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Reference: Alectra Utilities Corporation 2018 Audited Financial Statements
Reference: Exhibit 2, Tab 1, Schedule 5

Preamble:

In the notes to the December 31, 2018 consolidated financial statements of Alectra Utilities, under note 7 (Future Accounting Changes), Alectra Utilities explains the new lease standard, International Financial Reporting Standard (IFRS) 16, and states the following with respect to the Corporation's initial adoption of standard:

"In January 2016, the IASB [International Accounting Standards Board] issued IFRS 16, which replaces the IAS 17 Leases and related interpretations ("IAS 17"). IFRS 16 establishes the principles for the recognition, measurement, presentation and disclosure of leases, with the objective of ensuring that lessees and lessors provide relevant information that represents those transactions. The new standard brings most leases on-balance sheet for lessees under a single model, eliminating the distinction between the operating and finance leases… The Corporation [Alectra Utilities Corporation] will adopt IFRS 16 on January 1, 2019 using the modified retrospective approach. The Corporation has assessed the quantitative impact of adopting IFRS 16 at January 1, 2019 to be an increase of $15 [million] in total assets and total liabilities for the right-of use assets and the lease liabilities."

Questions:

a) **Please provide a copy of Alectra Utilities Corporation's 2018 Audited Financial Statements for the record in this proceeding.**

b) **Please provide any memorandum, presentation, or other internal documentation provided to Alectra Utilities' Board of Directors or executive management team that analyzes or discusses the impacts of adopting IFRS 16.**

c) **Please confirm that, as a result of adopting IFRS 16 at January 1, 2019, Alectra Utilities increased its assets (rate base for ratemaking purposes) by $15 million to account for the cumulative effect of various operating leases or right-of-use assets, which were previously classified as OM&A for ratemaking purposes. If this is not confirmed, please explain the interaction between OM&A and rate base with respect to the adoption of IFRS 16.**

d) **Please prepare a table identical to Table 20 in Exhibit 2, Tab 1, Schedule 5, from the years 2019 to 2026 to show what the annual and cumulative revenue requirement impact is resulting from the adoption of IFRS 16 (the revenue requirement impact from a change in accounting policies). Please extend the table by additional rows to also include the Guelph Rate Zone (GRZ). Please also separate the 2019 column into two columns; one for the modified retrospective**

adoption of IFRS 16 on January 1, 2019, and the other for the current 2019 fiscal year impacts. Please file a copy of this table in excel format.

e) **Please provide all supporting schedules and tables that show how the amounts in part d) above were calculated. Please file copies of the supporting schedules and tables in excel format.**

f) **Please explain how Alectra Utilities intends to address the impact of IFRS 16 in rates.**

g) **If Alectra Utilities intends to account for the revenue requirement impact of IFRS 16 using deferral accounts, is its preferred approach to use the existing deferral accounts for the Horizon Rate Zone (HRZ), Enersource Rate Zone (ERZ), and Brampton Rate Zone (BRZ) (those already established for the change in capitalization policies resulting from the Alectra Utilities' merger), or would it seek to establish a new set of deferral accounts for each of those three rate zones to separately record the impacts of IFRS 16?**

h) **Please confirm, and provide rationale for, whether or not Alectra Utilities intends to request that the OEB establish a deferral account for the PowerStream Rate Zone (PRZ) and GRZ for the revenue requirement impact of the adoption of IFRS 16. If Alectra Utilities does not intend to request deferral account establishment for the impacts of IFRS 16, please provide a detailed explanation to distinguish these impacts from the ones the OEB has issued its decision on with respect to changes in capitalization policy.**

i) **Please provide a draft accounting order related to the establishment of new deferral accounts for each of the five rate zones that Alectra Utilities is seeking to establish (GRZ and PRZ only, if Alectra Utilities intends to use the existing deferral accounts for the HRZ, ERZ, and BRZ to track the revenue requirement impacts of IFRS 16).**

Response:

a) A redacted version of Alectra Utilities Corporation's 2018 Audited Financial Statements is provided as Attachment 1. The specific information that has been redacted consists of financial information that is beyond the scope of the Application as it is not related to the regulated utility business.

b) Please find attached the following redacted reports discussing the impacts of adopting IFRS 16. The specific information that has been redacted consists of financial information that is beyond the scope of the Application as it is not related to the regulated utility business.

- G-Staff-1_Attach 2_AFRM Report 3.9, dated November 10, 2017
- G-Staff-1_Attach 3_AFRM Report 2.5, dated November 9, 2018

c) to i) Alectra Utilities consists of regulated and non-regulated operations. Non-regulated operations are comprised of Ring Fenced Solar Portfolio ("RFSP") and Solar Sunbelt General Partnership ("SSGP"). The majority of the increase in assets related to the transition to IFRS 16 are related to non-regulated operations. The increase in regulated assets as a result of IFRS 16 was $3.4MM.

Table 1 below, provides the balance sheet and income statement impact from the implementation of IFRS 16 for all five rate zones. The key change resulting from the new standard is that all operating leases previously recognized on the income statement as a lease expense will be recognized on the balance sheet as a lease liability with an offsetting right of use lease asset, and depreciation and interest expense recognized on the income statement. As provided in Table 1, the lease liability is reduced by the lease payments made, net of accrued interest; the right of use lease asset is depreciated in accordance with IAS 16, Property Plant and Equipment; both the asset and liability are fully reduced by 2025. Further, the net impact to the income statement is minimal as provided in the last line of the Table 1.

Table 1 – Impact of the Implementation of IFRS 16

Impact of the implementation of IFRS 16 ($000's)		2019	2020	2021	2022	2023	2024	2025	2026
Before the implementation of IFRS 16:									
Balance Sheet	Right of use asset	-	-	-	-	-	-	-	-
	Lease liability	-	-	-	-	-	-	-	-
	Net	-	-	-	-	-	-	-	-
Income Statement	Rent expense	(972)	(949)	(943)	(577)	(218)	(26)	(17)	-
	Depreciation expense	-	-	-	-	-	-	-	-
	Interest expense	-	-	-	-	-	-	-	-
	Net	(972)	(949)	(943)	(577)	(218)	(26)	(17)	-
After the implementation of IFRS 16:									
Balance Sheet (opening)	Right of use asset	3,442	2,530	1,642	765	230	38	15	-
	Lease liability, opening balance	(3,442)	(2,571)	(1,698)	(805)	(252)	(41)	(16)	-
	Net impact on BS - opening	-	(41)	(56)	(40)	(22)	(3)	(1)	-
Balance sheet (closing)	Right of use asset	2,530	1,642	765	230	38	15	-	-
	Lease liability, closing balance	(2,571)	(1,698)	(805)	(252)	(41)	(16)	-	-
	Net impact on BS - ending	(41)	(56)	(40)	(22)	(3)	(1)	-	-
Income Statement	Rent expense	-	-	-	-	-	-	-	-
	Depreciation expense	(912)	(888)	(877)	(535)	(192)	(23)	(15)	-
	Interest expense	(101)	(76)	(50)	(24)	(7)	(1)	(1)	-
	Net	(1,013)	(964)	(927)	(559)	(199)	(24)	(16)	-
Net Income Statement Impact		**(41)**	**(15)**	**16**	**18**	**19**	**2**	**1**	**-**

As a result of the above immaterial impacts, Alectra Utilities has not calculated the revenue requirement impact and is not requesting the creation of deferral accounts as a result of the adoption of IFRS 16.

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ATTACH 1 – ALECTRA UTILITIES CORPORATION'S 2018 AUDITED FINANCIAL STATEMENTS

Consolidated Financial Statements
(In millions of Canadian dollars)

ALECTRA UTILITIES CORPORATON

Year ended December 31, 2018

KPMG LLP
Bay Adelaide Centre
333 Bay Street, Suite 4600
Toronto, ON M5H 2S5
Canada
Tel 416-777-8500
Fax 416-777-8818

INDEPENDENT AUDITORS' REPORT

To the Shareholder of Alectra Utilities Corporation

Opinion

We have audited the consolidated financial statements of Alectra Utilities Corporation (the Entity), which comprise:

- the consolidated statement of financial position as at December 31, 2018
- the consolidated statement of income and comprehensive income for the year then ended
- the consolidated statement of changes in equity for the year then ended
- the consolidated statement of cash flows for the year then ended
- and notes to the consolidated financial statements, including a summary of significant accounting policies (Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the consolidated financial position of the Entity as at December 31, 2018, and its consolidated financial performance and its consolidated cash flows for the year then ended in accordance with International Financial Reporting Standards (IFRS).

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 "***Auditors' Responsibilities for the Audit of the Financial Statements***" section of our auditors' 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 responsibilities in accordance with these requirements.

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

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

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS, 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.

Auditors' 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 auditors' 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 auditors' 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 auditors' 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 represents 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.

- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Group Entity to express an opinion on the financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
March 1, 2019

ALECTRA UTILITIES CORPORATION
Consolidated Statement of Financial Position
As at December 31, 2018
(In millions of Canadian dollars)

	Notes	2018	2017
Assets			
Current assets			
Cash		13	120
Restricted cash	9	3	–
Accounts receivable and unbilled revenue	20	587	518
Inventory		21	20
Prepaid expenses		13	8
Due from related parties	14	11	5
Assets held for sale	10, 11	–	15
Total current assets		**648**	**686**
Non-current assets			
Property, plant, and equipment	11	3,036	2,880
Goodwill and intangible assets	12	899	850
Total non-current assets		**3,935**	**3,730**
Total assets		**4,583**	**4,416**
Liabilities and Shareholder's Equity			
Current liabilities			
Accounts payable and accrued liabilities	13	347	396
Due to related parties	14	50	39
Customer deposits liability		94	91
Current portion of loans and borrowings from parent	16	245	180
Other liabilities	15	35	20
Total current liabilities		**771**	**726**
Non-current liabilities			
Deferred revenue	24	361	300
Loans and borrowings from parent	16	1,670	1,672
Employee future benefits	17	61	65
Finance lease obligation	19	15	16
Deferred tax liabilities	25	44	15
Other long-term liabilities	15	3	4
Total non-current liabilities		**2,154**	**2,072**
Total liabilities		**2,925**	**2,798**
Shareholder’s equity			
Share capital	18	733	742
Contributed surplus	3	728	728
Accumulated other comprehensive income (loss)		3	(1)
Retained earnings		194	149
Total shareholder’s equity		**1,658**	**1,618**
Total liabilities and shareholder's equity		**4,583**	**4,416**

See accompanying notes to consolidated financial statements.

On behalf of the Board:

Director

Director

ALECTRA UTILITIES CORPORATION

Consolidated Statement of Income and Comprehensive Income
Year ended December 31, 2018 and eleven months ended December 31, 2017
(In millions of Canadian dollars)

	Notes	2018	2017
Revenue			
Distribution revenue		505	458
Electricity sales		2,850	2,592
Other revenue	23	76	51
Total revenue		**3,431**	**3,101**
Expenses			
Cost of power		2,833	2,567
Operating expenses	22	242	253
Depreciation and amortization	11, 12	138	122
Loss on derecognition of property, plant, and equipment		7	5
Total expenses		**3,220**	**2,947**
Income from operating activities		**211**	**154**
Finance income		1	2
Finance costs		64	55
Net finance costs		**63**	53
Income before income taxes		**148**	**101**
Income tax expense	25	39	29
Net income		**109**	**72**
Other comprehensive income (loss)			
Items that will not be subsequently reclassified to income			
Remeasurement of defined benefit obligation		6	(2)
Tax impact on remeasurement of defined benefit obligation		(2)	1
Total other comprehensive income (loss)		4	(1)
Total comprehensive income		**113**	**71**

See accompanying notes to consolidated financial statements.

ALECTRA UTILITIES CORPORATION

Consolidated Statement of Changes in Equity
Year ended December 31, 2018 and eleven months ended December 31, 2017
(In millions of Canadian dollars)

	Notes	Share capital	Contributed surplus	Accumulated other comprehensive income (loss)	Retained earnings	Total equity
Balance, January 31, 2017		342	–	–	113	455
Net income		–	–	–	72	72
Other comprehensive loss		–	–	(1)	–	(1)
Contribution from parent	18	122	–	–	–	122
Amalgamation adjustments	3	278	728	–	–	1,006
Dividends paid	18	–	–	–	(36)	(36)
Balance, December 31, 2017		**742**	**728**	**(1)**	**149**	**1,618**
Net income		–	–	–	109	109
Other comprehensive income		–	–	4	–	4
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dividends paid	18	–	–	–	(68)	(68)
Balance, December 31, 2018		**733**	**728**	**3**	**194**	**1,658**

See accompanying notes to consolidated financial statements.

ALECTRA UTILITIES CORPORATION

Consolidated Statement of Cash Flows
Year ended December 31, 2018 and eleven months ended December 31, 2017
(In millions of Canadian dollars)

	Notes	2018	2017
Cash provided by (used in)			
Operating activities			
Net income		109	72
Add (deduct) non-cash items:			
Depreciation of property, plant, and equipment		121	108
Amortization of intangible assets		17	14
Amortization of deferred revenue	24	(9)	(6)
Gain on disposal of Collus PowerStream		(6)	–
Loss on derecognition of property, plant, and equipment		7	5
Employee future benefits	17	5	4
Net finance costs		63	53
Income tax expense		39	29
Net change in non-cash operating working capital	26	(116)	206
Contributions received from customers		70	62
Increase in restricted cash		(3)	–
Operating cash flows before interest and taxes		**297**	**547**
Income taxes paid		(5)	(7)
Income taxes recovered		6	12
Cash provided by operating activities		**298**	**552**
Investing activities			
Contribution from parent		–	(12)
Contributions from shareholders		–	50
Acquisition of Brampton Hydro	8	–	(615)
Proceeds on sale of Collus PowerStream		14	–
Additions of property, plant, and equipment		(297)	(293)
Sale proceeds from property, plant, and equipment		2	–
Purchase of intangible assets	12	(47)	(2)
Cash used in investing activities		**(328)**	**(872)**
Financing activities			
Repayment of debt to parents		(180)	(292)
Issuance of debt		241	656
Other long-term liabilities		(1)	–
Repayment of finance lease obligation		(1)	–
Return of capital		(5)	–
Interest paid		(63)	(44)
Dividends paid	18	(68)	(36)
Cash (used in) provided by financing activities		**(77)**	**284**
Decrease in cash		**(107)**	**(36)**
Cash, beginning of year		**120**	**156**
Cash, end of period		**13**	**120**

See accompanying notes to consolidated financial statements.

1. Description of the business

On January 31, 2017, Alectra Utilities Corporation (the "Corporation" or "Alectra Utilities") was incorporated under the *Business Corporations Act (Ontario)* by amalgamation (the "Amalgamation Transaction") (Note 3) of the former entities: PowerStream Inc. ("PowerStream"); Enersource Hydro Mississauga Inc. ("Enersource"); and Horizon Utilities Corporation ("Horizon"). The Corporation is wholly-owned by Alectra Inc. and its registered head office is located at 55 John Street North, Hamilton, Ontario, Canada. The principal activity of the Corporation is to distribute electricity to customers in municipalities in the greater golden horseshoe area.

The former PowerStream was deemed the acquirer under the Amalgamation Transaction for accounting purposes. Consequently, the comparative year consolidated opening balances are from the former PowerStream as at January 31, 2017.

[redacted]

On February 28, 2017, the Corporation acquired 100% of the shares of Hydro One Brampton Networks Inc. ("Brampton Hydro") for proceeds of $615 (Note 8).

2. Basis of preparation

(a) Statement of compliance

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"). These consolidated financial statements were approved by the Board of Directors on March 1, 2019.

The prior year comparative information presented in these consolidated financial statements comprises only eleven months due to the Amalgamation Transaction (Note 3). As a result, the comparative amounts presented in certain consolidated financial statements, such as the Statement of Income and Comprehensive Income, Statement of Changes in Equity, Statement of Cash Flows, and related notes, are not entirely comparable with respect to the duration of fiscal year.

Certain prior year figures have been reclassified to conform to the presentation of the current year.

2. Basis of preparation (continued)

(b) Functional and presentation currency

These consolidated financial statements are presented in Canadian dollars, which is the functional currency of the Corporation, and have been prepared on a historical cost basis, except for the valuation of employee future benefits.

(c) Use of estimates and judgments

The preparation of the consolidated financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the amounts reported and disclosed in these consolidated financial statements.

Estimates and underlying assumptions are continually reviewed and are based on factors that are considered to be relevant such as historical experience and forecast trends. Actual results may differ from these estimates. Revisions of estimates are recognized prospectively.

Judgments included in these consolidated financial statements are decisions made by management, based on analysis of relevant information available at the time of each decision. Judgments relate to the application of accounting policies and decisions related to the measurement, recognition and disclosure of financial amounts.

The areas which require management to make significant estimates and assumptions in determining carrying values include, but are not limited to: unbilled revenue; useful lives of depreciable assets; valuation of financial instruments; employee future benefits; expected credit losses; provisions and contingencies; goodwill; and cash generating units.

Refer to the relevant section within the significant accounting policies note for details on estimates and judgments (Note 6).

(In millions of Canadian dollars)

3. Business combination

On January 31, 2017, PowerStream amalgamated with Enersource and Horizon to form the Corporation. Under the Amalgamation Transaction, shares of the former PowerStream, Enersource and Horizon were exchanged for the voting common shares of the Corporation. The Amalgamation Transaction has been recognized as a business combination in accordance with IFRS 3, Business Combinations using the acquisition method with the former PowerStream deemed as the acquirer based on its relative size compared to that of the former Enersource and Horizon. These consolidated financial statements include: the net fair value of the assets of former Enersource and Horizon as at January 31, 2017; and the net assets of PowerStream at its carrying amounts at January 31, 2017. As at December 31, 2017, Enersource and Horizon contributed revenue including electricity sales of $900 and $612 since the amalgamation date. The amalgamation is expected to result in more efficient and enhanced service delivery through lower operating costs, while providing significant benefits for communities and shareholders.

The aggregate purchase price was $1,008, resulting in an increase in share capital of $278, and goodwill of $432, which is not deductible for income tax purposes. As a result of the Amalgamation Transaction, the contributed surplus increased by $432 as a result of goodwill and $296 as a result of amalgamation adjustments.

The following table summarizes the estimated fair value of assets acquired and liabilities assumed at the date of amalgamation:

	Enersource	**Horizon**	**Total**
Accounts receivable and unbilled revenue	175	118	293
Income taxes receivable	2	9	11
Inventories	5	10	15
Other assets	29	9	38
Amounts due from related parties	50	–	50
Property, plant, and equipment	646	463	1,109
Intangible assets	54	20	74
Deferred tax asset	7	6	13
Bank overdraft	(46)	(30)	(76)
Accounts payable and accrued liabilities	(118)	(80)	(198)
Customer deposits	(24)	(23)	(47)
Deferred revenue	(25)	(39)	(64)
Other liabilities	(18)	(19)	(37)
Loans and borrowings	(378)	(190)	(568)
Employee future benefits	(7)	(30)	(37)
Fair value of identifiable net assets acquired	352	224	576
Goodwill			432
Total purchase price			**1,008**

3. Business combination (continued)

The valuation technique used for the purchase of Enersource and Horizon was the discounted cash flow ("DCF") approach. Under the DCF approach, the expected future cash flows are discounted to their present value equivalent using appropriate market-based risk-adjusted rates of return.

4. Regulation

The Corporation is regulated by the Ontario Energy Board ("OEB"). In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that differ from IFRS. The regulatory accounting treatments of the OEB require the recognition of regulatory assets and liabilities which do not meet the definition of an asset or liability under IFRS and, as a result, these regulatory assets and liabilities have not been recorded in these IFRS consolidated financial statements (Note 28).

The *Ontario Energy Board Act, 1998 (Ontario)* conferred on the OEB powers and responsibilities to regulate the electricity industry in Ontario. These powers and responsibilities include: approving or fixing rates for the transmission and distribution of electricity; providing continued rate protection for rural and remote residential electricity consumers; and ensuring that distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies ("LDCs"), such as the Corporation , which may include, among other things: record keeping; regulatory accounting principles; separation of accounts for distinct business; and filing and process requirements for rate setting purposes.

Rate Setting

The electricity distribution rates and other regulated charges of the Corporation are determined in a manner that provides the shareholders of Alectra Inc. with opportunity to earn a regulated Maximum Allowable Return on Equity ("MARE") on the amount of shareholders' equity supporting the business of electricity distribution, which is also determined by regulation.

The rate-making policies of the OEB are designed to support the cost-effective planning and operation of the electricity distribution network and to provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

The OEB regulates the electricity distribution rates charged by LDCs, such as the Corporation, through periodic rate applications to the OEB and its ongoing monitoring and reporting requirements. At present, LDCs may apply to the OEB for electricity distribution rates under options specified in its Report of the Board - *A Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (“RRFE”). The three rate-setting methods available to LDCs under the RRFE are: Price Cap Incentive Rate-setting (“Price Cap IR”); Custom Incentive Rate-setting ("Custom IR"); or Annual Incentive Rate-setting Index ("Annual IR").

4. Regulation (continued)

Price Cap IR

The Price Cap IR method establishes rates on a single forward test-year cost of service basis, indexed for four subsequent years through a formulaic adjustment.

The Incremental Capital Module ("ICM") is available to distributors under the Price Cap IR method. It is intended to address capital investment needs that arise during the rate-setting plan that are incremental to an OEB prescribed materiality threshold. The requested amount for an ICM claim must be: incremental to a distributor's capital requirements within the context of its financial capacities underpinned by existing rates; and satisfy the eligibility criteria of materiality, need, and prudence. The OEB requires that a distributor requesting relief for incremental capital during the Price Cap IR plan term include comprehensive evidence to support the need. This includes the calculation of a rate rider to recover the incremental revenue from each applicable customer class. The incremental revenue is recognized in the year when the actual ICM related expenditures are expected to be in-service. This approach is consistent with the timing of the actual capital investment benefit to customers, which aligns with the expected timing of the OEB approval of ICM rate adjustments.

Custom IR

The Custom IR method establishes rates based on a forecast of an LDC's revenue requirement and sales volumes. This rate-setting method is customized to fit the specific applicant's circumstances. The annual rate adjustment over the Custom IR term is determined by the OEB on a case-by-case basis.

Annual IR

The Annual IR method sets a distributor's rates through an annual adjustment mechanism.

Rate Applications

MAADs Application

In April 2016, Enersource, Horizon, and PowerStream filed a Mergers, Acquisitions, Amalgamations and Divestitures ("MAADs") application (the "MAADs Application") with the OEB pursuant to the *Handbook to Electricity Distributor and Transmitter Consolidation* (the "MAADs Handbook") seeking approval for the Amalgamation Transaction and for the Corporation to purchase and subsequently amalgamate with Brampton Hydro. The MAADs Application included a request for OEB approval for the continuation of regulated rates and charges of the predecessor LDC's of the Corporation.

4. Regulation (continued)

On December 8, 2016, the OEB issued its Decision and Order in respect of the MAADs Application. The OEB granted the requested approvals and also approved a rebasing deferral period of 10 years, under which, the Corporation will operate individual "rate zones" (based on the continuing rates and underlying regulated cost structures of the predecessor LDCs).

As provided within the OEB *Report of the Board Rate-Making Associated with Distributor Consolidation*, the rate zones of the Corporation will continue on current respective rate plan terms until such respective terms expire. Upon expiry of such, all rate zones will migrate to the Price Cap IR method. At its option, the Corporation is permitted to apply for: (a) inflationary increases to rates, adjusted for an efficiency factor; and (b) ICM rate adjustments that provide financing and recovery of incremental discrete capital projects.

2018 Rates Application

On July 7, 2017, the Corporation filed an application for all four predecessor utilities (rate zones) for the approval of 2018 electricity distribution rates, effective January 1, 2018 to December 31, 2018. On April 5, 2018, the OEB issued its Decision and Order on this application, approving distribution rates effective January 1, 2018, with an implementation date of May 1, 2018. Both the effective and implementation date of the ICM rate riders was May 1, 2018. The following rate changes were effective as of the implementation dates:

- Horizon Rate Zone – Third annual update to the Custom Incentive rate plan. Based on the Decision and Order of the OEB, the resulting change to the distribution portion of the bill for a typical residential customer consuming 750 kWh per month is a decrease of approximately $1.41 or 4.99%;

- Brampton Hydro Rate Zone – Price Cap adjustment and ICM rate rider under the OEB's Price Cap IR. Based on the Decision and Order of the OEB, the resulting change to the distribution portion of the bill for a typical residential customer consuming 750 kWh per month is an increase of approximately $0.33 or 1.37%;

- PowerStream Rate Zone – Price Cap adjustment and ICM rate rider under the OEB's Price Cap IR. Based on the Decision and Order of the OEB, the resulting change to the distribution portion of the bill for a typical residential customer consuming 750 kWh per month is an increase of approximately $0.22 or 0.78%; and

- Enersource Rate Zone – Price Cap adjustment and ICM rate rider under the OEB's Price Cap IR. Based on the Decision and Order of the OEB, the resulting change to the distribution portion of the bill for a typical residential customer consuming 750 kWh per month is an increase of approximately $0.13 or 0.52%.

4. Regulation (continued)

Select Energy Policies and Regulation Affecting the Corporation

Ontario's Fair Hydro Plan ("OFHP")

The *Ontario Fair Hydro Plan Act, 2017* came into effect on June 1, 2017. The OFHP established a framework for initiatives to reduce certain residential and some small business electricity bills in Ontario by an average of 25%, and limit future increases to the rate of inflation for four years.

The planned rate reductions were comprised of two phases. The first phase was implemented on May 1, 2017 representing a reduction in Regulated Price Plan ("RPP") rates and the removal of the Ontario Energy Support Payment ("OESP") charge of $0.0011/kWh. The second phase was implemented on July 1, 2017 representing a further reduction in RPP prices and a reduction of the Rural and Remote Rate Protection ("RRRP") charge from $0.0021/kWh to $0.0003/kWh.

The OFHP also included the Global Adjustment ("GA") Modifier credit, effective July 1, 2017, that provides a reduction of GA charges for eligible RPP customers that have a contract with a retailer or have opted out of the RPP. The GA Modifier credit was designed to provide a benefit that was equivalent to the reduction in the RPP prices. During the year, the OFHP reduces the total electricity bill for eligible customers and, accordingly, reduces current accounts receivable and unbilled revenue and accounts payable and accrued liabilities for LDC. No effect on distribution revenue or expense is recognized by LDC in respect of the OFHP.

Monthly Billing Requirement for Electricity Distributors in Ontario

On April 15, 2015, the OEB announced that, by the end of 2016, all electricity distributors in Ontario would be required to bill their customers on a monthly basis. This policy change incorporates an expectation that distributors will issue bills based on actual meter reads rather than estimates at least 98% of the time. The amendments regarding estimated billing and billing accuracy came into force on April 15, 2015. The amendment regarding monthly billing came into force on December 31, 2016. The OEB allowed an exemption for the implementation of monthly billing for the Horizon Rate Zone to June 30, 2017, and for the Enersource Rate Zone to December 31, 2018 in its Decision and Order for the MAADs application. The Corporation has implemented monthly billing in all rate zones as of the date of these consolidated financial statements.

4. Regulation (continued)

Customer Service Rules

On November 2, 2017, the OEB issued its Decision and Order amending the licenses of all Ontario electricity distributors to prohibit the disconnection of residential customers for reason of non-payment from November 15 of one year to April 30 of the next calendar year (the "Disconnection Ban Period"). The conditions also require distributors to remove load control devices installed on residential premises, and a ban regarding the installation of new load control devices during the Disconnection Ban Period. During the year, this policy change increased credit losses and reduced disconnection/reconnection revenues.

On September 6, 2018, the OEB issued a Report entitled, *Review of Customer Service Rules for Utilities Phase One*, which proposes to amend various aspects of the rules related to customer service as well as to remove certain charges the utility currently collects from customers. These proposals have not been finalized as at the date of these consolidated financial statements. Any financial impact resulting from any enacted proposals is expected to be prospective in nature.

Regulatory assets and liabilities

On January 30, 2014, the IASB issued interim standard IFRS 14, *Regulatory Deferral Accounts*. This standard allows first-time adopters of IFRS to apply previous Generally Accepted Accounting Principles to account for rate-regulated assets and liabilities. As PowerStream Inc., the deemed acquirer under the Amalgamation Transaction, adopted IFRS prior to the issuance of the interim standard, it does not apply regulatory accounting treatment to certain balances and transactions arising from rate-regulated activities. Under rate-regulated accounting, the timing and recognition of certain expenses and revenue may differ from those otherwise expected under IFRS in order to appropriately reflect the economic impact of regulatory decisions regarding the Corporation's regulated revenue and expenditures.

New 2015-2020 Conservation and Demand Management ("CDM") Framework

As a condition of its distribution license, the Corporation is required to meet specified CDM targets for reductions in electricity consumption and peak electricity demand through the delivery of programs funded by the Independent Electricity System Operator ("IESO").

On March 26, 2014, the Minister of Energy (Ontario) issued a directive to the OEB to amend the licenses of electricity distributors with new requirements to deliver CDM programs available to customers that are designed to: achieve energy reductions; meet regulated CDM requirements through either IESO programs, LDC programs, or a combination of the two; and make the results of local programs available to other distributors on request. The coordination and integration of CDM and Demand Side Management ("DSM") activities is intended to achieve energy efficiencies and deliver convenient integrated programs for electricity and natural gas customers. The OEB issued the amendments to LDC licenses on December 18, 2014.

4. Regulation (continued)

On March 31, 2014, the Minister of Energy (Ontario) issued a directive to the IESO through the Conservation First Framework ("CFF") to coordinate, support and finance the delivery of CDM programs through LDCs to achieve a total of 7 Terawatt Hours of province-wide reductions in electricity consumption between January 1, 2015 and December 31, 2020. There are two funding models available under the CFF: Full Cost Recovery Program ("FCR") and Pay for Performance Program ("P4P").

FCR

Each of the predecessor utilities entered into an Energy Conservation Agreement ("ECA") with the IESO to deliver energy savings based on their respective IESO-determined target. The ECA became binding upon approval of each respective predecessor utility's CDM Plan. On June 28, 2017, the Corporation submitted a joint CDM plan to the IESO to amalgamate the legacy LDC CDM plans together with Collus PowerStream and Erie Thames Powerlines. The plan was approved on October 1, 2017 bringing the aggregate allocated target to 1,649,040 MWh energy savings over the years 2015-2020. The Collus PowerStream CDM plan will continue even though the investment in Collus PowerStream is sold (Note 10). Prefunding amounts are received at the beginning of the CDM plan and included in accounts payable. Monthly settlements are made with the IESO for reimbursements of expenses incurred. These amounts are included as an offset to the prefunding amount in accounts payable. In the November Settlement with the IESO, the Corporation received a mid-term incentive in the amount of $14 in relation to achieving the mid-term incentive targets specified by the IESO. This incentive was recognized in other revenue. At December 31, 2018, the accounts payable and the offset to accounts payable were $15 (2017 - $15) and $7 (2017 - $4), respectively.

P4P

As part of its joint CDM plan, the Corporation will deliver a "Retrofit" program (a program that upgrades energy inefficient equipment in commercial businesses) via the P4P funding model. Under the P4P, the IESO will pay the Corporation a fixed rate per kWh of verified energy savings. Under the P4P, and unlike FCR, the Corporation bears the risk of covering all of its costs and the eligible funding is capped at a negotiated Internal Rate of Return. The Corporation recognizes an account receivable from the IESO which is equal to the revenue calculated per the internal rate of return model. There is an amount payable of which represents the difference between the funds received from the IESO and account receivable in relation to the verified and paid savings determined. At December 31, 2018, the accounts receivable and amount payable were $19 (2017 - $15) and $1 (2017 - $3), respectively.

5. Changes in accounting policies

(a) *IFRS 15 Revenue from Contracts with Customers ("IFRS 15")*

The Corporation adopted IFRS 15 with a date of initial application on January 1, 2018. IFRS 15 replaces pre-existing revenue recognition guidance, including IAS 18 *Revenue* and IFRIC 18 *Transfers of Assets from Customers*. The scope of IFRS 15 excludes lease contracts and financial instruments.

IFRS 15 provides a five step model that applies to contracts with customers and specifies that revenue is recognized at a point in time or over time, depending on when the entity has satisfied its performance obligation(s) to its customers. Where the Corporation has a right to consideration from a customer in an amount that corresponds directly with the value to the customer of the performance to date, the Corporation has elected to adopt the B16 practical expedient under IFRS 15. This practical expedient permits the recognition of revenue in an amount to which the Corporation has a "right to invoice". The right to invoice represents the fair value of the consideration received or receivable.

The Corporation is also required to determine the transaction price of each of its contracts with its customers. In making such determination, the Corporation assesses the impact of any variable consideration in the contract, due to factors such as, but not limited to: discounts or penalties; the existence of any significant financing component; and any non-cash consideration in the contract. The Corporation has determined that there are no variable considerations that will have a significant impact on the transaction price of the services provided.

Prior to the implementation of IFRS 15, contributions from customers and developers were initially recorded as deferred revenue when received and recognized as revenue on a straight line basis over the useful life of the asset. The Corporation has assessed the impact of contributions from customers under IFRS 15 and has determined that there is no change to the existing accounting treatment. However, contributions from developers are not within the scope of IFRS 15, as they do not give rise to a contract with the customer. As such, the Corporation has developed an accounting policy for the recognition of cash contributions from developers as currently, there is no specific guidance on accounting for these contributions. Refer to Note 6(c) for a description of such accounting policy.

The Corporation adopted IFRS 15 using the modified retrospective approach. The adoption of IFRS 15 resulted in no quantitative impact to the Consolidated Statement of Financial Position and Consolidated Statement of Income and Comprehensive Income. Refer to Note 6(c) for details on the Corporation's accounting policies for revenue recognition.

5. Changes in accounting policies (continued)

(b) IFRS 9 Financial instruments ("IFRS 9")

The Corporation adopted IFRS 9 with a date of initial application on January 1, 2018. IFRS 9 replaced IAS 39 - *Financial Instruments: Recognition and Measurement* ("IAS 39"). The Corporation adopted IFRS 9 retrospectively. Despite the retrospective adoption of IFRS 9, the Corporation is not required, upon initial application, to restate comparative figures.

IFRS 9 covers three broad topics: Classification and Measurement; Impairment; and Hedging. Hedging is not applicable to the Corporation. IFRS 9 also significantly amends other standards dealing with financial instruments such as IFRS 7 *Financial Instruments: Disclosures*.

(i) Classification and measurement

At initial recognition, the financial assets of the Corporation are measured at fair value including transaction costs except for accounts receivable which are initially recognized at the transaction price. Financial assets are subsequently measured at either amortized cost; fair value through Other Comprehensive Income ("OCI"); or fair value through profit or loss based on the cash flow characteristics of the assets and the business models under which they are managed.

The Corporation's assets are held for collection of contractual cash flows that represent payments of principal and interest and, accordingly, are subsequently measured at amortized cost. A gain or loss is recognized in the Consolidated Statement of Income and Comprehensive Income when the asset is derecognized or impaired.

5. Changes in accounting policies (continued)

The impact of IFRS 9 on the classification and measurement of the Corporation's financial instruments is set out below.

Financial instrument	IAS 39 Measurement	IFRS 9 Measurement Basis
Cash (including restricted cash)	Loans and receivables	Amortized cost
Accounts receivables and unbilled revenue	Loans and receivables	Amortized cost
Due from related parties	Loans and receivables	Amortized cost
Accounts payable and accrued liabilities	Financial liability – amortized cost	Financial liability – amortized cost
Customer deposits liability	Financial liability – amortized cost	Financial liability – amortized cost
Due to related parties	Financial liability – amortized cost	Financial liability – amortized cost
Other liabilities	Financial liability – amortized cost	Financial liability – amortized cost
Loans and borrowings from parent	Financial liability – amortized cost	Financial liability – amortized cost
Other long term liabilities	Financial liability – amortized cost	Financial liability – amortized cost

(ii) Impairment

The standard introduces a new single model for the measurement of impairment losses on all financial assets. The IFRS 9 expected credit loss (“ECL”) model replaces the current “incurred loss” model of IAS 39. The incurred loss model under IAS 39 recognizes impairment when there is objective evidence of deterioration in the credit quality of the asset. Under IFRS 9, ECL will be recognized in the profit or loss before a loss event has occurred, which could result in earlier recognition of credit losses compared to IAS 39.

Impairment of the Corporation’s financial assets is assessed on a forward-looking basis. The Corporation applies the simplified approach to its accounts receivable which requires expected lifetime losses to be recognized from initial recognition of the receivables and on an ongoing basis.

5. Changes in accounting policies (continued)

The Corporation assesses all information available in the measurement of the ECLs associated with its assets carried at amortized cost.

The measurement of ECLs for accounts receivable is based on management's judgment. This is determined using a provision matrix based on historical observed default rates and incorporated macroeconomic factors such as GDP growth forecast, inflation rates, unemployment rates, and customer-specific assessments. As the Corporation is not required to restate comparatives, ECLs are not included in unbilled revenue for prior year comparative amounts. The adoption of IFRS 9 did not have an impact on the financial statements.

6. Significant accounting policies

The significant accounting policies used in the preparation of these consolidated financial statements have been applied consistently to all periods presented herein, except for the new standards IFRS 15 and IFRS 9, which were adopted effective January 1, 2018. There was no impact to the Consolidated Statement of Financial Position or to the Consolidated Statement of Income and Comprehensive Income resulting from the adoption of the new standards (Note 5).

(a) Basis of consolidation

These consolidated financial statements include the accounts of the Corporation and its subsidiaries from the date that control commences until the date that control ceases. The Corporation controls a subsidiary if it is exposed, or has rights, to variable returns from its investment in the subsidiary and has the ability to affect those returns through its power over the subsidiary. All intercompany accounts and transactions have been eliminated on consolidation.

A joint venture is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the arrangement. The Corporation owned 50% of Collingwood PowerStream Utility Services Corp. ("Collus PowerStream") until it was sold on October 1, 2018 (Note 10). In 2017, this investment was accounted for using the equity method and was recognized initially at cost.

6. Significant accounting policies (continued)

(b) Business combinations

Acquisitions of businesses are accounted for using the acquisition method. The consideration for each acquisition is measured at the aggregate of the fair value of: assets conveyed; liabilities incurred or assumed; and the equity instruments issued by the Corporation in exchange for control of the acquired business. Where the consideration for the acquisition includes any asset or liability resulting from a contingent consideration arrangement, it is measured at fair value at the acquisition date. The Corporation records all identifiable intangible assets including identifiable assets that had not been recognized by the acquiree before the business combination. Any excess of the cost of acquisition over the Corporation's share of the net fair value of the identifiable assets acquired and liabilities assumed is recorded as goodwill.

During the measurement period (which is within one year from the acquisition date), the Corporation may, on a retrospective basis, adjust the amounts recognized at the acquisition date to reflect new information obtained about facts and circumstances that existed as of the acquisition date. No such adjustments were made during the year.

The Corporation accounts for acquisition-related costs as expenses in the periods in which the costs are incurred and the services are received.

6. Significant accounting policies (continued)

(c) Revenue from contracts with customers

(i) Distribution revenue and electricity sales

The Corporation has identified that its material performance obligation is the distribution and provision of electricity to customers. The Corporation is licensed by the OEB to distribute electricity. Distribution revenue is recognized based on OEB-approved distribution rates, set at a level intended to recover the costs incurred by the Corporation in delivering electricity to customers and a regulated return on invested capital, and includes revenue collected through OEB-approved rate riders. As a licensed distributor, the Corporation is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Corporation is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Corporation ultimately collects these amounts from customers. The Corporation has determined that it is acting as a principal for electricity distribution and therefore has presented the electricity revenues on a gross basis. Revenue attributable to the delivery of electricity is based upon OEB-approved distribution tariff rates and includes the amounts billed to customers for electricity, including the cost of electricity supplied, distribution charges, and any other regulatory charges. Revenue is recognized as electricity is delivered and consumed by customers. Electricity revenue is recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the year. The Corporation satisfies its performance obligation to the customer over time, which is to use reasonable diligence in providing a regular and uninterrupted supply of electricity over the contract term.

(ii) Other revenue

Other revenue includes revenue from [redacted] and government grants under CDM programs, contributions from customers, and other general revenue. The methods of recognition for other revenue are as follows:

- [redacted]

- IESO funding from CDM programs is recognized on a net basis when there is reasonable assurance that the funding will be received and the related conditions are met. "Net Basis" is used when the funding relates to an expense item, and, as such, the operating expenses are netted against other income. The Corporation records its CDM revenues and expenses in accordance with IAS 20 *Accounting for Government Grants and Disclosure of Government Assistance.*

6. Significant accounting policies (continued)

- Capital contributions received from electricity customers and developers to construct or acquire property, plant, and equipment for the purpose of connecting a customer to a network are recorded as deferred revenue. The deferred revenue is initially recorded at fair value of the capital contribution, and is recognized as revenue on a straight-line basis over the estimated lives of the contracts with customers. Non-refundable cash contributions from developers result in the Corporation having an obligation to provide goods and services with respect to the assets constructed or acquired, these contributions are considered deferred revenue and recognized on a straight-line basis over the estimated economic lives of the assets to which the contribution relates.

- Revenue is recognized as services are rendered where ancillary to: the electricity distribution; delivery of street lighting services; water billing; and pole and duct rentals.

(iii) Unbilled revenue

The measurement of unbilled revenue is based on an estimate of the amount of electricity delivered to customers but not yet billed. These accrual amounts are presented as unbilled revenues under IFRS 15. The Corporation assesses the unbilled revenues for impairment in accordance with IFRS 9.

(d) Financial instruments

Financial assets and financial liabilities are initially recognized at fair value plus directly attributable transaction costs, and are subsequently measured at amortized cost under IFRS 9.

Financial instruments at fair value

Financial instruments, which are disclosed at fair value, are classified using a three level hierarchy. Each level reflects the inputs used to measure the fair values of the disclosed 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).

6. Significant accounting policies (continued)

The Corporation's fair value hierarchy is classified as Level 2 for loans and borrowings to parent. The classification for disclosure purposes has been determined in accordance with generally accepted pricing models, based on discounted cash flow analysis, with the most significant inputs being the contractual terms of the instrument and the market discount rates that reflect the credit risk of counterparties.

Refer to Note 5(b) for details on the impact of adoption of IFRS 9 on financial instruments.

(e) Restricted cash

Cash that is restricted as to withdrawal or use under the terms of certain contractual agreements is classified as restricted cash.

(f) Inventories

Inventories, which consist of parts and supplies acquired for internal construction or consumption, are valued at the lower of cost and net realizable value. Cost is determined on a weighted-moving average basis and includes expenditures incurred in acquiring the inventories and other costs to bring the inventories to their existing location and condition.

(g) Property, plant, and equipment ("PP&E")

Land is carried at cost. PP&E (other than land) is measured at cost less accumulated depreciation and accumulated impairment losses. Cost includes expenditures that are directly attributable to the acquisition of the asset and includes contracted services, cost of materials, directly attributable overhead, direct labour, pension costs and borrowing costs incurred in respect of qualifying assets constructed. When components of an item of PP&E have different useful lives, each component is recorded separately within PP&E. These assets are classified to the appropriate categories of PP&E when completed and ready for intended use. Depreciation on these assets commences when such assets are ready for their intended use.

Work in progress assets are generally assets that are undergoing active construction or development and are not currently available for use. Such assets are therefore not depreciated.

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

When items of PP&E are retired or otherwise disposed of, a gain or loss on asset derecognition, if any, is determined by comparing the proceeds from disposal with the carrying amount of the item. Any gain or loss on asset derecognition is included in the Consolidated Statement of Income and Comprehensive Income.

6. Significant accounting policies (continued)

Leasehold improvements are investments made to customize buildings and offices occupied under lease contracts and are presented as part of PP&E.

Depreciation of PP&E is recognized on a straight-line basis over the estimated useful life of each component of PP&E.

The Corporation estimates the useful lives of its property, plant, and equipment based on management's judgment. Depreciation methods and useful lives are reviewed at each financial year-end and any changes are adjusted prospectively. The method of depreciation and estimated useful lives for each category of property, plant, and equipment are as follows:

Buildings and fixtures	Straight-line	10 to 60 years
Distribution assets	Straight-line	15 to 40 years
Transformer stations	Straight-line	20 to 40 years
Other PP&E	Straight-line	3 to 20 years

(h) Goodwill and other intangible assets

Intangible assets include: goodwill; land rights; computer software; and capital contributions.

Goodwill arising on the acquisition of subsidiaries or on amalgamation represents the excess of the purchase price over the fair value assigned to the Corporation's interest of the net identifiable assets acquired. Goodwill is measured at cost less accumulated impairment losses.

Land rights are measured at cost. Land rights held by the Corporation are effective in perpetuity and there is no foreseeable limit to the period over which the rights are expected to provide benefit to the Corporation. Consequently, no removal date can be determined and no reasonable estimate of the fair value of such asset retirement obligations can be determined. If, at some future date, it becomes possible to estimate the fair value cost of removing these assets and the Corporation is legally or constructively required to remove such assets, a related asset retirement obligation will be recognized at that time. The discounted amount is not material. Land rights have therefore been assessed as having an indefinite useful life.

6. Significant accounting policies (continued)

Finite life intangible assets are measured at cost less accumulated amortization and any applicable impairment losses. Amortization begins when the asset is available for use and is measured on a straight line basis.

Capital contributions represent contributions made to Hydro One Networks Inc., an electricity distributor and transmitter in the Province of Ontario, for building dedicated infrastructure to accommodate the Corporation's distribution system requirements. The contributions are measured at cost less accumulated amortization.

Gains or losses arising from derecognition of an intangible asset are measured as the difference between the net disposal proceeds and the carrying amount of the asset, and are recognized in the Statement of Income and Comprehensive Income when the asset is derecognized.

The Corporation estimates the useful lives of its intangible assets based on management's judgment. Amortization methods and useful lives are reviewed at each financial year-end and adjusted prospectively.

The estimated useful lives and amortization methods are as follows:

Goodwill	Not amortized	Indefinite
Land rights	Not amortized	Indefinite
Computer software	Straight-line	3 to 10 years
Capital contributions	Straight-line	16 to 45 years

(i) Assets held for sale

Non-financial assets classified as held-for-sale are measured at the lower of their carrying amount and fair value, less costs of disposal, and are presented within other assets in the Consolidated Statement of Financial Position. Assets classified as Held for Sale are not amortized.

6. Significant accounting policies (continued)

(j) Impairment of non-financial assets

Goodwill and intangible assets with indefinite lives are tested for impairment annually and when circumstances indicate that the recoverable amount of an asset or cash generating unit ("CGU") may be below their carrying value. The recoverable amount of an asset or CGU is the greater of its value in use and fair value less costs of disposal. The value in use calculation requires an estimate of the future cash flows expected to arise from the CGU and a suitable discount rate in order to calculate a present value as a basis for determining impairment. Property, plant, and equipment and intangible assets with finite lives are tested for impairment when management determines indicators of impairment exist. Significant judgment is applied in determining the non-financial assets recoverable amount and assessing whether certain indicators constitute objective evidence of impairment.

For the purpose of impairment testing, assets are grouped together into the smallest group that generates cash inflows that are largely independent of those from other assets or CGUs. Goodwill acquired in a business combination is allocated to groups of CGUs that are expected to benefit from the synergies of the combination.

Impairment losses are recognized in net income. Impairment losses relating to CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the CGUs and then to reduce the carrying amounts of the other assets in the CGUs on a pro rata basis.

An impairment loss in respect of goodwill is not reversed. In respect of other assets, an impairment loss is reversed only to the extent that the carrying amount of the asset does not exceed the carrying amount that would have been determined, net of depreciation or amortization, as if no impairment loss had been previously recognized.

(k) Provisions and contingencies

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be determined reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are subject to significant uncertainty and are determined by discounting the expected future cash flows at a rate, net of tax, that corresponds to current market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recorded as interest expense.

An assessment of the likelihood of a contingent event, such as events arising from legal proceedings and other losses, requires management's judgment as to the probability of a loss occurring. Actual results may differ from those estimates.

6. Significant accounting policies (continued)

(l) Employee future benefits

The Corporation provides pension and other benefit plans for its employees. Details on these plans are as follows:

(i) Multi-employer defined benefit pension plan

The Corporation provides a pension plan for all of its full-time employees through Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund ("the Fund") and provides pensions for employees of Ontario municipalities, local boards, public utilities, and school boards. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund.

