184	2,246	2,473	2,595	2,462	2,384	2,569	2,616	2,715

Hydro Ottawa   Peer Group Avg.   Linear (Hydro Ottawa)

Hydro Ottawa Performance Relative to % Rural Cohort

Administrative Expenses / Circuit KM

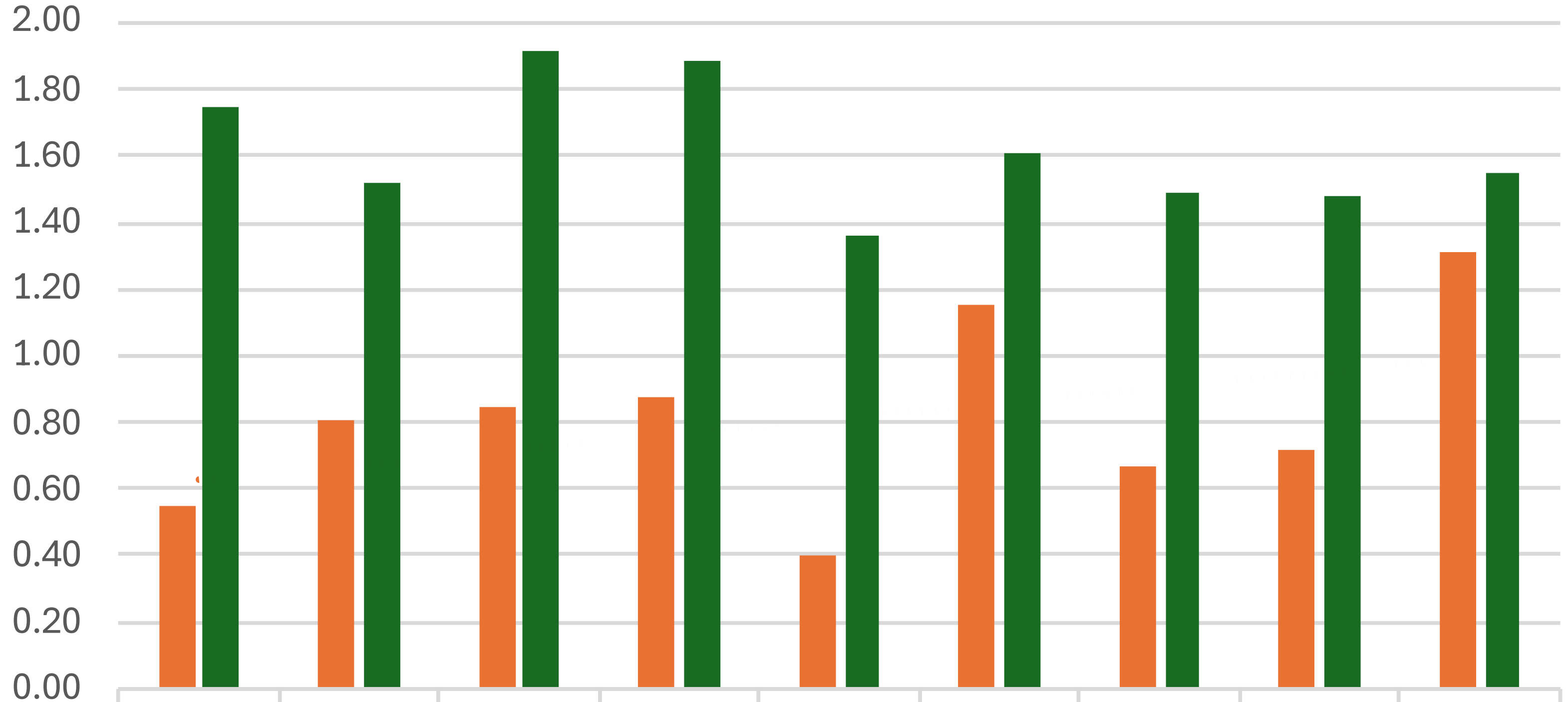


	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	9,600	9,787	9,383	9,938	9,935	8,802	9,355	9,833	10,859
Peer Group Avg.	7,280	7,852	7,870	7,648	7,496	7,053	7,140	7,561	7,772

Hydro Ottawa Peer Group Avg. Linear (Hydro Ottawa)

Hydro Ottawa Performance Relative to % Rural Cohort

OM&A / CapEx



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	0.55	0.80	0.85	0.87	0.40	1.15	0.67	0.71	1.31
Peer Group Avg.	1.74	1.52	1.91	1.88	1.36	1.61	1.49	1.48	1.55

Hydro Ottawa Peer Group Avg. Linear (Hydro Ottawa)