As OMERS does not segregate its pension asset and liability information by individual employers, there is insufficient information available to enable the Corporation to directly account for the plan as a defined benefit plan. Consequently, the plan has been accounted for as a defined contribution plan. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in net income when they are due.

(ii) Non-pension defined benefit plans

The Corporation provides some of its retired employees with life insurance and medical benefits beyond those provided by government sponsored plans. These benefits are provided through group defined benefit plans shared between entities under common control of Alectra Inc. The Corporation, which is controlled by Alectra Inc., is the legal sponsor of the plans. There is a stated policy in place to allocate the net defined benefit cost to the participating entities under the common control of Alectra Inc. based on the obligation attributable to the plan participants employed by each participating entity.

The Corporation has incorporated its share of the defined benefit costs and related liabilities, as calculated by the actuary, in these consolidated financial statements.

6. Significant accounting policies (continued)

The Corporation's net obligation in respect of defined benefit plans is calculated separately for each plan by estimating the amount of future benefit that employees have earned in return for their service in the current and prior periods and discounting such to determine its present value. Any unrecognized past service costs are deducted. The discount rate is the interest yield, at the reporting date, on high quality debt instruments with duration similar to the duration of the plan. Due to the long term nature of these plans, estimates used in the valuation such as discount rates, expected rates of return on assets, future salary increases, mortality rates and future pension increases, are subject to significant uncertainty.

The cost of these benefits is expensed as earned by employees through employment service. The accrued benefit obligation and the current service costs are actuarially determined by applying the projected unit credit method and incorporate management's best estimate of certain underlying assumptions. Remeasurements arising from defined benefit plans are recognized immediately in other comprehensive income and reported in accumulated other comprehensive income.

The measurement date used to determine the present value of the benefit obligation is December 31 of the applicable year. The latest full actuarial valuation was performed as at December 31, 2017.

(m) Customer deposits

Customer deposits comprise:

(i) Deposits in aid of securing energy bills

This form of deposit represents cash collections from customers as security for the payment of energy bills and water bills. Deposits held in respect of commercial customers are applied against any unpaid portion of individual customer accounts. Customer deposits in excess of unpaid account balances are refundable to individual customers upon termination of their electricity distribution service. These customer deposits are classified as a current liability as they are refundable on demand once a customer establishes a good payment history in accordance with the policies of the Corporation. Interest is accrued on customer deposits until the balance is refunded with the interest amount recognized as finance costs.

6. Significant accounting policies (continued)

(ii) Deposits in aid of the capital cost of construction

Certain customers and developers are required to contribute towards the capital cost of construction in order to provide them with ongoing service. Cash contributions are initially recorded as customer deposits, a current liability. Once the distribution system asset is completed or modified as outlined in the terms of the contract, the contribution amount is transferred to deferred revenue.

(n) Leases

Leases in which the Corporation assumes substantially all of the risks and rewards of ownership are classified as finance leases. On initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset. Payments under finance leases are apportioned between interest expense and a reduction of the outstanding liability using the effective interest method.

Other leases are operating leases and are not recognized in the Corporation's Consolidated Statement of Financial Position. Payments made under operating leases are recognized as an expense on a straight-line basis over the term of the lease.

(o) Income taxes

The Corporation is currently exempt from taxes under the *Income Tax Act (Canada)* and the *Ontario Corporations Tax Act* (collectively the "Tax Acts"). Pursuant to the *Electricity Act, 1998 (Ontario)* (“EA”), and as a consequence of its exemption from income taxes under the Tax Acts, the Corporation is required to make payments in lieu of income taxes (“PILs”) to the Ontario Electricity Finance Corporation ("OEFC"). These payments are calculated in accordance with the Tax Acts. These amounts are applied to reduce certain debt obligations of the former Ontario Hydro continuing in OEFC.

PILs comprise current and deferred payments in lieu of income tax. PILs is recognized in income and loss except to the extent that it relates to items recognized directly in either comprehensive income or in equity, in which case, it is recognized in comprehensive income or in equity.

Current PILs is the expected amount of cash taxes payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

6. Significant accounting policies (continued)

Deferred PILs comprise the net tax effects of temporary differences between the tax basis of assets and liabilities and their respective carrying amounts for accounting purposes, as well as for tax losses available to be carried forward to future years that are likely to be realized. Deferred PILs assets and liabilities are measured using enacted or substantively enacted tax rates, at the reporting date, expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred PILs assets and liabilities of a change in tax rates is recognized in income in the year that includes the date of enactment or substantive enactment.

A deferred PILs asset is recognized to the extent that it is probable that future taxable income will be available against which the temporary difference can be utilized. Deferred PILs assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(p) Financing income and costs

Finance costs comprise interest expense on borrowings and are recognized as an expense in the Consolidated Statement of Income and Comprehensive Income except for those amounts capitalized as part of the cost of qualifying property, plant, and equipment.

Finance income is recognized as it accrues in net income and is comprised of interest earned on cash.

7. Future accounting changes

(a) IFRS 16 Leases ("IFRS 16")

IFRS 16 is effective for periods beginning on or after January 1, 2019, although early application is permitted if IFRS 15 has also been applied. In January 2016, the IASB issued IFRS 16, which replaces the IAS 17 *Leases* and related interpretations ("IAS 17"). IFRS 16 establishes the principles for the recognition, measurement, presentation and disclosure of leases, with the objective of ensuring that lessees and lessors provide relevant information that represents those transactions. The new standard brings most leases on-balance sheet for lessees under a single model, eliminating the distinction between the operating and finance leases. Short-term leases, which are defined as those that have a lease term of 12 months or less and leases of low-value assets are exempt. Under the new standard, a lessee recognizes a right of use asset and a lease liability. The right of use asset is depreciated, similar to other non- financial assets and the liability accrues interest. The lease liability is initially measured as the present value of the lease payments over the lease term, discounted at the rate implicit in the lease.

7. Future accounting changes (continued)

The Corporation will adopt IFRS 16 on January 1, 2019 using the modified retrospective approach. The Corporation has assessed the quantitative impact of adopting IFRS 16 at January 1, 2019 to be an increase of $15 in total assets and total liabilities for the right-of-use assets and the lease liabilities.

(b) Other standards

The following amended standards and interpretations are not expected to have a significant impact on the Corporation's consolidated financial statements:

- IFRIC 23 - *Uncertainty over Tax Treatments*;
- Prepayment Features with Negative Compensation (Amendments to IFRS 9);
- Long-term Interests in Associates and Joint Ventures (Amendments to IAS 28);
- Plan Amendment, Curtailment or Settlement (Amendments to IAS 19);
- Annual Improvements to IFRS Standards 2015–2017 Cycle – various standards; and
- Amendments to References to Conceptual Framework in IFRS Standards.

8. Business acquisition

Purchase of Brampton Hydro

On February 28, 2017, the Corporation acquired 100% of the shares of Brampton Hydro for a total purchase price of $615, which was accounted for in accordance with IFRS 3, *Business Combinations* using the acquisition method. This acquisition is expected to provide synergistic opportunities and efficiencies within the Corporation which will benefit both customers and shareholders.

For the ten months ended December 31, 2017, Brampton Hydro contributed revenue of $462 and net income of $28 to the Corporation's results. If the acquisition had occurred on January 31, 2017, management estimates that the revenue for the eleven months ended would have been $504 and net income would have been $28.

(In millions of Canadian dollars)

8. Business acquisition (continued)

The following table summarizes the fair value consideration transferred as of the acquisition date.

	2017
Cash	515
Tax payable	69
Promissory note	31
Total consideration transferred	615

The promissory note and tax payable were settled with a cash payment of $100 in April 2017. The tax payable relates to amounts owing by Brampton Hydro as of the acquisition date.

The following table summarizes the fair value of assets acquired and liabilities assumed at the date of acquisition:

	2017
Cash	1
Accounts receivable, net	85
Income taxes receivable	6
Inventories	1
PP&E	376
Intangible assets	22
Goodwill	248
Accounts payable and accrued liabilities	64
Deferred tax liabilities	9
Deferred revenue	41
Employee future benefits	4
Income taxes payable	6
Total identifiable net assets acquired	615

Income taxes receivable of $24 (2017 - $6) are payable to the Province of Ontario, as the former shareholders of Brampton Hydro pursuant to the terms of the acquisition and, as such, the Corporation has recorded a corresponding Notes Payable to the Province of Ontario (Note 15).

Goodwill of $248 is the result of expected synergies from the acquisition, of which $126 is deductible for income tax purposes.

The fair value of Brampton Hydro was determined in accordance with the negotiated transaction price as per the Share Purchase Agreement dated March 24, 2016.

9. Restricted cash

Restricted cash includes cash where the availability of funds is restricted by government assistance or held in escrow as part of the Affordability Fund. The Affordability Fund was established by the Government of Ontario as part of the OFHP to assist electricity customers who do not qualify for low-income conservation programs and for whom electricity bills represent a burden.

10. Assets held for sale

In 2012, the former PowerStream acquired a 50% interest in Collus PowerStream which was determined to be a joint venture and accounted for using the equity method. As at December 31, 2017, the Corporation classified the investment in Collus PowerStream as held for sale. The sale closed on October 1, 2018 for proceeds of $14, which resulted in the Corporation recognizing a gain of $6 which is included in other revenue.

(In millions of Canadian dollars)

11. Property, plant, and equipment

	Land and buildings	Distribution assets	Other assets	Work-in-progress	Total
Cost					
Balance, January 31, 2017	78	1,133	171	58	1,440
Additions through acquisition	103	1,321	40	24	1,488
Additions	4	289	4	20	317
Transfer to assets held for sale	(8)	–	–	–	(8)
Disposals	–	(11)	(8)	(3)	(22)
Balance, December 31, 2017	177	2,732	207	99	3,215
Additions/transfers	18	260	12	15	305
Reclassifications	18	(16)	2	(20)	(16)
Disposals	(2)	(13)	(2)	–	(17)
Balance, December 31, 2018	211	2,963	219	94	3,487
Accumulated depreciation					
Balance, January 31, 2017	12	183	47	–	242
Depreciation	5	85	18	–	108
Disposals	(1)	(6)	(8)	–	(15)
Balance, December 31, 2017	16	262	57	–	335
Depreciation	6	97	18	–	121
Reclassifications	–	1	2	–	3
Disposals	–	(6)	(2)	–	(8)
Balance, December 31, 2018	22	354	75	–	451
Carrying amounts					
December 31, 2017	161	2,470	150	99	2,880
December 31, 2018	189	2,609	144	94	3,036

Other assets include [redacted] meters, vehicles, furniture and equipment, computer equipment, and leasehold improvements.

During the year ended December 31, 2018, borrowing costs of $4 (2017 - $3) were capitalized as part of the cost of PP&E and intangible assets. An average capitalization rate of 3.89% (2017 - 3.73%) was used to determine the amount of borrowing costs to be capitalized with respect to the Corporation.

(In millions of Canadian dollars)

11. Property, plant, and equipment (continued)

Included in work in progress as at December 31, 2018 is a reclassification of $19 with a corresponding impact to intangible assets work in progress. The immaterial adjustment arose in 2017 but was reflected prospectively in 2018.

[redacted]

Vacant land in the amount of $7 was transferred to assets held for sale during 2017. The sale was expected to close in 2018. However, the Corporation and the buyer were not able to reach a final agreement and the land was subsequently transferred back to PP&E.

12. Intangible assets and goodwill

(a) Intangible assets

	Goodwill	Land rights	Computer software	Work-in-progress	Capital contribution	Total
Cost or deemed cost						
Balance, January 31, 2017	43	1	68	–	6	118
Additions through acquisition	671	1	18	1	75	766
Additions	–	–	5	1	–	6
Disposals and write-off	–	–	(1)	–	–	(1)
Balance, December 31, 2017	714	2	90	2	81	889
Additions / transfers	–	–	34	6	7	47
Reclassifications	–	–	–	19	–	19
Balance, December 31, 2018	714	2	124	27	88	955
Accumulated amortization						
Balance at January 31, 2017	–	–	23	–	2	25
Amortization	–	–	12	–	2	14
Balance, December 31, 2017	–	–	35	–	4	39
Amortization	–	–	13	–	4	17
Balance, December 31, 2018	–	–	48	–	8	56
Carrying amounts						
December 31, 2017	714	2	55	2	77	850
December 31, 2018	714	2	76	27	80	899

Interest capitalized in intangibles and PP&E during the year is included in Note 11.

(In millions of Canadian dollars)

12. Intangible assets and goodwill (continued)

(b) Goodwill and indefinite life intangibles

Goodwill with a carrying amount of $714 (2017-$714) and land rights with a carrying amount of $2 (2017 - $2) have been allocated to the Corporation's rate regulated CGU and non-regulated CGUs. The Corporation tested goodwill and land rights for impairment as at September 30, 2018.

Fair values less costs of disposal were determined using a multiple of regulated rate base approach and were based on the following key assumptions:

- The multiple of rate base approach is a valuation technique used in the industry for purchase and sale transactions involving rate-regulated LDCs. A multiple is applied to the value of regulated assets to determine the value of the utility;
- The multiple of rate base is a key assumption in the determination of fair value less selling costs. Management utilized a range of multiples in the analysis to determine the recoverable amount of goodwill;
- The multiple of rate base used ranged from 1.4 to 2.1;
- Management obtained information regarding multiples used for recent purchase and sale transactions within the industry; and
- The fair value estimate is categorized as a Level 2 input.

Certain changes in key assumptions would not cause the recoverable amount of goodwill to fall below the carrying value. The recoverable amount of goodwill and land rights determined in the analysis was greater than the carrying value and no impairment was recorded.

13. Accounts payable and accrued liabilities

	2018	2017
Accounts payable - energy purchases	202	242
Accounts payable and accrued liabilities	109	119
Deferred conservation credit	15	15
Customer receivables in credit balances	21	14
Debt retirement charge payable	–	6
	347	396

(In millions of Canadian dollars)

14. Related party balances and transactions

(a) Balances and transactions with related parties

The amount due to/from related parties is comprised of amounts payable to/(receivable from): the City of Vaughan; the City of Markham; the City of Barrie; the City of Mississauga; the City of Hamilton; the City of St. Catharines; and wholly-owned subsidiaries of related parties. Alectra Inc. and Alectra Energy Solutions Inc. are also related parties of the Corporation.

Significant related party transactions, with the related parties not otherwise disclosed separately in the consolidated financial statements, are summarized below:

2018	Revenue	Expenses	Due from related parties	Due to related parties
City of Vaughan	9	1	1	11
City of Markham	9	1	2	9
City of Barrie	6	–	2	–
City of Mississauga	14	2	4	–
City of Hamilton	28	1	2	15
City of St. Catherines	3	–	–	–
Alectra Energy Solutions Inc.	1	3	–	–
Alectra Inc.	–	66	–	15
	70	74	11	50

2017	Revenue	Expenses	Due from related parties	Due to related parties
City of Vaughan	9	10	1	9
City of Markham	8	9	1	8
City of Barrie	6	–	1	–
City of Mississauga	14	1	2	–
City of Hamilton	27	1	–	14
City of St. Catherines	4	–	–	–
Alectra Energy Solutions Inc.	2	4	–	2
Alectra Inc.	–	26	–	6
	70	51	5	39

(In millions of Canadian dollars)

14. Related party balances and transactions (continued)

Revenue earned from related parties include: electricity distribution; street lighting; road projects; payroll; water; and sewage billing. Expenses paid include: municipal taxes; and facilities rental. There are also operating leases with the Cities of Vaughan, Markham, and Barrie. (Note 19(b)).

The Corporation provides services to and receives services from Alectra Inc. and affiliates under its common control. These services generally include administrative support such as information technology, finance, human resources and other services.

The Corporation also has unsecured intercompany loans with Alectra Inc. as described in Note 16.

(b) Key management personnel compensation

Key management personnel are comprised of the Corporation's senior leadership team. The compensation paid or payable to key management personnel is as follows:

	2018	2017
Salaries and current employment benefits	10	9
Employee future benefits	1	1
	11	10

15. Other liabilities

	2018	2017
Current:		
Notes payable to province of Ontario	24	6
Current portion of transition cost liability	3	6
Current portion of finance lease obligation	1	1
Other	7	7
	35	20
Other long-term liabilities:		
Transition cost liability	3	4

The transition cost liability represents payments to be made in relation to the restructuring costs from the Amalgamation Transaction.

(In millions of Canadian dollars)

16. Loans and borrowings from parent

	2018	2017
Non - current:		
4.890% note due 2020	40	40
4.610% note due 2021	110	110
3.090% note due 2022	150	150
4.410% note due 2024	78	78
4.410% note due 2024	68	68
4.410% note due 2024	20	20
3.310% note due 2024	149	149
2.880% note due 2027	587	586
[redacted]	[redacted]	[redacted]
5.340% note due 2041	209	209
4.010% note due 2042	199	198
Total non-current loans and borrowings	1,670	1,672
Current:		
Intercompany variable rate grid note	241	159
4.030% Note due 2018	–	9
4.030% Note due 2018	–	8
[redacted]	[redacted]	[redacted]
Total current loans and borrowings	245	180

All loans and borrowings are payable to Alectra Inc. at the respective maturity dates listed above with interest paid on a quarterly or semi-annual basis, [redacted] Interest expense on these loans and borrowings was $66 (2017 - $53).

[redacted]

16. Loans and borrowings from parent (continued)

The Corporation has access to short-term liquidity under terms of an intercompany loan agreement with its parent company, through Alectra Inc.'s $600 revolving credit facilities. The Corporation can borrow from Alectra Inc., on a revolving basis, to finance general corporate requirements, capital investments, working capital requirements and its prudential obligations to the IESO. As at December 31, 2018, $241 (2017 - $159) has been drawn on this facility. Interest expense on this credit facility was $3 (2017 - $1).

For the year ended December 31, 2018, the average annual outstanding borrowings under the Corporation's intercompany loans and borrowings were $130 (2017 - $111) with an average interest rate of 2.19% (2017 - 1.51%).

17. Employee future benefits

(a) Multi-employer defined benefit pension plan

The Corporation provides a pension plan for its employees through OMERS. The plan is a multi-employer, contributory defined benefit pension plan with equal contributions by the Corporation and its employees. During the year ended December 31, 2018, the Corporation made employer contributions of $16 (2017 - $14) to OMERS. These contributions have been recognized as salaries and benefits in the Consolidated Statement of Income and Comprehensive Income. The expected payment for 2019 is $16 and represents 90% of the group plan under common control by the Corporation. As at December 31, 2017, and subject to the estimates, assumptions and valuations of OMERS, the plan obligations are 94.0% (2016 - 93.4%) funded by its assets. OMERS has a strategy to return the plan to a fully funded position. The Corporation is not able to assess the implications, if any, of this strategy or of the withdrawal of other participating entities from the OMERS plan on its future contributions.

(b) Non-pension defined benefit plans

The Corporation provides certain unfunded health, dental and life insurance benefits on behalf of its retired employees, based on the availability of such through its parent, Alectra Inc. These benefits are provided through group defined benefit plans. There is a policy in place to allocate the net defined benefit cost to the entities participating in the group plans. The allocation is based on the obligation attributable to the plan participants. There are four defined benefit plans. Independent actuarial valuations of the plans were performed as at December 31, 2017. The group defined benefit plans as a whole provides benefits to eligible retirees of the Corporation.

(In millions of Canadian dollars)

17. Employee future benefits (continued)

Information about the group unfunded defined benefit plan and changes in the present value of the aggregate unfunded defined benefit obligation and the aggregate accrued benefit liability are as follows:

	2018	2017
Defined benefit obligation, beginning of period	65	21
Defined benefit obligation, assumed through acquisition	–	40
Benefit cost recognized in net income:		
Current service costs	3	2
Interest expense	2	2
Benefit cost recognized	5	4
Amounts recognized in other comprehensive income:		
Actuarial (gains) losses arising from changes in financial assumptions	(6)	6
Actuarial gains arising from changes in experience adjustments	–	(4)
Amounts recognized in other comprehensive income	(6)	2
Payments from the plans	(3)	(2)
Defined benefit obligation, end of year	**61**	**65**

The main actuarial assumptions underlying the valuation are as follows:

	2018	2017
Discount rate	4.00%	3.40%
Rate of compensation increase	3.30%	3.30%
Medical benefits costs escalation	5.96%	6.20%
Dental benefits costs escalation	4.50%	4.50%

(In millions of Canadian dollars)

17. Employee future benefits (continued)

(c) Sensitivity analysis

The approximate effect on the defined benefit obligation if the main actuarial assumptions underlying the valuation increased or decreased by 1% is as follows:

	2018	2017
Discount rate:		
1% increase	(8)	(9)
1% decrease	10	11
Medical and dental benefits costs escalation:		
1% increase	7	7
1% decrease	(6)	(6)

18. Share capital

The Corporation's authorized share capital is comprised of an unlimited number of voting common shares and 100,000 Class S non-voting shares, all of which are without nominal or par value as follows:

	2018		2017	
	Number of shares	Amount	Number of shares	Amount
Issued and outstanding:				
Common shares	114,149	682	114,149	682
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]

During 2017, the Corporation received $122 of contributed capital on account of the issued and outstanding common shares from Alectra Inc. in relation to the settlement of outstanding debt amounts.

[redacted]

(In millions of Canadian dollars)

18. Share capital (continued)

[redacted]

During the year ended December 31, 2018, the Corporation declared and paid dividends as follows:

- Common share dividends aggregating $59 or $517.85 per share (2017 - $28 or $243.84 per share); and
- [redacted]

[redacted]

19. Leases

(a) Finance lease

The Corporation has a 25 year lease agreement for the use of an operations centre which includes both land and building elements. Upon entering into this lease agreement, the Corporation classified the building element of the lease as a finance lease since it was determined that substantially all of the benefits and risks incidental to the ownership of the operation centre were transferred to the Corporation. The component of the annual basic rent related to the land is classified and recorded as an operating lease.

2018	Future minimum lease payments	Interest accretion	Present value of minimum lease payments
Less than one year	2	1	1
Between one and five years	6	4	2
More than five years	18	5	13
	26	10	16

(In millions of Canadian dollars)

19. Leases (continued)

2017	Future minimum lease payments	Interest accretion	Present value of minimum lease payments
Less than one year	2	1	1
Between one and five years	6	4	2
More than five years	19	5	14
	27	10	17

(b) Operating leases

The Corporation is also committed to certain lease agreements for vehicles; property; equipment; [redacted] and the land portion of an operations centre lease, all corresponding leases have been classified as operating leases. The leases have terms of 3 to 20 years.

As at December 31, 2018, the future minimum, non-cancellable lease payments (including the land portion of the operating centre lease referred to in (a) above) are as follows:

	2018	2017
Less than one year	3	3
Between one and five years	10	10
More than five years	21	22
	34	35

In 2018, operating lease expense of $3 (2017 - $2) was recognized in net income.

20. Financial instruments and risk management

(a) Fair value of financial instruments

The Corporation's accounting policies relating to the recognition and measurement of financial instruments are disclosed in Note 6(d).

The carrying amount of cash (including restricted cash), accounts receivable (including unbilled revenue), amounts due from related parties, customer deposits, accounts payable, amounts due to related parties and current portion of loans and borrowings approximates fair value because of the short maturity of these instruments.

(In millions of Canadian dollars)

20. Financial instruments and risk management (continued)

The fair value of the Corporation's long-term borrowings are $1,744 (2017 - $1,798).

		2018		2017	
	Maturity date	Carrying value(1)	Fair value(2)	Carrying value(1)	Fair value(2)
Loans and borrowings:					
Notes issued in 2002	2024	166	179	166	184
Notes issued in 2010	2020	40	42	40	43
Notes issued in 2011	2021	110	115	110	118
Notes issued in 2011	2041	210	257	210	271
Notes issued in 2012	2022	150	152	150	154
Notes issued in 2012	2042	200	205	200	216
Notes issued in 2014	2024	150	153	150	156
Notes issued in 2017	2027	605	578	605	586
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total loans and borrowings - long-term portion		1,691	1,744	1,695	1,798
Less: issuance costs		(21)	–	(23)	–
		1,670	1,744	1,672	1,798

(1) The carrying value of long-term debt represents the par value of the promissory notes.
(2) The fair value of long-term debt is based on unadjusted year-end market prices for the same or similar debt of the same remaining maturities. The fair value measurement of long-term debt is categorized as Level 2.

(b) *Financial risks*

The risks associated with the Corporation's financial instruments and policies for managing these risks are described below:

(i) *Credit risk*

The Corporation's primary source of credit risk to its accounts receivable and unbilled revenue results from customers failing to discharge their payment obligations for electricity consumed and billed, as they come due.

The carrying amount of accounts receivable, to the extent deemed necessary by management's judgment, is reduced through the use of ECLs with the amount of such during the year recognized in net income. Subsequent recoveries of accounts receivable previously recorded as impaired are credited to net income. The ECLs as at December 31, 2018 are $8 (2017 - $9). An impairment loss of $4 (2017 - $4) was recognized during the period.

(In millions of Canadian dollars)

20. Financial instruments and risk management (continued)

The Corporation's credit risk associated with accounts receivable primarily corresponds to payments from distribution customers. At December 31, 2018, approximately $22 (2017 - $19) is considered over 60 days past due. Credit risk is managed, in part, through the collection of security deposits from regulated electricity distribution customers in accordance with regulations prescribed by the OEB.

Accounts receivables and respective aging is provided as follows:

	2018	2017
Accounts receivables	261	214
Unbilled revenue	270	250
IESO receivable	26	28
Other	38	35
	595	527
Less: expected credit losses	(8)	(9)
Total accounts receivables, net	587	518
0 -30 days	554	497
30 - 60 days	19	11
61 - 90 days	7	6
Greater than 91 days	15	13
	595	527
Less: expected credit losses	(8)	(9)
Total accounts receivable, net	587	518

	Expected credit losses
Balance, January 31, 2017	(3)
Allowances acquired through acquisition	(4)
Additional allowances	(6)
Write-offs	4
Balance, December 31, 2017	(9)
Additional allowances	(3)
Write-offs	4
Balance, December 31, 2018	(8)

The Corporation determines the concentrations of its accounts receivable by type of customer. As at December 31, 2018, there was no significant concentration of credit risk with respect to any financial assets.

20. Financial instruments and risk management (continued)

(ii) Interest rate risk

The Corporation is exposed to fluctuations in interest rates for the valuation of its post-employment benefit obligations (Note 17). The Corporation is also exposed to short-term interest rate risk on its short-term loans and borrowings (Note 16). The Corporation manages interest rate risk by monitoring its mix of fixed and floating rate instruments, and taking action as necessary to maintain an appropriate balance.

As at December 31, 2018, in addition to the valuation of its post-employment benefit obligations, the Corporation was exposed to interest rate risk predominately from short-term borrowings and customer deposits, while most of its remaining obligations were either non-interest bearing or bear fixed interest rates, and its financial assets were predominately short-term in nature and mostly non-interest bearing (Note 16).

The Corporation estimates that a 100 basis point increase (decrease) in short-term interest rates, with all other variables held constant, would result in an increase (decrease) of approximately $2 to annual finance costs.

(In millions of Canadian dollars)

20. Financial instruments and risk management (continued)

(iii) Liquidity risk

Liquidity risks are those risks associated with the Corporation's inability to meet its financial obligations as they fall due. Liquidity risks associated with financial liabilities are as follows:

2018	Due within 1 year	Due between 1 and 5 years	Due past 5 years	Total
Accounts payable and accrued liabilities	347	–	–	347
Customer deposits liability	94	–	–	94
Due to related parties	50	–	–	50
Other liabilities	34	3	–	37
Intercompany variable rate grid note payable to Alectra Inc.	241	–	–	241
4.890% Note payable to Alectra Inc. due 2020	2	42	–	44
4.610% Note payable to Alectra Inc. due 2021	5	117	–	122
3.090% Note payable to Alectra Inc. due 2022	5	164	–	169
4.410% Note payable to Alectra Inc. due 2024	1	4	21	26
4.410% Note payable to Alectra Inc. due 2024	3	12	70	85
4.410% Note payable to Alectra Inc. due 2024	3	14	81	98
3.310% Note payable to Alectra Inc. due 2024	5	19	155	179
2.488% Note payable to Alectra Inc. due 2027	15	60	658	733
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5.340% Note payable to Alectra Inc. due 2041	11	44	405	460
4.010% Note payable to Alectra Inc. 2042	8	32	350	390
Obligations under operating leases	3	10	21	34
Obligations under finance leases	1	2	13	16
Total financial liabilities	834	547	1,824	3,205

(In millions of Canadian dollars)

20. Financial instruments and risk management (continued)

2017	Due within 1 year	Due between 1 and 5 years	Due past 5 years	Total
Accounts payable and accrued liabilities	396	–	–	396
Customer deposits liability	91	–	–	91
Due to related parties	39	–	–	39
Other liabilities	19	4	–	23
Intercompany variable rate grid note payable to Alectra Inc.	159	–	–	159
4.030% Note payable to Alectra Inc. due 2018	8	–	–	8
4.030% Note payable to Alectra Inc. due 2018	9	–	–	9
4.890% Note payable to Alectra Inc. due 2020	2	44	–	46
4.610% Note payable to Alectra Inc. due 2021	5	122	–	127
3.090% Note payable to Alectra Inc. due 2022	5	168	–	173
4.410% Note payable to Alectra Inc. due 2024	1	4	21	26
4.410% Note payable to Alectra Inc. due 2024	3	12	73	88
4.410% Note payable to Alectra Inc. due 2024	3	14	84	101
3.310% Note payable to Alectra Inc. due 2024	5	19	160	184
2.488% Note payable to Alectra Inc. due 2027	15	60	673	748
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5.340% Note payable to Alectra Inc. due 2041	11	44	416	471
4.010% Note payable to Alectra Inc. 2042	8	32	358	398
Obligations under operating leases	3	10	22	35
Obligations under finance leases	1	2	14	17
Total financial liabilities	789	559	1,877	3,225

The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet its operational and investment requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest rate exposure and cost. The Corporation monitors cash balances to ensure that sufficient levels of liquidity are on hand to meet financial commitments as they come due.

(In millions of Canadian dollars)

21. Capital structure

The main objectives of the Corporation when managing financial capital are to:

- ensure ongoing cost effective access to such to provide adequate investment in support of its regulated electricity distribution and other businesses;
- comply with covenants within its financial instruments;
- prudently manage its capital structure, with regard for maintaining a high level of creditworthiness;
- recover financing charges permitted by the OEB on its regulated electricity distribution business; and
- deliver reasonable returns on the investments of its shareholders.

The Corporation's definition of capital includes: shareholder's equity; indebtedness under existing credit facilities; and long-term loans and borrowings, which includes the current portion of long term loans and borrowings.

The OEB regulates the amount of interest on debt and MARE that may be recovered by the Corporation, through its electricity distribution rates, in respect of its regulated electricity distribution business. The OEB permits such recoveries on the basis of a deemed capital structure represented by 60% debt and 40% equity. The actual capital structure for the Corporation may differ from the OEB deemed structure.

22. Operating expenses

Operating expenses comprise:

	2018	2017
Labour	133	136
Contract/consulting	38	34
Office expenses	18	17
Information technology	12	12
Repairs and maintenance	12	15
Business taxes and fees	9	8
Facility expenses	6	6
Bad debt	4	4
Other	10	21
	242	253

(In millions of Canadian dollars)

23. Other revenue

	2018	2017
[redacted]	[redacted]	[redacted]
CDM performance incentive revenue	14	1
Amortization of deferred revenue	9	6
Water and waste water billing fees and customer charges	9	5
Regulatory service charges	8	8
Gain on sale of Collus PowerStream	6	–
Pole and other rental income	4	5
Scrap sales	1	1
Miscellaneous	9	9
	76	51

24. Deferred revenue

Balance, January 31, 2017	144
Contributions received through acquisitions	100
Contributions received from customers and developers	62
Amortization	(6)
Balance, December 31, 2017	300
Contributions received from customers and developers	70
Amortization	(9)
Balance, December 31, 2018	361

(In millions of Canadian dollars)

25. Income taxes

(a) Income tax expense

PILs recognized in net income comprise the following:

	2018	2017
Current tax expense	8	–
Deferred tax expense	31	29
Income tax expense	39	29

(b) Reconciliation of effective tax rate

PILs income tax expense differs from the amount that would have been recorded using the combined Canadian federal and provincial statutory income tax rates. The reconciliation between the statutory and effective tax rates is as follows:

	2018	2017
Income before taxes	148	101
Statutory Canadian federal and provincial income tax rates	26.5%	26.5%
Expected tax provision on income at statutory rates	39	27
Increase in income taxes resulting from:		
Permanent differences	(1)	–
Adjustments in respect of prior years	1	1
Other	–	1
Total income tax expense	39	29
Effective income tax rate	26.6%	28.8%

The statutory income tax rate for the current year comprises a combined 15% (2017 - 15%) federal corporate tax rate and an 11.5% (2017 - 11.5%) Ontario corporate tax rate.

(In millions of Canadian dollars)

25. Income taxes (continued)

(c) Deferred tax balances

The net deferred tax assets and liabilities consist of the following:

	2018	2017
Deferred tax liabilities:		
Employee future benefits	(16)	(17)
PP&E and intangibles	57	34
Non-capital losses	–	(5)
Tax credit carryovers	(9)	(9)
Non-deductible reserves	(2)	(4)
Energy variances	14	16
Total deferred tax liabilities	44	15

26. Change in non-cash operating working capital

	2018	2017
Accounts receivable	(60)	84
Inventory	(1)	(1)
Prepaid expenses	(5)	6
Due from related parties	(6)	(2)
Accounts payable and accrued liabilities	(55)	16
Due to related parties	11	66
Customer deposits liability	3	24
Other liabilities	(3)	13
Net change in non-cash operating working capital	(116)	206

27. Commitments, contingencies and guarantees

(a) Commitments

(i) Leases

Lease commitments have been disclosed in Note 19.

(ii) Security with IESO

Entities that purchase electricity in Ontario through the IESO are required to post security to mitigate its risk of their default on their expected activity in the market. The IESO could draw on this security if the Corporation fails to make the payment required on a default notice issued by the IESO. The Corporation has posted a letter of credit as security in the amount of $33 (2017 - $38).

(b) Contingencies

(i) Legal claims

The Corporation is subject to legal actions and claims in the normal course of business from customers, former employees, and other parties. On an ongoing basis, the Corporation assesses the likelihood of any adverse judgments or outcomes as well as potential ranges of probable costs and losses. A determination of the provision required, if any, for these contingencies is made after an analysis of each individual claim. The value of provisions for legal claims at December 31, 2018 is less than $1, other than the provision noted below. Such provisions are subject to change based on ongoing assessments or settlements of individual claims, including potential mitigation under the Corporation's insurance policies or otherwise.

(ii) Arbitration Judgment against the Corporation ("Arbitration Judgment")

The dispute in this arbitration arose from an agreement ("Project Agreement") between PowerStream, continuing in the Corporation, and another unrelated party ("Other Party") in connection with the development of renewable generation projects that would deliver electricity under the IESO FIT program. Based on the status of such projects and its interpretation of the Project Agreement, PowerStream delivered notice to terminate all projects under the Project Agreement in September of 2016. The principal issue in the arbitration is whether PowerStream was entitled under the Project Agreement to deliver such notice and if not, the consequences that might ensue. The Other Party to the Project Agreement took the position that PowerStream did not have such entitlement.

27. Commitments, contingencies and guarantees

On February 23, 2018, the arbitrator ruled against PowerStream and awarded the Other Party damages of $12 together with pre-judgment and post-judgment interest and costs of the arbitration. The ruling of the arbitrator further provided that such costs are to be paid by the Corporation to the Other Party.

Based on the award of damages and an estimate of pre-judgment and post-judgment interest and costs, at December 31, 2017, the Corporation recorded a liability of $13 with a corresponding charge to operating expenses. During 2018, the Corporation appealed the arbitration decision to the Superior Court of Ontario. The Corporation was successful in its appeal and the Superior Court of Ontario overturned the arbitration decision. The other party has been granted leave by the Ontario Court of Appeal on February 22, 2019. For the year ended December 31, 2018, the liability remains probable and has not been reversed.

(iii) Insurance

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange ("MEARIE"). MEARIE is a pooling of electricity industry liability insurance risks of many of the sector participants in Ontario. All members of the pool are subject to assessment for losses experienced by the pool, for the years in which they were members, on a pro-rata basis based on the total of their respective service revenues. It is anticipated that should such an assessment occur it would be funded over a period of up to five years. As at December 31, 2018, no assessments have been made.

(c) Guarantees

In the normal course of operations, the Corporation enters into agreements that meet the definition of a guarantee as follows:

(i) The Corporation has provided indemnities under lease agreements for the use of certain operating facilities. Under the terms of these agreements, the Corporation agrees to indemnify the counterparties for various matters including, but not limited to, all liabilities, loss, suits, and damages arising during, on or after the term of the agreement. The maximum amount of any potential future payment cannot be reasonably estimated.

27. Commitments, contingencies and guarantees

(ii) The Corporation has agreed to indemnify the directors and/or officers of the Corporation for various matters including, but not limited to, all costs to settle suits or actions due to association with the Corporation, subject to certain restrictions. The Corporation has purchased directors' and officers' liability insurance to mitigate the cost of any potential future suits or actions. The indemnified period is not explicitly defined, but it is limited to the period over which the indemnified party served as a director or officer of the Corporation. The maximum amount of any potential future payment cannot be reasonably estimated

(iii) In the normal course of business, the Corporation has entered into agreements that include indemnities in favor of counterparties, such as purchase and sale agreements, confidentiality agreements, engagement letters with advisor's and consultants, outsourcing agreements, leasing contracts, information technology agreements, and service agreements. These indemnification agreements may require the Corporation to compensate counterparties for losses incurred by the counterparties as a result of breaches of agreements such as breaches of representation or regulations or as a result of litigation claims or statutory sanctions that may be suffered by the counterparty as a consequence of the transaction. The terms of these indemnities are not explicitly defined and the maximum amount of any potential reimbursement cannot be reasonably estimated.

The nature of these indemnification agreements prevents the Corporation from making a reasonable estimate of the maximum exposure due to the difficulties in assessing the amount of liability, which results from the unpredictability of future events. Historically, the Corporation has not made any significant payments under such or similar indemnification agreements and therefore no amount has been accrued in the balance sheet with respect to these agreements. The Corporation is unaware of any breaches that would result in an indemnity claim against it.

28. Divisional information

The Corporation consists primarily of two operating divisions: regulated operations and non-regulated operations. Non-regulated operations are comprised of RFSP and Solar Sunbelt.

The designation of activities to the two operating divisions is based on a combination of regulatory status and the nature of the products and services provided. The accounting policies followed by the divisions are consistent with those described in the summary of significant accounting policies.

Financial information that adjusts IFRS results to show the effect of rate regulation is used by the Corporation's Board of Directors, shareholder’s, OEB, as well as management.

(In millions of Canadian dollars)

28. Divisional information (continued)

2018	**Regulated**	[redacted]	[redacted]	**Total**
Revenue				
Distribution revenue	536	[redacted]	[redacted]	505
Electricity sales	2,833	[redacted]	–	2,850
Other revenue	48	[redacted]	[redacted]	76
Total net revenue	**3,417**	[redacted]	[redacted]	**3,431**
Expenses				
Cost of power	2,833	[redacted]	[redacted]	2,833
Operating expenses	237	[redacted]	[redacted]	242
Depreciation and amortization	122	[redacted]	[redacted]	138
Total expenses	**3,192**	[redacted]	[redacted]	**3,213**
Income from operating activities	**225**	[redacted]	[redacted]	**218**
Loss on derecognition of property, plant, and equipment	(6)	[redacted]	[redacted]	(7)
Finance income	2	[redacted]	[redacted]	1
Finance costs	(64)	[redacted]	[redacted]	(64)
Income before payments in lieu of income taxes	**157**	[redacted]	[redacted]	**148**
Income tax expense	(20)	[redacted]	[redacted]	(39)
Net income	**137**	[redacted]	[redacted]	**109**
Other comprehensive income (loss)				
Remeasurement of defined benefit obligation	3	[redacted]	[redacted]	6
Less future income tax recovery	(2)	[redacted]	[redacted]	(2)
Total comprehensive income (loss)	**138**	[redacted]	[redacted]	**113**

(In millions of Canadian dollars)

28. Divisional information (continued)

2017	Regulated	Adjustments for regulatory activities	Non-regulated	Total
Revenue				
Distribution revenue	474	[redacted]	[redacted]	458
Electricity sales	2,567	[redacted]	[redacted]	2,592
Other revenue	37	[redacted]	12	51
Total net revenue	**3,078**	[redacted]	[redacted]	**3,101**
Expenses				
Cost of power	2,567	[redacted]	[redacted]	2,567
Operating expenses	251	[redacted]	[redacted]	253
Depreciation and amortization	113	[redacted]	[redacted]	122
Total expenses	**2,931**	[redacted]	[redacted]	**2,942**
Income from operating activities	**147**	[redacted]	[redacted]	**159**
Loss on derecognition of property, plant, and equipment	(5)	[redacted]	[redacted]	(5)
Share of net income from joint venture	1	[redacted]	[redacted]	–
Finance income	3	[redacted]	[redacted]	2
Finance costs	(54)	[redacted]	[redacted]	(55)
Income before payments in lieu of income taxes	**92**	[redacted]	[redacted]	**101**
Income tax expense	(11)	[redacted]	[redacted]	(29)
Net income	**81**	**(9)**	[redacted]	**72**
Other comprehensive income (loss)				
Remeasurement of defined benefit obligation	(2)	–	–	(2)
Less future income tax recovery	1	–	–	1
Total comprehensive income (loss)	**80**	[redacted]	[redacted]	**71**

(In millions of Canadian dollars)

28. Divisional information (continued)

2018	Alectra Utilities regulated	[redacted]	[redacted]	Total
Assets				
Current assets				
Cash and cash equivalents	7	–	[redacted]	16
Accounts receivable and unbilled revenue	586	–	[redacted]	587
Inventory	21	–	–	21
Prepaid expenses	13	–	–	13
Due from related parties	11	–	–	11
Total current assets	**638**	**–**	[redacted]	**648**
Non-current assets				
Property, plant, and equipment	2,898	[redacted]	[redacted]	3,036
Goodwill and intangible assets	889	[redacted]	–	899
Investment in subsidiary	4	[redacted]	[redacted]	–
Regulatory assets	111	[redacted]	[redacted]	[redacted]
Total non-current assets	**3,902**	[redacted]	[redacted]	**3,935**
Total assets	**4,540**	[redacted]	[redacted]	**4,583**
Liabilities and Shareholder's equity				
Current liabilities				
Accounts payable and accrued liabilities	348	[redacted]	[redacted]	347
Due to related parties	50	–	–	50
Customer deposits liability	94	–	–	94
Current portion of loans and borrowing from parents	241	–	[redacted]	245
Other liabilities	35	–	–	35
Total current liabilities	**768**	[redacted]	[redacted]	**771**
Non-current liabilities				
Deferred revenues	324	[redacted]	[redacted]	361
Loans and borrowings from parent	1,610	[redacted]	[redacted]	1,670
Regulatory liabilities	84	[redacted]	[redacted]	–
Employee future benefits	61	[redacted]	–	61
Finance lease obligations	15	–	[redacted]	15
Deferred tax liabilities	25	[redacted]	[redacted]	44
Other long-term liabilities	3	–	–	3
Total non-current liabilities	**2,122**	[redacted]	[redacted]	**2,154**
Total liabilities	**2,890**	[redacted]	[redacted]	**2,925**
Shareholder's equity				
Share capital	682	[redacted]	[redacted]	733
Contributed surplus	739	[redacted]	[redacted]	728
Accumulated other comprehensive income	–	[redacted]	[redacted]	3
Retained earnings	229	[redacted]	[redacted]	194
Total shareholder's equity	**1,650**	[redacted]	[redacted]	**1,658**
Total liabilities and Shareholder's equity (deficit)	**4,540**	[redacted]	[redacted]	**4,583**

(In millions of Canadian dollars)

28. Divisional information (continued)

2017	Alectra Utilities regulated	Adjustments for regulatory activities	Non-regulated	Total
Assets				
Current assets				
Cash	105	[redacted]	[redacted]	120
Accounts receivable and unbilled revenue	517	–	[redacted]	518
Inventory	20	–	–	20
Prepaid expenses	6	–	[redacted]	8
Due from related parties	5	–	–	5
Assets held for sale	17	[redacted]	–	16
Total current assets	**670**	[redacted]	[redacted]	**686**
Non-current assets				
Property, plant and equipment	2,735	[redacted]	[redacted]	2,880
Goodwill and intangible assets	841	[redacted]	[redacted]	850
Investment in subsidiary	4	–	[redacted]	–
Deferred tax asset	12	[redacted]	[redacted]	–
Regulatory assets	71	[redacted]	–	–
Total non-current assets	**3,663**	[redacted]	[redacted]	**3,730**
Total assets	**4,333**	[redacted]	[redacted]	**4,416**
Liabilities and Shareholder's equity				
Current liabilities				
Accounts payable and accrued liabilities	405	[redacted]	[redacted]	396
Due to related parties	34	–	5	39
Customer deposits liability	68	[redacted]	[redacted]	91
Current portion of loans and borrowing	180	–	–	180
Other liabilities	37	[redacted]	[redacted]	20
Total current liabilities	**724**	[redacted]	[redacted]	**726**
Non-current liabilities				
Deferred revenues	263	[redacted]	–	300
Loans and borrowings	1,608	–	[redacted]	1,672
Regulatory liabilities	86	[redacted]	–	–
Employee future benefits	65	–	–	65
Capital lease	15	–	[redacted]	16
Deferred tax liabilities	–	[redacted]	[redacted]	15
Other long-term liabilities	4	–	–	4
Total non-current liabilities	**2,041**	[redacted]	[redacted]	**2,072**
Total liabilities	**2,765**	[redacted]	[redacted]	**2,798**
Shareholder's equity				
Share capital	682	–	[redacted]	742
Contributed surplus	739	[redacted]	–	728
Accumulated other comprehensive loss	(2)	[redacted]	–	(1)
Retained earnings	149	[redacted]	[redacted]	149
Total shareholder's equity	**1,568**	[redacted]	[redacted]	**1,618**
Total liabilities and Shareholder's equity (deficit)	**4,333**	[redacted]	[redacted]	**4,416**

(In millions of Canadian dollars)

28. Divisional information (continued)

The Corporation derecognizes all rate-regulated assets and liabilities that do not qualify for recognition under IFRS. Certain items that are presented as rate-regulated assets as prescribed by the OEB qualify for recognition as other types of assets under IFRS.

	2018	2017
Regulatory assets:		
Deferred income tax asset	50	22
Retail settlement variance accounts (“RSVA's”)	22	18
Lost revenues adjustment mechanism variance account (“LRAMVA”)	22	16
Large commercial interval meter recovery	7	4
Renewable generation capital and operating cost deferral	3	3
OEB cost assessments deferral	3	2
Deferred revenue - adjustment to capitalized policy	3	–
Smart meter capital recovery	1	1
Net recovery of regulatory balances	–	4
Other	–	1
Total regulatory assets	111	71
Regulatory liabilities:		
Retail settlement variance accounts (RSVA's)	61	83
Net refund of regulatory balances	12	–
Deferred revenue - adjustment to capitalized policy	5	–
Re-measurements of post-employment benefits	4	2
Other	2	1
Total regulatory liabilities	84	86

(a) The most significant regulatory activities included in the regulatory adjustments are: retail settlement variances; the difference between the cost of the electricity commodity and the sales revenue at the OEB allowed rates. Specifically, these amounts include variances between the amounts charged by Hydro One and the IESO for the operation of the electricity markets and grid, as well as various wholesale market settlement charges and transmission charges as compared to the amount billed to consumers based on the OEB-approved rates. Under regulatory accounting, the Corporation would have adjusted energy sales or purchases for these variances with corresponding assets or liabilities. Under IFRS, the Corporation recognizes these differences in future periods as an increase or decrease to distribution revenue, when these differences are settled with customers.

28. Divisional information (continued)

(b) The OEB approved a variance account to record revenues associated with the delivery of CDM programs. The variance account tracks the difference between the results of actual, verified impacts of CDM activities and the level of CDM program activities included in a distributor's load forecast. The Corporation may recover or refund this revenue through future distribution rates.

(c) The OEB approved four deferral accounts to record qualifying incremental capital investments, operating, maintenance and administration expenses and funding adders approved by the OEB related to the connection of renewable generation or the development of smart grid. Under IFRS, the Corporation capitalizes or expenses these items as incurred and recognizes revenue when funding is received.

(d) The OEB approved a deferral account to record costs associated with replacing interval meters for its large commercial customers in order to meet amendments made to its Distribution System Code. Under IFRS, the Corporation capitalizes or expenses the amounts in the period they were incurred.

(e) The OEB requires the Corporation to accrue interest on regulatory assets and liabilities balances. Under IFRS, the Corporation recognizes the net interest on these balances in future periods as an increase or decrease to distribution revenue once approved for recovery or refund by the OEB.

(f) The OEB approved a deferral account to record any re-measurements of the post-employment net defined liability including actuarial gains or losses. Under IFRS, the Corporation recognizes any re-measurements of the post-employment net defined liability in other comprehensive income.

(g) 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 a new cost assessment model effective April 1, 2016. Under IFRS, the Corporation recognizes these costs under operating expenses in the period they were incurred.

(h) The OEB approved three variance accounts to record the difference between the revenue requirement calculated using pre-merger capitalization policies and the revenue requirement calculated using the Corporation's capitalization policy. Under IFRS, the Corporation recognizes these differences as an increase or decrease to distribution revenue, and will recover or refund these differences through future distribution rates.

(i) The OEB requires the Corporation to record eligible incremental capital investments subject to the assets being used and useful, accumulated amortization and revenues collected through rate riders related to incremental capital projects approved by the OEB. Under IFRS, the Corporation capitalizes or expenses these items as incurred and recognizes revenue in the period it was earned.

28. Divisional information (continued)

(j) The OEB approved a new pole attachment revenue variance account to record the difference between pole attachment revenue at the prior rate of $22.35 per pole, and pole attachment revenue based on the new pole attachment charge effective September 1, 2018, of $28.09. Under IFRS, the Corporation recognizes the revenue based on the effective rate in the period the revenue was earned.

(k) Deferred income taxes are presented as regulatory liabilities or assets and are not expensed through the Consolidated Statement of Income and Comprehensive Income as is the case under IFRS.

Future regulatory accounting treatments prescribed by the OEB and government policy changes may affect the electricity distribution rates charged and recoverable costs permitted by the OEB. Therefore, there is a risk that the timing and amount of recovery or settlement of amounts included in the adjustment for regulatory activities could be significantly different from the amounts that are eventually recovered or settled through distribution rates in the future.

29. Subsequent event

Merger

On January 1, 2019, the Corporation amalgamated with Guelph Hydro Electric Systems Inc. (“GHESI”). Alectra Inc. issued 485,000 Class G Common Shares to Guelph Municipal Holdings Inc. (“GMHI”) in consideration for all the issued and outstanding shares of GHESI. This common share issuance by Alectra Inc. represents an effective 4.6% interest in its aggregate issued and outstanding classes of common shares. The amalgamation is expected to result in more efficient and enhanced service delivery through lower operating costs, while providing significant benefits for communities and shareholders.

The accounting and valuation for the amalgamation is still being finalized. Consequently, disclosures regarding the amount of the purchased assets and liabilities cannot be determined.

G-Staff-1

ATTACH 2 – AFRM REPORT 3.9, DATED NOVEMBER 10, 2017

CONFIDENTIAL

REPORT TO THE AUDIT, FINANCE AND RISK COMMITTEE

Date of Report	July 19, 2017
Submitted by	John G. Basilio
Subject	IFRS Policies Update
Item #	3.9
Meeting Date	November 10, 2017

☒For Information ☐For Approval

Please refer to the attached presentation: IFRS Policies

Summary

There are a three new IFRS accounting standards requiring implementation over the next two years:

- IFRS 9 – Financial instruments – implementation date as of January 1, 2018, applied retrospectively;
- IFRS 15 – Revenue from Contracts with Customers standard – implementation date as of January 1, 2018, applied retrospectively;
- IFRS 16 – Leases standard – implementation date as of January 1, 2019, applied retrospectively

Based on preliminary analysis, with the exception of IFRS 16, the impact to Alectra resulting from the implementation of these new standards is not expected to be material.

IFRS Policies

November 10, 2017

Agenda

- Background
- Summary and impact of IFRS 9, Financial Instruments
- Summary and impact of IFRS 15, Revenue from Contracts with Customers
- Summary and impact of IFRS 16, Leases

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Background

- There are three new IFRS accounting standards that require implementation in the next two years, these include:
  - IFRS 9 – Financial instruments – implementation date as of January 1, 2018, applied retrospectively;
  - IFRS 15 – Revenue from contract with customers standard – implementation date as of January 1, 2018, applied retrospectively;
  - IFRS 16 – Leases standard – implementation date as of January 1, 2019, applied retrospectively

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IFRS 9 – Financial Instruments – Summary of Standard

- IFRS 9 *Financial Instruments* has been developed to by the International Standards Board to replace IAS 39 *Financial Instrument: Recognition and Measurement*. The new standard is effective for the periods beginning on or after 1 January 2018 with retrospective application and an early adoption is permitted.
- IFRS 9 establishes the principles for the financial reporting of financial assets and liabilities and prescribes the accounting treatment for the following areas:
  - Classification and measurement of financial assets and liabilities;
  - De-recognition of financial assets;
  - Impairment; and
  - Hedge accounting.

IFRS 9 – Financial Instruments – Impact to Alectra

- There will be no change to the classification of Alectra’s financial assets and liabilities. Classification will continue using “Amortized Cost”, with the initial measurement of fair value adjusted for transaction costs. Subsequent measurement for these assets will be Amortized Cost using the effective interest rate (“EIR”) method.
- Derecogntion of financial assets and liabilities methodology has not changed and is consistent with how it was done at each of the predecessor utilities.
- The calculation for allowance for doubtful accounts will be changed to a prospective based model whereby the amount of the credit loss provision is determined by using a forward looking approach, such as economic factors. A model is currently being developed and will be applied to the 2018 allowance for doubtful accounts provision. Based on preliminary analysis this should not substantially change the current provision amount.

IFRS 15 – Revenue from Contracts with Customers – Summary of standard

- IFRS 15 Revenue from Contracts with Customers has been developed by the International Accounting Standards Board to replace IAS 18 Revenue. This standard establishes a comprehensive framework for determining when and how much revenue to recognize.
- The core principle is that a company should recognize revenue to depict the transfer of promised goods or services to the customer in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services.
- Some of the key changes from the IAS 18 to IFRS 15 are as follows:
  - IAS 18 defines revenue as a gross inflow whereas IFRS 15 requires the transaction price to be allocated to each individual performance obligation.
  - Under IFRS 15, revenue is recognized as each performance obligation is satisfied. Under IAS 18, the timing of revenue recognition from the sale of goods is based primarily on the transfer of risks and rewards.
  - IFRS 15 also applies to the recognition and measurement of gains and losses on the sale of some non-financial assets that are not an output of the entity's ordinary activities (e.g., sales of property, plant and equipment or intangibles).

IFRS 15 – Revenue from Contract with customers – Impact on Alectra

- Alectra has analyzed all of its current contracts including the following significant contracts:
  - IESO contract
  - CDM contracts
  - Contracts with developers
  - Water billing
  - Solar contracts with the IESO
  - Non regulated contracts (such as sub-metering and street lighting)
- The analysis concludes that there will be no change in policy required with respect to revenue recognition and financial presentation. The analysis of the above significant contracts has also been reviewed among members of the Canadian Electricity Association ("CEA") and KPMG, and the conclusion reached is consistent with others.

IFRS 16 – Leases – Summary of standard

- IFRS 16 Leases has been developed by the International Accounting Standards Board to replace IAS 17 Leases. The new standard creates a single accounting model for all leases, with two exemptions ('low-value assets' and short-term leases) which are exempt from the standard.
- The key change resulting from the new standard is that all operating leases previously recognized on the income statement as a lease expense will be recognized on the balance sheet as a lease liability with offsetting right of use lease asset and depreciation and Interest expense recognized on the income statement.
- Lessees accrete the lease liability to reflect interest and reduce the liability to reflect lease payments made. The related right-of-use asset is depreciated in accordance with the depreciation requirements of IAS 16 *Property, Plant and Equipment.* For lessees that depreciate the right-of-use asset on a straight-line basis, the aggregate of interest expense on the lease liability and depreciation of the right-of-use asset generally results in higher total periodic expense in the earlier periods of a lease. Lessees re-measure the lease liability upon the occurrence of certain events (e.g., change in the lease term, change in variable rents based on an index or rate), which is generally recognized as an adjustment to the right-of-use asset.
- Right-of-use assets are subject to impairment testing under IAS 36 *Impairment of Assets.*

IFRS 16 – Leases – Impact on Alectra

- [redacted]
- [redacted]
  - Alectra Utilities Shared Consolidated does not have material operating leases and therefore the impact is not expected to be material.
  - A full analysis of all entities is currently being prepared. However, it is not expected that there will be any material changes in addition to that identified above.

G-Staff-1

ATTACH 3 – AFRM REPORT 2.5, DATED NOVEMBER 9, 2018

CONFIDENTIAL

REPORT TO THE AUDIT, FINANCE AND RISK COMMITTEE

Submitted by	John G. Basilio
Subject	IFRS Standards and Accounting Policies
Item #	2.5
Meeting Date	November 9, 2018

☐For Information ☒For Approval

<u>Summary</u>

There are a three new IFRS accounting standards requiring implementation over the next two years:

- IFRS 9 – Financial instruments – implementation date as of January 1, 2018, applied retrospectively;
- IFRS 15 – Revenue from Contracts with Customers standard – implementation date as of January 1, 2018, applied retrospectively;
- IFRS 16 – Leases standard – implementation date as of January 1, 2019, applied retrospectively

The attached slide presentation illustrates the impact of these standards on the 2018 and 2019 financial statements.

Motion

The AFRM Committee approves the accounting policy recommendations set forth by Management.

Adoption of New IFRS Standards

Audit, Finance & Risk Management Committee

November 9, 2018

Agenda

- Background
- Summary of overall impact by standard
- Discussion of the changes and impacts for each IFRS standard
  - IFRS 9, Financial Instruments
  - IFRS 15, Revenue from Contracts with Customers
  - IFRS 16, Leases

Background

- There are three new IFRS accounting standards that must be implemented in 2018 and 19
  - IFRS 9 – *Financial Instruments* – implementation date as of January 1, 2018, applied retrospectively;
  - IFRS 15 – *Revenue from Contracts with Customers* – implementation date as of January 1, 2018, applied retrospectively;
  - IFRS 16 – *Leases* – implementation date as of January 1, 2019, applied retrospectively.

Summary of Impact by Standard

Standard	EBT for 2019 ($MM)	B/S impact ($MM)	Covenant impact
IFRS 9	Immaterial	Immaterial	None
IFRS 15	None	None	None
IFRS 16			
AI Consol	MIFRS - $0.3 lower	ROU asset- $28.5 Lease liability - $33.4	Minor change in Debt to cap (0.2% higher)
AUC - Shared	MIFRS – No impact	ROU asset - $13.5 Lease liability - $17.5	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	

IFRS 9 – *Financial Instruments*

Summary

IFRS 9 establishes the principles for the financial reporting of financial assets and liabilities and prescribes the accounting treatment for the following items:

- Classification and measurement of financial assets and liabilities;
- Impairment including Allowance for Doubtful accounts (“AFDA”) calculations;
- Hedge accounting

Impact to Alectra

- There will be no change to the classification of Alectra’s financial assets and liabilities.
- IFRS 9 requires that Alectra include forward looking information within the AFDA calculation. Consequently Alectra now includes an allowance for unbilled revenue. This approach is consistent with other utilities and is applied at a rate of less than 1%.

IFRS 15 – *Revenue from Contracts with Customers*

Summary

Key changes from IAS 18 to IFRS 15 are described below:

- Under IFRS 15, revenue is recognized as each performance obligation is satisfied. Under IAS 18, the timing of revenue recognition from the sale of goods is based primarily on the transfer of risks and rewards.
- IFRS 15 applies to the recognition and measurement of gains and losses on the sale of some non-financial assets that are not an output of the entity's ordinary activities (e.g., sales of property, plant and equipment or intangibles).

Impact to Alectra

- Alectra analyzed all of its contracts for both regulated and non-regulated businesses (this includes IESO, sub-metering contracts, consulting contracts, etc.) and determined that there would be no change required to Alectra's accounting for revenue with the exception of set-up fees.

IFRS 15 – *Revenue from Contracts with Customers*

Impact to Alectra (continued)

- Set up fees are charged to residential customers when they open a new account. These charges are recognized when billed and add up to $3.4MM in revenue per year.
- Under IFRS 15 setup fees are considered admin tasks which are required to be recognized over the life of a customer contract and not when billed.
- Alectra performed an analysis between recognizing setup fees up front vs over the life of a customer contract. The difference was $0.12MM over 5 years which is not material.
- Alectra's Revenue Recognition Policy will be updated to indicate that set up fees will be recognized over the life of the contract with the customer. However, in practice Alectra will continue to recognize the set up fees when billed because this approach is easier to administer and there is no material impact to the financial statements.
- IFRS 15 requires new extensive disclosures that require revenue to be presented in categories that depict the nature, amount, timing and uncertainty of revenue and cash flows.

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IFRS 16 – *Leases*

Summary

Key changes from IAS 17 to IFRS 16 are described below:

- Under IFRS 16 all operating leases are recognized on the balance sheet as a right of use asset with a related lease liability compared to IAS 17 where operating leases were recognized as operating expenses.
- Under IFRS 16, lease payments are discounted using the interest rate implicit in the lease, or if that rate cannot be readily determined, then the lessee's incremental borrowing rate is used.
- Lessees accrete the lease liability to reflect interest and reduce the liability to reflect lease payments made. The related right-of-use asset is depreciated in accordance with the depreciation requirements of IAS 16 *Property, Plant and Equipment.*

IFRS 16 – *Leases*

Summary (continued)

- There are a number of transition options available for the implementation of this standard which include:
  - Recognition exemption for short term leases and low value leases (under $5,000 USD)
  - Option to 'grandfather' the previous assessment under IFRIC 4 and IAS 17 of whether an existing contracts is a lease or contains leases.
  - Option to implement as either full retrospective or modified retrospective.

Impact to Alectra

[redacted]

- Alectra used the APR implicit in the lease agreement for vehicle leases.
- For all other leases, the incremental borrowing rate at the date of transition for each respective entity and portfolio of leases was used.

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IFRS 16 – *Leases*

Impact to Alectra (continued)

- For all entities:
  - EBITDA has increased, as the leases move off the income statement
  - EBT has decreased, as depreciation and interest offset the savings in removing the operating leases from the income statement
- The transition options selected include the following:

OPTION	DETAIL	ELECTED?
Definition of a lease (accounting policy choice)	On transition, companies can elect the option to ‘grandfather’ their previous assessment under IFRIC 4 and IAS 17 as to which existing contracts are, or contain, leases, although this exemption must be applied to all contracts or none.	Yes
Recognition exemption: leases of low-value items (lease by lease)	On transition, companies can elect not to recognize right of use asset and lease liabilities for leases of low-value assets (<=5,000 USD), and recognize the associated lease payments as an expense on a straight-line basis over the lease term. This policy will need to be applied consistently on transition and subsequently.	N/A (All identified leases are above US$5,000)

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IFRS 16 – *Leases*

Impact to Alectra (continued)

Retrospective vs Modified retrospective options that are available on transition are summarized below along with the related recommendations:

OPTION	DETAIL	ELECTED?
Full retrospective vs modified retrospective (accounting policy choice)	• Under the full retrospective approach, the company restates its prior financial information, recognizes an adjustment in equity at the beginning of the earliest period presented, and makes the disclosures required by IAS 8 on a change in accounting policy. No further reliefs are available. • Under the modified retrospective approach, the company does not restate prior financial information, and recognizes the cumulative effect of initially applying IFRS 16 as an adjustment to opening equity on the date of transition. In addition, the company may make use of a number of transition reliefs.	Full retrospective is recommended (see analysis of impacts on next slide)
Modified retrospective approach: measurement of lease liability (lease by lease)	Under this approach, the lease liability is measured at the present value of remaining lease payments using the lessee's incremental borrowing rate at the date of transition. Furthermore, an entity can elect to: • apply a <u>single discount rate</u> to a portfolio of leases with reasonably similar characteristics. • account for leases for which the lease term ends within 12 months of the date of initial application as <u>short term leases</u>, irrespective of whether the original lease term was for more than 12 months.	N/A – recommending full retrospective
Modified retrospective approach: measurement of right of use asset (lease by lease)	Under this approach, the right of use asset is measured in one of two ways: i. at an amount equal to the lease liability, or ii. retrospectively as if IFRS 16 had always been applied but using the lessee's incremental borrowing rate at transition date	N/A – recommending full retrospective

IFRS 16 – *Leases*

Impact to Alectra (continued)

The tables below summarize the impact of IFRS 16 on Alectra in the first year of adoption (i.e. on December 31, 2019 under MIFRS):

FULL RETRO

(in millions)	[redacted]	[redacted]	AUC Consolidated	[redacted]	[redacted]	AI Consolidated
Impact to EBT	[redacted]	[redacted]	(0.2)	[redacted]	[redacted]	(0.3)
Impact to Equity	[redacted]	[redacted]	(4.6)	[redacted]	[redacted]	(4.9)
Right of Use Asset	[redacted]	[redacted]	23.4	[redacted]	[redacted]	28.5
Lease Liability	[redacted]	[redacted]	28.0	[redacted]	[redacted]	33.4

MODIFIED

(in millions)	[redacted]	[redacted]	AUC Consolidated	[redacted]	[redacted]	AI Consolidated
Impact to EBT	[redacted]	[redacted]	(0.2)	[redacted]	[redacted]	(0.3)
Impact to equity	[redacted]	[redacted]	(4.1)	[redacted]	[redacted]	(4.2)
Right of Use Asset	[redacted]	[redacted]	23.2	[redacted]	[redacted]	28.4
Lease Liability	[redacted]	[redacted]	27.4	[redacted]	[redacted]	32.7

IFRS 16 – *Leases*

Impact on Alectra (continued)

Over a five year period the EBT is $0.41MM higher under the modified retrospective approach compared with the full retrospective approach.

Recommendation

Management recommends that the full retrospective approach be elected as EBT is higher and there is no additional effort required for implementation.

G-Staff-2

Reference: Exhibit 2, Tab 1, Schedule 5

Questions:

On January 1, 2019, Alectra Utilities amalgamated with the former Guelph Hydro Electric System Inc. (Guelph Hydro). Please confirm that Alectra Utilities, as required by IFRS 10 *Consolidated Financial Statements* and IFRS 3 *Business Combinations*, updated the accounting policies of the former Guelph Hydro to align with that of the acquirer, Alectra Utilities.

a) Please provide any memorandum, presentation, or other internal documentation provided to Alectra Utilities' Board of Directors or executive management team that analyzes or discusses the impacts of updating Guelph Hydro's accounting policies to align with that of Alectra Utilities'.

b) Please extend the information presented in Exhibit 2, Tab 1, Schedule 5, Table 20 to show the impact of the GRZ's adoption of Alectra Utilities' accounting policies. Please file a copy of the updated Table 20 in excel format.

c) Please confirm that Alectra Utilities intends to request the establishment of a deferral account for the GRZ, following the amalgamation on January 1, 2019, similar to the ones the OEB has established for the HRZ, ERZ, and BRZ. If not, please explain why not, given the OEB's decision in the 2018 Alectra Utilities' rate application.

Response:

a) There were no memoranda, presentations or other documentation provided to Alectra Utilities' Board of Directors or executive management team that analyzes or discusses the impacts of updating Guelph Hydro's accounting policies to align with that of Alectra Utilities'.

b) Please see Alectra Utilities' response to G-Staff-3.

c) Alectra Utilities confirms that it intends to request the establishment of a deferral account for the Guelph RZ to track the impact of the capitalization policy change.

G-Staff-3

Reference: Exhibit 2, Tab 1, Schedule 5 – Table 20 – Net Impact of Capitalization Policy Change

Questions:

a) Please provide a more detailed breakdown of how Alectra Utilities calculated the capitalization policy impacts of certain revenue requirement components for the fiscal years of 2017 and 2018, found in Exhibit 2, Tab 1, Schedule 5, Table 20. Specifically, for each of the five rate zones separately (including GRZ), please provide the tables that show the detailed calculations of:

  i. PILs Impact: including the incremental return on equity, depreciation added back/deduction, CCA deduction/add back (with supporting CCA schedule), and grossed-up taxes
  ii. Return on Capital: including the cumulative effect on rate base, the supporting calculations for depreciation, and the weighting and rates of return on debt and equity.

Please file copies of the above supporting tables in excel format.

Response:

a) Alectra Utilities has filed its Capitalization Policy Impact Model as G-Staff-3_Attach 1_Capitalization Policy Impact Model. The model includes detailed calculations of the total net impact of the capitalization policy change for the Enersource (“ERZ”), Horizon Utilities (“HRZ”), Brampton (“BRZ”), PowerStream (“PRZ”), and Guelph Rate Zones (“GRZ”) including:

- **Tab 1 ‘Summary’** – this tab provides a summary of the impact of the capitalization policy change by rate zone, including the impact to OM&A, depreciation, PILs and return on capital. The total net impact presented in rows 33 through 37 by rate zone reflects the amount to be recorded in the capitalization policy deferral account. For the Horizon Utilities Rate Zone, as directed by the OEB in Procedural Order No. 3 in Alectra Utilities’ 2018 EDR Application (EB-2017-0024), “*Alectra Utilities shall retain the deferral account opened for the Horizon Utilities RZ, however, the first entries to the account shall begin January 1, 2020”.* The impact for the ERZ, HRZ, BRZ, and

PRZ are provided for the 2017 to 2026 period (rebasing deferral period); for the GRZ, the impact of the capitalization policy change is effective January 1, 2019, the effective date of the Guelph merger. The impact for the GRZ is provided for the 2019 to 2028 period, which is the 10-year rebasing deferral period for the Guelph merger.

- **Tab 2 'Capitalization Policy Impact'** – this tab provides the impact to OM&A/Capital and depreciation from the change in capitalization policy. Alectra Utilities has provided actuals for 2017 and 2018 and a forecast for the 2019 to 2028 period, as applicable. For the ERZ, HRZ, PRZ, and GRZ, the impact of the change in the capitalization policy results in an increase in capitalized costs, a corresponding reduction in OM&A expenditures and an increase in depreciation expense over the life of the underlying assets. For the BRZ, the impact of the change in the capitalization policy results in a decrease in capitalized costs, a corresponding increase in OM&A expenditures and a decrease in depreciation expense over the life of the underlying asset.

A full year of depreciation has been recovered, which is consistent with the OEB's policy in the *Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module* (EB-2014-0219), issued September 18, 2014. In the final year prior to rebasing (i.e. 2026 for the ERZ, HRZ, PRZ, and BRZ and 2028 for the GRZ), Alectra Utilities has applied the half year rule. This is consistent with the OEB's policy; at p. 23 of the ACM Report, the OEB states: "*The Board's general guidance on the application of the half-year rule is provided in the Supplemental Report. In that report the Board determined that the half-year rule should not apply so as not to build a deficiency for the subsequent years of the IR plan term. In a subsequent decision with respect to the application of the half-year rule in the context of an ICM, the Board decided that the half-year rule would apply in the final year of the Price Cap IR plan term.*" This has resulted in a minor change to the impact calculated for 2017 and 2018 as summarized in Table 1 and 2, below.

Table 1 – 2017 Capitalization Policy Impact

Capitalization Policy Net Impact Reporting Period: 2017	Alectra As Filed EB-2019-0018	Alectra Updated EB-2019-0018	Change
BRZ	$1,671,303	$1,642,128	($29,176)
ERZ	($1,716,767)	($1,687,688)	$29,078
PRZ	($180,076)	($176,608)	$3,468
HRZ	($5,022,498)	($4,935,270)	$87,228
Total Net Impact	**($5,248,037)**	**($5,157,439)**	**$90,599**

Table 2 – 2018 Capitalization Policy Impact

Capitalization Policy Net Impact Reporting Period: 2018	Alectra As Filed EB-2019-0018	Alectra Updated EB-2019-0018	Change
BRZ	$1,307,510	$1,279,898	($27,612)
ERZ	($1,423,621)	($1,394,341)	$29,281
PRZ	($367,330)	($359,150)	$8,179
HRZ	($4,467,177)	($4,377,878)	$89,299
Total Net Impact	**($4,950,618)**	**($4,851,470)**	**$99,147**

- **Tab 3 'Allocation Method'** – As identified in Alectra Utilities' Capitalization Policy submission, filed September 16, 2019, the BRZ, HRZ, PRZ, and ERZ rate zones, have migrated to Alectra Utilities' Enterprise Resource Planning ("ERP") system in July 2019. Legacy ERP systems and processes were relied upon to determine the impact of the capitalization policy change in 2017 and 2018. As these legacy systems are no longer in place, and due to the complexities and costs required to maintain four additional sets of general ledgers, Alectra Utilities can no longer determine the impact based on legacy systems. Further, consistent with the OEB's findings in the MAADs Decision (EB-2016-0025) with respect to reporting requirements for the utility, at p. 26 the OEB stated that "*the Handbook to Electricity Distributor and Transmitter Consolidation sets out that having consolidating entities operate as one entity as soon as possible after the transaction is in the best interest of consumers. The OEB is of the view that this principle continues to be applicable in this case. The OEB does not require, nor encourage reporting on a "separate" utility basis.*"

Alectra Utilities has used the actual impacts derived prior to the ERP convergence (2017 and 2018) as a proxy to calculate the actual impacts of the capitalization policy change in 2019, and the remainder of the rebasing deferral period.

For the ERZ, HRZ, BRZ, and PRZ, Alectra Utilities proposes to calculate the impact of the capitalization policy change for 2019 to 2026 as follows:

- o Determine the % of the impact relative to distribution plant capital in 2017 and 2018. The capitalization policy change impacted distribution plant assets, therefore Alectra Utilities has compared the total impact in 2017 and 2018 by rate zone to the level of distribution plant capital for the respective rate zones as provided in Table 1, below.

Table 3 – Ratio of Capitalization Policy Impact to Distribution Plant Capital

Allocation Method	2017 & 2018 Capitalization Policy Impact ("CPI")	2017 & 2018 Distribution Plant ("DP") Capital	Ratio of CPI/DP Capital
HRZ	$10,641,267	$92,036,058	11.56%
ERZ	$3,577,559	$105,723,142	3.38%
BRZ	$(3,440,222)	$42,922,541	(8.01%)
PRZ	$603,368	$193,346,786	0.31%

For the GRZ, the ratio of CPI/DP Capital was based on a forecast of the impact for 2019 relative to the forecast amount of Distribution Plant Capital for the GRZ.

Table 4 – Ratio of Capitalization Policy Impact to Distribution Plant Capital GRZ

Allocation Method	Capitalization Policy Impact ("CPI")	Distribution Plant ("DP") Capital	Ratio of CPI/DP Capital
GRZ	587,990	9,228,280	6.37%

- o Apply the percentages calculated in Tables 3 and 4 to forecast Distribution Plant capital based on Alectra Utilities' Distribution System Plan ("DSP") filed in this proceeding. As Alectra Utilities' DSP spans the 2020 to 2024 period, to complete the forecast for 2026 to 2028, where applicable, Alectra Utilities assumed the same impact from 2024 into the future years.

- **Tab 4 'Revenue Requirement Impact'** – this tab provides the capital related revenue requirement (i.e. the cost of capital, depreciation, and PILs) impact by rate zone. This includes the calculation of:
    - Return on rate base – this represents the annual return on the cumulative capital, calculated using the cost of capital parameters approved by the OEB in the predecessor utility's last rebasing application. The exception to this is the Horizon Utilities RZ cost of capital parameters that were updated in each of 2017, 2018 and 2019 per the Horizon Utilities Settlement Agreement (EB-2014-0002) and as approved by the OEB in the Decision and Order in each of the 2017, 2018 and 2019 rate application proceeding;
    - Depreciation expense – as identified previously, this reflects a full year of depreciation in each year, except for the year prior to rebasing where the half year rule was applied; and
    - Grossed up PILs – this is based on regulatory taxable income, with an add back for depreciation and a deduction for CCA. The tax rate of 26.5% is then applied to the incremental taxable income as presented in row 40 of Tab 4, to determine PILs before Gross Up. The final step in the PILs calculation is the determination of incremental Grossed Up PILs as presented in row 46 of Tab 4.

- **Tab 5 'CCA'** – this tab provides the calculation of Capital Cost Allowance used in Tab 4, Revenue Requirement Impact.

A summary of the net impact of the capitalization policy change is presented in Table 5, below.

Table 5 – Net Impact of Capitalization Policy Change

Capitalization Policy Impact ($000s)	2017_Act	2018_Act	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2017-2028
Enersource RZ	1,866	1,712	1,805	1,745	2,029	2,204	2,236	2,718	2,718	2,718			21,751
Horizon Utilities RZ	5,399	5,243	6,455	6,121	5,863	5,788	4,709	5,965	5,965	5,965			57,473
Brampton RZ	(1,831)	(1,610)	(2,330)	(2,557)	(2,281)	(2,635)	(2,591)	(2,635)	(2,635)	(2,635)			(23,739)
PowerStream RZ	194	410	267	302	300	295	365	340	340	$340			3,154
Guelph RZ			588	638	670	670	609	695	695	695	695	695	6,650
Total OM&A Impact	**5,628**	**5,754**	**6,785**	**6,249**	**6,581**	**6,322**	**5,328**	**7,084**	**7,084**	**7,084**	**695**	**695**	**65,289**
Enersource RZ	(47)	(89)	(135)	(178)	(229)	(284)	(340)	(408)	(476)	(510)			(2,695)
Horizon Utilities RZ	(135)	(266)	(427)	(580)	(727)	(872)	(989)	(1,139)	(1,288)	(1,362)			(7,786)
Brampton RZ	46	86	144	208	265	331	396	462	528	561			3,026
PowerStream RZ	(5)	(15)	(22)	(29)	(37)	(44)	(53)	(62)	(70)	(75)			(412)
Guelph RZ			(15)	(31)	(47)	(64)	(79)	(97)	(114)	(132)	(149)	(158)	(885)
Total Depreciation Impact	**(141)**	**(285)**	**(454)**	**(610)**	**(775)**	**(933)**	**(1,066)**	**(1,243)**	**(1,420)**	**(1,518)**	**(149)**	**(158)**	**(8,752)**
Enersource RZ	(13)	(1)	5	9	6	4	(0)	(11)	(19)	(18)			(39)
Horizon Utilities RZ	(37)	(5)	6	25	28	19	6	(38)	(71)	(85)			(153)
Brampton RZ	14	2	3	(1)	(6)	1	6	16	30	35			99
PowerStream RZ	(1)	(2)	2	2	2	1	0	(1)	(2)	(3)			-2
Guelph RZ			(4)	(1)	1	2	2	0	(2)	(5)	(9)	(11)	(27)
Total PILs Impact	**(38)**	**(6)**	**$10**	**$32**	**$31**	**$26**	**$14**	**(33)**	**(64)**	**(76)**	**(9)**	**(11)**	**(123)**
Enersource RZ	(118)	(227)	(341)	(452)	(581)	(721)	(862)	(1,035)	(1,207)	(1,382)			(6,927)
Horizon Utilities RZ	(291)	(593)	(967)	(1,313)	(1,644)	(1,972)	(2,238)	(2,575)	(2,912)	(3,254)			(17,759)
Brampton RZ	129	242	405	585	745	930	1,112	1,298	1,483	1,670			8,599
PowerStream RZ	(11)	(34)	(49)	(66)	(83)	(99)	(120)	(139)	(158)	(177)			(935)
Guelph RZ			(37)	(78)	(120)	(162)	(201)	(245)	(289)	(333)	(377)	(421)	(2,264)
Total Return on Capital Impact	**(291)**	**(612)**	**(989)**	**(1,323)**	**(1,682)**	**(2,023)**	**(2,308)**	**(2,696)**	**(3,084)**	**(3,476)**	**(377)**	**(421)**	**(19,284)**
Enersource RZ	1,688	1,394	1,334	1,123	1,226	1,203	1,033	1,264	1,016	808			12,090
Horizon Utilities RZ	4,935	4,378	5,067	4,252	3,520	2,963	1,488	2,214	1,694	1,263			31,775
Brampton RZ	(1,642)	(1,280)	(1,778)	(1,765)	(1,277)	(1,373)	(1,077)	(859)	(595)	(369)			(12,014)
PowerStream RZ	177	359	198	209	182	153	192	139	110	86			1,805
Guelph RZ			532	528	504	445	331	353	290	226	160	105	3,475
Total Net Impact	**5,157**	**4,851**	**5,353**	**4,348**	**4,155**	**3,392**	**1,968**	**3,111**	**2,516**	**2,014**	**160**	**105**	**37,130**
Total Net Impact _Excl Guelph	**5,157**	**4,851**	**4,821**	**3,819**	**3,652**	**2,947**	**1,636**	**2,757**	**2,226**	**1,788**	**0**	**0**	**33,656**

As identified in Alectra Utilities' Capitalization Policy submission, filed September 16, 2019, Alectra Utilities proposes that disposition of these accounts be applied through adjustments to rate base in Alectra Utilities' next rebasing application. Alectra Utilities has further reviewed OEB policy regarding the disposition of balances in Accounts 1575 and 1576. For 2013 rebasing applications, the OEB's Appendix 2-EA specified that the impact would be included as an adjustment to revenue requirement on rebasing. See extract below of Chapter 2 Appendix 2-EA applicable to 2013 rate applications.

Figure 1 – Appendix 2-EA (Chapter 2 Appendices, 2013 Rate Applications)

Appendix 2-EA
IFRS-CGAAP Transitional PP&E Amounts
2012 Adopters of IFRS for Financial Reporting Purposes

For applicants that adopt IFRS on January 1, 2012 for financial reporting purposes

Note: this sheet should be filled out if the applicant adopts IFRS for its financial reporting purpose as of January 1, 2012.

	2009 Rebasing Year	2010	2011	2012	2013 Rebasing Year	2014	2015	2016
Reporting Basis	CGAAP	IRM	IRM	IRM	MIFRS	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast			
			$	$				
PP&E Values under CGAAP								
Opening net PP&E - Note 1								
Additions								
Depreciation (amounts should be negative)								
Closing net PP&E (1)			0	0				
PP&E Values under MIFRS (Starts from 2011, the transition year)								
Opening net PP&E - Note 1								
Additions								
Depreciation (amounts should be negative)								
Closing net PP&E (2)			0	0				
Difference in Closing net PP&E, CGAAP vs. MIFRS (Shown as adjustment to rate base on rebasing)			0	0				
Account 1575 - IFRS-CGAAP Transitional PP&E Amounts								
Opening balance			0	0	0	0	0	0
Amounts added in the year			0	0				
Sub-total			0	0	0	0	0	0
Amount of amortization, included in depreciation expense - Note 2					0	0	0	0
Closing balance in deferral account			0	0	0	0	0	0

Effect on Revenue Requirement

Amortization of deferred balance as above - Note 2	0	**WACC**		
Return on Rate Base Associated with deferred PP&E balance at WACC - Note 3	0	**Disposition Period - Note 4**	4	Years
Amount included in Revenue Requirement on rebasing	0			

On June 25, 2013, the OEB issued its letter, *Accounting Policy Changes for Accounts 1575 and 1576,* to inform distributors of the accounting policy changes to Accounts 1575 and 1576 with respect to the disposition of these account balances for the 2014 cost of service rate applications and subsequent rate years. At p. 2 of the Letter, the OEB states:

> "*The Board's policy for Accounts 1575 and 1576 requires the dispositions of these account balances in rates to be applied through adjustments to the revenue requirement in the cost of service rate applications. The recoveries or refunds arising from the disposition of these balances were usually set for a period of four years to align with the rate-setting cycle. Due to the changes arising from the Renewed Regulatory Framework for Electricity, which provides distributors with rate application filing options, i.e., 4th Generation Incentive Rate-Setting ("IR"), Custom IR and Annual IR Index, there will be different rate-setting cycles for distributors depending on the option selected. As a result, the Board will require the use of separate rate riders for the disposition of these account balances to permit greater flexibility, effective for the 2014 cost of service rate applications and subsequent rate years."*

Consistent with this guidance, the disposition of the balances in the capitalization policy deferral accounts will be based on rate riders for each rate zone. An extract of the revised Appendix 2-EA applicable for 2014 rate applications is provided below. As identified in Figure 2, below, the impact would be included as part of the Deferral and Variance Account Rate Rider Calculation.

Figure 1 – Appendix 2-ED (Chapter 2 Appendices, 2014 Rate Applications)

Appendix 2-ED
Account 1576 - Accounting Changes under CGAAP
2012 Changes in Accounting Policies under CGAAP

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2012

	2009 Rebasing Year	2011	2012	2013	2014 Rebasing Year	2015	2016	2017	2018
Reporting Basis	CGAAP	IRM	IRM	IRM	CGAAP - ASPE	IRM	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast				
			$	$	$	$	$	$	$
PP&E Values under former CGAAP									
Opening net PP&E - Note 1				0					
Net Additions - Note 4									
Net Depreciation (amounts should be negative) - Note 4									
Closing net PP&E (1)			0	0					
PP&E Values under revised CGAAP (Starts from 2012)									
Opening net PP&E - Note 1				0					
Net Additions - Note 4									
Net Depreciation (amounts should be negative) - Note 4									
Closing net PP&E (2)			0	0					
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP			0	0					

Effect on Deferral and Variance Account Rate Riders

Closing balance in Account 1576	-	**WACC**	
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	-	**# of years of rate rider disposition period**	
Amount included in Deferral and Variance Account Rate Rider Calculation	-		

G-Staff-3

ATTACH 1 – CAPITALIZATION POLICY IMPACT MODEL

Alectra Utilities
Impact Analysis of Capitalization Policy Change

Capitalization Policy Impact ($000s)	2017_Act	2018_Act	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2017-2028
Enersource RZ	1,866	1,712	1,805	1,745	2,029	2,204	2,236	2,718	2,718	2,718			21,751
Horizon Utilities RZ	5,399	5,243	6,455	6,121	5,863	5,788	4,709	5,965	5,965	5,965			57,473
Brampton RZ	(1,831)	(1,610)	(2,330)	(2,557)	(2,281)	(2,635)	(2,591)	(2,635)	(2,635)	(2,635)			(23,739)
PowerStream RZ	194	410	267	302	300	295	365	340	340	$340			3,154
Guelph RZ			588	638	670	670	609	695	695	695	695	695	6,650
Total OM&A Impact	**5,628**	**5,754**	**6,785**	**6,249**	**6,581**	**6,322**	**5,328**	**7,084**	**7,084**	**7,084**	**695**	**695**	**65,289**
Enersource RZ	(47)	(89)	(135)	(178)	(229)	(284)	(340)	(408)	(476)	(510)			(2,695)
Horizon Utilities RZ	(135)	(266)	(427)	(580)	(727)	(872)	(989)	(1,139)	(1,288)	(1,362)			(7,786)
Brampton RZ	46	86	144	208	265	331	396	462	528	561			3,026
PowerStream RZ	(5)	(15)	(22)	(29)	(37)	(44)	(53)	(62)	(70)	(75)			(412)
Guelph RZ			(15)	(31)	(47)	(64)	(79)	(97)	(114)	(132)	(149)	(158)	(885)
Total Depreciation Impact	**(141)**	**(285)**	**(454)**	**(610)**	**(775)**	**(933)**	**(1,066)**	**(1,243)**	**(1,420)**	**(1,518)**	**(149)**	**(158)**	**(8,752)**
Enersource RZ	(13)	(1)	5	9	6	4	(0)	(11)	(19)	(18)			(39)
Horizon Utilities RZ	(37)	(5)	6	25	28	19	6	(38)	(71)	(85)			(153)
Brampton RZ	14	2	3	(1)	(6)	1	6	16	30	35			99
PowerStream RZ	(1)	(2)	2	2	2	1	0	(1)	(2)	(3)			-2
Guelph RZ			(4)	(1)	1	2	2	0	(2)	(5)	(9)	(11)	(27)
Total PILs Impact	**(38)**	**(6)**	**$10**	**$32**	**$31**	**$26**	**$14**	**(33)**	**(64)**	**(76)**	**(9)**	**(11)**	**(123)**
Enersource RZ	(118)	(227)	(341)	(452)	(581)	(721)	(862)	(1,035)	(1,207)	(1,382)			(6,927)
Horizon Utilities RZ	(291)	(593)	(967)	(1,313)	(1,644)	(1,972)	(2,238)	(2,575)	(2,912)	(3,254)			(17,759)
Brampton RZ	129	242	405	585	745	930	1,112	1,298	1,483	1,670			8,599
PowerStream RZ	(11)	(34)	(49)	(66)	(83)	(99)	(120)	(139)	(158)	(177)			(935)
Guelph RZ			(37)	(78)	(120)	(162)	(201)	(245)	(289)	(333)	(377)	(421)	(2,264)
Total Return on Capital Impact	**(291)**	**(612)**	**(989)**	**(1,323)**	**(1,682)**	**(2,023)**	**(2,308)**	**(2,696)**	**(3,084)**	**(3,476)**	**(377)**	**(421)**	**(19,284)**
Enersource RZ	1,688	1,394	1,334	1,123	1,226	1,203	1,033	1,264	1,016	808			12,090
Horizon Utilities RZ	4,935	4,378	5,067	4,252	3,520	2,963	1,488	2,214	1,694	1,263			31,775
Brampton RZ	(1,642)	(1,280)	(1,778)	(1,765)	(1,277)	(1,373)	(1,077)	(859)	(595)	(369)			(12,014)
PowerStream RZ	177	359	198	209	182	153	192	139	110	86			1,805
Guelph RZ			532	528	504	445	331	353	290	226	160	105	3,475
Total Net Impact	**5,157**	**4,851**	**5,353**	**4,348**	**4,155**	**3,392**	**1,968**	**3,111**	**2,516**	**2,014**	**160**	**105**	**37,130**
Total Net Impact _Excl Guelph	**5,157**	**4,851**	**4,821**	**3,819**	**3,652**	**2,947**	**1,636**	**2,757**	**2,226**	**1,788**	**0**	**0**	**33,656**

**The impact to the HRZ will flow through the ESM in 2017, 2018 & 2019*

Alectra Utilities
Impact of Change in Capitalization Policy

Horizon Utilities	2017_Act	2018_Act	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2017-2028
Direct Labour Costs	2,098,365	1,412,389											
Benefit Costs	-	460,588											
Material Handling Costs	1,810,241	1,807,080											
Fleet Costs	1,489,924	1,562,680											
Total Impact	**5,398,529**	**5,242,737**	**6,455,375**	**6,120,749**	**5,863,256**	**5,787,550**	**4,709,348**	**5,965,129**	**5,965,129**	**5,965,129**			**57,472,934**

Enersource	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2017-2028
Direct Labour Costs	519,256	(737,544)											
Benefit Costs	(48,759)	(7,465)											
Material Handling Costs	916,805	2,038,661											
Fleet Costs	478,739	417,866											
Total Impact	**1,866,041**	**1,711,518**	**1,804,925**	**1,745,024**	**2,029,155**	**2,204,155**	**2,236,114**	**2,717,893**	**2,717,893**	**2,717,893**			**21,750,612**

Brampton	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2017-2028
Direct Labour Costs	(849,888)	(1,952,705)											
Benefit Costs	(576,904)	(586,154)											
Material Handling Costs	(403,740)	929,169											
Fleet Costs	-	-											
Total Impact	**(1,830,532)**	**(1,609,690)**	**(2,330,085)**	**(2,557,315)**	**(2,281,490)**	**(2,634,725)**	**(2,591,103)**	**(2,634,712)**	**(2,634,712)**	**(2,634,712)**			**(23,739,077)**

PowerStream	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2017-2028
Direct Labour Costs	-	-											
Benefit Costs	(111,726)	(201,634)											
Material Handling Costs	305,386	611,342											
Fleet Costs	-	-											
Total Impact	**193,660**	**409,708**	**267,139**	**302,487**	**299,907**	**295,314**	**364,670**	**340,351**	**340,351**	**340,351**			**3,153,938**

Guelph	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2017-2028
Direct Labour Costs			15,806										
Benefit Costs			261,869										
Material Handling Costs			310,315										
Fleet Costs			-										
Total Impact	**-**	**-**	**587,990**	**638,149**	**670,468**	**669,869**	**609,233**	**694,954**	**694,954**	**694,954**	**694,954**	**694,954**	**5,260,571**

Consolidated	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2017-2028
Direct Labour Costs	1,767,732	(1,277,861)											
Benefit Costs	(737,389)	(334,665)											
Material Handling Costs	2,628,692	5,386,253											
Fleet Costs	1,968,663	1,980,546											
Total Impact	**5,627,698**	**5,754,273**	**6,785,345**	**6,249,093**	**6,581,297**	**6,322,163**	**5,328,262**	**7,083,615**	**7,083,615**	**7,083,615**	**694,954**	**694,954**	**63,898,978**

Impact on Depreciation Expense

Rate Zone	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2017-2028
Horizon Utilities	(134,963)	(266,032)	(427,416)	(580,435)	(727,016)	(871,705)	(989,439)	(1,138,567)	(1,287,695)	(1,362,259)			(7,785,527)
Enersource	(46,651)	(89,439)	(134,562)	(178,188)	(228,917)	(284,020)	(339,923)	(407,871)	(475,818)	(509,792)			(2,695,180)
Brampton	45,763	86,006	144,258	208,191	265,228	331,096	395,873	461,741	527,609	560,543			3,026,308
PowerStream	(4,842)	(15,084)	(21,763)	(29,325)	(36,823)	(44,205)	(53,322)	(61,831)	(70,340)	(74,594)			(412,128)
Guelph			(14,700)	(30,653)	(47,415)	(64,162)	(79,393)	(96,767)	(114,140)	(131,514)	(148,888)	(157,575)	(885,207)
Total	**(140,692)**	**(284,549)**	**(454,183)**	**(610,410)**	**(774,943)**	**(932,997)**	**(1,066,203)**	**(1,243,294)**	**(1,420,384)**	**(1,517,616)**	**(148,888)**	**(157,575)**	**(8,751,735)**

Alectra Utilities
Allocation Methodology

Capitalization Policy Impact ("CPI")	2017 & 2018
HRZ	10,641,267
ERZ	3,577,559
BRZ	(3,440,222)
PRZ	603,368

Capitalization Policy Impact ("CPI")	2019
GRZ	587,990

Distribution Plant ("DP") Capital	2017 & 2048
HRZ	92,036,058
ERZ	105,723,142
BRZ	42,922,541
PRZ	193,346,786

Distribution Plant ("DP") Capital	2019
GRZ	9,228,280

Ratio of CPI/DP Capital	2017 & 2048
HRZ	11.56%
ERZ	3.38%
BRZ	-8.01%
PRZ	0.31%

Ratio of CPI/DP Capital	2017 & 2048
GRZ	6.37%

2020-2024 DP Capital	2019	2020	2021	2022	2023	2024
HRZ	55,832,382	52,938,214	50,711,164	50,056,382	40,731,040	51,592,261
ERZ	53,338,691	51,568,514	59,965,088	65,136,658	66,081,077	80,318,510
BRZ	29,071,713	31,906,799	28,465,412	32,872,612	32,328,351	32,872,457
PRZ	85,603,710	96,930,653	96,104,123	94,632,073	116,857,213	109,064,127
GRZ	9,228,280	10,015,502	10,522,735	10,513,332	9,561,671	10,907,036

2020-2024 CPI	2019	2020	2021	2022	2023	2024
HRZ	6,455,375	6,120,749	5,863,256	5,787,550	4,709,348	5,965,129
ERZ	1,804,925	1,745,024	2,029,155	2,204,155	2,236,114	2,717,893
BRZ	(2,330,085)	(2,557,315)	(2,281,490)	(2,634,725)	(2,591,103)	(2,634,712)
PRZ	267,139	302,487	299,907	295,314	364,670	340,351
GRZ	587,990	638,149	670,468	669,869	609,233	694,954