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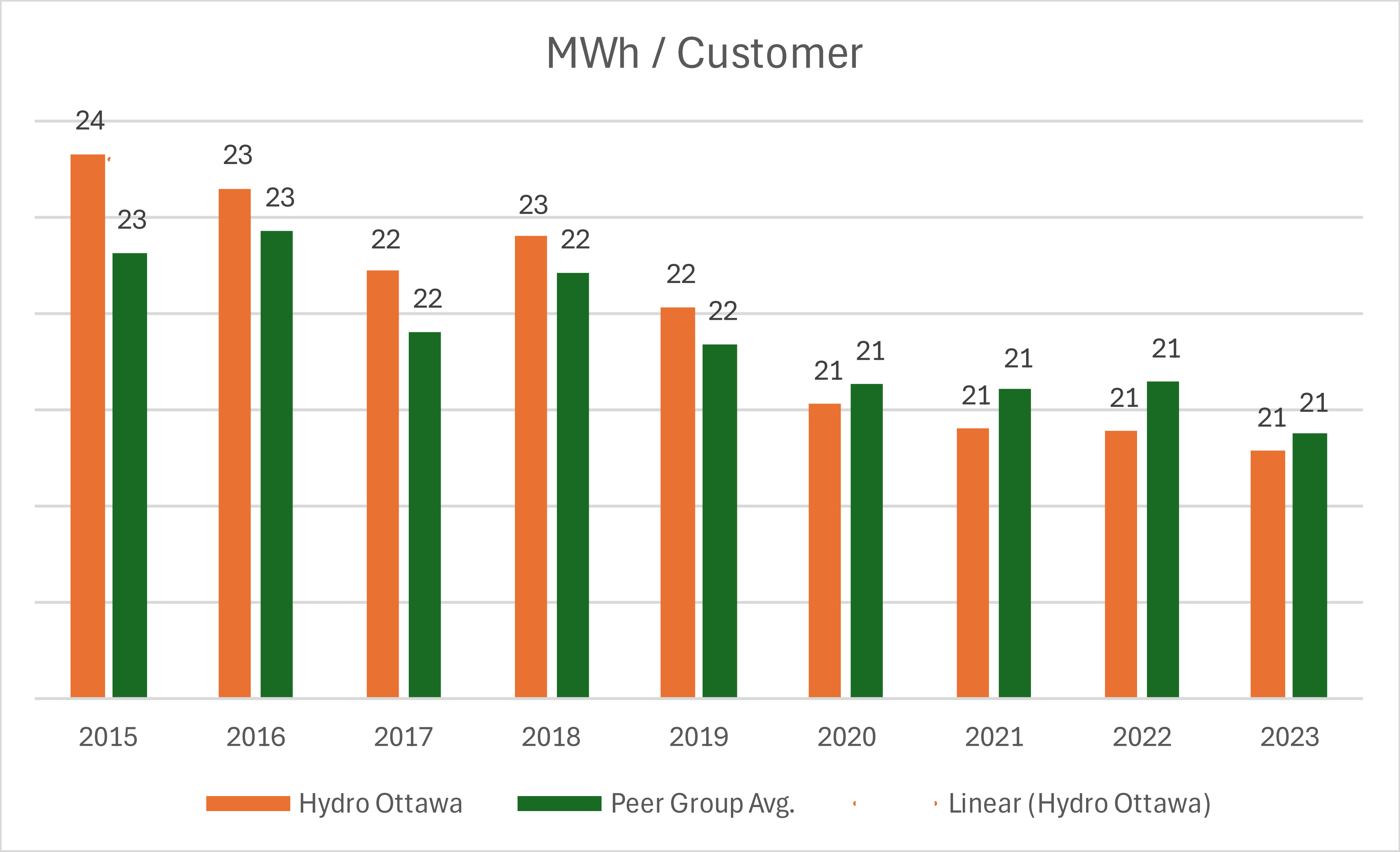
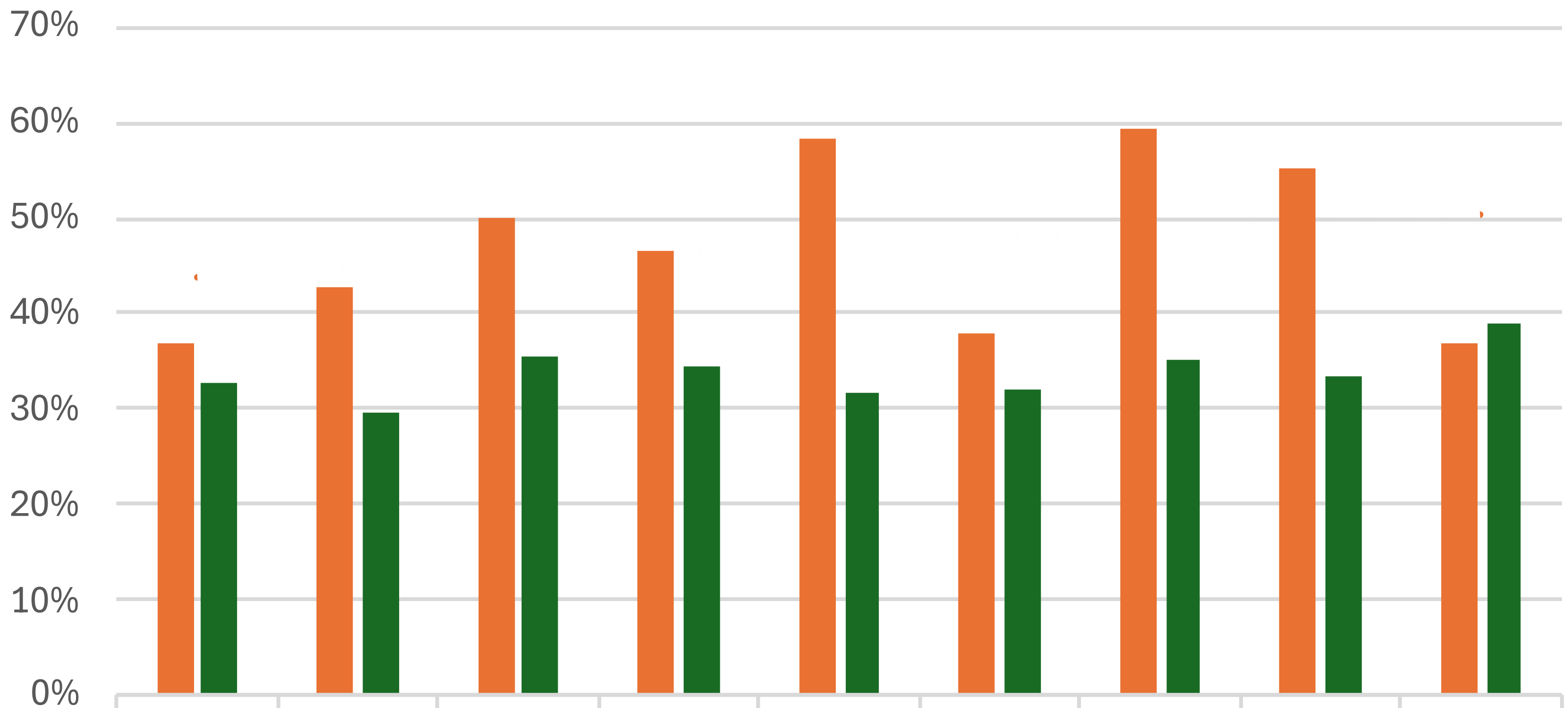
Hydro Ottawa Performance Relative to % Rural Cohort



Utilis

Hydro Ottawa Performance Relative to % Rural Cohort

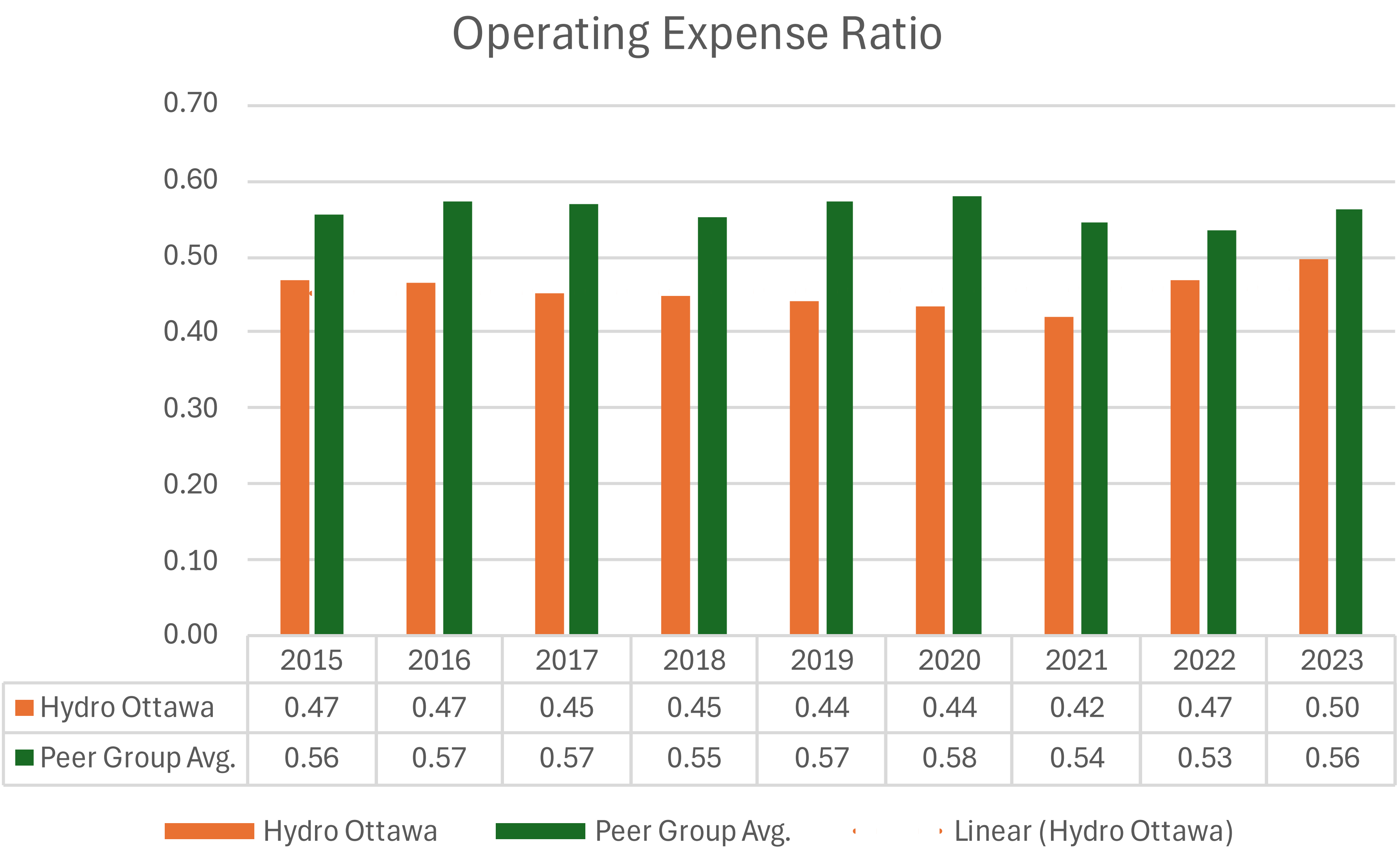
(Contract Services) / Total CapEx



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	37%	43%	50%	47%	58%	38%	59%	55%	37%
Peer Group Avg.	33%	29%	36%	34%	32%	32%	35%	33%	39%

Hydro Ottawa · Peer Group Avg. · Linear (Hydro Ottawa)

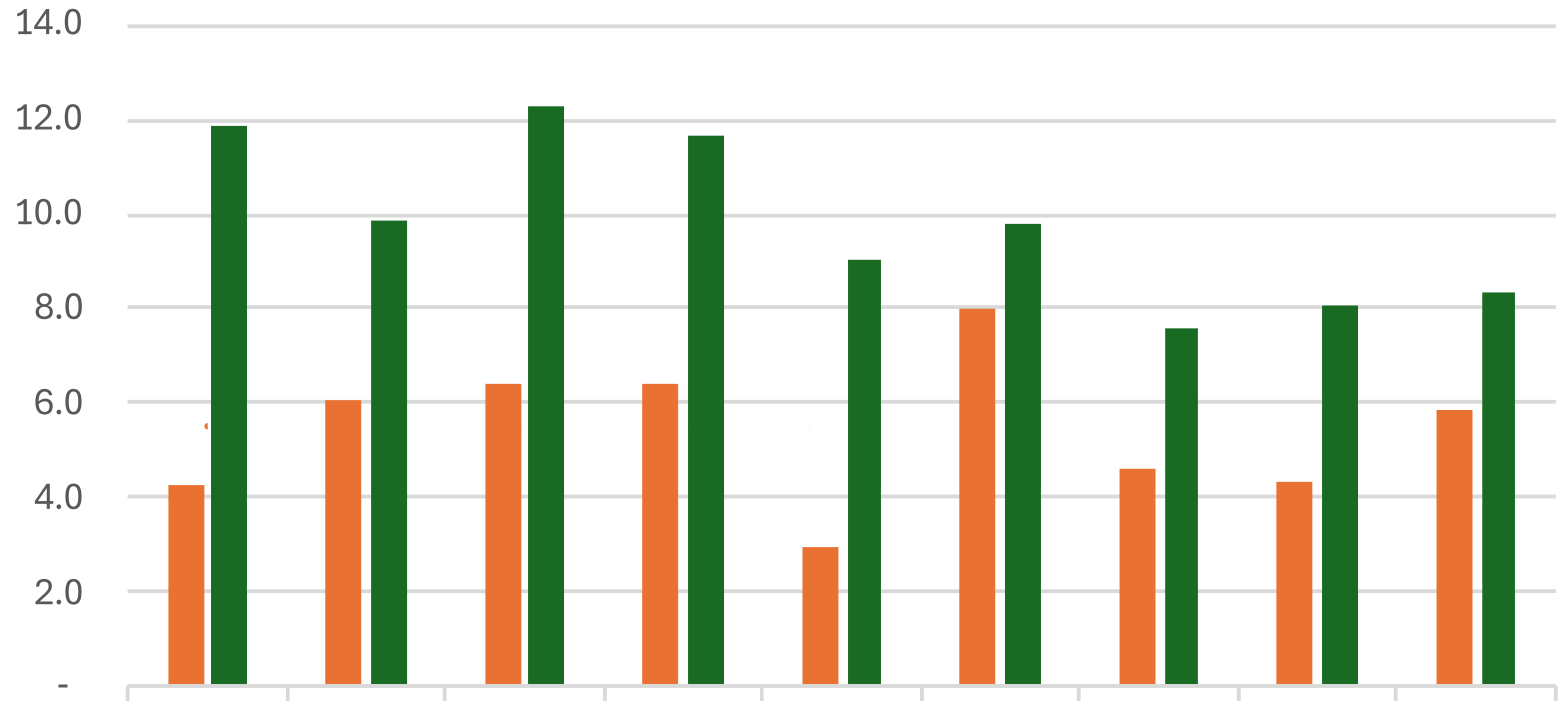
Hydro Ottawa Performance Relative to % Rural Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	0.47	0.47	0.45	0.45	0.44	0.44	0.42	0.47	0.50
Peer Group Avg.	0.56	0.57	0.57	0.55	0.57	0.58	0.54	0.53	0.56