Capitalization Policy_HRZ

Return on Rate Base	2017	2018	2019		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Incremental Capital					$ 5,398,529	$ 10,641,267	$ 17,096,641	$ 23,217,391	$ 29,080,647	$ 34,868,197	$ 39,577,546	$ 45,542,675	$ 51,507,805	$ 57,472,934
Depreciation Expense					$ 134,963	$ 266,032	$ 427,416	$ 580,435	$ 727,016	$ 871,705	$ 989,439	$ 1,138,567	$ 1,287,695	$ 1,362,259
Incremental Capital to be included in Rate Base					$ 5,263,566	$ 10,375,235	$ 16,669,225	$ 22,636,956	$ 28,353,631	$ 33,996,492	$ 38,588,107	$ 44,404,108	$ 50,220,110	$ 56,110,675
	2017	*2018*	*2019*											
Deemed ShortTerm Debt %	4.0%	4.0%	4.0%	**E**	$ 210,543	$ 415,009	$ 666,769	$ 905,478	$ 1,134,145	$ 1,359,860	$ 1,543,524	$ 1,776,164	$ 2,008,804	$ 2,244,427
Deemed Long Term Debt %	56.0%	56.0%	56.0%	**F**	$ 2,947,597	$ 5,810,132	$ 9,334,766	$ 12,676,695	$ 15,878,033	$ 19,038,036	$ 21,609,340	$ 24,866,301	$ 28,123,261	$ 31,421,978
Short Term Interest	1.76%	2.29%	2.82%	**I**	$ 3,706	$ 9,504	$ 18,803	$ 25,534	$ 31,983	$ 38,348	$ 43,527	$ 50,088	$ 56,648	$ 63,293
Long Term Interest	3.47%	3.62%	3.74%	**J**	$ 102,282	$ 210,327	$ 349,120	$ 474,108	$ 593,838	$ 712,023	$ 808,189	$ 930,000	$ 1,051,810	$ 1,175,182
Return on Rate Base - Interest					$ 105,987	$ 219,830	$ 367,923	$ 499,643	$ 625,821	$ 750,371	$ 851,717	$ 980,087	$ 1,108,458	$ 1,238,475
Deemed Equity %	40.00%	40.00%	40.00%	**N**	$ 2,105,426	$ 4,150,094	$ 6,667,690	$ 9,054,782	$ 11,341,452	$ 13,598,597	$ 15,435,243	$ 17,761,643	$ 20,088,044	$ 22,444,270
Return on Rate Base -Equity	8.78%	9.00%	8.98%	**O**	$ 184,856	$ 373,508	$ 598,759	$ 813,119	$ 1,018,462	$ 1,221,154	$ 1,386,085	$ 1,594,996	$ 1,803,906	$ 2,015,495
Return on Rate Base - Total					$ 290,844	$ 593,339	$ 966,682	$ 1,312,762	$ 1,644,284	$ 1,971,525	$ 2,237,802	$ 2,575,083	$ 2,912,365	$ 3,253,970

Depreciation Expense											
Depreciation Expense - Incremental	**C**	$ 134,963	$ 266,032	$ 427,416	$ 580,435	$ 727,016	$ 871,705	$ 989,439	$ 1,138,567	$ 1,287,695	$ 1,362,259

Grossed up PIL's														
Regulatory Taxable Income				**O**	$ 184,856	$ 373,508	$ 598,759	$ 813,119	$ 1,018,462	$ 1,221,154	$ 1,386,085	$ 1,594,996	$ 1,803,906	$ 2,015,495
Add Back Depreciation Expense				**S**	$ 134,963	$ 266,032	$ 427,416	$ 580,435	$ 727,016	$ 871,705	$ 989,439	$ 1,138,567	$ 1,287,695	$ 1,362,259
Deduct CCA					$ 215,941	$ 624,317	$ 1,042,296	$ 1,461,957	$ 1,824,361	$ 2,144,444	$ 2,392,765	$ 2,628,322	$ 2,895,267	$ 3,140,856
Incremental Taxable Income					$ 103,879	$ 15,224	-$ 16,121	-$ 68,403	-$ 78,882	-$ 51,585	-$ 17,241	$ 105,240	$ 196,334	$ 236,899
Current Tax Rate	26.5%	26.5%	26.5%	**X**										
PIL's Before Gross Up					$ 27,528	$ 4,034	-$ 4,272	-$ 18,127	-$ 20,904	-$ 13,670	-$ 4,569	$ 27,889	$ 52,029	$ 62,778
Incremental Grossed Up PIL's					$ 37,453	$ 5,489	-$ 5,812	-$ 24,662	-$ 28,440	-$ 18,599	-$ 6,216	$ 37,944	$ 70,787	$ 85,412

Incremental Revenue Requirement											
Return on Rate Base - Total	**Q**	$ 290,844	$ 593,339	$ 966,682	$ 1,312,762	$ 1,644,284	$ 1,971,525	$ 2,237,802	$ 2,575,083	$ 2,912,365	$ 3,253,970
Depreciation Expense - Total		$ 134,963	$ 266,032	$ 427,416	$ 580,435	$ 727,016	$ 871,705	$ 989,439	$ 1,138,567	$ 1,287,695	$ 1,362,259
Incremental Grossed Up PIL's	**Z**	$ 37,453	$ 5,489	-$ 5,812	-$ 24,662	-$ 28,440	-$ 18,599	-$ 6,216	$ 37,944	$ 70,787	$ 85,412
Incremental Revenue Requirement		$ 463,260	$ 864,859	$ 1,388,285	$ 1,868,535	$ 2,342,859	$ 2,824,631	$ 3,221,024	$ 3,751,594	$ 4,270,847	$ 4,701,642

Capitalization Policy_BRZ

			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Return on Rate Base												
Incremental Capital			$ (1,830,532)	$ (3,440,222)	$ (5,770,307)	$ (8,327,622)	$ (10,609,112)	$ (13,243,837)	$ (15,834,940)	$ (18,469,652)	$ (21,104,365)	$ (23,739,077)
Depreciation Expense			$ (45,763)	$ (86,006)	$ (144,258)	$ (208,191)	$ (265,228)	$ (331,096)	$ (395,873)	$ (461,741)	$ (527,609)	$ (560,543)
Incremental Capital to be included in Rate Base			$ (1,784,769)	$ (3,354,217)	$ (5,626,049)	$ (8,119,432)	$ (10,343,884)	$ (12,912,741)	$ (15,439,066)	$ (18,007,911)	$ (20,576,755)	$ (23,178,534)
Deemed ShortTerm Debt %	4.0%	E	$ (71,391)	$ (134,169)	$ (225,042)	$ (324,777)	$ (413,755)	$ (516,510)	$ (617,563)	$ (720,316)	$ (823,070)	$ (927,141)
Deemed Long Term Debt %	56.0%	F	$ (999,471)	$ (1,878,361)	$ (3,150,587)	$ (4,546,882)	$ (5,792,575)	$ (7,231,135)	$ (8,645,877)	$ (10,084,430)	$ (11,522,983)	$ (12,979,979)
Short Term Interest	2.16%	I	$ (1,542)	$ (2,898)	$ (4,861)	$ (7,015)	$ (8,937)	$ (11,157)	$ (13,339)	$ (15,559)	$ (17,778)	$ (20,026)
Long Term Interest	6.07%	J	$ (60,668)	$ (114,017)	$ (191,241)	$ (275,996)	$ (351,609)	$ (438,930)	$ (524,805)	$ (612,125)	$ (699,445)	$ (787,885)
Return on Rate Base - Interest			$ (62,210)	$ (116,915)	$ (196,102)	$ (283,011)	$ (360,546)	$ (450,086)	$ (538,144)	$ (627,684)	$ (717,223)	$ (807,911)
Deemed Equity %	40.00%	N	$ (713,908)	$ (1,341,687)	$ (2,250,420)	$ (3,247,773)	$ (4,137,554)	$ (5,165,096)	$ (6,175,626)	$ (7,203,164)	$ (8,230,702)	$ (9,271,414)
Return on Rate Base -Equity	9.30%	O	$ (66,393)	$ (124,777)	$ (209,289)	$ (302,043)	$ (384,792)	$ (480,354)	$ (574,333)	$ (669,894)	$ (765,455)	$ (862,241)
Return on Rate Base - Total			$ (128,603)	$ (241,691)	$ (405,391)	$ (585,054)	$ (745,339)	$ (930,440)	$ (1,112,477)	$ (1,297,578)	$ (1,482,679)	$ (1,670,152)
Depreciation Expense												
Depreciation Expense - Incremental		C	$ (45,763)	$ (86,006)	$ (144,258)	$ (208,191)	$ (265,228)	$ (331,096)	$ (395,873)	$ (461,741)	$ (527,609)	$ (560,543)
Grossed up PIL's												
Regulatory Taxable Income		O	$ (66,393)	$ (124,777)	$ (209,289)	$ (302,043)	$ (384,792)	$ (480,354)	$ (574,333)	$ (669,894)	$ (765,455)	$ (862,241)
Add Back Depreciation Expense		S	$ (45,763)	$ (86,006)	$ (144,258)	$ (208,191)	$ (265,228)	$ (331,096)	$ (395,873)	$ (461,741)	$ (527,609)	$ (560,543)
Deduct CCA			$ (73,221)	$ (204,972)	$ (346,166)	$ (513,968)	$ (666,403)	$ (809,739)	$ (953,993)	$ (1,086,707)	$ (1,210,547)	$ (1,324,480)
Incremental Taxable Income			$ (38,935)	$ (5,810)	$ (7,381)	$ 3,735	$ 16,383	$ (1,710)	$ (16,213)	$ (44,929)	$ (82,517)	$ (98,304)
Current Tax Rate	26.5%	X										
PIL's Before Gross Up			$ (10,318)	$ (1,540)	$ (1,956)	$ 990	$ 4,341	$ (453)	$ (4,297)	$ (11,906)	$ (21,867)	$ (26,051)
Incremental Grossed Up PIL's			$ (14,038)	$ (2,095)	$ (2,661)	$ 1,347	$ 5,907	$ (617)	$ (5,846)	$ (16,199)	$ (29,751)	$ (35,443)
Incremental Revenue Requirement												
Return on Rate Base - Total		Q	$ (128,603)	$ (241,691)	$ (405,391)	$ (585,054)	$ (745,339)	$ (930,440)	$ (1,112,477)	$ (1,297,578)	$ (1,482,679)	$ (1,670,152)
Depreciation Expense - Total			$ (45,763)	$ (86,006)	$ (144,258)	$ (208,191)	$ (265,228)	$ (331,096)	$ (395,873)	$ (461,741)	$ (527,609)	$ (560,543)
Incremental Grossed Up PIL's		Z	$ (14,038)	$ (2,095)	$ (2,661)	$ 1,347	$ 5,907	$ (617)	$ (5,846)	$ (16,199)	$ (29,751)	$ (35,443)
Incremental Revenue Requirement			$ (188,405)	$ (329,792)	$ (552,309)	$ (791,898)	$ (1,004,660)	$ (1,262,153)	$ (1,514,196)	$ (1,775,518)	$ (2,040,039)	$ (2,266,138)

Capitalization Policy_PRZ

			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Return on Rate Base												
Incremental Capital			$ 193,660	$ 603,368	$ 870,507	$ 1,172,994	$ 1,472,901	$ 1,768,214	$ 2,132,885	$ 2,473,236	$ 2,813,587	$ 3,153,938
Depreciation Expense			$ 4,842	$ 15,084	$ 21,763	$ 29,325	$ 36,823	$ 44,205	$ 53,322	$ 61,831	$ 70,340	$ 74,594
Incremental Capital to be included in Rate Base			$ 188,819	$ 588,283	$ 848,744	$ 1,143,669	$ 1,436,078	$ 1,724,009	$ 2,079,563	$ 2,411,405	$ 2,743,247	$ 3,079,344
Deemed ShortTerm Debt %	4.0%	E	$ 7,553	$ 23,531	$ 33,950	$ 45,747	$ 57,443	$ 68,960	$ 83,183	$ 96,456	$ 109,730	$ 123,174
Deemed Long Term Debt %	56.0%	F	$ 105,738	$ 329,439	$ 475,297	$ 640,454	$ 804,204	$ 965,445	$ 1,164,555	$ 1,350,387	$ 1,536,218	$ 1,724,433
Short Term Interest	1.76%	I	$ 133	$ 414	$ 598	$ 805	$ 1,011	$ 1,214	$ 1,464	$ 1,698	$ 1,931	$ 2,168
6	3.88%	J	$ 4,103	$ 12,782	$ 18,442	$ 24,850	$ 31,203	$ 37,459	$ 45,185	$ 52,395	$ 59,605	$ 66,908
Return on Rate Base - Interest			$ 4,236	$ 13,196	$ 19,039	$ 25,655	$ 32,214	$ 38,673	$ 46,649	$ 54,093	$ 61,537	$ 69,076
Deemed Equity %	40.00%	N	$ 75,527	$ 235,313	$ 339,498	$ 457,467	$ 574,431	$ 689,604	$ 831,825	$ 964,562	$ 1,097,299	$ 1,231,738
Return on Rate Base -Equity	8.78%	O	$ 6,631	$ 20,661	$ 29,808	$ 40,166	$ 50,435	$ 60,547	$ 73,034	$ 84,689	$ 96,343	$ 108,147
Return on Rate Base - Total			$ 10,867	$ 33,857	$ 48,847	$ 65,820	$ 82,649	$ 99,220	$ 119,683	$ 138,781	$ 157,879	$ 177,222
Depreciation Expense												
Depreciation Expense - Incremental		C	$ 4,842	$ 15,084	$ 21,763	$ 29,325	$ 36,823	$ 44,205	$ 53,322	$ 61,831	$ 70,340	$ 74,594
Grossed up PIL's												
Regulatory Taxable Income		O	$ 6,631	$ 20,661	$ 29,808	$ 40,166	$ 50,435	$ 60,547	$ 73,034	$ 84,689	$ 96,343	$ 108,147
Add Back Depreciation Expense		S	$ 4,842	$ 15,084	$ 21,763	$ 29,325	$ 36,823	$ 44,205	$ 53,322	$ 61,831	$ 70,340	$ 74,594
Deduct CCA			$ 7,746	$ 31,261	$ 55,834	$ 74,153	$ 92,316	$ 108,740	$ 126,440	$ 144,526	$ 160,192	$ 174,604
Incremental Taxable Income			$ 3,726	$ 4,483	-$ 4,264	-$ 4,662	-$ 5,059	-$ 3,987	-$ 84	$ 1,994	$ 6,491	$ 8,136
Current Tax Rate	26.5%	X										
PIL's Before Gross Up			$ 987	$ 1,188	-$ 1,130	-$ 1,235	-$ 1,341	-$ 1,057	-$ 22	$ 528	$ 1,720	$ 2,156
Incremental Grossed Up PIL's			$ 1,344	$ 1,616	-$ 1,537	-$ 1,681	-$ 1,824	-$ 1,438	-$ 30	$ 719	$ 2,340	$ 2,933
Incremental Revenue Requirement												
Return on Rate Base - Total		Q	$ 10,867	$ 33,857	$ 48,847	$ 65,820	$ 82,649	$ 99,220	$ 119,683	$ 138,781	$ 157,879	$ 177,222
Depreciation Expense - Total			$ 4,842	$ 15,084	$ 21,763	$ 29,325	$ 36,823	$ 44,205	$ 53,322	$ 61,831	$ 70,340	$ 74,594
Incremental Grossed Up PIL's		Z	$ 1,344	$ 1,616	-$ 1,537	-$ 1,681	-$ 1,824	-$ 1,438	-$ 30	$ 719	$ 2,340	$ 2,933
Incremental Revenue Requirement			$ 17,052	$ 50,558	$ 69,072	$ 93,464	$ 117,648	$ 141,988	$ 172,975	$ 201,331	$ 230,559	$ 254,750

Capitalization Policy_ERZ

Return on Rate Base

Return on Rate Base			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Incremental Capital			$ 1,866,041	$ 3,577,559	$ 5,382,484	$ 7,127,508	$ 9,156,663	$ 11,360,818	$ 13,596,932	$ 16,314,825	$ 19,032,718	$ 21,750,612
Depreciation Expense			$ 46,651	$ 89,439	$ 134,562	$ 178,188	$ 228,917	$ 284,020	$ 339,923	$ 407,871	$ 475,818	$ 509,792
Incremental Capital to be included in Rate Base			$ 1,819,390	$ 3,488,120	$ 5,247,922	$ 6,949,320	$ 8,927,746	$ 11,076,798	$ 13,257,009	$ 15,906,954	$ 18,556,900	$ 21,240,820
Deemed ShortTerm Debt %	4.0%	E	$ 72,776	$ 139,525	$ 209,917	$ 277,973	$ 357,110	$ 443,072	$ 530,280	$ 636,278	$ 742,276	$ 849,633
Deemed Long Term Debt %	56.0%	F	$ 1,018,858	$ 1,953,347	$ 2,938,836	$ 3,891,619	$ 4,999,538	$ 6,203,007	$ 7,423,925	$ 8,907,894	$ 10,391,864	$ 11,894,859
Short Term Interest	2.08%	I	$ 1,514	$ 2,902	$ 4,366	$ 5,782	$ 7,428	$ 9,216	$ 11,030	$ 13,235	$ 15,439	$ 17,672
Long Term Interest	5.09%	J	$ 51,860	$ 99,425	$ 149,587	$ 198,083	$ 254,476	$ 315,733	$ 377,878	$ 453,412	$ 528,946	$ 605,448
Return on Rate Base - Interest			$ 53,374	$ 102,327	$ 153,953	$ 203,865	$ 261,904	$ 324,949	$ 388,908	$ 466,646	$ 544,385	$ 623,121
Deemed Equity %	40.00%	N	$ 727,756	$ 1,395,248	$ 2,099,169	$ 2,779,728	$ 3,571,098	$ 4,430,719	$ 5,302,803	$ 6,362,782	$ 7,422,760	$ 8,496,328
Return on Rate Base -Equity	8.93%	O	$ 64,989	$ 124,596	$ 187,456	$ 248,230	$ 318,899	$ 395,663	$ 473,540	$ 568,196	$ 662,852	$ 758,722
Return on Rate Base - Total			$ 118,362	$ 226,923	$ 341,409	$ 452,095	$ 580,803	$ 720,612	$ 862,448	$ 1,034,843	$ 1,207,238	$ 1,381,843

Depreciation Expense

Depreciation Expense			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Depreciation Expense - Incremental		C	$ 46,651	$ 89,439	$ 134,562	$ 178,188	$ 228,917	$ 284,020	$ 339,923	$ 407,871	$ 475,818	$ 509,792

Grossed up PIL's

Grossed up PIL's			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Regulatory Taxable Income		O	$ 64,989	$ 124,596	$ 187,456	$ 248,230	$ 318,899	$ 395,663	$ 473,540	$ 568,196	$ 662,852	$ 758,722
Add Back Depreciation Expense		S	$ 46,651	$ 89,439	$ 134,562	$ 178,188	$ 228,917	$ 284,020	$ 339,923	$ 407,871	$ 475,818	$ 509,792
Deduct CCA			$ 74,642	$ 211,773	$ 335,489	$ 450,647	$ 565,563	$ 689,650	$ 812,089	$ 945,282	$ 1,087,091	$ 1,217,555
Incremental Taxable Income			$ 36,998	$ 2,262	-$ 13,471	-$ 24,230	-$ 17,747	-$ 9,967	$ 1,375	$ 30,785	$ 51,579	$ 50,959
Current Tax Rate	26.5%	X										
PIL's Before Gross Up			$ 9,804	$ 599	-$ 3,570	-$ 6,421	-$ 4,703	-$ 2,641	$ 364	$ 8,158	$ 13,669	$ 13,504
Incremental Grossed Up PIL's			$ 13,339	$ 816	-$ 4,857	-$ 8,736	-$ 6,399	-$ 3,593	$ 496	$ 11,099	$ 18,597	$ 18,373

Incremental Revenue Requirement

Incremental Revenue Requirement			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Return on Rate Base - Total		Q	$ 118,362	$ 226,923	$ 341,409	$ 452,095	$ 580,803	$ 720,612	$ 862,448	$ 1,034,843	$ 1,207,238	$ 1,381,843
Depreciation Expense - Total			$ 46,651	$ 89,439	$ 134,562	$ 178,188	$ 228,917	$ 284,020	$ 339,923	$ 407,871	$ 475,818	$ 509,792
Incremental Grossed Up PIL's		Z	$ 13,339	$ 816	-$ 4,857	-$ 8,736	-$ 6,399	-$ 3,593	$ 496	$ 11,099	$ 18,597	$ 18,373
Incremental Revenue Requirement			$ 178,353	$ 317,178	$ 471,114	$ 621,547	$ 803,321	$ 1,001,039	$ 1,202,867	$ 1,453,813	$ 1,701,652	$ 1,910,007

Capitalization Policy_GRZ

Return on Rate Base			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Incremental Capital			$ 587,990	$ 1,226,139	$ 1,896,607	$ 2,566,476	$ 3,175,709	$ 3,870,663	$ 4,565,617	$ 5,260,571	$ 5,955,525	$ 6,650,479
Depreciation Expense			$ 14,700	$ 30,653	$ 47,415	$ 64,162	$ 79,393	$ 96,767	$ 114,140	$ 131,514	$ 148,888	$ 157,575
Incremental Capital to be included in Rate Base			$ 573,291	$ 1,195,486	$ 1,849,192	$ 2,502,314	$ 3,096,316	$ 3,773,896	$ 4,451,476	$ 5,129,057	$ 5,806,637	$ 6,492,904
Deemed ShortTerm Debt %	4.0%	E	$ 22,932	$ 47,819	$ 73,968	$ 100,093	$ 123,853	$ 150,956	$ 178,059	$ 205,162	$ 232,265	$ 259,716
Deemed Long Term Debt %	56.0%	F	$ 321,043	$ 669,472	$ 1,035,548	$ 1,401,296	$ 1,733,937	$ 2,113,382	$ 2,492,827	$ 2,872,272	$ 3,251,717	$ 3,636,026
Short Term Interest	1.65%	I	$ 378	$ 789	$ 1,220	$ 1,652	$ 2,044	$ 2,491	$ 2,938	$ 3,385	$ 3,832	$ 4,285
Long Term Interest	4.91%	J	$ 15,763	$ 32,871	$ 50,845	$ 68,804	$ 85,136	$ 103,767	$ 122,398	$ 141,029	$ 159,659	$ 178,529
Return on Rate Base - Interest			$ 16,142	$ 33,660	$ 52,066	$ 70,455	$ 87,180	$ 106,258	$ 125,336	$ 144,414	$ 163,492	$ 182,814
Deemed Equity %	40.00%	N	$ 229,316	$ 478,194	$ 739,677	$ 1,000,926	$ 1,238,526	$ 1,509,558	$ 1,780,591	$ 2,051,623	$ 2,322,655	$ 2,597,162
Return on Rate Base -Equity	9.19%	O	$ 21,074	$ 43,946	$ 67,976	$ 91,985	$ 113,821	$ 138,728	$ 163,636	$ 188,544	$ 213,452	$ 238,679
Return on Rate Base - Total			$ 37,216	$ 77,606	$ 120,042	$ 162,440	$ 201,000	$ 244,986	$ 288,972	$ 332,958	$ 376,944	$ 421,493

Depreciation Expense												
Depreciation Expense - Incremental		C	$ 14,700	$ 30,653	$ 47,415	$ 64,162	$ 79,393	$ 96,767	$ 114,140	$ 131,514	$ 148,888	$ 157,575

Grossed up PIL's												
Regulatory Taxable Income		O	$ 21,074	$ 43,946	$ 67,976	$ 91,985	$ 113,821	$ 138,728	$ 163,636	$ 188,544	$ 213,452	$ 238,679
Add Back Depreciation Expense		S	$ 14,700	$ 30,653	$ 47,415	$ 64,162	$ 79,393	$ 96,767	$ 114,140	$ 131,514	$ 148,888	$ 157,575
Deduct CCA			$ 23,520	$ 70,684	$ 117,374	$ 161,597	$ 199,833	$ 236,014	$ 272,729	$ 306,507	$ 337,583	$ 366,173
Incremental Taxable Income			$ 12,254	$ 3,916	-$ 1,982	-$ 5,450	-$ 6,620	-$ 519	$ 5,047	$ 13,551	$ 24,757	$ 30,081
Current Tax Rate	26.5%	X										
PIL's Before Gross Up			$ 3,247	$ 1,038	-$ 525	-$ 1,444	-$ 1,754	-$ 138	$ 1,338	$ 3,591	$ 6,561	$ 7,972
Incremental Grossed Up PIL's			$ 4,418	$ 1,412	-$ 715	-$ 1,965	-$ 2,387	-$ 187	$ 1,820	$ 4,886	$ 8,926	$ 10,846

Incremental Revenue Requirement												
Return on Rate Base - Total		Q	$ 37,216	$ 77,606	$ 120,042	$ 162,440	$ 201,000	$ 244,986	$ 288,972	$ 332,958	$ 376,944	$ 421,493
Depreciation Expense - Total			$ 14,700	$ 30,653	$ 47,415	$ 64,162	$ 79,393	$ 96,767	$ 114,140	$ 131,514	$ 148,888	$ 157,575
Incremental Grossed Up PIL's		Z	$ 4,418	$ 1,412	-$ 715	-$ 1,965	-$ 2,387	-$ 187	$ 1,820	$ 4,886	$ 8,926	$ 10,846
Incremental Revenue Requirement			$ 56,334	$ 109,672	$ 166,743	$ 224,637	$ 278,006	$ 341,566	$ 404,932	$ 469,358	$ 534,758	$ 589,914

Capital Cost Allowance Calculation

Horizon Utilities RZ

	Class	Opening	Additions	Disposals	Net Additions	50% of Net Additions	Reduced UCC	Rate	CCA	Ending UCC
2017	47	-	5,398,529	-	5,398,529	2,699,265	2,699,265	8%	(215,941)	5,182,588
2018	47	5,182,588	5,242,737		5,242,737	2,621,369	7,803,957	8%	(624,317)	9,801,009
2019	47	9,801,009	6,455,375		6,455,375	3,227,687	13,028,696	8%	(1,042,296)	15,214,088
2020	47	15,214,088	6,120,749		6,120,749	3,060,375	18,274,463	8%	(1,461,957)	19,872,880
2021	47	19,872,880	5,863,256		5,863,256	2,931,628	22,804,509	8%	(1,824,361)	23,911,776
2022	47	23,911,776	5,787,550		5,787,550	2,893,775	26,805,551	8%	(2,144,444)	27,554,882
2023	47	27,554,882	4,709,348		4,709,348	2,354,674	29,909,556	8%	(2,392,765)	29,871,466
2024	47	29,871,466	5,965,129		5,965,129	2,982,565	32,854,031	8%	(2,628,322)	33,208,273
2025	47	33,208,273	5,965,129		5,965,129	2,982,565	36,190,838	8%	(2,895,267)	36,278,135
2026	47	36,278,135	5,965,129		5,965,129	2,982,565	39,260,700	8%	(3,140,856)	39,102,409
			57,472,934	-	57,472,934				(18,370,525)	

Enersource RZ

	Class	Opening	Additions	Disposals	Net Additions	50% of Net Additions	Reduced UCC	Rate	CCA	Ending UCC
2017	47	-	1,866,041	-	1,866,041	933,020	933,020	8%	(74,642)	1,791,399
2018	47	1,791,399	1,711,518		1,711,518	855,759	2,647,158	8%	(211,773)	3,291,145
2019	47	3,291,145	1,804,925		1,804,925	902,462	4,193,607	8%	(335,489)	4,760,581
2020	47	4,760,581	1,745,024		1,745,024	872,512	5,633,093	8%	(450,647)	6,054,957
2021	47	6,054,957	2,029,155		2,029,155	1,014,578	7,069,535	8%	(565,563)	7,518,550
2022	47	7,518,550	2,204,155		2,204,155	1,102,078	8,620,627	8%	(689,650)	9,033,055
2023	47	9,033,055	2,236,114		2,236,114	1,118,057	10,151,112	8%	(812,089)	10,457,080
2024	47	10,457,080	2,717,893		2,717,893	1,358,947	11,816,026	8%	(945,282)	12,229,691
2025	47	12,229,691	2,717,893		2,717,893	1,358,947	13,588,637	8%	(1,087,091)	13,860,493
2026	47	13,860,493	2,717,893		2,717,893	1,358,947	15,219,440	8%	(1,217,555)	15,360,831
			21,750,612	-	21,750,612				(6,389,780)	

Brampton RZ

	Class	Opening	Additions	Disposals	Net Additions	50% of Net Additions	Reduced UCC	Rate	CCA	Ending UCC
2017	47	-	(1,830,532)	-	(1,830,532)	(915,266)	(915,266)	8%	73,221	(1,757,311)
2018	47	(1,757,311)	(1,609,690)		(1,609,690)	(804,845)	(2,562,156)	8%	204,972	(3,162,028)
2019	47	(3,162,028)	(2,330,085)		(2,330,085)	(1,165,042)	(4,327,071)	8%	346,166	(5,145,947)
2020	47	(5,145,947)	(2,557,315)		(2,557,315)	(1,278,658)	(6,424,605)	8%	513,968	(7,189,294)
2021	47	(7,189,294)	(2,281,490)		(2,281,490)	(1,140,745)	(8,330,039)	8%	666,403	(8,804,381)
2022	47	(8,804,381)	(2,634,725)		(2,634,725)	(1,317,362)	(10,121,743)	8%	809,739	(10,629,366)
2023	47	(10,629,366)	(2,591,103)		(2,591,103)	(1,295,551)	(11,924,918)	8%	953,993	(12,266,476)
2024	47	(12,266,476)	(2,634,712)		(2,634,712)	(1,317,356)	(13,583,832)	8%	1,086,707	(13,814,482)
2025	47	(13,814,482)	(2,634,712)		(2,634,712)	(1,317,356)	(15,131,838)	8%	1,210,547	(15,238,647)
2026	47	(15,238,647)	(2,634,712)		(2,634,712)	(1,317,356)	(16,556,003)	8%	1,324,480	(16,548,879)
			(23,739,077)	-	(23,739,077)				7,190,198	

PowerStream RZ

	Class	Opening	Additions	Disposals	Net Additions	50% of Net Additions	Reduced UCC	Rate	CCA	Ending UCC
2017	47	-	193,660	-	193,660	96,830	96,830	8%	(7,746)	185,914
2018	47	185,914	409,708		409,708	204,854	390,767	8%	(31,261)	564,360
2019	47	564,360	267,139		267,139	133,570	697,929	8%	(55,834)	775,665
2020	47	775,665	302,487		302,487	151,243	926,908	8%	(74,153)	1,003,999
2021	47	1,003,999	299,907		299,907	149,954	1,153,952	8%	(92,316)	1,211,590
2022	47	1,211,590	295,314		295,314	147,657	1,359,247	8%	(108,740)	1,398,164
2023	47	1,398,164	364,670		364,670	182,335	1,580,499	8%	(126,440)	1,636,394
2024	47	1,636,394	340,351		340,351	170,175	1,806,570	8%	(144,526)	1,832,220
2025	47	1,832,220	340,351		340,351	170,175	2,002,395	8%	(160,192)	2,012,379
2026	47	2,012,379	340,351		340,351	170,175	2,182,555	8%	(174,604)	2,178,126
			3,153,938	-	3,153,938				(975,812)	

Guelph RZ

	Class	Opening	Additions	Disposals	Net Additions	50% of Net Additions	Reduced UCC	Rate	CCA	Ending UCC
2017	47	-	-	-	-	-	-	8%	-	-
2018	47	-	-		-	-	-	8%	-	-
2019	47	-	587,990		587,990	293,995	293,995	8%	(23,520)	564,471
2020	47	564,471	638,149		638,149	319,075	883,545	8%	(70,684)	1,131,936
2021	47	1,131,936	670,468		670,468	335,234	1,467,170	8%	(117,374)	1,685,030
2022	47	1,685,030	669,869		669,869	334,934	2,019,965	8%	(161,597)	2,193,302
2023	47	2,193,302	609,233		609,233	304,616	2,497,918	8%	(199,833)	2,602,701
2024	47	2,602,701	694,954		694,954	347,477	2,950,178	8%	(236,014)	3,061,641
2025	47	3,061,641	694,954		694,954	347,477	3,409,118	8%	(272,729)	3,483,866
2026	47	3,483,866	694,954		694,954	347,477	3,831,343	8%	(306,507)	3,872,312
2027	47	3,872,312	694,954		694,954	347,477	4,219,789	8%	(337,583)	4,229,683
2028	47	4,229,683	694,954		694,954	347,477	4,577,160	8%	(366,173)	4,558,465
			6,650,479	-	6,650,479				(2,092,015)	

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Reference: Exhibit 2, Tab 1, Schedule 5

Preamble:

Alectra Utilities states the following on page 8 of Exhibit 2, Tab 1, Schedule 5:

> **This approach [1576 approach - recording only the capitalization and depreciation impacts on rate base] ignores two key components of the calculation – PILs and Return on Capital, as identified in Table 20, above [Alectra Utilities' approach]. The OEB established Account 1576, Accounting Changes under CGAAP, for distributors to record the financial differences arising as a result of changes to accounting depreciation or capitalization. Account 1576 was intended only as a short-term measure to address the interim deferral of IFRS in 2012 with the expectation of a changeover to IFRS in 2013. This short-term measure was not intended to address special circumstances that arise for post-MAADs distributors. Alectra Utilities proposes a variant to Account 1576 that includes the impact of PILs and Return on Capital. The need for this variation arises as Alectra Utilities is in a rebasing deferral period.**

In a June 25, 2013 letter issued to Licensed Electricity Distributors,[1] the OEB stated the following with respect to the rate of return on balances in Accounts 1576 and 1575:

> **In several of the proceedings for 2013 cost of service rate applications, an issue was raised about the applicability of applying a rate of return component on the disposition of the balance in Account 1576, as required for Account 1575. The Board acknowledges that this issue has been a concern for parties in these proceedings and may continue to persist in the future since the use of Account 1576 will continue in light of the IFRS changeover deferrals. The Board is of the view that a generic policy on this issue provides for greater clarity and efficiency in the application proceedings. Consequently, the Board will require a rate of return component to be applied to the balance of Account 1576 upon its disposition in rates. This policy is effective for the 2014 cost of service rate applications and subsequent rate years.**

Questions:

a) **Please confirm that all five predecessor companies of Alectra Utilities have previously disposed of balances in Account 1575 and/or Account 1576, which included a rate of return component on the balances. If this is not confirmed, please explain.**

b) **For each predecessor company of Alectra Utilities, please provide a copy of the Chapter 2 Appendices tab 2-EA, 2-EB, 2-EC, 2-ED or 2-EE (as applicable to each entities' previous rebasing application) that shows the OEB-approved calculated**

[1] OEB Letter re: Accounting Policy Changes for Accounts 1575 and 1576

amount of the Account 1575/1576 principal balance(s), and the rate of return component applied to that balance (including the weighted average cost of capital and the associated rate rider disposition periods used).

c) **Please reconcile the statement "Alectra Utilities proposes a variant to Account 1576 that includes the impact of PILs and Return on Capital" with the fact that the predecessor entities of Alectra Utilities have included the impacts of return on capital in their previous OEB-approved Account 1575/1576 dispositions.**

d) **Please confirm that Alectra Utilities' approach calculates the return on capital component on the following basis:**

The return component represents the amount of return that would have been included in a distributor's updated revenue requirement if it were to perform an isolated rebasing of the accounting policy impacts in the year in which they occurred. In the case of increases to rate base, a return component on the incremental rate base should be collected from customers.

If this is not Alectra Utilities' approach to calculating the return component, please elaborate or explain.

e) **Please confirm Alectra Utilities' understanding that the return on capital component included on balances in Accounts 1575 and 1576 is calculated on the following basis:**

The return component represents the amount that a distributor will ultimately include in its revenue requirement, as return on rate base, in future rebasing applications. In the case of increases to rate base, ratepayers are refunded for the return component that a distributor will ultimately earn on that rate base difference.

If this is not Alectra Utilities' understanding of the return component calculated for Accounts 1575 and 1576, please elaborate or explain.

f) **Accounts 1575 and 1576 were established to address the impact of changes in accounting policy between rebasing years resulting from the adoption of IFRS (1575) or the adoption of capitalization and depreciation policies embedded in IFRS (1576). Alectra Utilities has undergone an accounting policy change between rebasing years resulting from compliance with IFRS. Aside from the distinction stated in the preamble (and the inclusion of PILs impacts), is there any other rationale that Alectra Utilities can provide to support the OEB varying its calculation methodology previously used for the impacts of changes in accounting policy between rebasing years?**

g) If the OEB ultimately decided to apply its approach for calculating the return on capital for Account 1575/1576 balances to the rate base impacts of Alectra Utilities' change in accounting policy, what initial interim disposition period does Alectra Utilities request for the associated rate riders? Please provide supporting rationale.

h) Please provide a set of tables that shows what the 2017 and 2018 disposition amounts for BRZ and ERZ would be using the 1575/1576 calculation approach, calculating the difference in rate base as the annual principal entry. For the return component, consistent with calculation of the return component in Chapter 2 Appendices for Accounts 1575/1576, the incremental rate base impact would be multiplied by the weighted average cost of capital, and then multiplied by the number of years of the proposed interim disposition period.

i) Please restate the amounts in Table 20 of Exhibit 2, Tab 1, Schedule 5 (including the GRZ), with the following change made in the calculation methodology:
   i. Rate of return is calculated using the 1575/1576 method, assuming a one-year interim disposition period

Response:

a) Alectra Utilities confirm that all five predecessor companies of Alectra Utilities have previously disposed of balances in Account 1575 and/or Account 1576, which included a rate of return component on the balances.

b) Alectra Utilities has filed copies of the Chapter 2 Appendices Tab 2-EA, 2-EB, 2-EE, as applicable, to the respective rate zone as Attachments 1 to 5.

c) For Alectra Utilities' predecessors, Enersource, PowerStream, Horizon Utilities and Guelph, the Property, Plant and Equipment ("PP&E") values after the accounting policy change were higher than under previous CGAAP. Therefore, the return on rate base associated with the PP&E balance reflected a refund to customers to ensure that utilities did not collect the same amount of expenditures from customers twice. With respect to the impact of the capitalization policy change, the capital is not currently included in rate base and Alectra Utilities is not earning a return on this capital. Therefore, Alectra Utilities has calculated the return associated with this capital over the rebasing deferral period, which reflects an amount to be recovered from customers.

d) Alectra Utilities agrees that the return component represents the amount of return that would have been included in a distributor's updated revenue requirement if this capital was included in rate base, and that in the case of increases to rate base, a return component on the incremental rate base should be collected from customers.

e) Please see response to part c).

f) Alectra Utilities' calculation method of return on rate base is consistent with the calculation of the return used for Accounts 1575 and 1576. For the calculation of the return please see Alectra Utilities' Capitalization Policy Impact Model filed in response to G-Staff-3.

g) Please see Alectra Utilities' response to G-Staff-3, pp.7-9.

h) Please see full calculation of the return on rate base in Alectra Utilities' Capitalization Policy Impact Model, Tab 4, Revenue Requirement Impact.

i) The calculation of the return is consistent with the calculation used in the 1575/1576 method. Alectra Utilities' Capitalization Policy Impact Model includes the calculation of the return for each year during the rebasing deferral period. A summary table of the impact is provided as Table 5 in response to G-Staff-3.

G-Staff-4

ATTACH 1 - BRAMPTON APPENDIX 2-EE

Appendix 2-EE
Account 1576 - Accounting Changes under CGAAP
2013 Changes in Accounting Policies under CGAAP

Assumes the applicant made capitalization and depreciation expense accounting policy changes under CGAAP effective January 1, 2013

	2011 Rebasing Year	2012	2013	2014	2015 Rebasing Year	2016	2017	2018	2019
Reporting Basis	CGAAP	IRM	IRM	IRM	CGAAP - ASPE	IRM	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast				
				$	$	$	$	$	$
PP&E Values under former CGAAP									
Opening net PP&E - Note 1			298,866,239	318,306,260					
Net Additions - Note 4			30,483,746	30,297,489					
Net Depreciation (amounts should be negative) - Note 4			-11,043,724	-11,472,593					
Closing net PP&E (1)			318,306,260	337,131,156					
PP&E Values under revised CGAAP (Starts from 2013)									
Opening net PP&E - Note 1			298,866,239	315,622,284					
Net Additions - Note 4			28,694,292	28,711,916					
Net Depreciation (amounts should be negative) - Note 4			-11,938,247	-12,038,606					
Closing net PP&E (2)			315,622,284	332,295,594					
Difference in Closing net PP&E, former CGAAP vs. revised CGAAP			2,683,976	4,835,562					

Effect on Deferral and Variance Account Rate Riders

Closing balance in Account 1576	4,835,562	**WACC**	7.21%
Return on Rate Base Associated with Account 1576 balance at WACC - Note 2	1,045,932	**# of years of rate rider disposition period**	3
Amount included in Deferral and Variance Account Rate Rider Calculation	5,881,494		

Notes:

1 For an applicant that made the capitalization and depreciation expense accounting policy changes on January 1, 2013, the PP&E values as of January 1, 2013 under both former

2 Return on rate base associated with Account 1576 balance is calculated as:
the variance account opening balance as of 2015 rebasing year x WACC X # of years of rate rider disposition period
* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.

3 Account 1576 is cleared by including the total balance in the deferral and variance account rate rider calculation.

4 Net additions are additions net of disposals; Net depreciation is additions to depreciation net of disposals.

G-Staff-4

ATTACH 2 - ENERSOURCE APPENDIX 2-EA

Appendix 2-EA
IFRS-CGAAP Transitional PP&E Amounts
2012 Adopters of IFRS for Financial Reporting Purposes

For applicants that adopt IFRS on January 1, 2012 for financial reporting purposes

Note: this sheet should be filled out if the applicant adopts IFRS for its financial reporting purpose as of January 1, 2012.

	2009 Rebasing Year	2010	2011	2012	2013 Rebasing Year	2014	2015	2016
Reporting Basis	CGAAP	IRM	IRM	IRM	MIFRS	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast			
			$	$				
PP&E Values under CGAAP								
Opening net PP&E - Note 1			453,053,965	467,850,354				
Additions			49,183,927	66328843.08				
Depreciation (amounts should be negative)			-34,387,539	-36409960.62				
Closing net PP&E (1)			467,850,354	497,769,236				
PP&E Values under MIFRS (Starts from 2011, the transition year)								
Opening net PP&E - Note 1			453,053,965	474,514,796				
Additions			46,909,059	63,287,087				
Depreciation (amounts should be negative)			-25,448,228	-26,991,423				
Closing net PP&E (2)			474,514,796	510,810,461				
Difference in Closing net PP&E, CGAAP vs. MIFRS (Shown as adjustment to rate base on rebasing)			(6,664,442)	(13,041,225)				
Account 1575 - IFRS-CGAAP Transitional PP&E Amounts								
Opening balance			-	(6,664,442)	(13,041,225)	(9,780,919)	(6,520,612)	(3,260,306)
Amounts added in the year			(6,664,442)	(6,376,782)				
Sub-total			(6,664,442)	(13,041,225)	(13,041,225)	(9,780,919)	(6,520,612)	(3,260,306)
Amount of amortization, included in depreciation expense - Note 2					3,260,306	3,260,306	3,260,306	3,260,306
Closing balance in deferral account			(6,664,442)	(13,041,225)	(9,780,919)	(6,520,612)	(3,260,306)	-

Effect on Revenue Requirement

Amortization of deferred balance as above - Note 2	(3,260,306)	**WACC**	6.5064%	
Return on Rate Base Associated with deferred PP&E balance at WACC - Note 3	(848,514)	**Disposition Period - Note 4**	4	Years
Amount included in Revenue Requirement on rebasing	(4,108,820)			

Notes:

1 For an applicant that adopts IFRS on January 1, 2012, the PP&E values as of January 1, 2011 under both CGAAP and MIFRS should be the same.

2 Amortization of the deferred balance in Account 1575 will start from the rebasing year.
Assume the utility requests for a certain disposition period, the amortization that should be included in the depreciation expense is calculated as:
the opening balance of Account 1575 / the approved disposition period

3 Return on rate base associated with deferred balance is calculated as:
the deferred account opening balance as of 2013 rebasing year x WACC
* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.

4 Consistent with the 4 year normal rate cycle, the model is using a 4 year amortization period as a default selection to "clear" the PP&E deferral account through a one-time adjustment to ratebase to capture and remove the impact of the accounting policy changes as caused by the transition from CGAAP to MIFRS.

G-Staff-4

ATTACH 3 - GUELPH APPENDIX 2-EB

File Number:	#REF!
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	20-Oct-15

Appendix 2-EB
Account 1576 - Accounting Changes under MIFRS
2014 Changes in Accounting Policies under MIFRS

	2011	2012	2013	2014	2015	2016 Rebasing Year
Reporting Basis	**MIFRS**	**IRM**	**IRM**	**IRM**	**IRM**	**MIFRS**
	Forecast	**Actual**	**Actual**	**Actual**	**Forecast**	**Forecast**
			$	$	$	$
PP&E Values uusing original Useful Lives (UL)						
Opening net PP&E - Note 1				120,582,538	125,377,376	
Net Additions - Note 2				10,895,415	12,278,431	
Net Depreciation (amounts should be negative) - Note 2				-6,100,577	-6,374,912	
Closing net PP&E (1)			0	125,377,376	131,280,895	
PP&E Values using 2014 updated Useful Lives (UL)						
Opening net PP&E - Note 1				120,582,538	125,740,622	
Net Additions - Note 2				10,895,415	12,278,431	
Net Depreciation (amounts should be negative) - Note 2				-5,737,331	-5,981,825	
Closing net PP&E (2)			0	125,740,622	132,037,228	
Difference in Closing net PP&E, Original UL v. Updated UL			0	-363,246	-756,333	

Effect on Deferral and Variance Account Rate Riders

Closing balance in Account 1576	-	756,333	**WACC**	6.49%
Return on Rate Base Associated with Account 1576 balance at WACC	-	49,119		
Amount included in Deferral and Variance Account Rate Rider Calculation	-	805,452	**# of years of rate rider disposition period**	1

Notes:

1 Useful lives were reviewed and updated effective fiscal 2014, therefore Opening PP&E January 1, 2014 would be the same at this date

2 Net additions are additions net of disposals. Net depreciation is additions to depreciation net of disposals

Instructions:

1 For an applicant that made the capitalization and depreciation expense accounting policy changes on January 1, 2012, the PP&E values as of January 1, 2012 under both former CGAAP and revised CGAAP should be the same.

2 Return on rate base associated with Account 1576 balance is calculated as:
the variance account opening balance as of 2015 rebasing year x WACC X # of years of rate rider disposition period
* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.

3 Account 1576 is cleared by including the total balance in the deferral and variance account rate rider calculation.

4 Net additions are additions net of disposals; Net depreciation is additions to depreciation net of disposals.

G-Staff-4

ATTACH 4 - HORIZON APPENDIX 2-EA

File Number:	0
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-EA
Account 1575 - IFRS-CGAAP Transitional PP&E Amounts
2012 Adopters of IFRS for Financial Reporting Purposes

For applicants that adopt IFRS on January 1, 2012 for financial reporting purposes

Note: this sheet should be filled out if the applicant adopts IFRS for its financial reporting purpose as of January 1, 2012.

	2011 Rebasing Year	2012	2013	2014	2015 Rebasing Year	2016 Rebasing Year	2017 Rebasing Year	2018 Rebasing Year	2019 Rebasing Year
Reporting Basis	**CGAAP**	**IRM**	**IRM**	**IRM**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Forecast vs. Actual Used in Rebasing Year	**Forecast**	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**
		$	$	$	$	$	$	$	$
PP&E Values under CGAAP									
Opening net PP&E - Note 1	304,878,268	316,997,965	365,070,186	382,168,427					
Net Additions - Note 4	10,739,863	79,043,474	48,352,195	51,959,529					
Net Depreciation (amounts should be negative) - Note 4	1,379,834	-30,971,254	-31,253,954	-33,363,213					
Closing net PP&E (1)	316,997,965	365,070,186	382,168,427	400,764,743					
PP&E Values under MIFRS (Starts from 2011, the transition year)									
Opening net PP&E - Note 1	304,878,268	317,737,285	366,100,384	383,071,763					
Net Additions - Note 4	28,938,504	68,229,924	36,114,427	38,018,561					
Net Depreciation (amounts should be negative) - Note 4	-16,079,487	-19,866,824	-19,143,048	-20,890,677					
Closing net PP&E (2)	317,737,285	366,100,384	383,071,763	400,199,647					
Difference in Closing net PP&E, CGAAP vs. MIFRS	-739,320	-1,030,199	-903,337	565,095					

Effect on Deferral and Variance Account Rate Riders

Closing balance in deferral account	565,095	**WACC**	5.77%
Return on Rate Base Associated with deferred PP&E balance at WACC - Note 2	32,619	**# of years of rate rider disposition period**	1
Amount included in Deferral and Variance Account Rate Rider Calculation	597,715		

Notes:

1 For an applicant that adopts IFRS on January 1, 2012, the PP&E values as of January 1, 2011 under both CGAAP and MIFRS should be the same.