Hydro Ottawa Performance Relative to % Rural Cohort

FTE / $1M of CapEx

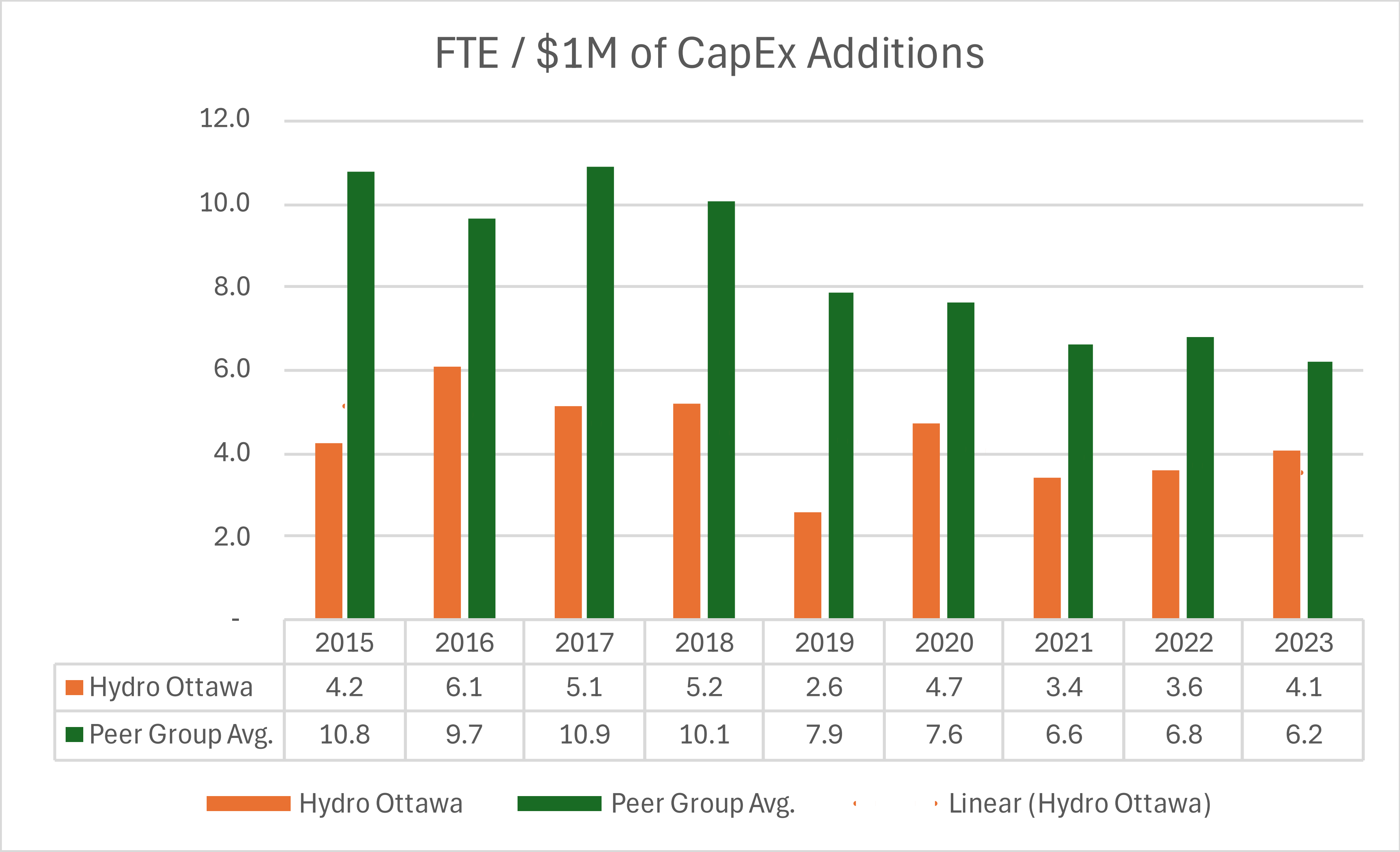


	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	4.2	6.1	6.4	6.4	2.9	8.0	4.6	4.3	5.9
Peer Group Avg.	11.9	9.9	12.3	11.7	9.1	9.8	7.6	8.1	8.3

Hydro Ottawa Peer Group Avg. Linear (Hydro Ottawa)