2 Return on rate base associated with deferred balance is calculated as:

the deferral account opening balance as of 2015 rebasing year x WACC X # of years of rate rider disposition period

* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.

3 The PP&E deferral account is cleared by including the total balance in the deferral and variance account rate rider calculation.

4 Net additions are additions net of disposals; Net depreciation is additions to depreciation net of disposals.

G-Staff-4

ATTACH 5 - POWERSTREAM APPENDIX 2-EA

Appendix 2-EA
IFRS-CGAAP Transitional PP&E Amounts
2012 Adopters of IFRS for Financial Reporting Purposes

For applicants that adopt IFRS on January 1, 2012 for financial reporting purposes

Note: this sheet should be filled out if the applicant adopts IFRS for its financial reporting purpose as of January 1, 2012.

	2009 Rebasing Year	2010	2011	2012	2013 Rebasing Year	2014	2015	2016
Reporting Basis	CGAAP	IRM	IRM	IRM	MIFRS	IRM	IRM	IRM
Forecast vs. Actual Used in Rebasing Year	Forecast	Actual	Actual	Forecast	Forecast			
			$	$				
PP&E Values under CGAAP								
Opening net PP&E - Note 1			613,158,000	651,911,000				
Additions			83,771,000	86,106,000				
Depreciation (amounts should be negative)			(45,018,000)	(48,924,000)				
Closing net PP&E (1)			651,911,000	689,093,000				
PP&E Values under MIFRS (Starts from 2011, the transition year)								
Opening net PP&E - Note 1			613,158,000	659,803,000				
Additions			81,202,000	72,347,000				
Depreciation (amounts should be negative)			(34,557,000)	(33,486,000)				
Closing net PP&E (2)			659,803,000	698,664,000				
Difference in Closing net PP&E, CGAAP vs. MIFRS (Shown as adjustment to rate base on rebasing)			(7,892,000)	(9,571,000)				
Account 1575 - IFRS-CGAAP Transitional PP&E Amounts								
Opening balance			-	(7,892,000)	(9,571,000)	(7,178,250)	(4,785,500)	(2,392,750)
Amounts added in the year			(7,892,000)	(1,679,000)				
Sub-total			(7,892,000)	(9,571,000)	(9,571,000)	(7,178,250)	(4,785,500)	(2,392,750)
Amount of amortization, included in depreciation expense - Note 2					2,392,750	2,392,750	2,392,750	2,392,750
Closing balance in deferral account			(7,892,000)	(9,571,000)	(7,178,250)	(4,785,500)	(2,392,750)	-

Effect on Revenue Requirement

Amortization of deferred balance as above - Note 2	(2,392,750)	**WACC**	5.98%
Return on Rate Base Associated with deferred PP&E balance at WACC - Note 3	(572,025)	**Disposition Period - Note 4**	4 Years
Amount included in Revenue Requirement on rebasing	(2,964,775)		

Notes:

1 For an applicant that adopts IFRS on January 1, 2012, the PP&E values as of January 1, 2011 under both CGAAP and MIFRS should be the same.

2 Amortization of the deferred balance in Account 1575 will start from the rebasing year.
Assume the utility requests for a certain disposition period, the amortization that should be included in the depreciation expense is calculated as:
the opening balance of Account 1575 / the approved disposition period

3 Return on rate base associated with deferred balance is calculated as:
the deferred account opening balance as of 2013 rebasing year x WACC
* Please note that the calculation should be adjusted once WACC is updated and finalized in the rate application.

4 Consistent with the 4 year normal rate cycle, the model is using a 4 year amortization period as a default selection to "clear" the PP&E deferral account through a one-time adjustment to ratebase to capture and remove the impact of the accounting policy changes as caused by the transition from CGAAP to MIFRS.

G-Staff-5

Reference: Exhibit 2, Tab 1, Schedule 5

Preamble:

Alectra Utilities states the following in Exhibit 2, Tab 1, Schedule 5:

"…the cash flow requirements do not change since the change in recognition of an operating and capital expense is "non-cash"… as a result of the OEB's decision, Alectra Utilities suffers a cash impairment and corresponding cost from the OEB's treatment of an accounting change that is wholly non-cash based."

Furthermore, Alectra Utilities states:

"…rate-making impacts from accounting policy changes are best considered in the broadest context of rate-making policy at the time of a full rebasing with appropriate re-balancing of revenue with consideration of all components of rate-base and the impacts of prior externalities and OEB policy changes. Such an approach will ensure a full and complete re-balancing of rates relative to rate-base and operating costs at that time with the result that customers and shareholders remain indifferent to such considerations within the rebasing deferral period."

In Table 20, Alectra Utilities provides its estimated impact of the capitalization policy change over a 10-year forecast.

a) **Given the information provided in Table 20, please confirm that the capitalization policy change is expected to result in a rate base increase of $56.84 million ($64.42 million of capitalized OM&A less $7.58 million of depreciation) by the end of 2026. If this is not confirmed, please explain.**

b) **Please confirm that when Alectra Utilities submits a rate rebasing application in 2027, if the amount of $56.84 million referred to in part a) is permitted by the OEB for inclusion in rate base, the result would be an increase in future revenue and cash flow, by virtue of collecting this capital-related revenue requirement (depreciation, PILs, return on capital) from ratepayers. If this is not the case, please explain.**

c) **Please confirm that, in the scenario in part b) of this question (where the net book value of reclassified OM&A is added to rate base at rebasing), absent any deferral account entries, this would result in collecting the same amounts of expenditures twice from customers: once in the form of rates underpinned by an OM&A-related revenue requirement from 2017 to 2026, and then again in the form of capital-related revenue requirement from 2027 until the end of the useful lives of the newly capitalized assets. If this is not the case, please explain in detail.**

d) If the amount of $56.84 million referred to in part a) were to be excluded from rate base in 2027 and beyond, does Alectra Utilities agree that this would require maintaining discrete asset continuity schedules for the net book value of the assets that comprise the $56.84 million, for the duration of their useful lives? If Alectra Utilities disagrees that this would be required, please explain in what practical manner Alectra Utilities could alternatively disconnect rate base in perpetuity, beginning in 2027, from the asset continuity schedule used for financial reporting?

e) If the cumulative revenue requirement impacts of accounting policy changes, as shown in Table 20, were recorded in deferral accounts and returned to customers, does Alectra Utilities agree that:

i. It would be appropriate to include the $56.84 million referred to in part a) in rate base in 2027 and beyond

ii. There would be no reason, with respect to merger-related capitalization changes, to create a disconnect between rate base and the asset continuity schedule kept for financial reporting purposes

iii. The issue of amounts being included in rate base in 2027 for expenditures that have previously been collected from customers in prior years would be eliminated

Please explain Alectra Utilities position if it disagrees with any of the above statements.

f) Does Alectra Utilities agree that deferring the impacts of capitalization policy changes to a rebasing application better aligns utility cash flows with amounts collected from customers? Please explain.

g) Does Alectra Utilities agree that disposing of the impacts of capitalization policy changes to/from customers in the year in which they occur better aligns utility earnings with amounts collected from customers in rates? Please explain.

Response:

a) Alectra Utilities has provided an updated forecast of the capitalization policy change over the rebasing deferral period in response to G-Staff-3. Based on the updated forecast, the capitalization policy change is expected to result in a rate base increase of $56.5MM by the end of 2026.

b) Alectra Utilities agrees that when it submits a rate rebasing application in 2027, if the amount of $56.5MM is permitted by the OEB for inclusion in rate base, the result would be an increase in future revenue and cash flow.

c) Consistent with the OEB's capitalization policy decision issued September 5, Alectra Utilities will continue to record the impact of the capitalization policy change in the OEB established deferral accounts for each of its rate zones. Alectra Utilities agrees that absent any deferral account entries, this would result in collecting the same amounts of expenditures twice from customers twice.

d) Alectra Utilities is not proposing that these amounts be excluded from rate base upon rebasing.

e) As provided in response to part c) and in response to G-Staff-3, Alectra Utilities will continue to record the impacts of the capitalization policy change in the deferral accounts. Alectra Utilities agrees that if the cumulative impact of the capitalization policy change is recorded in the deferral accounts, it would be appropriate to include the $56.5MM of capital in rate base in 2027 and beyond.

f) and g) Please see Alectra Utilities' response to G-Staff-3, pp. 7-9 related to the proposed disposition of the balances in the capitalization policy deferral accounts. Alectra Utilities proposes that the inclusion of the capital in rate base align with the disposition of the deferral account balances to customers.

HRZ-Staff-1

Reference: Exhibit 3, Tab 1, Schedule 2
Reference: Attachment 11-Table of Allocations Horizon ESM 2018
Reference: Attachment 9-Table of Allocations Horizon ESM 2017

Preamble:

OEB staff has populated the following table using OM&A reported in historical RRR filings of the four predecessor distributors of Alectra Utilities, as well as the pre-filed evidence provided in this proceeding:

	OM&A					Change	
	HRZ	BRZ	ERZ	PRZ	Total	$	%
2012	$ 51,478,365	$ 20,452,864	$ 51,796,786	$ 82,832,264	$ 206,560,278		
2013	$ 55,223,718	$ 23,773,756	$ 53,635,360	$ 81,191,175	$ 213,824,009	$ 7,263,731	3.5%
2014	$ 60,317,757	$ 26,754,051	$ 52,431,185	$ 85,818,364	$ 225,321,357	$ 11,497,348	5.4%
2015	$ 59,096,949	$ 26,975,737	$ 56,630,561	$ 92,481,578	$ 235,184,825	$ 9,863,468	4.4%
2016	$ 59,299,938	$ 30,006,692	$ 60,426,547	$ 86,645,596	$ 236,378,774	$ 1,193,948	0.5%
2017 - Adjusted	$ 66,370,580	$ 33,316,877	$ 63,777,652	$ 100,052,737	$ 263,517,846	$ 27,139,072	11.5%
2018 - Adjusted	$ 68,078,866	$ 32,561,236	$ 63,340,267	$ 97,852,017	$ 261,832,386	$ (1,685,460)	-0.6%
2017 - Table 1	$ 60,972,051	$ 35,147,409	$ 61,911,611	$ 99,858,737	$ 257,889,808		
2017 OM&A Adj	$ 5,398,529	$ (1,830,532)	$ 1,866,041	$ 194,000	$ 5,628,038		
2017 - Adjusted	$ 66,370,580	$ 33,316,877	$ 63,777,652	$ 100,052,737	$ 263,517,846		
2018 - Table 1	$ 62,836,129	$ 34,170,926	$ 61,628,749	$ 97,442,309	$ 256,078,113		
2018 OM&A Adj	$ 5,242,737	$ (1,609,690)	$ 1,711,518	$ 409,708	$ 5,754,273		
2018 - Adjusted	$ 68,078,866	$ 32,561,236	$ 63,340,267	$ 97,852,017	$ 261,832,386		

Years 2012 to 2016 are directly populated from the OM&A figures of the RRR 2.1.5.6 filings of each distributor. Years 2017 and 2018 have been populated from the figures in Attachments 9 and 11, and have been adjusted for the impacts of the changes in capitalization policies following the merger. The capitalization policy impacts have been adjusted for so that OM&A can be assessed year over year on a comparable basis. The capitalization policy impacts are derived from Table 20 of Exhibit 2, Tab 1, Schedule 5.

Questions:

a) **Please confirm the factual accuracy of the inputs used in the table above. If Alectra Utilities identifies any discrepancies or errors, please note and explain them and repopulate the table accordingly.**

b) **The average increase in OM&A from the prior year for Alectra Utilities during 2014 to 2016 was $7,518,255 or 3.4%. Please explain why there was an increase of $27,139,072 or 11.5% between 2016 and 2017.**

c) **Please provide a detailed breakdown of the drivers for the increase in total OM&A from 2016 to 2017 in both dollars and percentages, reconciling to the $27,139,072 figure where appropriate.**

d) Please provide any rationale to explain how the increase between 2016 and 2017 of $27.1 million is not driven by merger-related OM&A costs.

e) Please provide any rationale to explain why Alectra Utilities' allocation methodology results in HRZ's OM&A costs increasing in 2018 from 2017 while every other rate zone's OM&A costs decrease in 2018 from 2017.

Response:

a) Alectra Utilities has reviewed the inputs and confirms the factual accuracy of the data inputs for years 2012 to 2016 as directly populated from the OM&A figures in the RRR 2.1.5.6 filings of each distributor. However, Alectra Utilities has identified that the OM&A data input for 2015 for the PowerStream Rate Zone of $92,481,578 does not adjust for 2015 merger-related transaction costs of $4,798,000. Alectra Utilities has prepared a revised table to include for this adjustment.

Table 1 – OM&A Allocations Horizon Utilities RZ ESM

Year	OM&A					Change	
	HRZ	BRZ	ERZ	PRZ	Total	$	%
2012	$ 51,478,365	$ 20,452,864	$ 51,796,786	$ 82,832,264	**$ 206,560,278**		
2013	$ 55,223,718	$ 23,773,756	$ 53,635,360	$ 81,191,175	**$ 213,824,009**	$ 7,263,731	3.5%
2014	$ 60,317,757	$ 26,754,051	$ 52,431,185	$ 85,818,363	**$ 225,321,356**	$ 11,497,346	5.4%
2015	$ 59,096,949	$ 26,975,737	$ 56,630,561	$ 87,683,578	**$ 230,386,825**	$ 5,065,469	2.2%
2016	$ 59,299,938	$ 30,006,692	$ 60,426,547	$ 86,645,596	**$ 236,378,773**	$ 5,991,947	2.6%
2017 - Adjusted	$ 66,370,580	$ 33,316,877	$ 63,777,652	$ 100,052,737	**$ 263,517,846**	$ 27,139,073	11.5%
2018 - Adjusted	$ 68,078,866	$ 32,561,236	$ 63,340,267	$ 97,852,017	**$ 261,832,386**	-$ 1,685,460	-0.6%
2017 - Table 1	$ 60,972,051	$ 35,147,409	$ 61,911,611	$ 99,858,737	**$ 257,889,808**		
2017 - OM&A Adjusted	$ 5,398,529	$ (1,830,532)	$ 1,866,041	$ 193,660	**$ 5,627,698**		
2017 - Adjusted	$ 66,370,580	$ 33,316,877	$ 63,777,652	$ 100,052,397	**$ 263,517,506**		
2018 - Table 1	$ 62,836,129	$ 34,170,926	$ 61,628,749	$ 97,442,309	**$ 256,078,113**		
2018 - OM&A Adjusted	$ 5,242,737	$ (1,609,690)	$ 1,711,518	$ 409,708	**$ 5,754,273**		
2018 - Adjusted	$ 68,078,866	$ 32,561,236	$ 63,340,267	$ 97,852,017	**$ 261,832,386**		

Table 2, below identifies the resulting variances.

Table 2 – OM&A Variances

Year	OM&A				
	HRZ	BRZ	ERZ	PRZ	Total
2012	-$ 0	-$ 0	$ -	$ -	**-$ 1**
2013	$ 0	$ -	$ -	$ -	**$ 0**
2014	-$ 0	$ 0	-$ 0	-$ 1	**-$ 1**
2015	$ -	$ -	$ -	-$ 4,798,000	**-$ 4,798,000**
2016	$ -	$ -	-$ 0	$ -	**-$ 0**
2017 - Adjusted	$ -	$ -	$ -	$ -	**$ -**
2018 - Adjusted	$ -	$ -	$ -	$ -	**$ -**

b) The increase in OM&A costs from 2016 to 2017 was primarily driven by:

- Increased costs to transition to monthly billing as mandated by the OEB;
- One-time provision costs in 2017;
- As a much larger organization than any of the individual legacy utilities, Alectra Utilities increased the resources dedicated to certain functions such as Internal Audit and the Project Management Office;
- Normal inflationary increases for labour and materials; and
- Wage harmonization for management staff.

c) The response to part b) above provides a summary of the major drivers that account for the increase in OM&A from 2016 to 2017. Alectra Utilities is unable to provide a more detailed reconciliation of the changes in OM&A from 2016 to 2017. Each of Alectra Utilities' predecessor utilities operated separate Enterprise Resource Planning ("ERP") systems with different charts of accounts and different ways of charging costs. For example, in some legacy utilities, software licensing costs were all charged centrally to Information Technology ("IT") while in others they were decentralized. As a result, there is no simple way to combine the financial results of the legacy utilities and provide meaningful variance analysis. The account structures and treatment of costs were completely different.

After the creation of Alectra Utilities, the Finance team worked to create a common mapping structure and align costs in order to report financial results in 2017. However, the process of aligning costs and mapping the four legacy account structures into a common reporting structure took several months to complete in 2017. Since Alectra Utilities was a new entity and was not required to report prior year comparative results for financial reporting purposes, this mapping and cost alignment exercise was not undertaken for 2016 results. Therefore, there is no common account structure or cost alignment in place to allow 2017 and 2016 OM&A to be compared at a detailed level for Alectra Utilities.

d) The response to part b) above provides a summary of the major drivers that account for the increase in OM&A from 2016 to 2017. Merger costs were tracked separately and removed from the OM&A figures reported in the RRR ROE filing.

e) There are three reasons which contribute to the Horizon Utilities RZ's OM&A costs increasing in 2018 from 2017 while every other rate zone's OM&A costs decreased in 2018 from 2017. First, the ESM results for 2017 (Attachment 9) includes actuals for one month (ERZ, HRZ, & PRZ) and two months (BRZ) where actual OM&A for HRZ was lower than the other rate zones. Secondly, in the 2017 allocation portion of OM&A, there were specific one-time OM&A adjustments directly allocated to the ERZ and PRZ which effectively lowered the allocation of OM&A to HRZ. Finally, the capitalization policy change impact for the HRZ in 2018 was lower, which lowered the percentage OM&A allocation to HRZ in 2018.

HRZ-Staff-2

Reference: Exhibit 3, Tab 1, Schedule 2
Reference: Attachment 11-Table of Allocations Horizon ESM 2018
Reference: Attachment 9-Table of Allocations Horizon ESM 2017

Preamble:

OEB staff has prepared the following table of historical averages of OM&A for each rate zone, based on the table of RRR data from HRZ-Staff-1:

RRR Averages					
	HRZ	BRZ	ERZ	PRZ	Total
2012-2016 avg	$ 57,083,346	$ 25,592,620	$ 54,984,088	$ 85,793,795	$ 223,453,849
2013-2016 avg	$ 58,484,591	$ 26,877,559	$ 55,780,913	$ 86,534,178	$ 227,677,241
2014-2016 avg	$ 59,571,548	$ 27,912,160	$ 56,496,098	$ 88,315,180	$ 232,294,985
2015-2016 avg	$ 59,198,444	$ 28,491,215	$ 58,528,554	$ 89,563,587	$ 235,781,799
2016	$ 59,299,938	$ 30,006,692	$ 60,426,547	$ 86,645,596	$ 236,378,774

Questions:

a) **OEB staff is unable to reconcile the 2014-2016 average OM&A figures calculated with the amounts used by Alectra Utilities in the 2017 and 2018 allocations of OM&A (reproduced below):**

	Enersource	Horizon Utilities	Brampton	PowerStream	Total Alectra
2014-2016 RRR Average	$56,300,996	$60,901,688	$28,658,213	$86,722,101	$232,582,998

Please explain the discrepancies between OEB staff's calculated 3-year OM&A averages, based on the table of historical OM&A reported in RRR, versus the amounts used by Alectra Utilities in Tables 32 and 45 of Exhibit 3, Tab 1, Schedule 2.

b) **If Alectra Utilities believes that OEB staff has made an error in the historical OM&A table from the RRR filings, and this is causing the RRR averages table to be presented in error as well, please reproduce the RRR averages table above with the corrected figures.**

c) **Please provide Alectra Utilities' rationale for using 3-year averages rather than 5-year averages.**

d) **Please provide Alectra Utilities' rationale for using 3-year averages, rather than applying 2016 as a proxy for proportional OM&A, being the most recently available data for each individual distributor.**

e) **Please revise Attachments 9 and 11 to show what the Earnings Sharing Mechanism (ESM) calculations for 2017 and 2018 would be under the following conditions:**

a. 5-year average OM&A is used in Tables 32 and 45 of Exhibit 3, Tab 1, Schedule 2 rather than 3-year averages for OM&A allocation in 2017 and 2018

b. 2016 OM&A is used in Tables 32 and 45 of Exhibit 3, Tab 1, Schedule 2 rather than 3-year averages for OM&A allocation in 2017 and 2018

Please file these revised attachments in excel format with an itemized list of which items were adjusted for this change.

Response:

a) Alectra Utilities relied on OM&A information from the OEB's Annual Yearbook of Electricity Distributors and adjusted the OM&A for merger-related transaction costs. OEB Staff relied on OM&A figures from Alectra Utilities' predecessors' RRR 2.1.5.6 annual filing which adjusts for all non-distribution related items. Alectra Utilities' OM&A data reconciles to OEB Staff's OM&A data except for 2015 OM&A for the PowerStream Rate Zone. OEB Staff's 2015 OM&A for the PowerStream RZ of $92,481,578 does not include an adjustment for 2015 merger-related transaction costs of $4,798,000.

Alectra Utilities has reproduced the RRR averages table, based on the data provided by OEB Staff in interrogatory HRZ-Staff 1a), including the adjustment made to account for merger-related transaction costs in the PRZ.

Table 1 - RRR Averages

RRR Averages	HRZ	BRZ	ERZ	PRZ	Total
2012-2016 avg	$ 57,083,345	$ 25,592,620	$ 54,984,088	$ 84,834,195	**$ 222,494,248**
2013-2016 avg	$ 58,484,591	$ 26,877,559	$ 55,780,913	$ 85,334,678	**$ 226,477,741**
2014-2016 avg	$ 59,571,548	$ 27,912,160	$ 56,496,098	$ 86,715,846	**$ 230,695,651**
2015-2016 avg	$ 59,198,444	$ 28,491,215	$ 58,528,554	$ 87,164,587	**$ 233,382,799**
2016	$ 59,299,938	$ 30,006,692	$ 60,426,547	$ 86,645,596	**$ 236,378,773**

Table 2 below identifies variances between OEB Staff's calculated 3-year OM&A averages and RRR averages presented in Table 1, above.

Table 2 - RRR Averages, Variance to OEB Staff's Calculated Values

RRR Averages	HRZ	BRZ	ERZ	PRZ	Total
2012-2016 avg	-$ 0	$ 0	-$ 0	-$ 959,600	**-$ 959,600**
2013-2016 avg	$ 0	$ 0	-$ 0	-$ 1,199,500	**-$ 1,199,500**
2014-2016 avg	-$ 0	$ 0	-$ 0	-$ 1,599,334	**-$ 1,599,334**
2015-2016 avg	$ -	$ -	-$ 0	-$ 2,399,000	**-$ 2,399,000**
2016	$ -	$ -	-$ 0	$ -	**-$ 0**

b) Please see response to HRZ-Staff-2a).

c) Alectra Utilities relied on a 3-year average of OM&A rather than a 5-year average as the shorter term was a better representation of each legacy utility's portion of 2017 OM&A pre-merger costs. As provided in the Table 3 below, the 3-year average OM&A allocation (before any adjustment for the capitalization policy change) to the Horizon Utilities RZ is 25.8%, and the 5 year average is 25.7%.

Based on the response to HRZ-Staff-2 a), the percentage allocations for each scenario is provided in Table 3, below.

Table 3 – OM&A Allocations

5 to 1 Year Averages	HRZ	BRZ	ERZ	PRZ	Total
2012-2016 avg	25.7%	11.5%	24.7%	38.1%	100.0%
2013-2016 avg	25.8%	11.9%	24.6%	37.7%	100.0%
2014-2016 avg	25.8%	12.1%	24.5%	37.6%	100.0%
2015-2016 avg	25.4%	12.2%	25.1%	37.3%	100.0%
2016	25.1%	12.7%	25.6%	36.7%	100.0%

d) Alectra Utilities relied on a 3-year average of OM&A rather than applying 2016 as a proxy for proportional OM&A, as the reliance of the 3-year average accounts for the relative differences in costs to serve across the rate zones and eliminates anomalies in costs in any single year. In addition, reliance on a 3-year actual average implicitly includes a growth rate which would include OM&A cost increases to serve new customers over the period.

Please also see Alectra Utilities' response to HRZ-Staff-1 which identifies the drivers of the change in OM&A from 2016 to 2017.

e) a) Alectra Utilities has reproduced Table 32 and Table 45 below to include the adjustments to the 3-year average as provided in response to HRZ Staff 2a) and presents a comparison to the 5-year average of OM&A by rate zone for 2017 and 2018.

Table 4 – 2017 OM&A by Rate Zone – 3 Year Average Revised (Table 32 reproduced)

Table 32 - 2017 OM&A by Rate Zone Allocators - 3 Year Average Revised	Enersource	Horizon	Brampton	PowerStream	Total Alectra
2014-2016 RRR Average	$56,496,098	$59,571,548	$27,912,160	$86,715,846	$230,695,651
Adjust to Alectra Overhead capitalization	($2,035,681)	($5,889,304)	$2,196,638	($211,265)	($5,939,613)
Revised OM&A	**$54,460,416**	**$53,682,244**	**$30,108,799**	**$86,504,580**	**$224,756,039**
% of total	24.23%	23.88%	13.40%	38.49%	100.00%
Prorate for 2017 part year:					
Months	11	11	10	11	
Prorated (Alectra Overhead basis)	$ 49,922,048	$ 49,208,723	$ 25,090,665	$ 79,295,865	$203,517,302
% of total	**24.53%**	**24.18%**	**12.33%**	**38.96%**	**100.0%**

Table 5 – 2017 OM&A by Rate Zone – 5 Year Average (Table 32 reproduced)

Table 32 - 2017 OM&A by Rate Zone Allocators - 5 Year Average	Enersource	Horizon	Brampton	PowerStream	Total Alectra
2012-2016 RRR Average	$54,984,088	$57,083,345	$25,592,620	$84,834,195	$222,494,248
Adjust to Alectra Overhead capitalization	($2,035,681)	($5,889,304)	$2,196,638	($211,265)	($5,939,613)
Revised OM&A	**$52,948,407**	**$51,194,041**	**$27,789,258**	**$84,622,930**	**$216,554,636**
% of total	24.45%	23.64%	12.83%	39.08%	100.00%
Prorate for 2017 part year:					
Months	11	11	10	11	
Prorated (Alectra Overhead basis)	$ 48,536,039	$ 46,927,871	$ 23,157,715	$ 77,571,019	$196,192,645
% of total	**24.74%**	**23.92%**	**11.80%**	**39.54%**	**100.0%**

Table 6 – 2018 OM&A by Rate Zone – 3 Year Average Revised (Table 45 reproduced)

Table 45 - 2018 OM&A by Rate Zone Allocators - 3 Year Average Revised	Enersource	Horizon	Brampton	PowerStream	Total Alectra
2014-2016 RRR Average	$56,496,098	$59,571,548	$27,912,160	$86,715,846	$230,695,651
Adjust to Alectra Overhead capitalization	($1,711,518)	($5,242,737)	$1,609,690	($409,708)	($5,754,273)
Revised OM&A	**$54,784,580**	**$54,328,811**	**$29,521,850**	**$86,306,138**	**$224,941,378**
% of total	24.36%	24.15%	13.12%	38.37%	100.00%

Table 7 – 2018 OM&A by Rate Zone – 5 Year Average (Table 45 reproduced)

Table 45 - 2018 OM&A by Rate Zone Allocators - 5 Year Average	Enersource	Horizon	Brampton	PowerStream	Total Alectra
2012-2016 RRR Average	$54,984,088	$57,083,345	$25,592,620	$84,834,195	$222,494,248
Adjust to Alectra Overhead capitalization	($1,711,518)	($5,242,737)	$1,609,690	($409,708)	($5,754,273)
Revised OM&A	**$53,272,570**	**$51,840,608**	**$27,202,310**	**$84,424,487**	**$216,739,975**
% of total	24.58%	23.92%	12.55%	38.95%	100.00%

b) Alectra Utilities has reproduced Table 32 and Table 45 below to include the adjustments to the 3-year average provided in response to HRZ Staff 2a) and presents a comparison to2016 actual OM&A by rate zone.

Table 8 – 2017 OM&A by Rate Zone – 3 Year Average Revised (Table 32 reproduced)

Table 32 - 2017 OM&A by Rate Zone Allocators - 3 Year Average Revised	Enersource	Horizon	Brampton	PowerStream	Total Alectra
2014-2016 RRR Average	$56,496,098	$59,571,548	$27,912,160	$86,715,846	$230,695,651
Adjust to Alectra Overhead capitalization	($2,035,681)	($5,889,304)	$2,196,638	($211,265)	($5,939,613)
Revised OM&A	**$54,460,416**	**$53,682,244**	**$30,108,799**	**$86,504,580**	**$224,756,039**
% of total	24.23%	23.88%	13.40%	38.49%	100.00%
Prorate for 2017 part year:					
Months	11	11	10	11	
Prorated (Alectra Overhead basis)	$ 49,922,048	$ 49,208,723	$ 25,090,665	$ 79,295,865	$203,517,302
% of total	**24.53%**	**24.18%**	**12.33%**	**38.96%**	**100.0%**

Table 9 – 2017 OM&A by Rate Zone – 2016 Year (Table 32 reproduced)

Table 32 - 2017 OM&A by Rate Zone Allocators - 2016 Year	Enersource	Horizon	Brampton	PowerStream	Total Alectra
2012-2016 RRR Average	$60,426,547	$59,299,938	$30,006,692	$86,645,596	$236,378,773
Adjust to Alectra Overhead capitalization	($2,035,681)	($5,889,304)	$2,196,638	($211,265)	($5,939,613)
Revised OM&A	**$58,390,866**	**$53,410,634**	**$32,203,330**	**$86,434,331**	**$230,439,160**
% of total	25.34%	23.18%	13.97%	37.51%	100.00%
Prorate for 2017 part year:					
Months	11	11	10	11	
Prorated (Alectra Overhead basis)	$ 53,524,960	$ 48,959,748	$ 26,836,109	$ 79,231,470	$208,552,286
% of total	**25.67%**	**23.48%**	**12.87%**	**37.99%**	**100.0%**

Table 10 – 2018 OM&A by Rate Zone – 3 Year Average Revised (Table 45 reproduced)

Table 45 - 2018 OM&A by Rate Zone Allocators - 3 Year Average Revised	Enersource	Horizon	Brampton	PowerStream	Total Alectra
2014-2016 RRR Average	$56,496,098	$59,571,548	$27,912,160	$86,715,846	$230,695,651
Adjust to Alectra Overhead capitalization	($1,711,518)	($5,242,737)	$1,609,690	($409,708)	($5,754,273)
Revised OM&A	**$54,784,580**	**$54,328,811**	**$29,521,850**	**$86,306,138**	**$224,941,378**
% of total	24.36%	24.15%	13.12%	38.37%	100.00%

Table 11 – 2018 OM&A by Rate Zone – 2016 Year (Table 45 reproduced)

Table 45 - 2018 OM&A by Rate Zone Allocators - 2016 Year					
	Enersource	Horizon	Brampton	PowerStream	Total Alectra
2012-2016 RRR Average	$60,426,547	$59,299,938	$30,006,692	$86,645,596	$236,378,773
Adjust to Alectra Overhead capitalization	($1,711,518)	($5,242,737)	$1,609,690	($409,708)	($5,754,273)
Revised OM&A	**$58,715,029**	**$54,057,201**	**$31,616,382**	**$86,235,888**	**$230,624,500**
% of total	25.46%	23.44%	13.71%	37.39%	100.00%

Alectra Utilities has filed the following attachments in live excel format:

- HRZ-Staff-2_Attach 1_2017 ESM revised 3 year average OM&A allocation
- HRZ-Staff-2_Attach 2_2017 ESM with 5 year average OM&A allocation
- HRZ-Staff-2_Attach 3_2017 ESM with Year 2016 OM&A allocation
- HRZ-Staff-2_Attach 4_2018 ESM revised 3 year average OM&A allocation
- HRZ-Staff-2_Attach 5_2018 ESM with 5 year average OM&A allocation
- HRZ-Staff-2_Attach 6_2018 ESM with Year 2016 OM&A allocation

Alectra Utilities notes that Attachment 1 and Attachment 4 include revisions to the original filing (Ref: Attachment 9-Table of Allocations Horizon ESM 2017 and Ref: Attachment 11-Table of Allocations Horizon ESM 2018). These attachments have been updated to include the revised 3-year average OM&A as calculated in response to HRZ-Staff 2a). Alectra Utilities has also updated the PILs calculation as a result of a formula calculation error. The revised calculation is included as part of Attachments 4 to this response.

A summary of the ESM calculation for 2017 and 2018 based on the above scenarios is provided in Table 12, below. As identified above, the most appropriate basis for the calculation of the ESM for the Horizon Utilities RZ is the 3-year OM&A average.

Table 12 – ESM Calculation Summary

ESM Calculations		2017	2018
Deemed Regulatory ROE per EB-2016-0077/EB-2017-0024:		8.780%	9.000%
3 Year Average OM&A - Original	Regulatory Net Income	$ 20,113,167	$ 17,887,010
	Regulatory Deemed Equity	$ 207,057,276	$ 214,920,389
	Regulatory ROE	9.714%	8.323%
	% Return in Excess of Approved in Rates	0.934%	-0.677%
	Return in Excess	$ 1,933,538	$ -
	Amount Payable to Ratepayers	$ 966,769	$ -
3 Year Average OM&A - Revised	Regulatory Net Income	$ 20,780,781	$ 17,980,733
	Regulatory Deemed Equity	$ 207,013,768	$ 214,873,011
	Regulatory ROE	10.038%	8.368%
	% Return in Excess of Approved in Rates	1.258%	-0.632%
	Return in Excess	$ 2,604,972	$ -
	Amount Payable to Ratepayers	$ 1,302,486	$ -
5 Year Average OM&A	Regulatory Net Income	$ 21,216,902	$ 18,420,746
	Regulatory Deemed Equity	$ 206,985,340	$ 214,844,238
	Regulatory ROE	10.250%	8.574%
	% Return in Excess of Approved in Rates	1.470%	-0.426%
	Return in Excess / (N/A)	$ 3,043,589	$ -
	Amount Payable to Ratepayers / (N/A)	$ 1,521,795	$ -
2016 OM&A	Regulatory Net Income	$ 21,960,866	$ 19,320,842
	Regulatory Deemed Equity	$ 206,936,845	$ 214,785,378
	Regulatory ROE	10.612%	8.995%
	% Return in Excess of Approved in Rates	1.832%	-0.005%
	Return in Excess / (N/A)	$ 3,791,812	$ -
	Amount Payable to Ratepayers / (N/A)	$ 1,895,906	$ -

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ATTACH 1 – 2017 ESM revised 3 year average OM&A allocation

Table 1: 2017 Allocations for Calculation of HRZ Earnings Sharing - UPDATED NEW 3 YEAR AVERAGE (HRZ-Staff-2)

	Rate Zone		Rate Zones				
Category	**Actual/Allocation**	**Total Alectra**	**HRZ**	**BRZ**	**ERZ**	**PRZ**	**Updates**
Alectra Direct Allocations							
Cost of Power	Actual	$ 2,776,778,326	$510,177,988	$468,678,841	$791,265,940	$1,006,655,557	
Distribution Revenues	Actual	$ 521,314,962	$113,495,042	$ 74,436,566	$ 131,932,386	$ 201,450,968	
Other Revenue	Actual	$ 32,013,512	$5,300,163	$ 4,450,643	$ 6,318,438	$ 15,944,267	
Alectra OM&A - Direct Allocations:							
OM&A	Actual	$ 29,971,130	$ 5,266,751	$ 6,398,891	$ 6,321,238	$ 11,984,250	
Alectra OM&A - Formula Allocations:		100.00%	24.18%	12.33%	24.53%	38.96%	Revised 3 Year Average
Distribution - Operations	Allocation	$ 55,776,105	$ 13,486,180	$ 6,876,367	$ 13,681,674	$ 21,731,885	
Distribution - Maintenance	Allocation	$ 27,671,305	$ 6,690,682	$ 3,411,462	$ 6,787,670	$ 10,781,492	
Billing & Collecting	Allocation	$ 44,060,911	$ 10,653,547	$ 5,432,057	$ 10,807,980	$ 17,167,327	*Alectra (11/10 months) allocation for OM&A based on historical 3 year average based of legacy utilities (2014-2016), excluding merger related costs.*
Community Relations	Allocation	$ 3,053,879	$ 738,401	$ 376,498	$ 749,105	$ 1,189,874	
Administrative & General Expenses	Allocation	$ 96,317,830	$ 23,288,818	$ 11,874,560	$ 23,626,411	$ 37,528,041	
Property Taxes & Donations	Allocation	$ 3,071,318	$ 742,618	$ 378,648	$ 753,383	$ 1,196,669	
Net Merger Costs	Allocation	$ (2,032,671)	$ (491,482)	$ (250,598)	$ (498,607)	$ (791,984)	
Total OM&A Formula Allocations		***$ 227,918,678***	***$ 55,108,765***	***$ 28,098,993***	***$ 55,907,616***	***$ 88,803,304***	
Total Alectra OM&A		**$ 257,889,808**	**$ 60,375,516**	**$ 34,497,884**	**$ 62,228,854**	**$ 100,787,554**	
Rate Base							
Opening Net Fixed Assets - Direct Allocations	Actual	$ 2,376,442,007	$ 436,391,621	$ 350,797,724	$ 664,020,095	$ 925,232,567	
Capital Additions - Direct Allocations							
Distribution Plant	Actual	$ 300,110,508	$ 51,430,152	$ 35,770,525	$ 56,468,245	$ 156,441,586	
Capital Additions - Formula Allocations							
General Plant	Allocation	$ 14,313,050	$ 2,833,456	$ 714,171	$ 7,426,596	$ 3,338,827	
Merger Capital Net Savings	Allocation	$ 17,174,112	$ 2,891,170	$ 3,941,707	$ 1,199,302	$ 9,141,933	
Depreciation - Direct Allocations							
Distribution Plant	Actual	$ 89,752,970	$ 15,231,321	$ 12,422,030	$ 23,222,853	$ 38,876,766	
Depreciation - Formula Allocations							
General Plant	Allocation	$ 31,244,277	$ 7,020,923	$ 4,749,606	$ 10,005,323	$ 9,468,425	
Asset Retirements - Direct Allocations	Actual	$ 7,807,008	$ 1,629,843	$ 843,961	$ 1,563,803	$ 3,769,401	
Work in Progress		$ 21,287,460	$ 3,158,696	$ 460,295	$ 1,468,007	$ 16,200,462	
Capital Contributions	Actual	$ 61,155,634	$ 4,761,239	$ 11,891,967	$ 3,733,074	$ 40,769,354	
Closing Net Fixed Assets		$ 2,496,792,328	$ 461,744,377	$ 360,856,268	$ 689,121,178	$ 985,070,505	
Average NFA for Rev. Req. Purposes		$ 2,436,617,168	$ 449,067,999	$ 355,826,996	$ 676,570,637	$ 955,151,536	
Working Capital Allowance Rate			12.00%	13.00%	13.50%	7.50%	
Working Capital Allowance		$ 332,159,425	$ 68,466,421	$ 65,412,974	$ 115,221,797	$ 83,058,233	Updated Working Capital Calculation
Total Rate Base		$ 2,768,776,593	$ 517,534,420	$ 421,239,970	$ 791,792,434	$ 1,038,209,769	
Regulatory Net Income before interest & tax		$ 166,634,411	$ 34,537,602	$ 26,373,728	$ 41,229,991	$ 64,493,089	
Regulatory Deemed Debt		$ 71,652,286	$ 10,424,864	$ 14,689,513	$ 23,234,230	$ 23,303,678	Updated Cost of Capital Calculation - See Table 2
Regulatory Net Income before tax		$ 94,982,125	$ 24,112,738	$ 11,684,215	$ 17,995,760	$ 41,189,411	
ESM Adjustments per Settlement Agreement		$ 487,232	$ 487,232	$ -	$ -	$ -	
PILs		$ 13,482,778	$ 3,819,189	$ 1,658,272	$ 757,779	$ 7,247,538	Updated PILs - See Table 3
Regulatory Net Income		$ 81,986,578	$ 20,780,781	$ 10,025,943	$ 17,237,982	$ 33,941,873	
Regulatory Deemed Equity		$ 1,107,510,637	$ 207,013,768	$ 168,495,988	$ 316,716,973	$ 415,283,908	Updated Deemed Equity Calculation
Regulatory ROE		7.40%	10.038%				
Per Annual Filling EB-2016-0077			8.780%				
Return in Excess			$ 2,604,972				
Amount Payable to Ratepayers			$ 1,302,486				

Table 2: Capitalization / Cost of Capital 2017 Actual (12 Months)

Horizon

	Actual Rate Base		$ 517,534,420		
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$289,819,275	3.47%	$10,060,542
9	Short-term Debt	4.00%	$20,701,377	1.76%	$364,344
10	**Total Debt**	60.00%	$310,520,652	3.36%	$10,424,886
	Equity				
11	Common Equity	40.00%	$207,013,768	8.78%	$18,175,809
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$207,013,768	8.78%	$18,175,809
14	**Total**	100.00%	$517,534,420	5.53%	$28,600,695

PowerStream

	Actual Rate Base		$ 1,038,209,769		
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$581,397,471	3.88%	$22,572,778
9	Short-term Debt	4.00%	$41,528,391	1.76%	$730,900
10	**Total Debt**	60.00%	$622,925,862	3.74%	$23,303,678
	Equity				
11	Common Equity	40.00%	$415,283,908	8.78%	$36,461,927
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$415,283,908	8.78%	$36,461,927
14	**Total**	100.00%	$1,038,209,769	5.76%	$59,765,605

Enersource

	Actual Rate Base		$ 791,792,434		
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$443,403,763	5.09%	$22,575,459
9	Short-term Debt	4.00%	$31,671,697	2.08%	$658,771
10	**Total Debt**	60.00%	$475,075,460	4.89%	$23,234,230
	Equity				
11	Common Equity	40.00%	$316,716,973	8.93%	$28,282,826
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$316,716,973	8.93%	$28,282,826
14	**Total**	100.00%	$791,792,434	6.51%	$51,517,056

Brampton

	Actual Rate Base		$ 421,239,970		
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$235,894,383	6.07%	$14,325,562
9	Short-term Debt	4.00%	$16,849,599	2.16%	$363,951
10	**Total Debt**	60.00%	$252,743,982	5.81%	$14,689,513
	Equity				
11	Common Equity	40.00%	$168,495,988	9.30%	$15,670,127
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$168,495,988	9.30%	$15,670,127
14	**Total**	100.00%	$421,239,970	7.21%	$30,359,640

ALECTRA

	Actual Rate Base		$ 2,768,776,593		
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$1,550,514,892	4.48%	$69,534,342
9	Short-term Debt	4.00%	$110,751,064	1.91%	$2,117,967
10	**Total Debt**	60.00%	$1,661,265,956	4.31%	$71,652,308
	Equity				
11	Common Equity	40.00%	$1,107,510,637	8.90%	$98,590,689
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$1,107,510,637	8.90%	$98,590,689
14	**Total**	100.00%	$2,768,776,593	6.15%	$170,242,997

Table 3: Reconciliation of additions / (deductions) for tax

	AUC - LDC Provision IFRS	11 months: (February 1 - December 31, 2017) Updated 3 Yr Average HRZ Portion	ERZ	BRZ	PRZ	Non-Regulated, MIFRS & Merger	Allocation Basis
		24.18%	24.53%	12.33%	38.96%		
Net Income before tax	99,454,037						
Additions:							
Interest and penalities on taxes	75,819				75,819		
Amortization of tangible assets	116,773,494	20,355,959	30,375,678	14,386,972	48,344,970	3,309,915	From ESM depreciation calculation
Derecognition expense	5,635,328	1,564,672	1,737,468	678,504	1,654,684		HRZ specific
Non-deductible club dues and fees	140,792	34,042	34,536	17,358	54,856		OM&A %
Non-deductible meals	235,230	56,877	57,701	29,000	91,652		OM&A %
Non-deductible automobile expenses	15,452	3,736	3,790	1,905	6,020		OM&A %
Amortization	265,786	-				265,786	Not Attributable to HRZ
Non-deductible reserves - closing	80,364,899	30,754,715	7,831,661	5,514,859	26,276,409	9,987,254	HRZ specific
Capital Items Expensed	140,000	140,000					HRZ specific
Debt issuance cost	102,227	-	102,227				Not Attributable to HRZ
Interest on capital lease - building	957,924	-			957,924		Not Attributable to HRZ
12(1)(x) income on capital contributions	61,886,099	4,687,789	4,590,989	11,891,968	40,715,354		HRZ specific
Total Additions	266,593,050	57,597,790	44,734,051	32,520,566	118,177,688	13,562,955	
Deductions:							
Accounting loss (gain) on sale of assets	(518,417)	(368,526)	(47,115)	(9,042)	(93,733)		HRZ specific
Reverse book income on joint venture	(121,856)	-			(121,856)		Not Attributable to HRZ
Removal Costs (Included in deprecation above; deductible for tax)	(94,469)	-		(94,469)			Not Attributable to HRZ
SR&ED and Apprenticeship ITCs	(460,402)	6,285	(466,687)				HRZ specific
CCA	(165,769,927)	(29,755,422)	(42,446,887)	(18,731,641)	(62,239,337)	(12,596,640)	HRZ specific
Capitalized Interest (AFUDC) (income recorded in P&L)	(2,668,430)	(306,323)	(480,683)	(342,153)	(1,539,272)		HRZ specific
Deductible OMERS contributions 20.1(q); capitalized for accounting	(223,631)	-		(223,631)			Not Attributable to HRZ
Less: Amortization of deferred revenue (IFRS)	(6,510,214)	-				(6,510,214)	Not Applicable
Stranded Meter Rate Rider applied against UCC	(2,438,301)	-				(2,438,301)	Not Attributable to HRZ
13(7.4) election	(61,886,099)	(4,687,789)	(4,590,989)	(11,891,968)	(40,715,354)		HRZ specific
Non-deductible - opening	(76,554,199)	(34,443,812)	(7,145,433)	(5,223,726)	(23,963,454)	(5,777,774)	HRZ specific
Cash payment on capital leases	(1,310,752)	-			(1,310,752)		Not Attributable to HRZ
20(1)(e)	(233,437)	-	(44,128)	(8,583)	(180,726)		Not Attributable to HRZ
Regulatory Balance Movement - Energy Accounts	(9,693,160)	-				(9,693,160)	Not Applicable
Accounting accrual for ITCs	(800,000)	(193,433)	(196,237)	(98,628)	(311,702)		OM&A %
Total Deductions	(329,283,295)	(69,749,019)	(55,418,159)	(36,623,840)	(130,476,186)	(37,016,090)	
Total	36,763,792	(12,151,229)	(10,684,108)	(4,103,274)	(12,298,497)	(23,453,134)	
Donation carryforward utilization	(1,185,131)						
	35,578,661						
Loss utilization	(35,578,661)						
	-						
	26.50%						
Current Tax Expense	- [A]						
One-time adjustments to current tax for prior years	(28,065) [A]						
Deferred Tax Expense	28,506,495 [A]						
Total IFRS Tax Expense	28,478,430 SUM OF [A]						

HRZ-Staff-2

ATTACH 2 – 2017 ESM with 5 year average OM&A allocation

Table 1: Allocations for Calculation of HRZ Earnings Sharing - (HRZ-Staff 2 e.) Updated to 5 Year Average