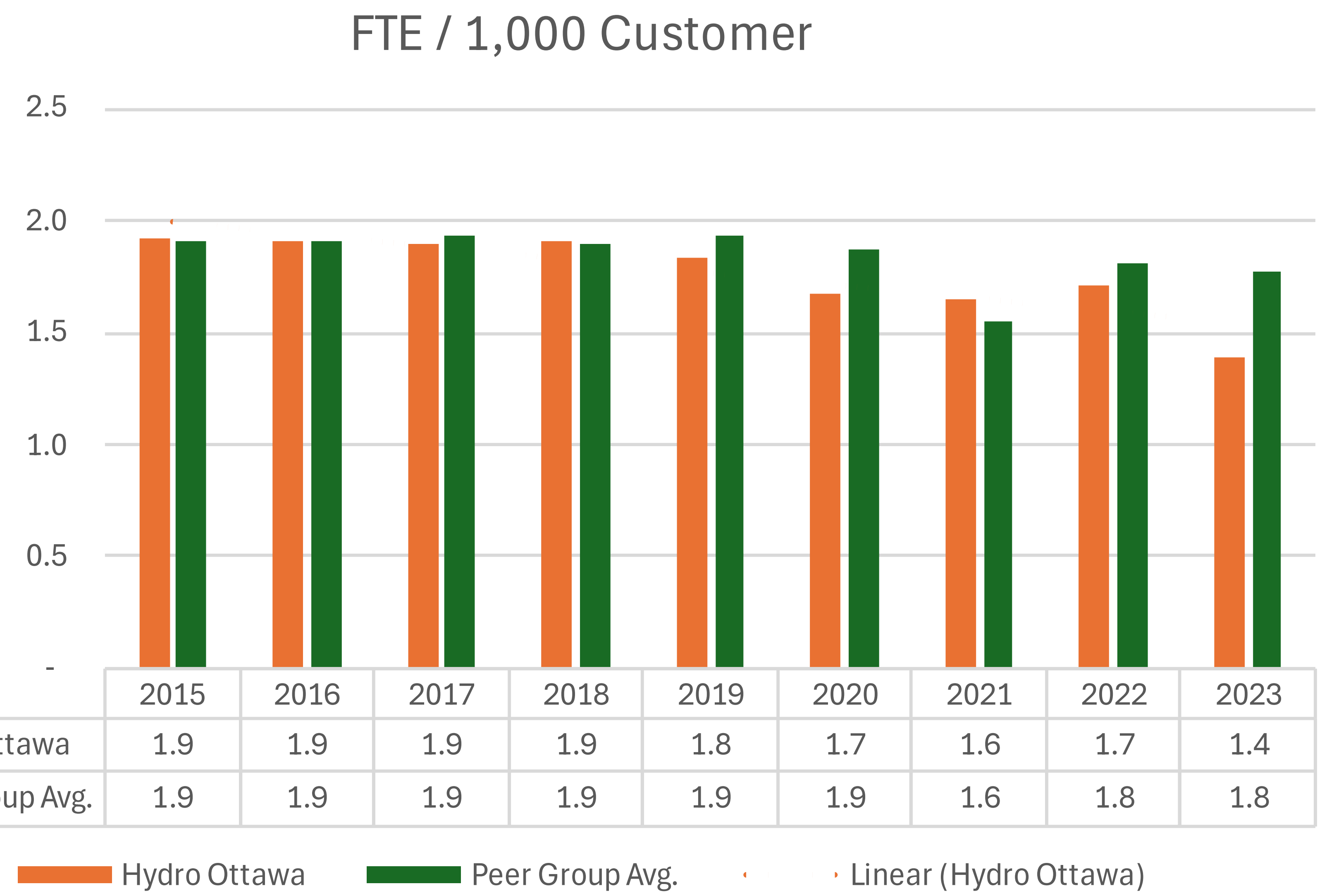
Utilis

Hydro Ottawa Performance Relative to % Rural Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	4.2	6.1	5.1	5.2	2.6	4.7	3.4	3.6	4.1
Peer Group Avg.	10.8	9.7	10.9	10.1	7.9	7.6	6.6	6.8	6.2

Hydro Ottawa Performance Relative to % Rural Cohort

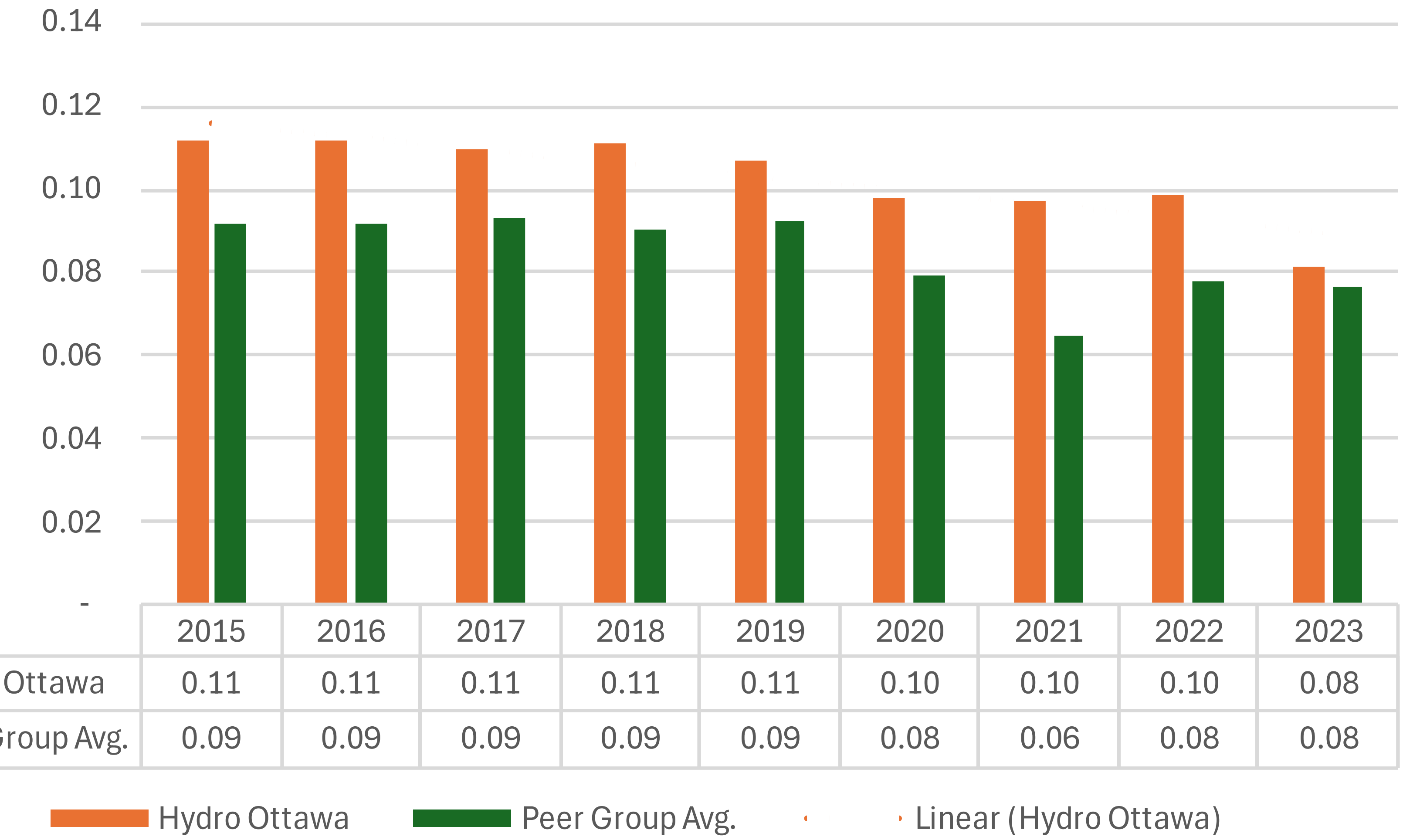


	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	1.9	1.9	1.9	1.9	1.8	1.7	1.6	1.7	1.4
Peer Group Avg.	1.9	1.9	1.9	1.9	1.9	1.9	1.6	1.8	1.8