	Rate Zone	Revised ESM		Rate Zones				
Category	**Actual/Allocation**	**HRZ- Staff #17**	**Total Alectra**	**HRZ**	**BRZ**	**ERZ**	**PRZ**	**Reference updates**
Alectra Direct Allocations								
Cost of Power	Actual	$ 510,177,988	$ 2,776,778,326	$510,177,988	$468,678,841	$791,265,940	$1,006,655,557	
Distribution Revenues	Actual	$ 113,495,042	$ 521,314,962	$113,495,042	$ 74,436,566	$ 131,932,386	$ 201,450,968	
Other Revenue	Actual	$ 5,300,163	$ 32,013,512	$5,300,163	$ 4,450,643	$ 6,318,438	$ 15,944,267	
Alectra OM&A - Direct Allocations:								
OM&A	Actual	$ 5,266,751	$ 29,971,130	$ 5,266,751	$ 6,398,891	$ 6,321,238	$ 11,984,250	
Alectra OM&A - Formula Allocations:			100.00%	23.92%	11.80%	24.74%	39.54%	Updated OM&A Allocation 5 Year Average
Distribution - Operations	Allocation	$ 13,707,080	$ 55,776,105	$ 13,341,244	$ 6,583,566	$ 13,798,434	$ 22,052,862	
Distribution - Maintenance	Allocation	$ 6,800,274	$ 27,671,305	$ 6,618,777	$ 3,266,199	$ 6,845,596	$ 10,940,733	
Billing & Collecting	Allocation	$ 10,828,049	$ 44,060,911	$ 10,539,053	$ 5,200,756	$ 10,900,216	$ 17,420,886	
Community Relations	Allocation	$ 750,496	$ 3,053,879	$ 730,466	$ 360,466	$ 755,498	$ 1,207,448	
Administrative & General Expenses	Allocation	$ 23,670,282	$ 96,317,830	$ 23,038,533	$ 11,368,932	$ 23,828,039	$ 38,082,326	
Property Taxes & Donations	Allocation	$ 754,782	$ 3,071,318	$ 734,637	$ 362,525	$ 759,812	$ 1,214,344	
Net Merger Costs	Allocation	$ (495,777)	$ (2,032,671)	$ (486,200)	$ (239,928)	$ (502,862)	$ (803,681)	
Total OM&A Formula Allocations		***$ 56,015,186***	***$ 227,918,678***	***$ 54,516,510***	***$ 26,902,517***	***$ 56,384,733***	***$ 90,114,918***	
Total Alectra OM&A		**$ 61,281,937**	**$ 257,889,808**	**$ 59,783,261**	**$ 33,301,408**	**$ 62,705,971**	**$ 102,099,168**	
Rate Base								
Opening Net Fixed Assets - Direct Allocations	Actual	$ 436,391,621	$ 2,376,442,007	$ 436,391,621	$ 350,797,724	$ 664,020,095	$ 925,232,567	
Capital Additions - Direct Allocations								
Distribution Plant	Actual	$ 51,430,152	$ 300,110,508	$ 51,430,152	$ 35,770,525	$ 56,468,245	$ 156,441,586	
Capital Additions - Formula Allocations								
General Plant	Allocation	$ 2,833,456	$ 14,313,050	$ 2,833,456	$ 714,171	$ 7,426,596	$ 3,338,827	
Merger Capital Net Savings	Allocation	$ 2,891,170	$ 17,174,112	$ 2,891,170	$ 3,941,707	$ 1,199,302	$ 9,141,933	
Depreciation - Direct Allocations								
Distribution Plant	Actual	$ 15,231,321	$ 89,752,970	$ 15,231,321	$ 12,422,030	$ 23,222,853	$ 38,876,766	
Depreciation - Formula Allocations								
General Plant	Allocation	$ 7,020,923	$ 31,244,277	$ 7,020,923	$ 4,749,606	$ 10,005,323	$ 9,468,425	
Asset Retirements - Direct Allocations	Actual	$ 1,629,843	$ 7,807,008	$ 1,629,843	$ 843,961	$ 1,563,803	$ 3,769,401	
Work in Progress		$ 3,158,696	$ 21,287,460	$ 3,158,696	$ 460,295	$ 1,468,007	$ 16,200,462	
Capital Contributions	Actual	$ 4,761,239	$ 61,155,634	$ 4,761,239	$ 11,891,967	$ 3,733,074	$ 40,769,354	
Closing Net Fixed Assets		$ 461,744,377	$ 2,496,792,328	$ 461,744,377	$ 360,856,268	$ 689,121,178	$ 985,070,505	
Average NFA for Rev. Req. Purposes		$ 449,067,999	$ 2,436,617,168	$ 449,067,999	$ 355,826,996	$ 676,570,637	$ 955,151,536	
Working Capital Allowance Rate		12.00%		12.00%	13.00%	13.50%	7.50%	
Working Capital Allowance		$ 68,575,191	$ 332,095,595	$ 68,395,350	$ 65,257,432	$ 115,286,208	$ 83,156,604	Updated Working Capital Calculation
Total Rate Base		$ 517,643,190	$ 2,768,712,762	$ 517,463,349	$ 421,084,428	$ 791,856,845	$ 1,038,308,140	
Regulatory Net Income before interest & tax		$ 33,631,181	$ 166,634,411	$ 35,129,857	$ 27,570,205	$ 40,752,874	$ 63,181,475	
Regulatory Deemed Debt		$ 10,427,055	$ 71,649,529	$ 10,423,433	$ 14,684,089	$ 23,236,121	$ 23,305,886	Updated Cost of Capital Calculation - See Table 2
Regulatory Net Income before tax		$ 23,204,125	$ 94,984,882	$ 24,706,424	$ 12,886,116	$ 17,516,753	$ 39,875,589	
ESM Adjustments per Settlement Agreement		$ 487,232	$ 487,232	$ 487,232	$ -	$ -	$ -	
PILs		$ 3,578,190	$ 13,482,778	$ 3,976,754	$ 1,631,234	$ 745,423	$ 7,129,367	Updated PILs - See Table 3
Regulatory Net Income		$ 20,113,167	$ 81,989,336	$ 21,216,902	$ 11,254,882	$ 16,771,330	$ 32,746,222	
Regulatory Deemed Equity		$ 207,057,276	$ 1,107,485,105	$ 206,985,340	$ 168,433,771	$ 316,742,738	$ 415,323,256	Updated Deemed Equity Calculation
Regulatory ROE		9.714%	7.40%	10.250%				
Per Annual Filling EB-2016-0077		8.780%		8.780%				
Return in Excess		$ 1,933,538		$ 3,043,589				
Amount Payable to Ratepayers		$ 966,769		$ 1,521,795				

Table 2: Capitalization / Cost of Capital 2017 Actual (12 Months)

Horizon

	Actual Rate Base		**$ 517,463,349**			
		(%)	($)	(%)	($)	
	Debt					
8	Long-term Debt	56.00%	$289,779,475	3.47%	$10,059,161	
9	Short-term Debt	4.00%	$20,698,534	1.76%	$364,294	
10	**Total Debt**	60.00%	$310,478,009	3.36%	$10,423,455	
	Equity					
11	Common Equity	40.00%	$206,985,340	8.78%	$18,173,313	
12	Preferred Shares	0.00%	$ -	0.00%	$ -	
13	**Total Equity**	40.00%	$206,985,340	8.78%	$18,173,313	
14	**Total**	100.00%	$517,463,349	5.53%	$28,596,768	

PowerStream

	Actual Rate Base		**$ 1,038,308,140**		
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$581,452,559	3.88%	$22,574,917
9	Short-term Debt	4.00%	$41,532,326	1.76%	$730,969
10	**Total Debt**	60.00%	$622,984,884	3.74%	$23,305,886
	Equity				
11	Common Equity	40.00%	$415,323,256	8.78%	$36,465,382
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$415,323,256	8.78%	$36,465,382
14	**Total**	100.00%	$1,038,308,140	5.76%	$59,771,268

Enersource

Actual Rate Base		$ 791,856,845		
	(%)	($)	(%)	($)
Debt				
8 Long-term Debt	56.00%	$443,439,833	5.09%	$22,577,296
9 Short-term Debt	4.00%	$31,674,274	2.08%	$658,825
10 **Total Debt**	60.00%	$475,114,107	4.89%	$23,236,121
Equity				
11 Common Equity	40.00%	$316,742,738	8.93%	$28,285,126
12 Preferred Shares	0.00%	$ -	0.00%	$ -
13 **Total Equity**	40.00%	$316,742,738	8.93%	$28,285,126
14 **Total**	100.00%	$791,856,845	6.51%	$51,521,247

Brampton

Actual Rate Base		$ 421,084,428		
	(%)	($)	(%)	($)
Debt				
8 Long-term Debt	56.00%	$235,807,280	6.07%	$14,320,272
9 Short-term Debt	4.00%	$16,843,377	2.16%	$363,817
10 **Total Debt**	60.00%	$252,650,657	5.81%	$14,684,089
Equity				
11 Common Equity	40.00%	$168,433,771	9.30%	$15,664,341
12 Preferred Shares	0.00%	$ -	0.00%	$ -
13 **Total Equity**	40.00%	$168,433,771	9.30%	$15,664,341
14 **Total**	100.00%	$421,084,428	7.21%	$30,348,430

ALECTRA

Actual Rate Base		$ 2,768,712,762		
	(%)	($)	(%)	($)
Debt				
8 Long-term Debt	56.00%	$1,550,479,147	4.48%	$69,531,646
9 Short-term Debt	4.00%	$110,748,510	1.91%	$2,117,905
10 **Total Debt**	60.00%	$1,661,227,657	4.31%	$71,649,551
Equity				
11 Common Equity	40.00%	$1,107,485,105	8.90%	$98,588,162
12 Preferred Shares	0.00%	$ -	0.00%	$ -
13 **Total Equity**	40.00%	$1,107,485,105	8.90%	$98,588,162
14 **Total**	100.00%	$2,768,712,762	6.15%	$170,237,712

Table 3: Reconciliation of additions / (deductions) for tax

	AUC - LDC Provision IFRS	11 months: (February 1 - December 31, 2017) Updated 5 Yr Average HRZ Portion	ERZ	BRZ	PRZ	Non-Regulated, MIFRS & Merger	Allocation Basis
		23.92%	11.80%	24.74%	39.54%		
Net Income before tax	99,454,037						
Additions:							
Interest and penalities on taxes	75,819				75,819		
Amortization of tangible assets	116,773,494	20,355,959	30,375,678	14,386,972	48,344,970	3,309,915	From ESM depreciation calculation
Derecognition expense	5,635,328	1,564,672	1,737,468	678,504	1,654,684		HRZ specific
Non-deductible club dues and fees	140,792	33,677	16,619	34,831	55,667		OM&A %
Non-deductible meals	235,230	56,265	27,766	58,194	93,006		OM&A %
Non-deductible automobile expenses	15,452	3,696	1,824	3,823	6,109		OM&A %
Amortization	265,786	-				265,786	Not Attributable to HRZ
Non-deductible reserves - closing	80,364,899	30,754,715	7,831,661	5,514,859	26,276,409	9,987,254	HRZ specific
Capital Items Expensed	140,000	140,000					HRZ specific
Debt issuance cost	102,227	-	102,227				Not Attributable to HRZ
Interest on capital lease - building	957,924	-			957,924		Not Attributable to HRZ
12(1)(x) income on capital contributions	61,886,099	4,687,789	4,590,989	11,891,968	40,715,354		HRZ specific
Total Additions	266,593,050	57,596,773	44,684,231	32,569,150	118,179,941	13,562,955	
Deductions:							
Accounting loss (gain) on sale of assets	(518,417)	(368,526)	(47,115)	(9,042)	(93,733)		HRZ specific
Reverse book income on joint venture	(121,856)	-			(121,856)		Not Attributable to HRZ
Removal Costs (Included in deprecation above; deductible for tax)	(94,469)	-		(94,469)			Not Attributable to HRZ
SR&ED and Apprenticeship ITCs	(460,402)	6,285	(466,687)				HRZ specific
CCA	(165,769,927)	(29,755,422)	(42,446,887)	(18,731,641)	(62,239,337)	(12,596,640)	HRZ specific
Capitalized Interest (AFUDC) (income recorded in P&L)	(2,668,430)	(306,323)	(480,683)	(342,153)	(1,539,272)		HRZ specific
Deductible OMERS contributions 20.1(q); capitalized for accounting	(223,631)	-		(223,631)			Not Attributable to HRZ
Less: Amortization of deferred revenue (IFRS)	(6,510,214)	-				(6,510,214)	Not Applicable
Stranded Meter Rate Rider applied against UCC	(2,438,301)	-				(2,438,301)	Not Attributable to HRZ
13(7.4) election	(61,886,099)	(4,687,789)	(4,590,989)	(11,891,968)	(40,715,354)		HRZ specific
Non-deductible - opening	(76,554,199)	(34,443,812)	(7,145,433)	(5,223,726)	(23,963,454)	(5,777,774)	HRZ specific
Cash payment on capital leases	(1,310,752)	-			(1,310,752)		Not Attributable to HRZ
20(1)(e)	(233,437)	-	(44,128)	(8,583)	(180,726)		Not Attributable to HRZ
Regulatory Balance Movement - Energy Accounts	(9,693,160)	-				(9,693,160)	Not Applicable
Accounting accrual for ITCs	(800,000)	(191,354)	(94,428)	(197,912)	(316,306)		OM&A %
Total Deductions	(329,283,295)	(69,746,940)	(55,316,350)	(36,723,124)	(130,480,789)	(37,016,090)	
Total	36,763,792	(12,150,168)	(10,632,119)	(4,153,974)	(12,300,848)	(23,453,134)	

Donation carryforward utilization	(1,185,131)	
	35,578,661	
Loss utilization	(35,578,661)	
	-	
	26.50%	
Current Tax Expense	-	[A]
One-time adjustments to current tax for prior years	(28,065)	[A]
Deferred Tax Expense	28,506,495	[A]
Total IFRS Tax Expense	28,478,430	SUM OF [A]

HRZ-Staff-2

ATTACH 3 – 2017 ESM with Year 2016 OM&A allocation

Table 1: 2017 Allocations for Calculation of HRZ Earnings Sharing - (HRZ-Staff 2 e.) Updated to 2016 YEAR OM&A Allocation

Category	Rate Zone Actual/Allocation	Total Alectra	HRZ	BRZ	ERZ	PRZ	Explanation / Reference
			Rate Zones				
Alectra Direct Allocations							
Cost of Power	Actual	$ 2,776,778,326	$510,177,988	$468,678,841	$791,265,940	$1,006,655,557	
Distribution Revenues	Actual	$ 521,314,962	$113,495,042	$ 74,436,566	$ 131,932,386	$ 201,450,968	
Other Revenue	Actual	$ 32,013,512	$5,300,163	$ 4,450,643	$ 6,318,438	$ 15,944,267	
Alectra OM&A - Direct Allocations:							
OM&A	Actual	$ 29,971,130	$ 5,266,751	$ 6,398,891	$ 6,321,238	$ 11,984,250	
Alectra OM&A - Formula Allocations:		100.00%	23.48%	12.87%	25.67%	37.99%	Revised 2016 YEAR OM&A Allocation
Distribution - Operations	Allocation	$ 55,776,105	$ 13,094,002	$ 7,177,162	$ 14,314,942	$ 21,189,999	
Distribution - Maintenance	Allocation	$ 27,671,305	$ 6,496,117	$ 3,560,691	$ 7,101,843	$ 10,512,655	
Billing & Collecting	Allocation	$ 44,060,911	$ 10,343,742	$ 5,669,674	$ 11,308,236	$ 16,739,259	
Community Relations	Allocation	$ 3,053,879	$ 716,929	$ 392,967	$ 783,778	$ 1,160,205	
Administrative & General Expenses	Allocation	$ 96,317,830	$ 22,611,580	$ 12,393,994	$ 24,719,978	$ 36,592,278	
Property Taxes & Donations	Allocation	$ 3,071,318	$ 721,023	$ 395,211	$ 788,254	$ 1,166,830	
Net Merger Costs	Allocation	$ (2,032,671)	$ (477,190)	$ (261,560)	$ (521,685)	$ (772,236)	
Total OM&A Formula Allocations		***$ 227,918,678***	***$ 53,506,203***	***$ 29,328,139***	***$ 58,495,346***	***$ 86,588,990***	
Total Alectra OM&A		**$ 257,889,808**	**$ 58,772,954**	**$ 35,727,030**	**$ 64,816,584**	**$ 98,573,240**	
Rate Base							
Opening Net Fixed Assets - Direct Allocations	Actual	$ 2,376,442,007	$ 436,391,621	$ 350,797,724	$ 664,020,095	$ 925,232,567	
Capital Additions - Direct Allocations							
Distribution Plant	Actual	$ 300,110,508	$ 51,430,152	$ 35,770,525	$ 56,468,245	$ 156,441,586	
Capital Additions - Formula Allocations							
General Plant	Allocation	$ 14,313,050	$ 2,833,456	$ 714,171	$ 7,426,596	$ 3,338,827	
Merger Capital Net Savings	Allocation	$ 17,174,112	$ 2,891,170	$ 3,941,707	$ 1,199,302	$ 9,141,933	
Depreciation - Direct Allocations							
Distribution Plant	Actual	$ 89,752,970	$ 15,231,321	$ 12,422,030	$ 23,222,853	$ 38,876,766	
Depreciation - Formula Allocations							
General Plant	Allocation	$ 31,244,277	$ 7,020,923	$ 4,749,606	$ 10,005,323	$ 9,468,425	
Asset Retirements - Direct Allocations	Actual	$ 7,807,008	$ 1,629,843	$ 843,961	$ 1,563,803	$ 3,769,401	
Work in Progress		$ 21,287,460	$ 3,158,696	$ 460,295	$ 1,468,007	$ 16,200,462	
Capital Contributions	Actual	$ 61,155,634	$ 4,761,239	$ 11,891,967	$ 3,733,074	$ 40,769,354	
Closing Net Fixed Assets		$ 2,496,792,328	$ 461,744,377	$ 360,856,268	$ 689,121,178	$ 985,070,505	
Average NFA for Rev. Req. Purposes		$ 2,436,617,168	$ 449,067,999	$ 355,826,996	$ 676,570,637	$ 955,151,536	
Working Capital Allowance Rate			12.00%	13.00%	13.50%	7.50%	
Working Capital Allowance		$ 332,310,177	$ 68,274,113	$ 65,572,763	$ 115,571,141	$ 82,892,160	Updated Working Capital Calculation
Total Rate Base		$ 2,768,927,344	$ 517,342,112	$ 421,399,759	$ 792,141,777	$ 1,038,043,696	
Regulatory Net Income before interest & tax		$ 166,634,411	$ 36,140,164	$ 25,144,583	$ 38,642,261	$ 66,707,403	
Regulatory Deemed Debt		$ 71,660,508	$ 10,420,991	$ 14,695,085	$ 23,244,482	$ 23,299,950	Updated Cost of Capital Calculation - See Table 2
Regulatory Net Income before tax		$ 94,973,903	$ 25,719,173	$ 10,449,497	$ 15,397,780	$ 43,407,453	
ESM Adjustments per Settlement Agreement		$ 487,232	$ 487,232	$ -	$ -	$ -	
PILs		$ 13,482,778	$ 4,245,539	$ 1,585,110	$ 724,346	$ 6,927,783	Updated PILs - See Table 3
Regulatory Net Income		$ 81,978,357	$ 21,960,866	$ 8,864,387	$ 14,673,433	$ 36,479,670	
Regulatory Deemed Equity		$ 1,107,570,938	$ 206,936,845	$ 168,559,904	$ 316,856,711	$ 415,217,478	Updated Deemed Equity Calculation
Regulatory ROE		7.40%	10.612%				
Per Annual Filling EB-2016-0077			8.780%				
Return in Excess			$ 3,791,812				
Amount Payable to Ratepayers			$ 1,895,906				

Table 2: Capitalization / Cost of Capital 2017 Actual (12 Months)

Horizon

Actual Rate Base $ 517,342,112

		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$289,711,583	3.47%	$10,056,804
9	Short-term Debt	4.00%	$20,693,684	1.76%	$364,209
10	**Total Debt**	60.00%	$310,405,267	3.36%	$10,421,013
	Equity				
11	Common Equity	40.00%	$206,936,845	8.78%	$18,169,055
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$206,936,845	8.78%	$18,169,055
14	**Total**	100.00%	$517,342,112	5.53%	$28,590,068

PowerStream

Actual Rate Base $ 1,038,043,696

		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$581,304,470	3.88%	$22,569,168
9	Short-term Debt	4.00%	$41,521,748	1.76%	$730,783
10	**Total Debt**	60.00%	$622,826,217	3.74%	$23,299,950
	Equity				
11	Common Equity	40.00%	$415,217,478	8.78%	$36,456,095
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$415,217,478	8.78%	$36,456,095
14	**Total**	100.00%	$1,038,043,696	5.76%	$59,756,045

Enersource

	Actual Rate Base		$ 792,141,777		
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$443,599,395	5.09%	$22,585,420
9	Short-term Debt	4.00%	$31,685,671	2.08%	$659,062
10	**Total Debt**	60.00%	$475,285,066	4.89%	$23,244,482
	Equity				
11	Common Equity	40.00%	$316,856,711	8.93%	$28,295,304
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$316,856,711	8.93%	$28,295,304
14	**Total**	100.00%	$792,141,777	6.51%	$51,539,786

Brampton

	Actual Rate Base		$ 421,399,759		
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$235,983,865	6.07%	$14,330,996
9	Short-term Debt	4.00%	$16,855,990	2.16%	$364,089
10	**Total Debt**	60.00%	$252,839,855	5.81%	$14,695,085
	Equity				
11	Common Equity	40.00%	$168,559,904	9.30%	$15,676,071
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$168,559,904	9.30%	$15,676,071
14	**Total**	100.00%	$421,399,759	7.21%	$30,371,156

ALECTRA

	Actual Rate Base		$ 2,768,927,344		
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$1,550,599,313	4.48%	$69,542,387
9	Short-term Debt	4.00%	$110,757,094	1.91%	$2,118,143
10	**Total Debt**	60.00%	$1,661,356,407	4.31%	$71,660,530
	Equity				
11	Common Equity	40.00%	$1,107,570,938	8.90%	$98,596,525
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$1,107,570,938	8.90%	$98,596,525
14	**Total**	100.00%	$2,768,927,344	6.15%	$170,257,055

Table 3: Reconciliation of additions / (deductions) for tax

	AUC - LDC Provision IFRS		11 months: (February 1 - December 31, 2017) Updated 2016 Year HRZ Portion	ERZ	BRZ	PRZ	Non-Regulated, MIFRS & Merger	Allocation Basis
			23.48%	12.87%	25.67%	37.99%		
Net Income before tax	99,454,037							
Additions:								
Interest and penalities on taxes	75,819					75,819		
Amortization of tangible assets	116,773,494		20,355,959	30,375,678	14,386,972	48,344,970	3,309,915	From ESM depreciation calculation
Derecognition expense	5,635,328		1,564,672	1,737,468	678,504	1,654,684		HRZ specific
Non-deductible club dues and fees	140,792		33,052	18,117	36,134	53,489		OM&A %
Non-deductible meals	235,230		55,223	30,269	60,372	89,367		OM&A %
Non-deductible automobile expenses	15,452		3,627	1,988	3,966	5,870		OM&A %
Amortization	265,786		-				265,786	Not Attributable to HRZ
Non-deductible reserves - closing	80,364,899		30,754,715	7,831,661	5,514,859	26,276,409	9,987,254	HRZ specific
Capital Items Expensed	140,000		140,000					HRZ specific
Debt issuance cost	102,227		-	102,227				Not Attributable to HRZ
Interest on capital lease - building	957,924		-			957,924		Not Attributable to HRZ
12(1)(x) income on capital contributions	61,886,099		4,687,789	4,590,989	11,891,968	40,715,354		HRZ specific
Total Additions	266,593,050		57,595,037	44,688,398	32,572,775	118,173,885	13,562,955	
Deductions:								
Accounting loss (gain) on sale of assets	(518,417)		(368,526)	(47,115)	(9,042)	(93,733)		HRZ specific
Reverse book income on joint venture	(121,856)		-			(121,856)		Not Attributable to HRZ
Removal Costs (Included in deprecation above; deductible for tax)	(94,469)		-		(94,469)			Not Attributable to HRZ
SR&ED and Apprenticeship ITCs	(460,402)		6,285	(466,687)				HRZ specific
CCA	(165,769,927)		(29,755,422)	(42,446,887)	(18,731,641)	(62,239,337)	(12,596,640)	HRZ specific
Capitalized Interest (AFUDC) (income recorded in P&L)	(2,668,430)		(306,323)	(480,683)	(342,153)	(1,539,272)		HRZ specific
Deductible OMERS contributions 20.1(q); capitalized for accounting	(223,631)		-		(223,631)			Not Attributable to HRZ
Less: Amortization of deferred revenue (IFRS)	(6,510,214)		-				(6,510,214)	Not Applicable
Stranded Meter Rate Rider applied against UCC	(2,438,301)		-				(2,438,301)	Not Attributable to HRZ
13(7.4) election	(61,886,099)		(4,687,789)	(4,590,989)	(11,891,968)	(40,715,354)		HRZ specific
Non-deductible - opening	(76,554,199)		(34,443,812)	(7,145,433)	(5,223,726)	(23,963,454)	(5,777,774)	HRZ specific
Cash payment on capital leases	(1,310,752)		-			(1,310,752)		Not Attributable to HRZ
20(1)(e)	(233,437)		-	(44,128)	(8,583)	(180,726)		Not Attributable to HRZ
Regulatory Balance Movement - Energy Accounts	(9,693,160)		-				(9,693,160)	Not Applicable
Accounting accrual for ITCs	(800,000)		(187,808)	(102,942)	(205,320)	(303,929)		OM&A %
Total Deductions	(329,283,295)		(69,743,394)	(55,324,864)	(36,730,532)	(130,468,413)	(37,016,090)	
Total	36,763,792		(12,148,357)	(10,636,467)	(4,157,757)	(12,294,528)	(23,453,134)	
Donation carryforward utilization	(1,185,131)							
	35,578,661							
Loss utilization	(35,578,661)							
	-							
	26.50%							
Current Tax Expense	-	[A]						
One-time adjustments to current tax for prior years	(28,065)	[A]						
Deferred Tax Expense	28,506,495	[A]						
Total IFRS Tax Expense	28,478,430	SUM OF [A]						

HRZ-Staff-2

ATTACH 4 – 2018 ESM revised 3 year average OM&A allocation

Table 1: 2018 Allocations for Calculation of HRZ Earnings Sharing - UPDATED NEW 3 YEAR AVERAGE (HRZ-Staff-2)

Category	Rate Zone Actual/Allocation	Total Alectra	Rate Zones HRZ	BRZ	ERZ	PRZ	Explanation / Reference
Alectra Direct Allocations							
Cost of Power	Actual	$ 2,614,964,903	$494,866,319	$443,298,237	$755,915,626	$920,884,722	
Distribution Revenues	Actual	$ 535,447,023	$114,566,462	$ 78,166,703	$ 134,161,789	$ 208,552,069	
Other Revenue	Actual	$ 25,505,673	$4,908,678	$ 3,254,133	$ 4,701,000	$ 12,641,863	
Alectra OM&A - % Allocations:							
Alectra OM&A - Formula Allocations:		100.00%	24.15%	13.12%	24.36%	38.37%	Revised 3 Year Average (HRZ-Staff-2)
Distribution - Operations	Allocation	$ 54,422,774	$ 13,144,423	$ 7,142,576	$ 13,254,692	$ 20,881,082	
Distribution - Maintenance	Allocation	$ 32,782,854	$ 7,917,856	$ 4,302,501	$ 7,984,280	$ 12,578,217	
Billing & Collecting	Allocation	$ 37,049,228	$ 8,948,289	$ 4,862,430	$ 9,023,357	$ 14,215,152	
Community Relations	Allocation	$ 3,024,349	$ 730,454	$ 396,923	$ 736,582	$ 1,160,391	
Administrative & General Expenses	Allocation	$ 101,136,768	$ 24,426,988	$ 13,273,434	$ 24,631,908	$ 38,804,438	
Property Taxes & Donations	Allocation	$ 3,641,979	$ 879,626	$ 477,982	$ 887,006	$ 1,397,365	
Net Merger Costs	Allocation	$ 24,020,161	$ 5,801,453	$ 3,152,464	$ 5,850,122	$ 9,216,123	
Total OM&A Formula Allocations		***$ 256,078,113***	***$ 61,849,089***	***$ 33,608,310***	***$ 62,367,946***	***$ 98,252,767***	
Total Alectra OM&A		**$ 256,078,113**	**$ 61,849,089**	**$ 33,608,310**	**$ 62,367,946**	**$ 98,252,767**	
Rate Base							
Opening Net Fixed Assets - Direct Allocations	Actual	$ 2,496,792,328	$ 461,744,377	$ 360,856,268	$ 689,121,178	$ 985,070,505	
Capital Additions - Direct Allocations							
Distribution Plant	Actual	$ 304,197,741	$ 43,812,267	$ 36,276,670	$ 89,398,920	$ 134,709,884	
Capital Additions - Formula Allocations							
General Plant	Allocation	$ 57,924,202	$ 10,600,129	$ 8,804,479	$ 16,276,701	$ 22,242,894	
Merger Capital Net Savings	Allocation	$ 5,233,012	$ 957,641	$ 795,418	$ 1,470,476	$ 2,009,477	
Depreciation - Direct Allocations							
Distribution Plant	Actual	$ 92,007,358	$ 16,034,721	$ 14,646,811	$ 25,601,175	$ 35,724,651	
Depreciation - Formula Allocations							
General Plant	Allocation	$ 31,376,300	$ 6,935,435	$ 2,162,773	$ 7,411,051	$ 14,867,040	
Asset Retirements - Direct Allocations	Actual	$ 7,163,199	$ 2,395,404	$ 739,320	$ 1,656,091	$ 2,372,384	
Work in Progress		$ 17,477,371	$ 6,743,683	$ 380,760	$ 6,328,097	$ 4,024,831	
Capital Contributions	Actual	$ 63,392,161	$ 5,996,189	$ 9,416,961	$ 4,662,297	$ 43,316,714	
Closing Net Fixed Assets		$ 2,652,730,894	$ 479,008,982	$ 379,386,210	$ 750,608,564	$ 1,043,727,139	
Average NFA for Rev. Req. Purposes		$ 2,574,761,611	$ 470,376,680	$ 370,121,239	$ 719,864,871	$ 1,014,398,822	
Working Capital Allowance Rate			12.00%	13.00%	13.50%	7.50%	
Working Capital Allowance		$ 315,707,294	$ 66,805,849	$ 61,997,851	$ 110,468,282	$ 76,435,312	Updated Working Capital Calculation
Total Rate Base		$ 2,890,468,905	$ 537,182,529	$ 432,119,090	$ 830,333,153	$ 1,090,834,134	Updated Rate Base
Regulatory Net Income before interest & tax		$ 174,327,727	$ 32,260,491	$ 30,263,621	$ 41,826,525	$ 69,977,090	
Regulatory Deemed Debt		$ 75,307,758	$ 11,388,819	$ 15,068,891	$ 24,365,163	$ 24,484,886	Updated Deemed Debt
Regulatory Net Income before tax		$ 99,019,968	$ 20,871,672	$ 15,194,730	$ 17,461,362	$ 45,492,204	
ESM Adjustments per Settlement Agreement		$ (57,048)	$ (57,048)	$ -	$ -	$ -	
PILs		$ 10,829,013	$ 2,833,891	$ 2,753,975	$ 931,033	$ 4,310,114	Includes adjustment in PILS Additions & Updated 3 YR AVG
Regulatory Net Income		$ 88,133,907	$ 17,980,733	$ 12,440,756	$ 16,530,329	$ 41,182,090	
Regulatory Deemed Equity		$ 1,156,187,562	$ 214,873,011	$ 172,847,636	$ 332,133,261	$ 436,333,653	
Regulatory ROE		7.62%	8.368%	7.20%	4.98%	9.44%	
Per Annual Filling EB-2017-0024			9.000%				
Return in Excess / (N/A)			$ (1,357,838)				
Amount Payable to Ratepayers / (N/A)			$ (678,919)				

Table 2: Capitalization / Cost of Capital 2018 Actual (12 Months)

Horizon

	Actual Rate Base		$ 537,182,529		
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$300,822,216	3.62%	$10,896,760
9	Short-term Debt	4.00%	$21,487,301	2.29%	$492,059
10	**Total Debt**	60.00%	$322,309,517	3.36%	$11,388,819
	Equity				
11	Common Equity	40.00%	$214,873,011	9.00%	$19,338,571
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$214,873,011	9.00%	$19,338,571
14	**Total**	100.00%	$537,182,529	5.53%	$30,727,390

PowerStream

	Actual Rate Base		$ 1,090,834,134		
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$610,867,115	3.88%	$23,716,938
9	Short-term Debt	4.00%	$43,633,365	1.76%	$767,947
10	**Total Debt**	60.00%	$654,500,480	3.74%	$24,484,886
	Equity				
11	Common Equity	40.00%	$436,333,653	8.78%	$38,310,095
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$436,333,653	8.78%	$38,310,095
14	**Total**	100.00%	$1,090,834,134	5.76%	$62,794,980

Enersource

	Actual Rate Base		$ 830,333,153		
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$464,986,566	5.09%	$23,674,326
9	Short-term Debt	4.00%	$33,213,326	2.08%	$690,837
10	**Total Debt**	60.00%	$498,199,892	4.89%	$24,365,163
	Equity				
11	Common Equity	40.00%	$332,133,261	8.93%	$29,659,500
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$332,133,261	8.93%	$29,659,500
14	**Total**	100.00%	$830,333,153	6.51%	$54,024,663

Brampton

	Actual Rate Base		$ 432,119,090		
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$241,986,690	6.07%	$14,695,540
9	Short-term Debt	4.00%	$17,284,764	2.16%	$373,351
10	**Total Debt**	60.00%	$259,271,454	5.81%	$15,068,891
	Equity				
11	Common Equity	40.00%	$172,847,636	9.30%	$16,074,830
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$172,847,636	9.30%	$16,074,830
14	**Total**	100.00%	$432,119,090	7.21%	$31,143,721

ALECTRA

	Actual Rate Base		$ 2,890,468,905		
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$1,618,662,587	4.51%	$72,983,564
9	Short-term Debt	4.00%	$115,618,756	2.01%	$2,324,195
10	**Total Debt**	60.00%	$1,734,281,343	4.34%	$75,307,758
	Equity				
11	Common Equity	40.00%	$1,156,187,562	8.94%	$103,382,996
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$1,156,187,562	8.94%	$103,382,996
14	**Total**	100.00%	$2,890,468,905	6.18%	$178,690,755

Table 3: Reconciliation of additions / (deductions) for tax

	Provision IFRS	HRZ	ERZ	BRZ	PRZ	Non-Regulated, MIFRS & Merger	Allocation Basis
		12 months: 2018					
		24.15%	13.12%	24.36%	38.37%		
Net Income before tax	148,270,099						
Additions:							
Interest and penalities on taxes	(3,162)	(3,162)					
Amortization of tangible assets	131,754,575	22,970,156	33,012,226	16,809,584	50,591,691	8,370,918	From ESM depreciation calculation
Derecognition expense	7,305,330	2,395,404	1,656,091	739,320	2,372,384	142,131	HRZ specific
Non-deductible club dues and fees	79,909	19,300	10,487	19,462	30,660	-	OM&A %
Non-deductible meals	284,114	68,620	37,288	69,196	109,010	-	OM&A %
Non-deductible automobile expenses	16,867	4,074	2,214	4,108	6,472	-	OM&A %
Amortization						-	Not Attributable to HRZ
Non-deductible reserves - closing	67,037,175	30,660,573	8,263,445	5,705,602	19,860,914	2,546,642	HRZ specific
Capital Items Expensed						-	HRZ specific
Debt issuance cost	85,565		85,565			-	Not Attributable to HRZ
Interest on capital lease - building	1,020,053				1,020,053	-	Not Attributable to HRZ
12(1)(x) income on capital contributions	68,266,584	5,996,189	9,048,363	9,416,961	43,805,071	-	HRZ specific
Non-regulated solar	918,287					918,287	
Capital costs expensed for accounting	268,362					268,362	
Total Additions	277,033,659	62,111,153	52,115,679	32,764,233	117,796,254	12,246,340	
Deductions:							
Accounting loss (gain) on sale of assets	(680,975)	(396,825)	(150,875)	14,588	(147,864)	-	HRZ specific
SR&ED and Apprenticeship ITCs						-	HRZ specific
CCA	(200,441,645)	(33,064,772)	(47,011,284)	(20,887,268)	(69,177,711)	(30,300,610)	HRZ specific
Capitalized Interest (AFUDC) (income recorded in P&L)	(3,776,038)	(316,885)	(406,001)	(458,274)	(2,594,878)	-	HRZ specific
Deductible OMERS contributions 20.1(q); capitalized for accounting	(4,861,883)	(968,231)	(1,174,143)	(532,095)	(2,187,414)	-	HRZ specific
Less: Amortization of deferred revenue (IFRS)	(8,824,272)					(8,824,272)	Not Applicable
13(7.4) election	(68,266,584)	(5,996,189)	(9,048,363)	(9,416,961)	(43,805,071)	-	HRZ specific
Capital gain on disposition of fixed assets	25,299	20,963			4,336	-	HRZ specific
Non-deductible - opening	(80,364,899)	(30,754,715)	(7,831,661)	(5,514,859)	(26,276,409)	(9,987,254)	HRZ specific
Cash payment on capital leases	(1,429,911)				(1,429,911)	-	Not Attributable to HRZ
20(1)(e)	(250,480)		(31,014)	(10,205)	(209,261)	-	Not Attributable to HRZ
Regulatory Balance Movement - Energy Accounts	8,034,409					8,034,409	Not Applicable
Accounting accrual for ITCs	(428,672)	(103,535)	(56,260)	(104,403)	(164,474)	-	OM&A %
Sale of Collus	(3,652,434)				-	(3,652,434)	
Total Deductions	(364,918,086)	(71,580,189)	(65,709,601)	(36,909,478)	(145,988,657)	(44,730,161)	

Total	60,385,672				
Donation carryforward utilization	-				
	60,385,672				
Loss utilization	(17,766,999)				
	42,618,673				
ITC Carryforward Utilization	(1,529,632)				
	41,089,041				
			Taxable income	Aggregate Inv Inc	
Taxable income multiplied by 38%	16,195,096	38%			
Aggregate investment income	270,353	10.67%	42,618,673	(2,534,557)	40,084,116
Less: Federal tax abatement	(4,261,867)	10.00%			
Less: General tax reduction	(5,210,935.12)	13%			
Less: Federal invstemetn tax credit	(1,529,632)				
Federal Tax Payable	5,463,014				
Ontario Taxable income	42,618,673				
	11.50%				
	4,901,147				
Ontario ITC Utilization	(335,915)				
Ontario Tax Payable	4,565,232				
Total Current Tax Payable / Expense	10,028,246	[A]			
One-time adjustments to current tax for prior years	(1,938,102)	[A]			
Deferred Tax Expense	30,239,376	[A]			
Total IFRS Tax Expense	38,329,520	SUM OF [A]			
	0				

			HRZ	ERZ	BRZ	PRZ
Regulatory Net Income before tax	$ 99,019,968		$ 20,871,672	$ 17,461,362	$ 15,194,730	$ 45,492,204
Net Tax Adjustments	$ (55,400,606)		$ (9,469,036)	$ (13,593,922)	$ (4,145,246)	$ (28,192,403)
Total Taxable income	$ 43,619,362		$ 11,402,636	$ 3,867,441	$ 11,049,485	$ 17,299,801
Total PILS	$ 11,559,131	0.265	$ 3,021,699	$ 1,024,872	$ 2,928,113	$ 4,584,447
ESM Adjustments Pils Impact	$ (15,118)		$ (15,118)			
Total PILS	$ 11,544,013	0.265	$ 3,006,581	$ 1,024,872	$ 2,928,113	$ 4,584,447
Tax Credits	$ (715,000)		$ (172,690)	$ (93,838)	$ (174,139)	$ (274,333)
Final Pils without ESM Adjustments	$ 10,844,131		$ 2,849,009	$ 931,033	$ 2,753,975	$ 4,310,114
Final Pils with ESM Adjustments	$ 10,829,013		$ 2,833,891	$ 931,033	$ 2,753,975	$ 4,310,114

HRZ-Staff-2

ATTACH 5 – 2018 ESM with 5 year average OM&A allocation

Table 1: 2018 Allocations for Calculation of HRZ Earnings Sharing - UPDATED NEW 5 YEAR AVERAGE (HRZ-Staff-2e)

Category	Rate Zone Actual/Allocation	Total Alectra	Rate Zones HRZ	BRZ	ERZ	PRZ	Explanation / Reference
Alectra Direct Allocations							
Cost of Power	Actual	$ 2,614,964,903	$494,866,319	$443,298,237	$755,915,626	$920,884,722	
Distribution Revenues	Actual	$ 535,447,023	$114,566,462	$ 78,166,703	$ 134,161,789	$ 208,552,069	
Other Revenue	Actual	$ 25,505,673	$4,908,678	$ 3,254,133	$ 4,701,000	$ 12,641,863	
Alectra OM&A - % Allocations:							
Alectra OM&A - Formula Allocations:		100.00%	23.92%	12.55%	24.58%	38.95%	Updated 5 Year Average
Distribution - Operations	Allocation	$ 54,422,774	$ 13,017,025	$ 6,830,420	$ 13,376,586	$ 21,198,742	
Distribution - Maintenance	Allocation	$ 32,782,854	$ 7,841,115	$ 4,114,466	$ 8,057,705	$ 12,769,567	
Billing & Collecting	Allocation	$ 37,049,228	$ 8,861,561	$ 4,649,925	$ 9,106,339	$ 14,431,404	
Community Relations	Allocation	$ 3,024,349	$ 723,374	$ 379,576	$ 743,356	$ 1,178,044	
Administrative & General Expenses	Allocation	$ 101,136,768	$ 24,190,238	$ 12,693,338	$ 24,858,430	$ 39,394,762	
Property Taxes & Donations	Allocation	$ 3,641,979	$ 871,101	$ 457,093	$ 895,163	$ 1,418,622	
Net Merger Costs	Allocation	$ 24,020,161	$ 5,745,224	$ 3,014,690	$ 5,903,921	$ 9,356,326	
Total OM&A Formula Allocations		***$ 256,078,113***	***$ 61,249,639***	***$ 32,139,508***	***$ 62,941,500***	***$ 99,747,466***	
Total Alectra OM&A		**$ 256,078,113**	**$ 61,249,639**	**$ 32,139,508**	**$ 62,941,500**	**$ 99,747,466**	
Rate Base							
Opening Net Fixed Assets - Direct Allocations	Actual	$ 2,496,792,328	$ 461,744,377	$ 360,856,268	$ 689,121,178	$ 985,070,505	
Capital Additions - Direct Allocations							
Distribution Plant	Actual	$ 304,197,741	$ 43,812,267	$ 36,276,670	$ 89,398,920	$ 134,709,884	
Capital Additions - Formula Allocations							
General Plant	Allocation	$ 57,924,202	$ 10,600,129	$ 8,804,479	$ 16,276,701	$ 22,242,894	
Merger Capital Net Savings	Allocation	$ 5,233,012	$ 957,641	$ 795,418	$ 1,470,476	$ 2,009,477	
Depreciation - Direct Allocations							
Distribution Plant	Actual	$ 92,007,358	$ 16,034,721	$ 14,646,811	$ 25,601,175	$ 35,724,651	
Depreciation - Formula Allocations							
General Plant	Allocation	$ 31,376,300	$ 6,935,435	$ 2,162,773	$ 7,411,051	$ 14,867,040	
Asset Retirements - Direct Allocations	Actual	$ 7,163,199	$ 2,395,404	$ 739,320	$ 1,656,091	$ 2,372,384	
Work in Progress		$ 17,477,371	$ 6,743,683	$ 380,760	$ 6,328,097	$ 4,024,831	
Capital Contributions	Actual	$ 63,392,161	$ 5,996,189	$ 9,416,961	$ 4,662,297	$ 43,316,714	
Closing Net Fixed Assets		$ 2,652,730,894	$ 479,008,982	$ 379,386,210	$ 750,608,564	$ 1,043,727,139	
Average NFA for Rev. Req. Purposes		$ 2,574,761,611	$ 470,376,680	$ 370,121,239	$ 719,864,871	$ 1,014,398,822	
Working Capital Allowance Rate			12.00%	13.00%	13.50%	7.50%	
Working Capital Allowance		$ 315,633,948	$ 66,733,915	$ 61,806,907	$ 110,545,712	$ 76,547,414	Updated Working Capital Calculation
Total Rate Base		$ 2,890,395,559	$ 537,110,594	$ 431,928,146	$ 830,410,583	$ 1,090,946,236	Updated Rate Base
Regulatory Net Income before interest & tax		$ 174,327,727	$ 32,859,941	$ 31,732,423	$ 41,252,972	$ 68,482,391	
Regulatory Deemed Debt		$ 75,304,363	$ 11,387,294	$ 15,062,232	$ 24,367,435	$ 24,487,402	Updated Deemed Debt
Regulatory Net Income before tax		$ 99,023,364	$ 21,472,647	$ 16,670,191	$ 16,885,536	$ 43,994,989	
ESM Adjustments per Settlement Agreement		$ (57,048)	$ (57,048)	$ -	$ -	$ -	
PILs		$ 10,829,913	$ 2,994,853	$ 3,143,342	$ 782,613	$ 3,909,105	Adjusted PILS & Updated for 5 YR Average
Regulatory Net Income		$ 88,136,403	$ 18,420,746	$ 13,526,849	$ 16,102,923	$ 40,085,884	
Regulatory Deemed Equity		$ 1,156,158,224	$ 214,844,238	$ 172,771,258	$ 332,164,233	$ 436,378,494	
Regulatory ROE		7.62%	8.574%	7.83%	4.85%	9.19%	
Per Annual Filling EB-2017-0024			9.000%				
Return in Excess / (N/A)			$ (915,235)				
Amount Payable to Ratepayers / (N/A)			$ (457,617)				

Table 2: Capitalization / Cost of Capital 2018 Actual (12 Months)

Horizon

Actual Rate Base $ 537,110,594

		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$300,781,933	3.62%	$10,895,301
9	Short-term Debt	4.00%	$21,484,424	2.29%	$491,993
10	**Total Debt**	60.00%	$322,266,357	3.36%	$11,387,294
	Equity				
11	Common Equity	40.00%	$214,844,238	9.00%	$19,335,981
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$214,844,238	9.00%	$19,335,981
14	**Total**	100.00%	$537,110,594	5.53%	$30,723,275

PowerStream

Actual Rate Base $ 1,090,946,236

		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$610,929,892	3.88%	$23,719,376
9	Short-term Debt	4.00%	$43,637,849	1.76%	$768,026
10	**Total Debt**	60.00%	$654,567,742	3.74%	$24,487,402
	Equity				
11	Common Equity	40.00%	$436,378,494	8.78%	$38,314,032
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$436,378,494	8.78%	$38,314,032
14	**Total**	100.00%	$1,090,946,236	5.76%	$62,801,434

Enersource

	Actual Rate Base		$ 830,410,583		
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$465,029,926	5.09%	$23,676,534
9	Short-term Debt	4.00%	$33,216,423	2.08%	$690,902
10	**Total Debt**	60.00%	$498,246,350	4.89%	$24,367,435
	Equity				
11	Common Equity	40.00%	$332,164,233	8.93%	$29,662,266
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$332,164,233	8.93%	$29,662,266
14	**Total**	100.00%	$830,410,583	6.51%	$54,029,701

Brampton

	Actual Rate Base		$ 431,928,146		
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$241,879,762	6.07%	$14,689,046
9	Short-term Debt	4.00%	$17,277,126	2.16%	$373,186
10	**Total Debt**	60.00%	$259,156,887	5.81%	$15,062,232
	Equity				
11	Common Equity	40.00%	$172,771,258	9.30%	$16,067,727
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$172,771,258	9.30%	$16,067,727
14	**Total**	100.00%	$431,928,146	7.21%	$31,129,959

ALECTRA

	Actual Rate Base		$ 2,890,395,559		
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$1,618,621,513	4.51%	$72,980,256
9	Short-term Debt	4.00%	$115,615,822	2.01%	$2,324,107
10	**Total Debt**	60.00%	$1,734,237,335	4.34%	$75,304,363
	Equity				
11	Common Equity	40.00%	$1,156,158,224	8.94%	$103,380,006
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$1,156,158,224	8.94%	$103,380,006
14	**Total**	100.00%	$2,890,395,559	6.18%	$178,684,369