Utilis

Hydro Ottawa Performance Relative to % Rural Cohort

FTE / Circuit KM

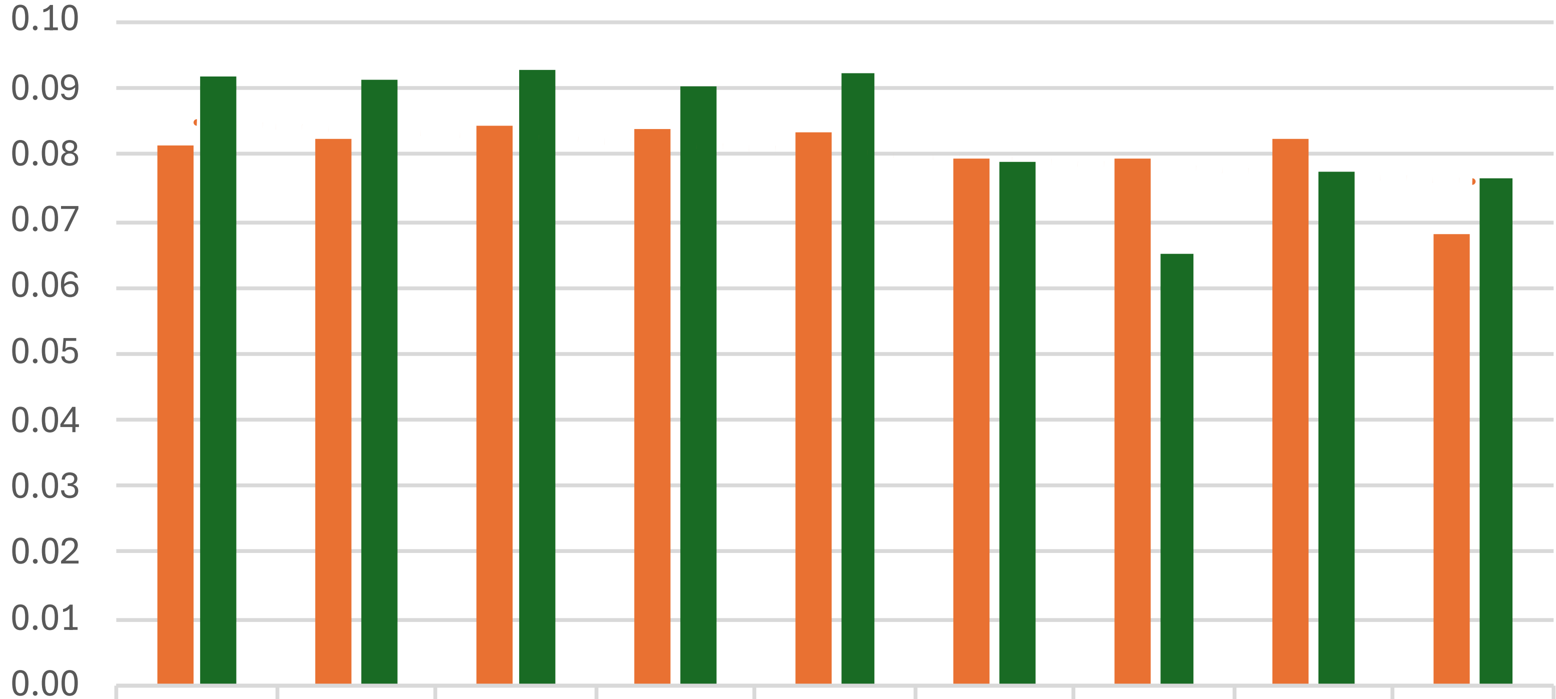


	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	0.11	0.11	0.11	0.11	0.11	0.10	0.10	0.10	0.08
Peer Group Avg.	0.09	0.09	0.09	0.09	0.09	0.08	0.06	0.08	0.08