Table 3: Reconciliation of additions / (deductions) for tax

12 months: 2018

	Provision IFRS		HRZ	ERZ	BRZ	PRZ	Non-Regulated, MIFRS & Merger	Allocation Basis
			23.92%	12.55%	24.58%	38.95%		
Net Income before tax	148,270,099							
Additions:								
Interest and penalities on taxes	(3,162)		(3,162)					
Amortization of tangible assets	131,754,575		22,970,156	33,012,226	16,809,584	50,591,691	8,370,918	From ESM depreciation calculation
Derecognition expense	7,305,330		2,395,404	1,656,091	739,320	2,372,384	142,131	HRZ specific
Non-deductible club dues and fees	79,909		19,113	10,029	19,641	31,126	-	OM&A %
Non-deductible meals	284,114		67,955	35,658	69,832	110,668	-	OM&A %
Non-deductible automobile expenses	16,867		4,034	2,117	4,146	6,570	-	OM&A %
Amortization							-	Not Attributable to HRZ
Non-deductible reserves - closing	67,037,175		30,660,573	8,263,445	5,705,602	19,860,914	2,546,642	HRZ specific
Capital Items Expensed							-	HRZ specific
Debt issuance cost	85,565			85,565			-	Not Attributable to HRZ
Interest on capital lease - building	1,020,053					1,020,053	-	Not Attributable to HRZ
12(1)(x) income on capital contributions	68,266,584		5,996,189	9,048,363	9,416,961	43,805,071	-	HRZ specific
Non-regulated solar	918,287						918,287	
Capital costs expensed for accounting	268,362						268,362	
Total Additions	277,033,659		62,110,262	52,113,494	32,765,086	117,798,477	12,246,340	
Deductions:								
Accounting loss (gain) on sale of assets	(680,975)		(396,825)	(150,875)	14,588	(147,864)	-	HRZ specific
SR&ED and Apprenticeship ITCs							-	HRZ specific
CCA	(200,441,645)		(33,064,772)	(47,011,284)	(20,887,268)	(69,177,711)	(30,300,610)	HRZ specific
Capitalized Interest (AFUDC) (income recorded in P&L)	(3,776,038)		(316,885)	(406,001)	(458,274)	(2,594,878)	-	HRZ specific
Deductible OMERS contributions 20.1(q); capitalized for accounting	(4,861,883)		(968,231)	(1,174,143)	(532,095)	(2,187,414)	-	HRZ specific
Less: Amortization of deferred revenue (IFRS)	(8,824,272)						(8,824,272)	Not Applicable
13(7.4) election	(68,266,584)		(5,996,189)	(9,048,363)	(9,416,961)	(43,805,071)	-	HRZ specific
Capital gain on disposition of fixed assets	25,299		20,963			4,336	-	HRZ specific
Non-deductible - opening	(80,364,899)		(30,754,715)	(7,831,661)	(5,514,859)	(26,276,409)	(9,987,254)	HRZ specific
Cash payment on capital leases	(1,429,911)					(1,429,911)	-	Not Attributable to HRZ
20(1)(e)	(250,480)			(31,014)	(10,205)	(209,261)	-	Not Attributable to HRZ
Regulatory Balance Movement - Energy Accounts	8,034,409						8,034,409	Not Applicable
Accounting accrual for ITCs	(428,672)		(102,531)	(53,801)	(105,363)	(166,976)	-	OM&A %
Sale of Collus	(3,652,434)					-	(3,652,434)	
Total Deductions	(364,918,086)		(71,579,185)	(65,707,142)	(36,910,438)	(145,991,159)	(44,730,161)	
Total	60,385,672							
Donation carryforward utilization	-							
	60,385,672							
Loss utilization	(17,766,999)							
	42,618,673							
ITC Carryforward Utilization	(1,529,632)							
	41,089,041							
Taxable income multiplied by 38%	16,195,096	38%		Taxable income	Aggregate Inv Inc			
Aggregate investment income	270,353	10.67%		42,618,673	(2,534,557)	40,084,116		
Less: Federal tax abatement	(4,261,867)	10.00%						
Less: General tax reduction	(5,210,935.12)	13%						
Less: Federal invstemetn tax credit	(1,529,632)							
Federal Tax Payable	5,463,014							
Ontario Taxable income	42,618,673							
	11.50%							
	4,901,147							
Ontario ITC Utilization	(335,915)							
Ontario Tax Payable	4,565,232							
Total Current Tax Payable / Expense	10,028,246	[A]						
One-time adjustments to current tax for prior years	(1,938,102)	[A]						
Deferred Tax Expense	30,239,376	[A]						
Total IFRS Tax Expense	38,329,520	SUM OF [A]						
	0							

			HRZ	ERZ	BRZ	PRZ
Regulatory Net Income before tax	$ 99,023,364		$ 21,472,647	$ 16,885,536	$ 16,670,191	$ 43,994,989
Net Tax Adjustments	$ (55,400,606)		$ (9,468,924)	$ (13,593,647)	$ (4,145,353)	$ (28,192,682)
Total Taxable income	$ 43,622,758		$ 12,003,724	$ 3,291,889	$ 12,524,839	$ 15,802,306
Total PILS	$ 11,560,031	0.265	$ 3,180,987	$ 872,351	$ 3,319,082	$ 4,187,611
ESM Adjustments Pils Impact	$ (15,118)		$ (15,118)			
Total PILS	$ 11,544,913	0.265	$ 3,165,869	$ 872,351	$ 3,319,082	$ 4,187,611
Tax Credits	$ (715,000)		$ (171,016)	$ (89,737)	$ (175,740)	$ (278,507)
Final Pils without ESM Adjustments	$ 10,845,031		$ 3,009,971	$ 782,613	$ 3,143,342	$ 3,909,105
Final Pils with ESM Adjustments	$ 10,829,913		$ 2,994,853	$ 782,613	$ 3,143,342	$ 3,909,105

HRZ-Staff-2

ATTACH 6 – 2018 ESM with Year 2016 OM&A allocation

Table 1: 2018 Allocations for Calculation of HRZ Earnings Sharing - UPDATED 2016 YEAR OM&A ALLOCATION (HRZ-Staff-2e)

	Rate Zone		Rate Zones				
Category	**Actual/Allocation**	**Total Alectra**	**HRZ**	**BRZ**	**ERZ**	**PRZ**	**Explanation / Reference**
Alectra Direct Allocations							
Cost of Power	Actual	$ 2,614,964,903	$494,866,319	$443,298,237	$755,915,626	$920,884,722	
Distribution Revenues	Actual	$ 535,447,023	$114,566,462	$ 78,166,703	$ 134,161,789	$ 208,552,069	
Other Revenue	Actual	$ 25,505,673	$4,908,678	$ 3,254,133	$ 4,701,000	$ 12,641,863	
Alectra OM&A - % Allocations:							
Alectra OM&A - Formula Allocations:		100.00%	23.44%	13.71%	25.46%	37.39%	Revised 2016 YEAR OM&A Allocation
Distribution - Operations	Allocation	$ 54,422,774	$ 12,756,419	$ 7,460,834	$ 13,855,574	$ 20,349,947	
Distribution - Maintenance	Allocation	$ 32,782,854	$ 7,684,133	$ 4,494,211	$ 8,346,235	$ 12,258,275	
Billing & Collecting	Allocation	$ 37,049,228	$ 8,684,149	$ 5,079,090	$ 9,432,417	$ 13,853,572	
Community Relations	Allocation	$ 3,024,349	$ 708,892	$ 414,609	$ 769,974	$ 1,130,875	
Administrative & General Expenses	Allocation	$ 101,136,768	$ 23,705,940	$ 13,864,870	$ 25,748,558	$ 37,817,400	
Property Taxes & Donations	Allocation	$ 3,641,979	$ 853,661	$ 499,280	$ 927,217	$ 1,361,821	
Net Merger Costs	Allocation	$ 24,020,161	$ 5,630,203	$ 3,292,931	$ 6,115,328	$ 8,981,699	
Total OM&A Formula Allocations		***$ 256,078,113***	***$ 60,023,398***	***$ 35,105,826***	***$ 65,195,301***	***$ 95,753,589***	
Total Alectra OM&A		**$ 256,078,113**	**$ 60,023,398**	**$ 35,105,826**	**$ 65,195,301**	**$ 95,753,589**	
Rate Base							
Opening Net Fixed Assets - Direct Allocations	Actual	$ 2,496,792,328	$ 461,744,377	$ 360,856,268	$ 689,121,178	$ 985,070,505	
Capital Additions - Direct Allocations							
Distribution Plant	Actual	$ 304,197,741	$ 43,812,267	$ 36,276,670	$ 89,398,920	$ 134,709,884	
Capital Additions - Formula Allocations							
General Plant	Allocation	$ 57,924,202	$ 10,600,129	$ 8,804,479	$ 16,276,701	$ 22,242,894	
Merger Capital Net Savings	Allocation	$ 5,233,012	$ 957,641	$ 795,418	$ 1,470,476	$ 2,009,477	
Depreciation - Direct Allocations							
Distribution Plant	Actual	$ 92,007,358	$ 16,034,721	$ 14,646,811	$ 25,601,175	$ 35,724,651	
Depreciation - Formula Allocations							
General Plant	Allocation	$ 31,376,300	$ 6,935,435	$ 2,162,773	$ 7,411,051	$ 14,867,040	
Asset Retirements - Direct Allocations	Actual	$ 7,163,199	$ 2,395,404	$ 739,320	$ 1,656,091	$ 2,372,384	
Work in Progress		$ 17,477,371	$ 6,743,683	$ 380,760	$ 6,328,097	$ 4,024,831	
Capital Contributions	Actual	$ 63,392,161	$ 5,996,189	$ 9,416,961	$ 4,662,297	$ 43,316,714	
Closing Net Fixed Assets		$ 2,652,730,894	$ 479,008,982	$ 379,386,210	$ 750,608,564	$ 1,043,727,139	
Average NFA for Rev. Req. Purposes		$ 2,574,761,611	$ 470,376,680	$ 370,121,239	$ 719,864,871	$ 1,014,398,822	
Working Capital Allowance Rate			12.00%	13.00%	13.50%	7.50%	
Working Capital Allowance		$ 315,877,143	$ 66,586,766	$ 62,192,528	$ 110,849,975	$ 76,247,873	Updated Working Capital Calculation
Total Rate Base		$ 2,890,638,754	$ 536,963,446	$ 432,313,767	$ 830,714,846	$ 1,090,646,695	Updated Rate Base
Regulatory Net Income before interest & tax		$ 174,327,727	$ 34,086,182	$ 28,766,106	$ 38,999,170	$ 72,476,268	
Regulatory Deemed Debt		$ 75,316,896	$ 11,384,174	$ 15,075,679	$ 24,376,364	$ 24,480,678	Updated Deemed Debt
Regulatory Net Income before tax		$ 99,010,831	$ 22,702,008	$ 13,690,427	$ 14,622,807	$ 47,995,590	
ESM Adjustments per Settlement Agreement		$ (57,048)	$ (57,048)	$ -	$ -	$ -	
PILs		$ 10,826,592	$ 3,324,118	$ 2,347,300	$ 174,561	$ 4,980,613	Adjusted PILS & Updated 2016 YEAR OM&A
Regulatory Net Income		$ 88,127,191	$ 19,320,842	$ 11,343,126	$ 14,448,246	$ 43,014,977	
Regulatory Deemed Equity		$ 1,156,255,501	$ 214,785,378	$ 172,925,507	$ 332,285,938	$ 436,258,678	
Regulatory ROE		7.62%	8.995%	6.56%	4.35%	9.86%	
Per Annual Filling EB-2017-0024			9.000%				
Return in Excess / (N/A)			$ (9,842)				
Amount Payable to Ratepayers / (N/A)			$ (4,921)				

Table 2: Capitalization / Cost of Capital 2018 Actual (12 Months)

Horizon

Actual Rate Base $ 536,963,446

		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$300,699,529	3.62%	$10,892,316
9	Short-term Debt	4.00%	$21,478,538	2.29%	$491,859
10	**Total Debt**	60.00%	$322,178,067	3.36%	$11,384,174
	Equity				
11	Common Equity	40.00%	$214,785,378	9.00%	$19,330,684
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$214,785,378	9.00%	$19,330,684
14	**Total**	100.00%	$536,963,446	5.53%	$30,714,858

PowerStream

Actual Rate Base $ 1,090,646,695

		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$610,762,149	3.88%	$23,712,863
9	Short-term Debt	4.00%	$43,625,868	1.76%	$767,815
10	**Total Debt**	60.00%	$654,388,017	3.74%	$24,480,678
	Equity				
11	Common Equity	40.00%	$436,258,678	8.78%	$38,303,512
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$436,258,678	8.78%	$38,303,512
14	**Total**	100.00%	$1,090,646,695	5.76%	$62,784,190

Enersource

	Actual Rate Base			$ 830,714,846			
		(%)		($)	(%)		($)
	Debt						
8	Long-term Debt	56.00%		$465,200,314	5.09%		$23,685,209
9	Short-term Debt	4.00%		$33,228,594	2.08%		$691,155
10	**Total Debt**	60.00%		$498,428,908	4.89%		$24,376,364
	Equity						
11	Common Equity	40.00%		$332,285,938	8.93%		$29,673,134
12	Preferred Shares	0.00%		$ -	0.00%		$ -
13	**Total Equity**	40.00%		$332,285,938	8.93%		$29,673,134
14	**Total**	100.00%		$830,714,846	6.51%		$54,049,498

Brampton

	Actual Rate Base			$ 432,313,767			
		(%)		($)	(%)		($)
	Debt						
8	Long-term Debt	56.00%		$242,095,709	6.07%		$14,702,160
9	Short-term Debt	4.00%		$17,292,551	2.16%		$373,519
10	**Total Debt**	60.00%		$259,388,260	5.81%		$15,075,679
	Equity						
11	Common Equity	40.00%		$172,925,507	9.30%		$16,082,072
12	Preferred Shares	0.00%		$ -	0.00%		$ -
13	**Total Equity**	40.00%		$172,925,507	9.30%		$16,082,072
14	**Total**	100.00%		$432,313,767	7.21%		$31,157,751

ALECTRA

	Actual Rate Base			$ 2,890,638,754			
		(%)		($)	(%)		($)
	Debt						
8	Long-term Debt	56.00%		$1,618,757,702	4.51%		$72,992,548
9	Short-term Debt	4.00%		$115,625,550	2.01%		$2,324,348
10	**Total Debt**	60.00%		$1,734,383,252	4.34%		$75,316,896
	Equity						
11	Common Equity	40.00%		$1,156,255,501	8.94%		$103,389,402
12	Preferred Shares	0.00%		$ -	0.00%		$ -
13	**Total Equity**	40.00%		$1,156,255,501	8.94%		$103,389,402
14	**Total**	100.00%		$2,890,638,754	6.18%		$178,706,298

Table 3: Reconciliation of additions / (deductions) for tax

	Provision IFRS		HRZ	ERZ	BRZ	PRZ	Non-Regulated, MIFRS & Merger	Allocation Basis
			12 months: 2018					
			23.44%	13.71%	25.46%	37.39%		
Net Income before tax	148,270,099							
Additions:								
Interest and penalities on taxes	(3,162)		(3,162)					
Amortization of tangible assets	131,754,575		22,970,156	33,012,226	16,809,584	50,591,691	8,370,918	From ESM depreciation calculation
Derecognition expense	7,305,330		2,395,404	1,656,091	739,320	2,372,384	142,131	HRZ specific
Non-deductible club dues and fees	79,909		18,730	10,955	20,344	29,880	-	OM&A %
Non-deductible meals	284,114		66,595	38,949	72,333	106,237	-	OM&A %
Non-deductible automobile expenses	16,867		3,954	2,312	4,294	6,307	-	OM&A %
Amortization							-	Not Attributable to HRZ
Non-deductible reserves - closing	67,037,175		30,660,573	8,263,445	5,705,602	19,860,914	2,546,642	HRZ specific
Capital Items Expensed							-	HRZ specific
Debt issuance cost	85,565			85,565			-	Not Attributable to HRZ
Interest on capital lease - building	1,020,053					1,020,053	-	Not Attributable to HRZ
12(1)(x) income on capital contributions	68,266,584		5,996,189	9,048,363	9,416,961	43,805,071	-	HRZ specific
Non-regulated solar	918,287						918,287	
Capital costs expensed for accounting	268,362						268,362	
Total Additions	277,033,659		62,108,438	52,117,906	32,768,438	117,792,537	12,246,340	
Deductions:								
Accounting loss (gain) on sale of assets	(680,975)		(396,825)	(150,875)	14,588	(147,864)	-	HRZ specific
SR&ED and Apprenticeship ITCs							-	HRZ specific
CCA	(200,441,645)		(33,064,772)	(47,011,284)	(20,887,268)	(69,177,711)	(30,300,610)	HRZ specific
Capitalized Interest (AFUDC) (income recorded in P&L)	(3,776,038)		(316,885)	(406,001)	(458,274)	(2,594,878)	-	HRZ specific
Deductible OMERS contributions 20.1(q); capitalized for accounting	(4,861,883)		(968,231)	(1,174,143)	(532,095)	(2,187,414)	-	HRZ specific
Less: Amortization of deferred revenue (IFRS)	(8,824,272)						(8,824,272)	Not Applicable
13(7.4) election	(68,266,584)		(5,996,189)	(9,048,363)	(9,416,961)	(43,805,071)	-	HRZ specific
Capital gain on disposition of fixed assets	25,299		20,963			4,336	-	HRZ specific
Non-deductible - opening	(80,364,899)		(30,754,715)	(7,831,661)	(5,514,859)	(26,276,409)	(9,987,254)	HRZ specific
Cash payment on capital leases	(1,429,911)					(1,429,911)	-	Not Attributable to HRZ
20(1)(e)	(250,480)			(31,014)	(10,205)	(209,261)	-	Not Attributable to HRZ
Regulatory Balance Movement - Energy Accounts	8,034,409						8,034,409	Not Applicable
Accounting accrual for ITCs	(428,672)		(100,479)	(58,767)	(109,136)	(160,290)	-	OM&A %
Sale of Collus	(3,652,434)					-	(3,652,434)	
Total Deductions	(364,918,086)		(71,577,133)	(65,712,107)	(36,914,211)	(145,984,474)	(44,730,161)	
Total	60,385,672							
Donation carryforward utilization	-							
	60,385,672							
Loss utilization	(17,766,999)							
	42,618,673							
ITC Carryforward Utilization	(1,529,632)							
	41,089,041							
Taxable income multiplied by 38%	16,195,096	38%		Taxable income	Aggregate Inv Inc			
Aggregate investment income	270,353	10.67%		42,618,673	(2,534,557)	40,084,116		
Less: Federal tax abatement	(4,261,867)	10.00%						
Less: General tax reduction	(5,210,935.12)	13%						
Less: Federal invstemetn tax credit	(1,529,632)							
Federal Tax Payable	5,463,014							
Ontario Taxable income	42,618,673							
	11.50%							
	4,901,147							
Ontario ITC Utilization	(335,915)							
Ontario Tax Payable	4,565,232							
Total Current Tax Payable / Expense	10,028,246	[A]						
One-time adjustments to current tax for prior years	(1,938,102)	[A]						
Deferred Tax Expense	30,239,376	[A]						
Total IFRS Tax Expense	38,329,520	SUM OF [A]						
	0							

			HRZ	ERZ	BRZ	PRZ
Regulatory Net Income before tax	$ 99,010,831		$ 22,702,008	$ 14,622,807	$ 13,690,427	$ 47,995,590
Net Tax Adjustments	$ (55,400,606)		$ (9,468,695)	$ (13,594,201)	$ (4,145,773)	$ (28,191,937)
Total Taxable income	$ 43,610,225		$ 13,233,313	$ 1,028,606	$ 9,544,653	$ 19,803,653
Total PILS	$ 11,556,710	0.265	$ 3,506,828	$ 272,581	$ 2,529,333	$ 5,247,968
ESM Adjustments Pils Impact	$ (15,118)		$ (15,118)			
Total PILS	$ 11,541,592	0.265	$ 3,491,710	$ 272,581	$ 2,529,333	$ 5,247,968
Tax Credits	$ (715,000)		$ (167,592)	$ (98,020)	$ (182,033)	$ (267,355)
Final Pils without ESM Adjustments	$ 10,841,710		$ 3,339,236	$ 174,561	$ 2,347,300	$ 4,980,613
Final Pils with ESM Adjustments	$ 10,826,592		$ 3,324,118	$ 174,561	$ 2,347,300	$ 4,980,613

HRZ-Staff-3

Reference: Exhibit 3, Tab 1, Schedule 2
Reference: IRR G-Staff-7 (EB-2018-0016)

Preamble:

Interrogatory G-Staff-7 from EB-2018-0016 asked Alectra Utilities to prepare an illustrative example of what the OM&A allocations in 2017 would be for each rate zone if they were adjusted for growth rates, using customer count as the growth factor. In response, Alectra Utilities provided G-Staff-7_Attach 1_OM&A as a supporting table for that analysis.

A copy of Alectra Utilities attachment is provided below:

G-Staff-7_Attach 1_OM&A

i) Total Metered Connection Count

	2014	2015	2016	Average	Average %
Enersource RZ	201,359	203,466	204,728	203,184	21.2%
Brampton RZ	149,618	154,105	158,630	154,118	16.1%
PowerStream RZ	353,284	358,772	364,505	358,854	37.5%
Horizon Utilities RZ	240,076	241,986	244,114	242,059	25.3%
	944,337	**958,329**	**971,977**	**958,214**	**100%**

ii) Revised OM&A / Customer

	2014-2016 OM&A Average	2014-2016 Customer Avg	2014-2016 Average / Cust
Enersource RZ	$ 54,508,996	203,184	**$ 268**
Brampton RZ	$ 31,008,213	154,118	**$ 201**
PowerStream RZ	$ 86,165,101	358,854	**$ 240**
Horizon Utilities RZ	$ 54,621,688	242,059	**$ 226**
	226,303,998	**958,214**	**$ 935**

iii & iv) Total Customer Count

	2017 Actual Customers	2014-2016 Average / Cust	2017 Allocation of Total OM&A	2017 Prorated Allocation of Total OM&A	Revised %	Months	Prorated	Revised %
Enersource RZ	197,617	268	$ 53,015,427	$ 53,905,946	23.82%	11	$ 49,413,784	24.13%
Brampton RZ	154,638	201	$ 31,112,903	$ 31,635,517	13.98%	10	$ 26,362,931	12.87%
PowerStream RZ	355,105	240	$ 85,265,001	$ 86,697,227	38.31%	11	$ 79,472,458	38.80%
Horizon Utilities RZ	235,635	226	$ 53,172,157	$ 54,065,308	23.89%	11	$ 49,559,866	24.20%
	942,995	**935**	**$ 222,565,488**	**226,303,998**	**100.0%**		**204,809,038**	**100.0%**

v) Allocation to Rate Zones:

LDC/Rate Zone	Alectra 2017	Revised Allocation %	Allocated Amount	Rate Zone Specific	OM&A by Rate Zone
Brampton RZ		12.87%	$ 29,337,594		$ 29,337,594
Enersource RZ		24.13%	$ 54,989,391	$ 1,153,000	$ 56,142,391
Horizon Utilities RZ		24.20%	$ 55,151,956		$ 55,151,956
PowerStream RZ		38.80%	$ 88,439,737	$ 2,403,000	$ 90,842,737
Alectra	$ 227,918,678				
Total	**$ 227,918,678**	**100.00%**	**$ 227,918,678**	**$ 3,556,000**	**$ 231,474,678**

vi) HRZ 2017 OM&A for ESM calculation

		Notes
Horizon Utilities Corporation - 1 month ending Jan 31/17	$ 5,266,751	1
HRZ share of Alectra OM&A - 11 months ending Dec 31/17	$ 55,151,956	2
Total for 2017	$ 60,418,707	

Comparison of Methodologies

Horizon OM&A based on actual 3 year average OM&A	$ 60,972,051
Horizon OM&A based on actual 3 year average OM&A & Growth Rate	$ 60,418,707
Decrease to Horizon OM&A in comparison to filed evidence	$ (553,344)

Questions:

a) **Please confirm that the assumptions used in the 2017 growth-rate adjusted OM&A analysis remain valid. If any revisions to the assumptions used by Alectra Utilities is required, please update the analysis accordingly.**

b) **Please provide an identical analysis for 2018 OM&A by updating parts iii to vi, using the 2018 average connection count and 2018 total OM&A, as well as**

removing the monthly proration elements since all rate zones are part of Alectra Utilities for a full year. Please file both analyses in excel format.

c) As part of its response to G-Staff-7 from EB-2018-0016, Alectra Utilities asserted that OM&A costs are not driven by increases in customers. Please confirm whether or not Alectra Utilities maintains its position there is no correlation between customer count and OM&A and that OM&A should not be allocated based on growth rates.

Response:

a) Alectra Utilities' 2017 OM&A growth analysis provided in response to G-Staff-7 (EB-208-0016) did not include retailer customers. The 2017 analysis has been updated to reflect total customer count (Standard Supply Service and Retailer Customers). In addition, based on Alectra Utilities' response to HRZ-Staff-1a) and HRZ-Staff-2a), the average 3-year OM&A allocation has been updated. The analysis has been updated to reflect these adjustments accordingly. The inclusion of retailer customers in the OM&A growth analysis did not materially impact the analysis.

The analysis of 2017 OM&A adjusted for growth is provided in excel format as Attachment 1 (Tab 2017 Revised).

b) The analysis of 2018 OM&A adjusted for growth is provided in excel format as Attachment 1 (Tab 2018). This analysis also reflects the revisions to the 3-year average OM&A discussed in response to HRZ-Staff-1a) and HRZ-Staff-2a).

c) In response to G-Staff-7 from EB-2018-0016 Alectra Utilities stated that "total OM&A expenses are not driven by increases in customers". Alectra believes there are many factors that drive changes in OM&A expenses on a year over year basis. A primary driver of OM&A increases on a year over year basis are inflationary increases which are not necessarily tied to the number of customers or changes in customers in any given year.

The reliance on the pre-merger 3 year actual OM&A average is an appropriate representation of each rate zone's portion of the OM&A costs pre-merger. In addition, reliance on a 3 year average would appropriately take into account the relative differences in costs to serve across the rate zones and eliminates anomalies in costs in any single year.

Finally reliance on a pre-merger 3 year actual OM&A average implicitly includes a growth rate which would include OM&A cost increases over the period.

HRZ-Staff-3

ATTACH 1 – 2017 & 2018 OM&A ADJUSTED FOR GROWTH

2017 G-Staff-7 Revised to include 2017 Actual Total Customers & Updated OM&A Average

i) **Total Metered Connection Count**

Rate Zone	2014	2015	2016	Average	Average %
Enersource	201,359	203,466	204,728	203,184	21.2%
Brampton	149,618	154,105	158,630	154,118	16.1%
PowerStream	353,284	358,772	364,505	358,854	37.5%
Horizon	240,076	241,986	244,114	242,059	25.3%
	944,337	**958,329**	**971,977**	**958,214**	**100%**

ii) **Revised OM&A / Customer**

Rate Zone	2014-2016 OM&A Average	2014-2016 Customer Avg	2014-2016 Average / Cust
Enersource	$ 49,922,048	203,184	**$ 246**
Brampton	$ 25,090,665	154,118	**$ 163**
PowerStream	$ 79,295,865	358,854	**$ 221**
Horizon	$ 49,208,723	242,059	**$ 203**
	203,517,302		

iii & iv) **Total Customer Count**

	2017 Actual Customers	2014-2016 Average / Cust	2017 Allocation of Total OM&A	2017 Prorated Allocation of Total OM&A	Revised %	Months	Prorated	Revised %
Enersource	205,730	246	$ 50,547,514	$ 49,388,880	24.27%	11	$ 45,273,140	24.55%
Brampton	162,396	163	$ 26,438,395	$ 25,832,382	12.69%	10	$ 21,526,985	11.67%
PowerStream	368,002	221	$ 81,317,372	$ 79,453,441	39.04%	11	$ 72,832,321	39.50%
Horizon	245,894	203	$ 49,988,418	$ 48,842,599	24.00%	11	$ 44,772,383	24.28%
	982,022		**$ 208,291,699**	**203,517,302**	**100.0%**		**184,404,829**	**100.0%**

v) **Allocation to Rate Zones:**

LDC/Rate Zone	Alectra 2017	Revised Allocation %	Allocated Amount	Rate Zone Specific	OM&A by Rate Zone
Brampton		11.67%	$ 26,606,689		$ 26,606,689
Enersource		24.55%	$ 55,956,204	$ 1,153,000	$ 57,109,204
Horizon		24.28%	$ 55,337,283		$ 55,337,283
PowerStream		39.50%	$ 90,018,501	$ 2,403,000	$ 92,421,501
Alectra	$ 227,918,678				
Total	**$ 227,918,678**	**100.00%**	**$ 227,918,678**	**$ 3,556,000**	**$ 231,474,678**

vi) **HRZ 2017 OM&A for ESM calculation**

Horizon Utilities Corporation - 1 month ending Jan 31/17	$ 5,266,751
HRZ share of Alectra OM&A - 11 months ending Dec 31/17	$ 55,337,283
Total for 2017	$ 60,604,034

Comparison of Methodologies

Horizon OM&A based on actual 3 year average OM&A (updated in HRZ-Staff-2)	$ 60,375,516
Horizon OM&A based on actual 3 year average OM&A & Growth Rate	$ 60,604,034
Increase to Horizon OM&A	$ 228,519

Notes

1 Section ii) includes revised OM&A 3 year average based on response in HRZ 1a & HRZ 2a less capitalization impact

2 Section iii) includes update to include total customers - SSS and retailer

2018

i) **Total Metered Connection Count**

Rate Zone	2014	2015	2016	Average	Average %
Enersource	201,359	203,466	204,728	203,184	21.2%
Brampton	149,618	154,105	158,630	154,118	16.1%
PowerStream	353,284	358,772	364,505	358,854	37.5%
Horizon	240,076	241,986	244,114	242,059	25.3%
	944,337	**958,329**	**971,977**	**958,214**	**100%**

ii) **Revised OM&A / Customer**

Rate Zone	2014-2016 OM&A Average	2014-2016 Customer Avg	2014-2016 Average / Cust
Enersource	$ 54,784,580	203,184	**$ 270**
Brampton	$ 29,521,850	154,118	**$ 192**
PowerStream	$ 86,306,138	358,854	**$ 241**
Horizon	$ 54,328,811	242,059	**$ 224**
	224,941,378		

iii & iv) **Total Customer Count**

	2018 Actual Customers	2014-2016 Average / Cust	2018 Allocation of Total OM&A	2018 Prorated Allocation of Total OM&A	Revised %
Enersource	206,261	270	$ 55,614,141	$ 53,843,006	23.94%
Brampton	164,425	192	$ 31,496,261	$ 30,493,204	13.56%
PowerStream	372,516	241	$ 89,591,999	$ 86,738,776	38.56%
Horizon	247,893	224	$ 55,638,297	$ 53,866,392	23.95%
	991,095		**$ 232,340,697**	**224,941,378**	**100.0%**

v) **Allocation to Rate Zones:**

LDC/Rate Zone	Alectra 2018	Revised Allocation %	Allocated Amount	Rate Zone Specific	OM&A by Rate Zone
Brampton		13.56%	$ 34,714,121		$ 34,714,121
Enersource		23.94%	$ 61,296,038		$ 61,296,038
Horizon		23.95%	$ 61,322,662		$ 61,322,662
PowerStream		38.56%	$ 98,745,292		$ 98,745,292
Alectra	$ 256,078,113				
Total	**$ 256,078,113**	**100.00%**	**$ 256,078,113**		**$ 256,078,113**

vi) **HRZ 2018 OM&A for ESM calculation**

HRZ share of Alectra OM&A - 12 months ending Dec 31/18 $ 61,322,662

Comparison of Methodologies

Horizon OM&A based on actual 3 year average OM&A (updated in HRZ-Staff-2)	$ 61,849,089
Horizon OM&A based on actual 3 year average OM&A & Growth Rate	$ 61,322,662
Decrease to Horizon OM&A	$ (526,427)

Notes

1 Section ii) includes revised OM&A 3 year average based on response in HRZ 1a & HRZ 2a less capitalization impact

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Reference: Exhibit 3, Tab 1, Schedule 2, Tables 34 and 46

Preamble:

For the 11 months of 2017, Alectra Utilities has identified only $3.6mm out of $231.5mm of total OM&A as directly identifiable to specific rate zones. For 2018, Alectra Utilities has not identified any OM&A costs that are specific to any particular rate zone and has allocated all OM&A of $256mm.

Questions:

a) Please explain why only a small proportion of the OM&A costs can be traced to specific rate zones and why such a large proportion of OM&A costs require an allocation methodology?

b) Does Alectra Utilities track any of the OM&A components by service territory in order to assess Alectra Utilities' cost performance by service territory? If not, why not? If so, why has that data not been utilized to directly attribute a greater proportion of total OM&A from 2017 to 2018 for a more accurate representation of rate zone OM&A costs?

Response:

a) Consistent with the OEB's findings in the MAADs Decision (EB-2016-0025) with respect to reporting requirements for the utility, at p. 26 the OEB stated that "the *Handbook to Electricity Distributor and Transmitter Consolidation sets out that having consolidating entities operate as one entity as soon as possible after the transaction is in the best interest of consumers. The OEB is of the view that this principle continues to be applicable in this case. The OEB does not require, nor encourage reporting on a "separate" utility basis."*

Having amalgamated in 2017, Alectra Utilities is in transition and moving from individual utilities to an integrated utility operating as one company. Upon the creation of Alectra Utilities (February 1, 2017), one set of financial records was established for financial reporting purposes. Although several legacy Enterprise Resource Planning ("ERP") systems continued to be maintained (until the completion of Alectra Utilities' ERP Project in July 2019) a new organizational structure was established for Alectra Utilities. As Alectra Utilities began operating as a single entity, costs were no longer tracked on a legacy rate zone basis and therefore a large proportion of OM&A costs require an allocation methodology.

The 2017 directly identifiable rate zone costs of $3.6MM were related to specific provisions tied to the respective rate zones. These costs were identified separately given the one-time nature of the expense. In 2018, there were no similar directly identifiable one-time expenses.

b) Alectra Utilities does not track any of the OM&A components by rate zone, as provided in response to part a). Maintaining the tracking of OM&A costs by rate zone would be extremely difficult and require a considerable amount of resources (i.e., both people, systems), time and effort to support. More particularly, such an approach is inconsistent with the OEB's MAADs Decision. Further, a significant portion of costs are typically incurred at a corporate or entity level to support the operations of the organization. For example, salaries and benefits, depreciation on general plant, professional fees, insurance, IT expenditures, etc. are incurred for the benefit of all rate zones.

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Reference: Exhibit 3, Tab 1, Schedule 2
Reference: Attachment 11-Table of Allocations Horizon ESM 2018
Reference: Attachment 9-Table of Allocations Horizon ESM 2017

Questions:

a) **Please provide a copy of the following schedules from Alectra Utilities Corporations' 2018 Corporate Tax Return:**
   i. **Schedule 1 (Net Income (Loss) for Income Tax Purposes)**
   ii. **Schedule 4 (Corporation Loss Continuity and Application)**
   iii. **Schedule 8 (Capital Cost Allowance (CCA))**
   iv. **Schedule 13 (Continuity of Reserves)**

b) **Please explain, in detail, how Alectra Utilities determines what elements of Table 3 (additions/deductions for tax) are attributable to the merger and allocated to the Non-Regulated, MIFRS & Merger column.**

c) **Please provide the supporting tables or calculations to show how the figures are derived for the Merger-related additions/deductions for tax purposes**

d) **PILs for ratemaking purposes is calculated on a current tax basis (taxes payable), rather than deferred tax basis. Please provide Alectra Utilities' rationale for why loss utilization is not being allocated and applied to the PILs calculation for the purposes of HRZ's ESM calculation.**

e) **Please provide a more detailed explanation of where the losses from Alectra Utilities Corporation originated from and how Alectra Utilities believes they should be allocated to each rate zone, if they were to be applied to the ESM calculation. Please explain any assumption made in the allocation methodology.**

Response:

a) The requested schedules from Alectra Utilities Corporation's 2018 Corporate Tax Return are provided in the following attachments. Alectra Utilities has provided redacted versions of Attachments 3 and 4 as the specific information that has been redacted consists of information that is beyond the scope of the Application as it is not related to the regulated utility business.

- HRZ-Staff-5_Attach 1_Schedule 1
- HRZ-Staff-5_Attach 2_Schedule 4
- HRZ-Staff-5_Attach 3_Schedule 8

- HRZ-Staff-5_Attac 4_Schedule 13

The tax returns are filed on a legal entity basis and therefore include both the regulated and non-distribution related activities of Alectra Utilities Corporation.

b) The elements included in Table 3 column "Non-Regulated, MIFRS and Merger" that are attributed to the merger are:

i) capital cost allowance related to the deductible portion of the acquisition premium paid by shareholders to acquire the shares of Hydro One Brampton Networks Inc. This premium is a merger cost and is not recoverable from ratepayers as a component of rate base or revenue requirement. This is consistent with the Board's policy that the "revenues from future rates will not provide any funds to cover any purchase premium".[1] As a result, the corresponding capital cost allowance deduction generated by the acquisition premium is excluded from the PILs calculation for ratemaking purposes;

ii) capital cost allowance and depreciation related to capital transition costs; and

iii) opening and closing balances of non-deductible accounting accruals specifically related to the merger.

c) The supporting table is provided in Table 1, below.

Table 1 - Merger-related additions/deductions for tax purposes

$000s	2017	2018
Capital cost allowance relating to Hydro One Brampton transaction	($12,597)	($14,059)
Depreciation related to merger transition costs		$1,206
Capital cost allowance relating to merger transition costs	$ nil	($16,241)
Opening non-deductible merger related reserves	$ nil	($9,987)
Closing non-deductible merger related reserves	$9,987	$2,547

[1] EB-2013-0196/EB-2013-0187/EB-2013-0198 *Decision and Order,* July 3, 2014, p. 15.

d) The loss utilization is not being allocated and applied to the PILs calculation for the purposes of Horizon Utilities RZ's ESM calculation as the losses were generated by the non-regulated business that is held within the legal entity. The losses were not generated by the regulated distribution business and therefore do not form part of the ESM calculation.

e) Please see Alectra Utilities' response to part d).

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ATTACH 1 – SCHEDULE 1

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name	Business number	Tax year-end Year Month Day
ALECTRA UTILITIES CORPORATION	72860 4299 RC0002	2018-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation – Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Net income (loss) after taxes and extraordinary items from line 9999 of Schedule 125			111,248,280	A
Add:				
Provision for income taxes – current	101	39,362,041		
Amortization of tangible assets	104	138,009,786		
Loss on disposal of assets	111	7,305,330		
Charitable donations and gifts from Schedule 2	112	91,099		
Taxable capital gains from Schedule 6	113	2,645,263		
Scientific research expenditures deducted per financial statements	118	2,434,468		
Non-deductible club dues and fees	120	63,567		
Non-deductible meals and entertainment expenses	121	284,421		
Non-deductible automobile expenses	122	16,867		
Reserves from financial statements – balance at the end of the year	126	67,037,172		
Subtotal of additions		257,250,014	257,250,014	
Other additions:				
Financing fees deducted in books	216	85,565		
Taxable/non-deductible other comprehensive income items	239	1,507,647		

Miscellaneous other additions:

	1 Description 605	2 Amount 295
1	Inducement under 12(1)(x) ITA	763,173
2	Other additions	8,302,771
3	Solar Sunbelt GP - Taxable income	919,094
4	Interest on capital lease - building	1,020,053
5	12(1)(x) income	68,662,855
	Total of column 2	79,667,946

Total of column 2	296	79,667,946		
Subtotal of other additions	199	81,261,158	81,261,158	
Total additions	500	338,511,172	338,511,172	B
Amount A **plus** amount B			449,759,452	C
Deduct:				
Gain on disposal of assets per financial statements	401	626,072		
Capital cost allowance from Schedule 8	403	206,791,602		
SR&ED expenditures claimed in the year on line 460 from Form T661	411	3,097,583		
Reserves from financial statements – balance at the beginning of the year	414	80,372,719		
Subtotal of deductions		290,887,976	290,887,976	

Other deductions:

Miscellaneous other deductions:

	1 Description 705	2 Amount 395
1	Deduction under 20(1)(e) ITA	251,004
2	13(7.4) Election	68,662,855

	1 Description 705	2 Amount 395
3	PY ITCs recorded in accounting income	1,236,838
4	See attached	23,723,970

Total of column 2 93,874,667 ▶	396	93,874,667	
Subtotal of other deductions	499	93,874,667 ▶	93,874,667
Total deductions	510	384,762,643 ▶	384,762,643 D

Net income (loss) for income tax purposes (amount C **minus** amount D) . . . . 64,996,809 E

Enter amount E on line 300 of the T2 return.

Attached Schedule with Total

Line 395 – Amount

Title Line 395 – Amount

Explanatory note

THE TAXPAYER HEREBY ELECTS, PURSUANT TO SUBSECTION 13(7.4) TO NOT INCLUDE $68,662,855 IN INCOME PURSUANT TO PARAGRAPH 12(1)(x). ACCORDINGLY, THE TAXPAYER HAS REDUCED THE COST OF PROPERTY ACQUIRED DURING THE YEAR BY $68,662,855.

Description	Operator (Note)	Amount	
Election 13(7.4)		68,662,855	00
	+		
	+		
	Total	68,662,855	00

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

Attached Schedule with Total

Line 395 – Amount

Title Line 395 – Amount

Description	Operator (Note)	Amount	
AFUDC - interest capitalized for book purposes - deductible for tax		3,776,038	00
OMERS contributions deductible for tax 20.1(q), capitalized for accounting	+	4,861,883	00
Customer contribution revenue amortization	+	8,824,272	00
Cash payment on capital leases	+	1,429,911	00
Net reversal of non-deductible interest and penalty on taxes	+	3,162	00
Accounting gain on sale of Collus shares (excl. $1.3M Collus dividend)	+	4,828,704	00
	+		
	Total	23,723,970	00

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

Attached Schedule with Total

Line 295 – Amount

Title Line 295 – Amount

Description	Operator (Note)	Amount	
Guelph merger costs capitalized in UCC class 14.1		268,362	00
Net energy expenses RSVA, not deductible	+	8,034,409	00
	+		
	Total	8,302,771	00

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

Attached Schedule with Total

Line 395 – Amount

Title Line 395 – Amount

Description	Operator (Note)	Amount	
2017 ITCs recorded in 2018		521,838	00
2018 Apprenticeship/Co-op accrual	+	715,000	00
	+		
	Total	1,236,838	00

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

Inducement

This form is used to calculate inducements that a corporation must add to its income under paragraph 12(1)(x) of the ITA. If an amount reduces the capital cost of a property, this amount will be indicated in Part "Tax credits whose amount should reduce the capital cost of property."

If you want to transfer an amount to Schedule 1 and include it in the corporation's income for tax purposes, select the corresponding check box in column A. You can also select the option **Select this check box to add all the amounts to income calculated in Schedule 1** to transfer all the amounts to Schedule 1. In either case, the column A check box will be selected for that amount and it will therefore be updated to Schedule 1.

Tax credits whose amount should be added to income

Select this check box to add all the amounts to income calculated in Schedule 1. ☐

Ontario

A	Tax credit	Amount
X	Portion of the Ontario research and development tax credit that relates to the prescribed proxy amount (PPA) and portion of the Ontario investment tax credit that relates to contributions made to SR&ED farming organizations	25,536
X	Ontario co-operative education tax credit	349,813
X	Ontario apprenticeship training tax credit	387,824
	Ontario computer animation and special effects tax credit* * Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
	Ontario film and television tax credit* * Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
	Ontario production services tax credit* * Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
	Ontario interactive digital media tax credit* * Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
	Ontario sound recording tax credit* * Please verify if the credit amount relates to depreciable property. For more information, press F1 to consult the Help.	
	Ontario book publishing tax credit	
	Portion of the Ontario innovation tax credit that relates to the prescribed proxy amount (PPA) and portion of the Ontario investment tax credit that relates to contributions made to SR&ED farming organizations	
	Ontario business-research institute tax credit	
	Ontario community food program donation tax credit for farmers	

Tax credits whose amount should reduce the capital cost of property

Deduction summary as per paragraph 20(1)(e) of the ITA

Federal

Deduction summary as per paragraph 20(1)(e) of the ITA

Description	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	E Annual deduction (This amount is posted to one of the lines 395 of Schedule 1)	F Balance at the end of the year
1. 2016 Financing Costs (PSI)	2016-12-31	46,840	18,736	9,368	18,736
2. Jan 2017 Financing Costs (PSI)	2017-01-30	22,834	4,566	4,567	13,701
3. 2016 Financing Costs (HUC)	2016-12-31	15,306	6,123	3,061	6,122
4. 2015 Financing Costs (EHM)	2015-12-31	139,766	83,860	27,953	27,953
5. 2014 Financing Costs (PSI)	2014-12-31	981,697	785,847	195,850	
6. 2014 Financing Costs transferred on amalgamation (BHI)	2014-12-31	51,024	40,819	10,205	
	Totals	1,257,467	939,951	251,004	66,512

Deduction as per paragraph 20(1)(e) of the ITA

This workchart allows you to determine the tax deduction as per paragraph 20(1)(e) of the Income Tax Act (ITA). It relates to the expenses of issuing or selling shares, units or interests and expenses of borrowing money.

Ensure that any of these expenses deducted in the financial statements have been added back on line 216, "Financing fees deducted in books," and/or on line 235, "Share issue expense" to Schedule 1, if applicable.

* If the check box was selected, the annual deduction will be equal to the amount in column C.

1 Description: 2016 Financing Costs (PSI)

		A	B	C	D	E	F
Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	Expense amount	Amounts deductible in the preceding taxation years	Balance before the annual expense (column A minus column B)	20 % of amount A x number of days in the taxation year 365 / **365**	Annual deduction (C or D, whichever is less)*	Balance at the end of the year (column C minus column E)
☐	2016-12-31	46,840	18,736	28,104	9,368	9,368	18,736

2 Description: Jan 2017 Financing Costs (PSI)

		A	B	C	D	E	F
Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	Expense amount	Amounts deductible in the preceding taxation years	Balance before the annual expense (column A minus column B)	20 % of amount A x number of days in the taxation year 365 / **365**	Annual deduction (C or D, whichever is less)*	Balance at the end of the year (column C minus column E)
☐	2017-01-30	22,834	4,566	18,268	4,567	4,567	13,701

3 Description: 2016 Financing Costs (HUC)

		A	B	C	D	E	F
Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	Expense amount	Amounts deductible in the preceding taxation years	Balance before the annual expense (column A minus column B)	20 % of amount A x number of days in the taxation year 365 / **365**	Annual deduction (C or D, whichever is less)*	Balance at the end of the year (column C minus column E)
☐	2016-12-31	15,306	6,123	9,183	3,061	3,061	6,122

4 Description: 2015 Financing Costs (EHM)

		A	B	C	D	E	F
Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	Expense amount	Amounts deductible in the preceding taxation years	Balance before the annual expense (column A minus column B)	20 % of amount A x number of days in the taxation year 365 / **365**	Annual deduction (C or D, whichever is less)*	Balance at the end of the year (column C minus column E)
☐	2015-12-31	139,766	83,860	55,906	27,953	27,953	27,953

5 Description: 2014 Financing Costs (PSI)

		A	B	C	D	E	F
Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	Expense amount	Amounts deductible in the preceding taxation years	Balance before the annual expense (column A minus column B)	20 % of amount A x number of days in the taxation year 365 / **365**	Annual deduction (C or D, whichever is less)*	Balance at the end of the year (column C minus column E)
☐	2014-12-31	981,697	785,847	195,850	196,339	195,850	

6 Description: 2014 Financing Costs transferred on amalgamation (BHI)

		A	B	C	D	E	F
Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	Expense amount	Amounts deductible in the preceding taxation years	Balance before the annual expense (column A minus column B)	20 % of amount A x number of days in the taxation year 365 / **365**	Annual deduction (C or D, whichever is less)*	Balance at the end of the year (column C minus column E)
☐	2014-12-31	51,024	40,819	10,205	10,205	10,205	

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ATTACH 2 – SCHEDULE 4

Canada Revenue Agency / Agence du revenu du Canada

Schedule 4

Corporation Loss Continuity and Application

Corporation's name	Business number	Tax year-end Year Month Day
ALECTRA UTILITIES CORPORATION	72860 4299 RC0002	2018-12-31

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, or limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the *Income Tax Act*, when control has been acquired, no amount of capital loss incurred for a tax year ending before that time is deductible in computing taxable income in a tax year ending after that time. Also, no amount of capital loss incurred in a tax year ending after that time is deductible in computing taxable income of a tax year ending before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the *T2 Corporation – Income Tax Guide.*
- File one completed copy of this schedule with the T2 return, or send the schedule by itself to the tax centre where the return is filed.
- All legislative references are to the *Income Tax Act*.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes			64,996,809	A
Deduct: (increase a loss)				
Net capital losses deducted in the year (enter as a positive amount)		a		
Taxable dividends deductible under section 112 or subsections 113(1) or 138(6)	1,332,988	b		
Amount of Part VI.1 tax deductible under paragraph 110(1)(k)	7,613,802	c		
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)		d		
Subtotal (total of amounts a to d)	8,946,790	▶	8,946,790	B
Subtotal (amount A **minus** amount B; if positive, enter "0")				C
Deduct: (increase a loss)				
Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions				D
Subtotal (amount C **minus** amount D)				E
Add: (decrease a loss)				
Current-year farm loss (the lesser of: the net loss from farming or fishing included in income and the non-capital loss before deducting the farm loss)				F
Current-year non-capital loss (amount E **plus** amount F; if positive, enter "0") If amount G is negative, enter it on line 110 as a positive.				G

Continuity of non-capital losses and request for a carryback

Non-capital loss at the end of the previous tax year		19,553,899	e		
Deduct: Non-capital loss expired (note 1)	100		f		
Non-capital losses at the beginning of the tax year (amount e **minus** amount f)	102	19,553,899	▶	19,553,899	H
Add:					
Non-capital losses transferred on an amalgamation or on the wind-up of a subsidiary (note 2) corporation	105		g		
Current-year non-capital loss (from amount G)	110		h		
Subtotal (amount g **plus** amount h)			▶		I
Subtotal (amount H **plus** amount I)				19,553,899	J

Note 1: A non-capital loss expires as follows:

- after **10** tax years if it arose in a tax year ending after March 22, 2004, and before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

An allowable business investment loss becomes a net capital loss after **10** tax years if it arose in a tax year ending after March 22, 2004.