Utilis

Hydro Ottawa Performance Relative to % Rural Cohort

FTE / GWh



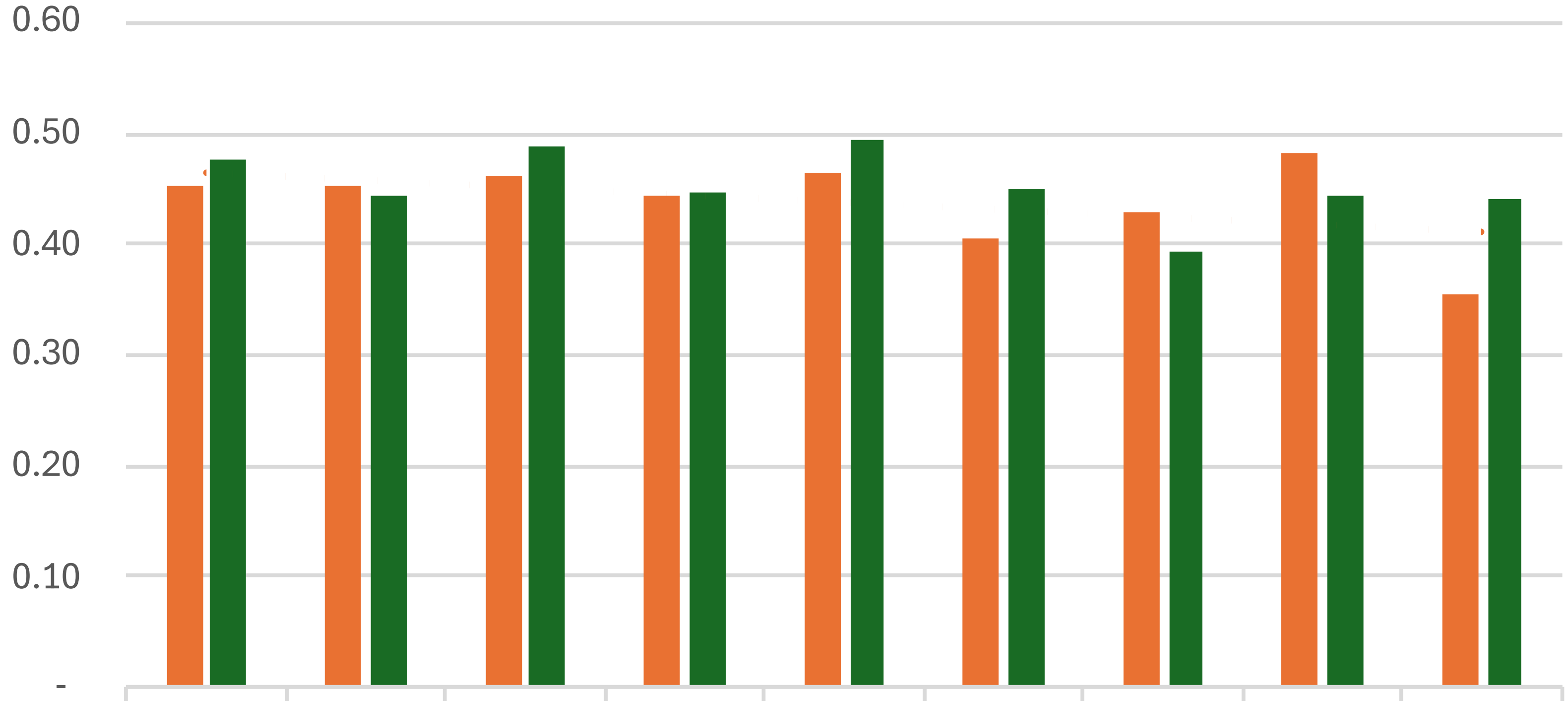
	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.07
Peer Group Avg.	0.09	0.09	0.09	0.09	0.09	0.08	0.06	0.08	0.08

Hydro Ottawa Peer Group Avg. Linear (Hydro Ottawa)

Utilis

Hydro Ottawa Performance Relative to % Rural Cohort

FTE / Summer Peak Load (MWh)

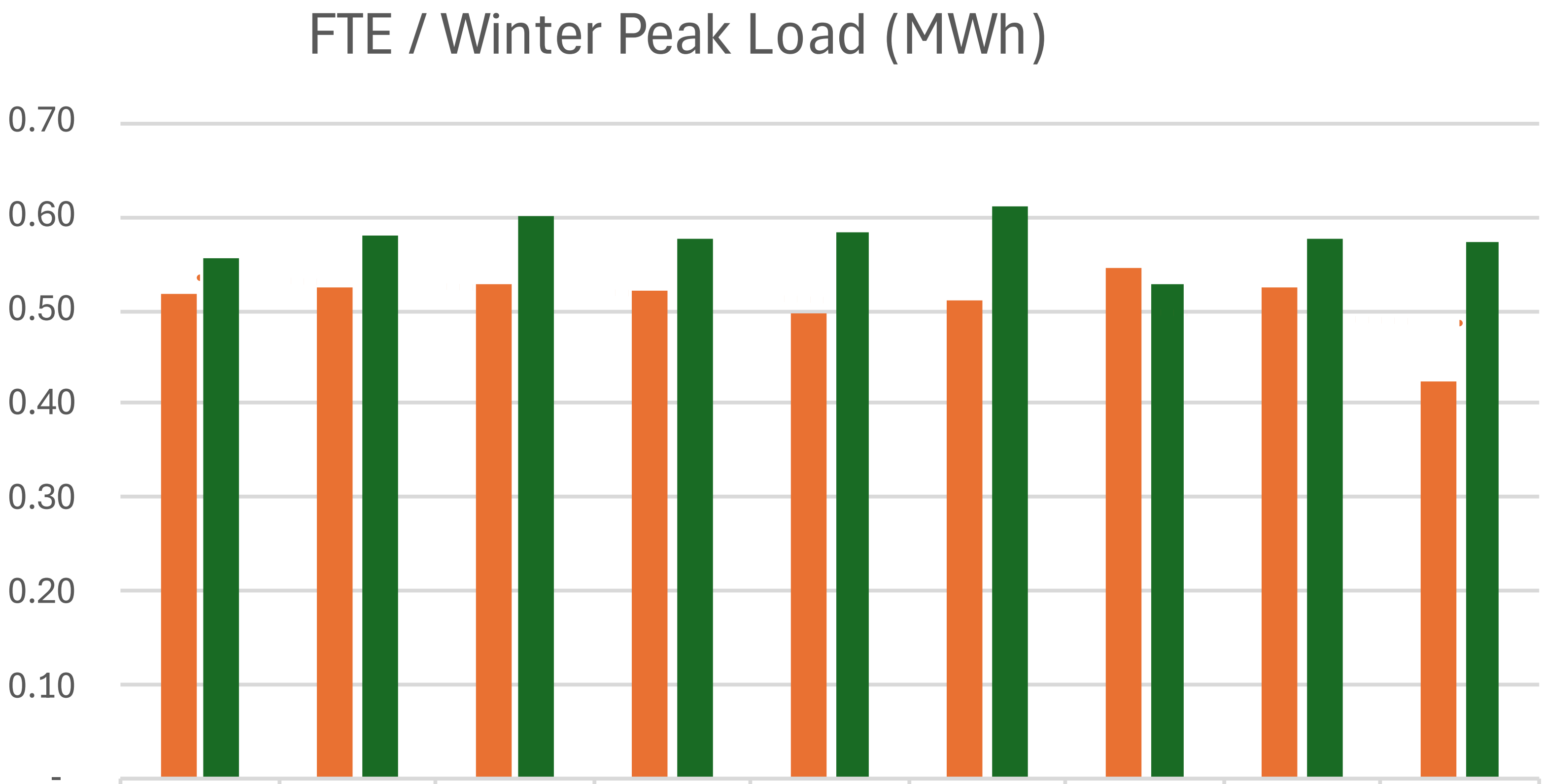


	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	0.45	0.45	0.46	0.44	0.46	0.40	0.43	0.48	0.35
Peer Group Avg.	0.48	0.44	0.49	0.45	0.49	0.45	0.39	0.44	0.44

Hydro Ottawa   Peer Group Avg.   Linear (Hydro Ottawa)

Utilis

Hydro Ottawa Performance Relative to % Rural Cohort



	2015	2016	2017	2018	2019	2020	2021	2022	2023
Hydro Ottawa	0.52	0.53	0.53	0.52	0.50	0.51	0.55	0.52	0.42
Peer Group Avg.	0.56	0.58	0.60	0.58	0.58	0.61	0.53	0.58	0.57

Utilis

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT3.18

EVIDENCE REFERENCE:

1-SEC-13

UNDERTAKING(S):

Provide forecast costs past the base year that were forecast to estimate forecast costs into the future and what those costs would look like.