Note 2: Subsidiary is defined in subsection 88(1) as a taxable Canadian corporation of which 90% or more of each class of issued shares are owned by its parent corporation and the remaining shares are owned by persons that deal at arm's length with the parent corporation.

Part 1 – Non-capital losses (continued)

Deduct:

Other adjustments (includes adjustments for an acquisition of control)	150		i		
Section 80 – Adjustments for forgiven amounts	140		j		
Subsection 111(10) – Adjustments for fuel tax rebate			j.1		
Non-capital losses of previous tax years applied in the current tax year Enter amount k on line 331 of the T2 Return.	130	19,553,899	k		
Current and previous year non-capital losses applied against current-year taxable dividends subject to Part IV tax (note 3)	135		l		
Subtotal (total of amounts i to l)		19,553,899	▶	19,553,899	K
Non-capital losses before any request for a carryback (amount J **minus** amount K)					L

Deduct – **Request to carry back non-capital loss to:**

First previous tax year to reduce taxable income	901		m		
Second previous tax year to reduce taxable income	902		n		
Third previous tax year to reduce taxable income	903		o		
First previous tax year to reduce taxable dividends subject to Part IV tax	911		p		
Second previous tax year to reduce taxable dividends subject to Part IV tax	912		q		
Third previous tax year to reduce taxable dividends subject to Part IV tax	913		r		
Total of requests to carry back non-capital losses to previous tax years (total of amounts m to r)			▶		M
Closing balance of non-capital losses to be carried forward to future tax years (amount L **minus** amount M)	180				N

Note 3: Amount l is the total of lines 330 and 335 from Schedule 3, *Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation*.

Part 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200		a		
Capital losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	205		b		
Subtotal (amount a **plus** amount b)			▶		A
Deduct:					
Other adjustments (includes adjustments for an acquisition of control)	250		c		
Section 80 – Adjustments for forgiven amounts	240		d		
Subtotal (amount c **plus** amount d)			▶		B
Subtotal (amount A **minus** amount B)					C
Add: Current-year capital loss (from the calculation on Schedule 6, *Summary of Dispositions of Capital Property*)			210		D
Unused non-capital losses that expired in the tax year (note 4)			e		
Allowable business investment losses (ABILs) that expired as non-capital losses at the end of the previous tax year (note 5)			f		
Enter amount e or f, whichever is less	215		g		
ABILs expired as non-capital losses: line 215 **multiplied** by 2.000000			220		E
Subtotal (total of amounts C to E)					F

Note
If there has been an amalgamation or a wind–up of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary corporation. Add all these amounts and enter the total on line 220 above.

Note 4: If the loss was incurred in a tax year ending after March 22, 2004, determine the amount of the loss from the 11th previous tax year and enter the part of that loss that was not used in previous years and the current year on line e.

Note 5: If the ABILs were incurred in a tax year ending after March 22, 2004, enter the amount of the ABILs from the 11th previous tax year. Enter the full amount on line f.

Part 2 – Capital losses (continued)

Deduct: Capital losses from previous tax years applied against the current-year net capital gain (note 6) . . . . 225 ______ G

Capital losses before any request for a carryback (amount F **minus** amount G) ______ H

Deduct – Request to carry back capital loss to (note 7):

	Capital gain (100%)		Amount carried back (100%)	
First previous tax year		951		h
Second previous tax year		952		i
Third previous tax year		953		j

Subtotal (total of amounts h to j) ______ ► ______ I

Closing balance of capital losses to be carried forward to future tax years (amount H **minus** amount I) 280 ______ J

Note 6: To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the current-year tax, enter the amount from line 225 **divided** by 2 at line 332 of the T2 return.

Note 7: On line 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, divide this amount by 2. The result represents the 50% inclusion rate.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year . . . . ______ a

Deduct: Farm loss expired (note 8) . . . . 300 ______ b

Farm losses at the beginning of the tax year (amount a **minus** amount b) . . . . 302 ______ ► ______ A

Add:

Farm losses transferred on an amalgamation or on the wind–up of a subsidiary corporation . . . 305 ______ c

Current-year farm loss (amount F in Part 1) . . . . 310 ______ d

Subtotal (amount c **plus** amount d) ______ ► ______ B

Subtotal (amount A **plus** amount B) ______ C

Deduct:

Other adjustments (includes adjustments for an acquisition of control) . . . . 350 ______ e

Section 80 – Adjustments for forgiven amounts . . . . 340 ______ f

Farm losses of previous tax years applied in the current tax year . . . . 330 ______ g

Enter amount g on line 334 of the T2 Return.

Current and previous year farm losses applied against current-year taxable dividends subject to Part IV tax (note 9) . . . . 335 ______ h

Subtotal (total of amounts e to h) ______ ► ______ D

Farm losses before any request for a carryback (amount C **minus** amount D) ______ E

Deduct – Request to carry back farm loss to:

First previous tax year to reduce taxable income . . . . 921 ______ i

Second previous tax year to reduce taxable income . . . . 922 ______ j

Third previous tax year to reduce taxable income . . . . 923 ______ k

First previous tax year to reduce taxable dividends subject to Part IV tax . . . . 931 ______ l

Second previous tax year to reduce taxable dividends subject to Part IV tax . . . . 932 ______ m

Third previous tax year to reduce taxable dividends subject to Part IV tax . . . . 933 ______ n

Subtotal (total of amounts i to n) ______ ► ______ F

Closing balance of farm losses to be carried forward to future tax years (amount E **minus** amount F) 380 ______ G

Note 8: A farm loss expires as follows:

- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

Note 9: Amount h is the total of lines 340 and 345 from Schedule 3.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business	485			A
Minus the deductible farm loss:				
(amount A above ______ – $2,500) **divided** by 2 = ______ a				
Amount a or $ 15,000 (note 10), whichever is less ______ ▶			b	
		2,500	c	
Subtotal (amount b **plus** amount c)		2,500 ▶	2,500	B
Current-year restricted farm loss (amount A **minus** amount B)				C

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year			d	
Deduct: Restricted farm loss expired (note 11)	400		e	
Restricted farm losses at the beginning of the tax year (amount d **minus** amount e)	402	▶		D
Add:				
Restricted farm losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	405		f	
Current-year restricted farm loss (from amount C) Enter amount g on line 233 of Schedule 1, *Net Income (Loss) for Income Tax Purposes*.	410		g	
Subtotal (amount f **plus** amount g)		▶		E
Subtotal (amount D **plus** amount E)				F
Deduct:				
Restricted farm losses from previous tax years applied against current farming income Enter amount h on line 333 of the T2 return.	430		h	
Section 80 – Adjustments for forgiven amounts	440		i	
Other adjustments	450		j	
Subtotal (total of amounts h to j)		▶		G
Restricted farm losses before any request for a carryback (amount F **minus** amount G)				H
Deduct – Request to carry back restricted farm loss to:				
First previous tax year to reduce farming income	941		k	
Second previous tax year to reduce farming income	942		l	
Third previous tax year to reduce farming income	943		m	
Subtotal (total of amounts k to m)		▶		I
Closing balance of restricted farm losses to be carried forward to future tax years (amount H **minus** amount I)	480			J

Note

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

Note 10: For tax years that end before March 21, 2013, use $6,250 instead of $15,000.

Note 11: A restricted farm loss expires as follows:
- after **10** tax years if it arose in a tax year ending before 2006; and
- after **20** tax years if it arose in a tax year ending after 2005.

Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at the end of the previous tax year			a		
Deduct: Listed personal property loss expired after 7 tax years	500		b		
Listed personal property losses at the beginning of the tax year (amount a **minus** amount b)	502		▶		A
Add: Current-year listed personal property loss (from Schedule 6)				510	B
Subtotal (amount A **plus** amount B)					C
Deduct:					
Listed personal property losses from previous tax years applied against listed personal property gains	530		c		
Enter amount c on line 655 of Schedule 6.					
Other adjustments	550		d		
Subtotal (amount c **plus** amount d)			▶		D
Listed personal property losses remaining before any request for a carryback (amount C **minus** amount D)					E
Deduct – Request to carry back listed personal property loss to:					
First previous tax year to reduce listed personal property gains	961		e		
Second previous tax year to reduce listed personal property gains	962		f		
Third previous tax year to reduce listed personal property gains	963		g		
Subtotal (total of amounts e to g)			▶		F
Closing balance of listed personal property losses to be carried forward to future tax years (amount E **minus** amount F)				580	G

Part 7 – Limited partnership losses

Current-year limited partnership losses

	1	2	3	4	5	6	7
	Partnership account number **600**	Tax year ending yyyy/mm/dd **602**	Corporation's share of limited partnership loss **604**	Corporation's at-risk amount **606**	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses **608**	Column 4 **minus** column 5 (if negative, enter "0")	Current-year limited partnership losses (column 3 **minus** column 6) **620**
1.							

Total (enter this amount on line 222 of Schedule 1)

Limited partnership losses from previous tax years that may be applied in the current year

	1	2	3	4	5	6	7
	Partnership account number **630**	Tax year ending yyyy/mm/dd **632**	Limited partnership losses at the end of the previous tax year and amounts transferred on an amalgamation or on the wind-up of a subsidiary **634**	Corporation's at-risk amount **636**	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses **638**	Column 4 **minus** column 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6) **650**
1.							

Continuity of limited partnership losses that can be carried forward to future tax years

	1	2	3	4	5	6
	Partnership account number **660**	Limited partnership losses at the end of the previous tax year **662**	Limited partnership losses transferred in the year on an amalgamation or on the wind-up of a subsidiary **664**	Current-year limited partnership losses (from line 620) **670**	Limited partnership losses applied in the current year (must be equal to or less than line 650) **675**	Current year limited partnership losses closing balance to be carried forward to future years (column 2 **plus** column 3 **plus** column 4 **minus** column 5) **680**
1.						

Total (enter this amount on line 335 of the T2 return)

Note

If you need more space, you can attach more schedules.

Part 8 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), check the box . . . . **190** Yes ☐

In the case of the wind-up of a subsidiary, if the election is made, the non-capital loss, restricted farm loss, farm loss, or limited partnership loss of the subsidiary—that otherwise would become the loss of the parent corporation for a particular tax year starting after the wind–up began—will be considered as the loss of the parent corporation for its immediately preceding tax year and not for the particular year.

Note

This election is only applicable for wind-ups under subsection 88(1) that are reported on Schedule 24, *First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent*.

Non-Capital Loss Continuity Workchart

Part 6 – Analysis of balance of losses by year of origin

Non-capital losses

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce Taxable income	Applied to reduce Part IV tax	Balance at end of year
Current	N/A				N/A		
1st preceding taxation year 2017-12-31		N/A		N/A			
2nd preceding taxation year 2017-01-30	281,136	N/A		N/A	281,136		
3rd preceding taxation year 2016-12-31	19,272,763	N/A		N/A	19,272,763		
4th preceding taxation year 2015-12-31		N/A		N/A			
5th preceding taxation year 2014-12-31		N/A		N/A			
6th preceding taxation year 2013-12-31		N/A		N/A			
7th preceding taxation year 2012-12-31		N/A		N/A			
8th preceding taxation year 2011-12-31		N/A		N/A			
9th preceding taxation year 2010-12-31		N/A		N/A			
10th preceding taxation year 2009-12-31		N/A		N/A			
11th preceding taxation year 2008-12-31		N/A		N/A			
12th preceding taxation year 2007-12-31		N/A		N/A			
13th preceding taxation year 2006-12-31		N/A		N/A			
14th preceding taxation year 2005-12-31		N/A		N/A			
15th preceding taxation year 2004-12-31		N/A		N/A			
16th preceding taxation year 2003-12-31		N/A		N/A			
17th preceding taxation year 2002-12-31		N/A		N/A			
18th preceding taxation year 2001-12-31		N/A		N/A			
19th preceding taxation year		N/A		N/A			
20th preceding taxation year		N/A		N/A			*
Total	19,553,899				19,553,899		

* **This balance expires this year and will not be available next year.**

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ATTACH 3 – SCHEDULE 8

Canada Revenue Agency / Agence du revenu du Canada

Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business number	Tax year-end Year Month Day
ALECTRA UTILITIES CORPORATION	72860 4299 RC0002	2018-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under *Regulation* 1101(5q)? **101** Yes [ ] No [X]

	1 Class number * 200	Description	2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8) 201	3 Cost of acquisitions during the year (new property must be available for use) (see note 1 below) 203	4 Adjustments and transfers (see note 2 below) 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) (see notes 3 and 7 below) 211	7 Reduced undepreciated capital cost (column 2 **plus** column 3 **plus** or **minus** column 4 **minus** column 5 **minus** column 6) (see note 7 below)	8 CCA rate % (see note 4 below) 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) (see note 5 below) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) (see notes 6 and 7 below) 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	1		844,710,487	2,586,782		0	1,293,391	846,003,878	4	0	0	33,840,155	813,457,114
2.	1b		10,569,279			0		10,569,279	6	0	0	634,157	9,935,122
3.	1b	2185 Derry Rd	3,513,967			0		3,513,967	6	0	0	210,838	3,303,129
4.	1b	Aquitaine Substation	411,179			0		411,179	6	0	0	24,671	386,508
5.	1b	BCM Building	696,632			0		696,632	6	0	0	41,798	654,834
6.	1b	Erin Mills Substation	1,585,562			0		1,585,562	6	0	0	95,134	1,490,428
7.	1b	Rubin MS	617,766			0		617,766	6	0	0	37,066	580,700
8.	1b	Winston Churchill Substation	116,338			0		116,338	6	0	0	6,980	109,358
9.	2		91,697,952			0		91,697,952	6	0	0	5,501,877	86,196,075
10.	3		3,132,484			0		3,132,484	5	0	0	156,624	2,975,860
11.	6		8,549			0		8,549	10	0	0	855	7,694
12.	8		36,003,745	2,365,200	-7,676,163	2,280	1,181,460	29,509,042	20	0	0	5,901,808	24,788,694
13.	8	[redacted]	[redacted]										
14.	10		16,076,530	7,417,009		411,581	3,502,714	19,579,244	30	0	0	5,873,773	17,208,185
15.	10.1	#48560	3,423			N/A		3,423	30	N/A	N/A	1,027	2,396
16.	10.1	019-07	829			N/A		829	30	N/A	N/A	249	580
17.	10.1	020-07	580			N/A		580	30	N/A	N/A	174	406
18.	10.1	50740-14 NW				N/A			30	N/A	N/A		
19.	10.1	50826-14 CH				N/A			30	N/A	N/A		
20.	10.1	51239-14 DP				N/A			30	N/A	N/A		
21.	10.1	Dodge Sprinter Van	410			N/A		410	30	N/A	N/A	123	287
22.	10.1	Explorer JM	9,979			N/A		9,979	30	N/A	N/A	1,497	
23.	10.1	Ford Escape Hybrid	410			N/A		410	30	N/A	N/A	123	287

	1 Class number * 200	Description	2 Undepreciated capital cost at the beginning of the year (amount from column 12 of last year's schedule 8) 201	3 Cost of acquisitions during the year (new property must be available for use) (see note 1 below) 203	4 Adjustments and transfers (see note 2 below) 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) (see notes 3 and 7 below) 211	7 Reduced undepreciated capital cost (column 2 **plus** column 3 **plus** or **minus** column 4 **minus** column 5 **minus** column 6) (see note 7 below)	8 CCA rate % (see note 4 below) 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) (see note 5 below) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) (see notes 6 and 7 below) 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
24.	10.1	Ford Escape Hybrid	410			N/A		410	30	N/A	N/A	123	287
25.	10.1	Lexus PG				N/A			30	N/A	N/A		
26.	10.1	Vehicle 023-08	1,174			N/A		1,174	30	N/A	N/A	352	822
27.	10.1	Vehicle 024-09	1,174			N/A		1,174	30	N/A	N/A	352	822
28.	12		2,922,595	32,435,355		0	16,217,678	19,140,272	100	0	0	19,140,272	16,217,678
29.	13	Addiscott Ops Centre	805,107			0		805,107	NA	0	0	36,882	768,225
30.	13	Barrie Hydro - right to use	392,452			0		392,452	NA	0	0	32,143	360,309
31.	13	PS Inc - 2005 Addition	143,541			0		143,541	NA	0	0	15,110	128,431
32.	14	Churchill Meadows	35,555,454			0		35,555,454	NA	0	0	2,023,631	33,531,823
33.	14	Dundas	48,847			0		48,847	NA	0	0	4,509	44,338
34.	14	H1 Midhurst CC	3,659,137			0		3,659,137	NA	0	0	312,375	3,346,762
35.	14	Nebo Road	923,016			0		923,016	NA	0	0	42,262	880,754
36.	14	Vansickle Substation	6,803,510			0		6,803,510	NA	0	0	310,431	6,493,079
37.	14	Winona	6,073,901			0		6,073,901	NA	0	0	607,045	5,466,856
38.	14.1		164,313,683	296,390		0	148,195	164,461,878	5	0	0	8,701,879	155,908,194
39.	17		865,666		-19,676	0		845,990	8	0	0	67,679	778,311
40.	43.1	HUC	39,428			0		39,428	30	0	0	11,828	27,600
41.	43.2	PSI Smart Grid	102,141	1,160,031		0	580,016	682,156	50	0	0	341,078	921,094
42.	43.2	[redacted]	[redacted]	[redacted]									
43.	45		15,362			0		15,362	45	0	0	6,913	8,449
44.	47		1,303,363,365	180,600,160	10,257,534	514,130	90,043,015	1,403,663,914	8	0	0	112,293,113	1,381,413,816
45.	50		3,736,608	2,517,081		0	1,258,541	4,995,148	55	0	0	2,747,331	3,506,358
46.	52		1,282			0		1,282	100	0	0	1,282	
47.	95		109,752,464	22,799,558	-629,545	0	11,399,779	120,522,698	0	0	0		131,922,477
48.	95	[redacted]	[redacted]	[redacted]									
49.	14	Pleasant CCRA (Brampton)		6,804,600		0		6,804,600	NA	0	0	264,727	6,539,873
50.	1b	2185 Derry Rd. 2018		3,643,616		0	1,821,808	1,821,808	6	0	0	109,308	3,534,308
51.	1b	55 John St. 2018		4,541,638		0	2,270,819	2,270,819	6	0	0	136,249	4,405,389
		Totals	2,663,148,211	267,249,756	1,932,150	927,991	129,758,584	2,801,643,542				206,791,602	2,724,602,042

* Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

Note 1. Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see *Regulation* 1100(2) and (2.2).

Note 2. Enter in column 4, "Adjustments and transfers", amounts that increase or reduce the undepreciated capital cost. Items that **increase** the undepreciated capital cost include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that **reduce** the undepreciated capital cost include government assistance received or entitled to be received in the year, or a reduction of capital cost after the application of section 80. See the *T2 Corporation Income Tax Guide* for other examples of adjustments and transfers to include in column 4.

Note 3. The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments and transfers from column 4. For information on the exceptions to the 50% rule, as well as how to calculate the amounts to enter in column 6 in those cases, see Interpretation Bulletin IT-285, *Capital Cost Allowance - General Comments*.

Note 4. Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

Note 5. For every entry in column 9, "Recapture of capital cost allowance", there must be a corresponding entry in column 5, "Proceeds of dispositions during the year". The recapture and terminal loss rules do not apply to passenger vehicles in Class 10.1.

Note 6. If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

Note 7. At the time the program was released, the official CRA Schedule 8 had not yet been updated to take into account the new measures added to subsection 1100(2) ITR, as proposed in the *Notice of Ways and Means Motion to amend the Income Tax Act and the Income Tax Regulations* published on November 21, 2018. Therefore, the amounts calculated in columns 6 and 7 do not reflect these new measures. However, the CCA amount calculated in column 12 takes these new measures into account.

T2 SCH 8 (17)

Canada

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ATTACH 4 – SCHEDULE 13

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	Employee future benefits	64,770,930			3,772,941	60,997,989
2	Allowance for doubtful account	3,264,806			2,003,399	1,261,407
3						
4	Enivornmental liability	978,056			99,422	878,634
5	Vested sick leave	44,766			44,766	
6						
7	Legal claim provision	100,000				100,000
8	Other deferred credits	1,219,085		33,416		1,252,501
9	Transition Accrual	9,987,254			7,440,613	2,546,641
10	[redacted]	[redacted]				
	Reserves from Part 2 of Schedule 13					
	Totals	80,372,719		33,416	13,368,963	67,037,172

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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Reference: Exhibit 3, Tab 1, Schedule 3 – Horizon Utilities Capital Investment Variance Account
Reference: Attachment 11-Table of Allocations Horizon ESM 2018
Reference: Attachment 9-Table of Allocations Horizon ESM 2017

a) OEB staff is unable to reconcile the amount of $6,818,684 (2018 Share of Alectra GP additions) used in Table 56 with the methodology described by Alectra Utilities (18.3% proportion of rate base for HRZ x $57,294,202 total Alectra GP additions). Please confirm that the actual amount should be $10,600,129, consistent with the information provided in Table 1 of Attachment 11.

b) In Table 52, the total 2017 capital additions for GP is $31,487,162. This reconciles with the sum of the General Plant Capital Additions of $14,313,050 and Merger Capital Net Savings of $17,174,112 presented in Table 1 of Attachment 9. In Table 53, the total capital additions for GP is shown as $57,924,202, which reconciles only to the General Plant additions in Table 1 of Attachment 11. Please confirm whether or not Alectra Utilities intends to include the Merger Capital Net Savings with the total Alectra GP additions for the purposes of calculating the 2017 and 2018 HRZ Capital Investment Variance Account (CIVA) additions and update either the 2017 or 2018 CIVA additions accordingly.

c) Please provide rationale for why the Merger Capital Net Savings either should or should not be included in the Alectra Utilities total GP additions figure for the purposes of calculating the HRZ CIVA figures.

d) Please present the actual in-service capital additions in Table 51 (or revised Table 51 if any changes are made following the response to parts a and b, above), on the basis of the pre-merger capitalization policy of the HRZ, consistent with the capital forecast used in the Custom IR Application (EB-2014-0002).

e) Is there any supporting rationale that Alectra Utilities can provide, other than the fact that it has prepared the HRZ's ESM under Alectra Utilities' post-merger capitalization policies, for comparing actual capital additions under one measurement basis to forecast capital additions under another?

Response:

a) Horizon Utilities' 2018 share of General Plant additions should be $11,557,770 which is comprised of:

- $10,600,129 which reflects 18.3% (Horizon Utilities' proportion of Alectra Utilities' rate base) of Alectra Utilities' GP additions for the Horizon Utilities RZ; and
- $5,233,012 which reflects 18.3% of Alectra Utilities' net merger capital savings additions for the Horizon Utilities RZ.

Table 1 below provides the calculation relied on in Attachment 11-Table of Allocations Horizon ESM 2018. Tables 2, 3 and 4 reflect the revised Tables 56, 53 and 51.

Table 1 – GP Additions Horizon Utilities RZ

2018 General Plant Additions	Amount	HRZ Portion
Alectra General Plant additions	$57,924,202	$10,600,129
Remove 2018 merger related capital costs energized	($36,997,826)	($6,770,602)
Add back merger related capital savings	$42,230,838	$7,728,243
Net merger capital costs (savings) to remove (add) to capital	($5,233,012)	($957,641)
Total General Plant additions	**$63,157,214**	**$11,557,770**

Table 2 – Horizon Utilities RZ 2018 Capital Additions (Table 56 revised)

Horizon Rate Zone	Capital Additions
DP capital additions	
Jan 1- Dec 31, 2018	$ 37,816,078
Total DP additions	**$ 37,816,078**
Share of Alectra GP additions	$ 11,557,770
Total GP additions	**$ 11,557,770**
Total capital additions	**$ 49,373,848**

Table 3 - Horizon Utilities RZ 2018 Capital Additions (Table 53 revised)

Horizon Rate Zone	Brampton	Enersource	Horizon	PowerStream	Alectra	Total
1) Distribution Plant (DP)						
Total DP additions	$ 26,859,709	$ 54,124,769	$ 37,816,078	$ 90,508,540		**$ 209,309,096**
2) General Plant (GP)						
Total GP additions					$ 57,924,202	$ 57,924,202
Net Merger Capital Savings					$ 5,233,012	**$ 5,233,012**
Total new capital additions	**$ 26,859,709**	**$ 54,124,769**	**$ 37,816,078**	**$ 90,508,540**	**$ 63,157,214**	**$ 214,542,108**

Table 4 - Horizon Utilities RZ 2015 - 2018 Capital Additions (Table 51 revised)

Capital Additions	Actual	Custom IR Application (EB-2014-0002)	Variance
2015	$ 46,643,216	$ 38,314,524	$ 8,328,692
2016	$ 44,295,265	$ 41,147,533	$ 3,147,732
2017	$ 52,393,539	$ 45,626,114	$ 6,767,425
2018	$ 49,373,848	$ 47,142,504	$ 2,231,344
Cumulative total	**$ 192,705,868**	**$ 172,230,675**	**$ 20,475,193**

b) Please see response in part a), above.

c) For the purposes of the Horizon Utilities RZ CIVA calculation, merger capital net savings / (costs) are added / (excluded)) in order to be consistent with the Settlement Agreement for Alectra Utilities' predecessor, Horizon Utilities in the 2015 to 2019 Custom Incentive Regulation Application (EB-2014-0002) and take it back to Horizon Utilities on a stand alone basis (as the Applicants indicated they would in the MAADs Application (EB-2016-0025). The CIVA was established to refund ratepayers any difference in the revenue requirement should in-service capital additions be lower than was forecast over the 2015-2019 period.

d) Alectra Utilities provides the revised Table 51 (as adjusted in the response to part a above) on the basis of the pre-merger capitalization policy, below.

Table 5 – 2015-2018 Capital Additions (Table 51 Revised)

Capital Additions	Actual	Actuals with change in Capitalization Impact	Custom IR Application (EB-2014-0002)	Actual Variance	Actual with Capitalization Variance
2015	$ 46,643,216	$ 46,643,216	$ 38,314,524	$ 8,328,692	$ 8,328,692
2016	$ 44,295,265	$ 44,295,265	$ 41,147,533	$ 3,147,732	$ 3,147,732
2017	$ 52,393,539	$ 46,995,010	$ 45,626,114	$ 6,767,425	$ 1,368,896
2018	$ 49,373,848	$ 44,131,111	$ 47,142,504	$ 2,231,344	($ 3,011,393)
Cumulative total	**$ 192,705,868**	**$ 182,064,602**	**$ 172,230,675**	**$ 20,475,193**	**$ 9,833,927**

e) As directed by the OEB in its Decision in Alectra Utilities' 2018 Electricity Distribution Rate ("EDR") Application dated April 5, 2018 and revised on April 6, 2018, Alectra Utilities was directed to flow the impact of the capitalization policy change through the HRZ ESM. In the Decision at page 81, the OEB stated: “The approved settlement proposal did not specify how a material change in accounting practice would be treated, just that it would be noted. The approved settlement proposal was a “package deal” which the OEB approved. The approved settlement proposal did not include mandated accounting changes as a reopener, and therefore the OEB will not approve one now. For the remainder of the Custom IR term, the effect on earnings resulting from the change in the capitalization policy will be dealt with through the ESM. Once the Custom IR term ends, the Horizon Utilities RZ will move to Price Cap IR per the MAADs policy, and it will be treated consistently with the Brampton and Enersource RZs”. As the impact of the capitalization policy change is captured through the ESM for the Horizon Utilities RZ, determining the CIVA using the pre-merger capitalization policy would result in the same impact being refunded to or recovered from customers through both the ESM and the CIVA. Therefore, it is appropriate to determine capital additions on the post amalgamation capitalization policy.

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Reference: EB-2016-0025, Application, Exhibit B, Tab 6, Schedule 1, Pages 1-2 of 4
Reference: EB-2016-0025; LDC Co_IRR_OEB-Staff-1-ATTACH1_20160727
Reference: Exhibit 3, Tab 1, Schedule 3 – Horizon Utilities Capital Investment Variance Account
Reference: Attachment 11-Table of Allocations Horizon ESM 2018
Reference: Attachment 9-Table of Allocations Horizon ESM 2017

Preamble:

Alectra Utilities provided the following table as part of its forecast synergies in its MAADs application:

Figure 25 – Total Net Synergies

($MMs)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Gross Synergies											
Operating	7.2	20.1	31.7	40.6	42.5	42.5	42.5	42.5	42.5	42.5	354.6
Capital	23.0	22.6	28.8	23.2	30.0	8.0	8.0	8.0	8.0	8.0	167.6
Total Synergies	30.2	42.7	60.5	63.8	72.5	50.5	50.5	50.5	50.5	50.5	522.2
Transition Costs											
Charged to Operating	20.9	11.1	8.2	2.3	0.5	-	-	-	-	-	43.0
Charged to Capital	33.7	15.2	4.4	-	-	-	-	-	-	-	53.3
Total Transition Costs	54.6	26.3	12.6	2.3	0.5	-	-	-	-	-	96.3
Net Synergies											
Operating	(13.7)	9.0	23.5	38.3	42.0	42.5	42.5	42.5	42.5	42.5	311.6
Capital	(10.7)	7.4	24.4	23.2	30.0	8.0	8.0	8.0	8.0	8.0	114.3
Total Net Synergies	(24.4)	16.4	47.9	61.5	72.0	50.5	50.5	50.5	50.5	50.5	425.9

Alectra Utilities received approval for its MAADs transaction on December 8, 2016.

Questions:

a) **Please confirm that the first year of operations for Alectra Utilities was 2017.**

b) **Please confirm that, if the Total Net Synergies table above was updated at the time Alectra Utilities received OEB approval to merge, the first year would be shown as 2017 and the last year would be 2026, coinciding with Alectra Utilities' deferred rebasing period.**

c) **Please reconcile the forecast merger-related net operating costs of $13.7 million in year one (2017) with the amount of $2,032,671 used to adjust the 2017 OM&A allocation in HRZ's 2017 ESM calculation. Please include in this reconciliation a detailed breakdown of the elements that make up the forecast and compare that**

detailed breakdown versus actuals used in the ESM calculation, explaining variances between each item.

d) Please reconcile the forecast merger-related net operating savings of $9.0 million in year two (2018) with the amount of $24,020,161 used to adjust the 2018 OM&A allocation in HRZ's 2018 ESM calculation. Please include in this reconciliation a detailed breakdown of the elements that make up the forecast and compare that detailed breakdown versus actuals used in the ESM calculation, explaining variances between each item.

e) Please reconcile the forecast merger-related net capital costs of $10.7 million in year one (2017) with the reported capital savings amount of $17,174,112 used to adjust the 2017 capital additions allocation in HRZ's 2017 ESM calculation and 2017 CIVA additions. Please include in this reconciliation a detailed breakdown of the elements that make up the forecast and compare that detailed breakdown versus actuals used in the ESM and CIVA calculation, explaining variances between each item.

f) Please reconcile the forecast merger-related net capital savings of $7.4 million in year two (2018) with the amount of $5,233,012 used to adjust the 2018 capital additions allocation in HRZ's 2018 ESM calculation and 2018 CIVA additions. Please include in this reconciliation a detailed breakdown of the elements that make up the forecast and compare that detailed breakdown versus actuals used in the ESM and CIVA calculation, explaining variances between each item.

g) For each of the reconciliations between forecast and reported merger-related capital and operating costs/savings (parts c to f), please use, at a minimum, the following categories and sub-categories, as outlined in Section 5.6 – Opportunities on pages 77-78 of the Business Plan filed by Alectra Utilities to support the MAADs application:

OPEX Savings

- **Payroll Cost Savings**

- **Non-payroll Cost Savings:**
  - **Reduction of third party costs e.g. consulting, legal etc.**
  - **Consolidation of contracts and services**
  - **Volume discounts**
  - **Software licensing and maintenance**
  - **Consolidation of systems**

- **Transition Costs (Operating):**
  - **Voluntary separation packages**

- **IT system migration and integration costs**
- **Re-branding and communication tool integration**
- **Third-party costs**

CAPEX Savings

- **Avoided Capital Expenditures:**
  - **Elimination of IT costs due to converged IT Systems (e.g. programming, maintenance and license fees).**
  - **Purchasing power will result in volume discounts for inventory and third party contractors.**
  - **Rationalization of fleet and equipment across the three Regions.**
  - **Elimination of duplicated programming costs due to regulatory compliance or changes in regulation (e.g. CIS programming for billing changes).**
  - **Reduction of labour costs from the elimination of future hires and best practice adoption of work methods**

- **Transition Costs (Capital):**
  IT systems such as CIS, ERP, GIS/OMS, telephone system, miscellaneous IT systems etc. will be consolidated over the first three years of the merger (please disaggregate the costs for different IT system types, where appropriate).

Response:

a) Alectra Utilities confirms that the first year of operations was 2017.

b) Alectra Utilities confirms that, if the total net synergies from the table above was updated at the time Alectra Utilities received OEB approval to merge, the first year would be shown as 2017 and the last year would be 2026.

c) A reconciliation of 2017 actual versus forecast merger-related net operating costs is provided in Table 1, below.

Table 1 – Reconciliation of 2017 actual versus forecast merger-related net operating costs

Alectra Utilities 2017 Merger Costs and Savings

	Actuals	Forecast	Variance	Explanations
OM&A Transition Costs	$18,161,012	$20,900,000	($2,738,988)	Explanation 1.
OM&A Savings	($16,128,341)	($7,200,000)	($8,928,341)	Explanation 2.
Net OM&A merger Costs to remove / (Savings to add) to OM&A	**$2,032,671**	**$13,700,000**	**($11,667,329)**	

Explanation 1:

OM&A transition costs compare favourably to the merger Business Plan by $2.7M, principally attributable to (i) lower re-branding costs (1.6M); and (ii) timing of IT consolidation projects ($1.4M).

Explanation 2:

OM&A savings compare favourably to the merger Business Plan by $8.9M, principally attributable to: (i) higher IT system maintenance and capitalized labour synergies ($2.9M); (ii) early achievement of headcount reductions ($2M); (iii) avoided implementation of monthly billing ($1.2M); (iv) higher finance operating synergies ($0.5M); (v) board of directors synergies ($0.5M), (vi) favourable operations costs resulting from implementation of best practices to all Alectra service territories ($0.4M); and (vii) other operating synergies ($1.4M).

Notes

1. Net OM&A merger results do not include pre-close synergies and transition costs recognized prior to the Alectra merger on February 1, 2017.

d) A reconciliation of 2018 actual versus forecast merger-related net operating costs is provided in Table 2, below.

Table 2 – Reconciliation of 2018 actual versus forecast merger-related net operating costs

Alectra Utilities 2018 Merger Costs and Savings

	Actuals	Forecast	Variance	Explanations
OM&A Transition Costs	$3,573,289	$11,100,000	($7,526,711)	Explanation 1.
OM&A Savings	($27,593,450)	($20,100,000)	($7,493,450)	Explanation 2.
Net OM&A merger Costs to remove / (Savings to add) to OM&A	**($24,020,161)**	**($9,000,000)**	**($15,020,161)**	

Explanation 1:

OM&A transition costs compare favourably to the merger Business Plan by $7.5M, principally attributable to lower severance costs due to delay in collective bargaining ($7.5M).

Explanation 2:

OM&A savings compare favourably to the merger Business Plan by $7.5M, principally due to (i) higher IT system maintenance and capitalized labour synergies ($5.2M); (ii) favourable operations costs resulting from implementation of best practices to all Alectra service territories ($1.6M); (iii) higher Treasury operating synergies ($1.5M); (iv) board of directors synergies ($0.8M); (v) consolidation of membership commitments ($0.5M); partially offset by (vi) Customer Service outsourcing costs ($1.1M); (vii) delay in achieving facilities maintenance contracts synergies ($0.9M); and (viii) other operating synergies ($0.1M) .

Notes

1. OM&A Savings exclude financing cost savings.

e) A reconciliation of 2017 actual versus forecast merger-related net capital costs is provided in Table 3, below.

Table 3 – Reconciliation of 2017 actual versus forecast merger-related net capital costs

Alectra Utilities 2017 Merger Costs and Savings

	Actuals	Forecast	Variance	Explanations
Capital Transition Costs	$22,794,043	$33,700,000	$10,905,957	Explanation 1.
Capital Savings	($17,890,669)	($23,000,000)	($5,109,331)	Explanation 2.
Net merger capital costs (savings) subtotal	**$4,903,374**	**$10,700,000**	**$5,796,626**	
Adjust for merger capital costs in WIP	($22,077,486)	0	**$22,077,486**	
Net merger capital costs (savings) to remove (add) to capital	**($17,174,112)**	**$10,700,000**	**$27,874,112**	

Explanation 1:

Capital transition costs compare favourably to the merger Business Plan by $10.9M, principally attributable to (i) deferral and delays in IT transition projects ($12.2M); partially offset by (ii) unplanned facilities renovation ($1.2M).

Explanation 2:

Capital synergies compare unfavourably to the merger Business Plan by $5.1M, principally attributable to (i) timing of IT synergies ($6M); (ii) lower reduction in contractor costs achieved ($1.6M); (iii) unachieved headcount capital reductions ($1M); partially offset by (iv) higher rationalization of fleet and facilities reductions ($2.8M), and (v) avoided implementation of monthly billing ($0.7M).

Notes

1. Net OM&A merger results do not include pre-close synergies and transition costs recognized prior to the Alectra merger on February 1, 2017.

f) A reconciliation of 2018 actual versus forecast merger-related net capital costs is provided in Table 4, below.

Table 4 – Reconciliation of 2018 actual versus forecast merger-related net capital costs

Alectra Utilities 2018 Merger Costs and Savings

Capital Expenditures

	Actuals	Forecast	Variance	Explanations
Capital Transition Costs	$42,118,620	$15,200,000	($26,918,620)	Explanation 1.
Capital Savings	($42,230,838)	($22,600,000)	$19,630,838	Explanation 2.
Net merger capital costs (savings) subtotal	**($112,218)**	**($7,400,000)**	**($7,287,782)**	

Net Merger Capital Costs / (Savings) for 2018

	Amount
Alectra General Plant additions	$57,924,202
Remove 2018 merger related capital costs energized	($36,997,826)
Add back merger related capital savings	$42,230,838
Net merger capital costs (savings) to remove (add) to capital	**($5,233,012)**
Total General Plant additions	$63,157,214

Explanation 1:

Capital transition costs compare unfavourably to the merger Business Plan by $26.9M, principally attributable to (i) deferral of projects from 2017 to 2018 and increase in IT integration projects ($15M); (ii) unplanned facilities renovations($6M); (iii) timing of IT integration projects ($3.4M); (iv) and other unplanned integration projects ($2.5M).

Explanation 2:

Capital synergies compare favourably to the merger Business Plan by $19.6M, principally attributable to (i) timing of IT capital savings ($16.8M); and (ii) higher facilities capital reductions ($3M); partially offset by (iii) other capital synergies ($0.2M).

g) A detailed breakdown of the drivers of the merger-related capital and operating costs/savings is provided in Table 5, below.

Table 5 – Merger-related capital costs/savings drivers

	ACTUAL 2017	ACTUAL 2018	Business Plan 2017	Business Plan 2018	Variance 2017	Variance 2018
OPEX Savings	**(6,082,148)**	**(32,475,161)**	**13,626,826**	**(8,995,921)**	**(19,708,974)**	**(23,479,240)**
Payroll Cost Savings:	**(7,070,612)**	**(11,190,807)**	**(6,916,527)**	**(14,412,235)**	**(154,085)**	**3,221,428**
Payroll	(7,070,612)	(11,190,807)	(6,916,527)	(14,412,235)	(154,085)	3,221,428
Non-payroll Cost Savings:	**(17,172,549)**	**(24,857,644)**	**(322,855)**	**(5,649,942)**	**(16,849,694)**	**(19,207,702)**
Reduction of third party costs e.g. consulting, legal etc.	660,916	218,642	(300,000)	(768,750)	960,916	987,392
Consolidation of contracts and services	(14,883,525)	(20,141,833)	(5,542,006)	(10,241,476)	(9,341,519)	(9,900,358)
Volume discounts	(341,691)	(132,158)	-	(430,000)	(341,691)	297,842
Software licensing and maintenance	(426,028)	(346,057)	468,000	867,000	(894,028)	(1,213,057)
Consolidation of systems	(2,182,220)	(4,456,237)	5,051,151	4,923,284	(7,233,371)	(9,379,521)
Transition Costs (Operating):	**18,161,012**	**3,573,289**	**20,866,208**	**11,066,256**	**(2,705,196)**	**(7,492,967)**
Voluntary separation packages	15,029,117	1,529,021	15,622,957	9,003,240	(593,840)	(7,474,219)
IT system migration and communication tool integration	1,005,149	1,322,809	2,368,251	1,163,016	(1,363,102)	159,793
Re-branding and communication tool integration	438,694	-	2,075,000	150,000	(1,636,306)	(150,000)
Third-party costs	1,688,053	721,459	800,000	750,000	888,053	(28,541)
CAPEX Savings	**4,903,374**	**(112,219)**	**10,747,833**	**(7,371,295)**	**(5,844,459)**	**7,259,076**
Avoided Capital Expenditures:	**(17,890,669)**	**(42,230,838)**	**(22,972,820)**	**(22,564,587)**	**5,082,151**	**(19,666,252)**
Elimination of IT costs due to converged IT Systems (e.g. programming, maintenance and license fees)	(11,764,557)	(30,620,951)	(17,764,557)	(13,787,651)	6,000,000	(16,833,300)
Purchasing power will result in volume discounts for inventory and third party contractors	(770,523)	(4,688,048)	(2,000,000)	(4,320,000)	1,229,477	(368,048)
Rationalization of fleet and equipment across the three Regions	(3,306,950)	(3,942,343)	(500,000)	(900,000)	(2,806,950)	(3,042,343)
Elimination of duplicated programming costs due to regulatory compliance or changes in regulation (e.g. CIS programming for billing changes)	(2,048,639)	(1,300,000)	(1,675,000)	(1,600,000)	(373,639)	300,000
Reduction of labour costs from the elimination of future hires and best practice adoption of work methods	-	(1,679,496)	(1,033,263)	(1,956,936)	1,033,263	277,440
Transition Costs (Capital):	**22,794,043**	**42,118,620**	**33,720,653**	**15,193,292**	**(10,926,610)**	**26,925,328**
CIS consolidation	16,327,638	14,904,508	13,825,097	9,109,616	2,502,541	5,794,892
ERP consolidation	958,143	11,213,592	5,885,631	2,017,308	(4,927,488)	9,196,284
GIS/OMS consolidation	116,951	1,719,041	2,892,736	2,187,714	(2,775,785)	(468,673)
IT system migration and integration	2,074,597	5,046,995	9,367,189	1,433,654	(7,292,592)	3,613,341
Facilities renovations	2,565,004	6,033,517	1,350,000	-	1,215,004	6,033,517
Non-IT system and service consolidation	751,711	3,200,966	400,000	445,000	351,711	2,755,966

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Reference: EB-2016-0025 IRR B-EP-1
Reference: Exhibit 3, Tab 1, Schedule 2
Reference: Exhibit 3, Tab 1, Schedule 3

In response to interrogatory B-EP-1 from the Alectra Utilities amalgamation application (EB-2016-0025), the applicants stated the following with respect to maintaining compliance with the Horizon Utilities Corporation's (Horizon Utilities) settlement agreement:

> **The Applicants identify that the merger creates complexity in certain areas related to the Capital Investment Variance Account ("CIVA"). For instance, there will be challenges regarding tracking capital expenditures in isolation of capital synergies. Similarly, for the purposes of the Earnings Sharing Mechanism ("ESM"), there will be challenges in tracking earnings in isolation of merger savings.**

a) Please describe the challenges and complexities in isolating capital and operating synergies that Alectra Utilities has encountered with respect to its calculation of the HRZ CIVA and ESM calculations for 2017 and 2018.

b) Please describe any other types of challenges (unrelated to identifying and allocating merger costs/savings) that Alectra Utilities has experienced with respect to calculating the HRZ CIVA and ESM figures for 2017 and 2018.

c) Please explain the steps that Alectra Utilities has taken to address the challenges in part a) and b) and how those measures have been reflected in the various components of the CIVA and ESM calculations.

d) Does Alectra Utilities believe that revising the assumptions and methodologies used to identify the achieved capital and operating synergies can have a material impact on the calculations for the HRZ CIVA and ESM? If so, are there any further assessments that can be undertaken (either internally or by third party) to minimize the risk of a material error in either the CIVA or ESM calculations?

Response:

a) Alectra Utilities' actual merger savings and costs are tracked and recorded on a monthly basis. This information is reviewed and audited annually by Alectra Utilities' internal audit department. The actual merger savings and costs form the basis of the information relied on for the purposes of the ESM and CIVA calculations for the Horizon Utilities' RZ. In completing the calculation, Alectra Utilities ensures that the merger operating and capital net savings / (net costs) are included / (excluded) in order to be consistent with the Settlement Agreement for Alectra Utilities' predecessor, Horizon Utilities in the 2015 to 2019 Custom Incentive Regulation Application (EB-2014-0002).

Complexities exist as allocations must be relied on to apportion the operating and capital merger savings / costs to the rate zones, in order to take the HRZ back to Horizon Utilities on a stand-alone basis, for the purposes of the ESM and the CIVA.

b) Alectra Utilities has experienced other challenges with respect to:

a. developing allocations for costs which are not identifiable by rate zone namely, OM&A, General Plant and PILs; and
b. collecting and reconciling information from four different ERP systems.

c) Alectra Utilities has developed allocations for costs which are not identifiable by rate zone, ensuring costs are allocated on an appropriate basis appropriate. Alectra Utilities has relied on various cost allocation methodologies based on the appropriateness of the cost to be allocated. Further details on the various allocations and calculation of the ESM and CIVA are provided at Exhibit 3, Tab 1, Schedule 2 and Exhibit 3, Tab 1, Schedule 3.

d) As provided in response to part a) above, Alectra Utilities' actual merger savings and costs are tracked and recorded on a monthly basis and reviewed and audited by internal audit. As synergy savings are as a result of the merger, the OM&A and capital savings are allocated to the Horizon Utilities RZ using an allocation method.

The net merger OM&A savings are allocated to the rate zones based on the 3-year (2014-2016) pre-merger OM&A. This represents each rate zone's proportion of OM&A costs pre-merger and eliminates anomalies in any given year. Net merger capital savings for the purpose of the CIVA are allocated to the rate zones based on their proportion of the 2016 pre-merger rate base.