RESPONSE(S):

Please see Table A below for the OM&A forecast compared to the OM&A escalated by annual Custom Revenue OM&A Factor (CROF) in years two through five.

Table A - 2026-2030 OM&A Forecast (‘000)

OM&A	Test Years				
	2026	2027	2028	2029	2030
OM&A forecast	$ 140,010	$ 151,916	$ 159,435	$ 163,550	$ 172,104
YOY% Increase		8.50%	4.95%	2.58%	5.23%
OM&A with CROF	$ 140,010	$ 147,263	$ 154,891	$ 162,914	$ 171,353
YOY% Increase		5.18%	5.18%	5.18%	5.18%

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT3.19

EVIDENCE REFERENCE:

1-SEC-14

UNDERTAKING(S):

Provide concrete proposal of what rules are being proposed to be put in place re ESM model

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RESPONSE(S):

As part of Hydro Ottawa's Original Evidence, Schedule 1-3-1 - Rate Setting Framework, Hydro Ottawa proposed an asymmetrical Earning Sharing Mechanism (ESM) account on a 50/50 basis above a dead band of 150 basis points if the utility's efficiency cohort determined by the adjusted Pacific Economics Group (PEG) benchmarking model (as described in Attachment 1-3-3 (A) - PEG Benchmarking Analysis) remains constant or reduces over the rate period. Specifically, Hydro Ottawa must maintain its Cohort III efficiency position in the adjusted PEG Model.

As part of Technical Conference Hydro Ottawa was asked how it would evaluate the PEG cohort outcome in the future should the current OEB review of the Total Cost Benchmarking (TCB) Model (EB-2025- 0102) result in the PEG model no longer being published in its current state or something very similar.

Should the PEG model no longer be updated and published in its current format, Hydro Ottawa would intend to use the current PEG forecast model as adjusted in Attachment 1-3-3(A) and update it annually. Hydro Ottawa would maintain its current methodology of utilizing the regulatory net income as calculated in the same manner as the calculation of net income under the Reporting and Record Keeping Requirements (RRR) filings. Please also see the proposed accounting order as provided in Attachment JT4.7(A) - Hydro Ottawa 2026-2030 Draft Accounting Orders.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT3.20

EVIDENCE REFERENCE:

1-SEC-5
9-VECC-72 Table A

UNDERTAKING(S):

Provide greater detail

RESPONSE(S):

Please refer to undertaking responses JT3.28 and JT4.14.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO SCHOOL ENERGY COALITION

JT3.22

EVIDENCE REFERENCE:

8-SEC-85

UNDERTAKING(S):

Provide how Hydro Ottawa arrived at forecast of numbers for unprocessed payment and the reconnect at meter charge during regular hours and after regular hours

---

RESPONSE(S):

Regarding unprocessed payments and reconnecting at meter charge during regular hours, the unit projections for 2026 were developed using an average of historical actuals and bridge year estimates for 2021 through 2025.

Regarding reconnecting at meter charge after regular hours, an average of historical actuals for 2022-2023 was used.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO COMMUNITY ACTION FOR ENVIRONMENTAL SUSTAINABILITY

JT3.23

EVIDENCE REFERENCE:

2-CO-21 Table A

UNDERTAKING(S):

Provide inquiries, submitted load form, signed offer to connect or connected.

RESPONSE(S):

Table A in interrogatory response 2-CO-21 summarizes the cumulative demand by year for various types of Large Load customers. Table A below provides the breakdown of data center customers from the referenced Table A, by stage (inquiry, submitted load summary form, signed offer to connect, or connected).

At the time of submitting 2-CO-21, all three data centre customers were in the Inquiry stage. Since that time one of the data centre customers has moved to the Submitted Load Summary Form stage.

Table A - Number of Data Centre Customers By Stage

	Customer Count (Cumulative)					
Stage	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Inquiries			1	1	3	

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT3.25

EVIDENCE REFERENCE:

1-CCC-2

UNDERTAKING(S):

Update tables to reflect updated requested revenue requirement

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RESPONSE(S):

This undertaking was to update the revenue requirement tables if they were based on the Original evidence rather than 1-Staff-1.

Hydro Ottawa confirms that interrogatory response 1-CCC-2 part (d) detailed requested scenario adjustments to 2026-2030 proposed revenue requirements calculations, were based on the updated revenue requirement filed as part of interrogatory response 1-Staff-1.

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO CONSUMERS COUNCIL OF CANADA

JT3.26

EVIDENCE REFERENCE:

4-Staff-138 Table B

UNDERTAKING(S):

Provide the number of locates, average cost per locate, the total external locate cost and the inspections line for the 2019 to 2020 period

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RESPONSE(S):

Please see Table A for the 2019 and 2020 figures added to Table B provided in interrogatory response 4-Staff-138.

1 **Table A - Cost per Field Locate 2019-2026 ($'000s)**

	Historical Years						Bridge Year	Test Year
	2019	2020	2021	2022	2023	2024	2025	2026
Number of Locates (segments)	81,031	72,254	71,574	56,532	58,558	56,263	66,599	66,599
Average Cost per locate ($)	$ 36.02	$ 37.25	$ 32.89	$ 49.40	$ 58.94	$ 64.57	$ 80.59	$ 79.45
Total External Locate Deliver Services Costs ($000s)	$ 2,922	$ 2,969	$ 2,631	$ 3,015	$ 3,622	$ 3,716	$ 5,443	$ 5,399
Less: Inspections ($000s)	$ (3)	$ (277)	$ (277)	$ (222)	$ (171)	$ (83)	$ (76)	$ (108)
Less: amounts in DVA accounts due to Bill 93					$ (738)	$ (271)	$ (1,645)	
Net Costs ($000s)	$ 2,919	$ 2,692	$ 2,354	$ 2,793	$ 2,714	$ 3,362	$ 3,722	$ 5,291

2