Management's Discussion and Analysis

Alectra Inc.

Year ended December 31, 2018

GLOSSARY of ACRONYMS and ABBREVIATIONS

The following acronyms and abbreviations are used in this document.

AES	Alectra Energy Solutions Inc.
AESI	Alectra Energy Services Inc.
APS	Alectra Power Services Inc.
AUC	Alectra Utilities Corporation
BA	Banker's Acceptance
BU	Business unit
CCA	Capital Cost Allowance
CCP	Community Conservation Program
CCRA	Connection Cost Recovery Agreement
CDM	Conservation & Demand Management
CFF	Conservation First Framework
CIS	Customer Information System
CP	Commercial Paper
DRC	Debt Retirement Charge
DSP	Distribution System Plan
DVA	Deferral & Variance Accounts
ECA	Energy Conservation Agreement
EDA	Electricity Distributors Association
EDR	Electricity Distribution Rate
ERP	Enterprise Resource Planning
ESM	Earnings Sharing Mechanism
ETR	Express Toll Route
EV	Electric Vehicle
FCR	Full Cost Recovery
FIT	Feed In Tariff
FY	Full Year
GEA	Green Energy Act
GIS	Geographic Information Systems
GS	General Service
GWh	Gigawatt Hours
HST	Harmonized Sales Tax
ICI	Industrial Commercial and Institutional customers
ICM	Incremental Capital Module
IESO	Independent Electricity System Operator
IFRS	International Financial Reporting Standards
IST	Information Systems & Technology
IT	Information Technology
kWh	Kilowatt Hours
LC	Letters of Credit
LDC	Local Distribution Company
LED	Light-Emitting Diode
LRAMVA	Lost Revenue Adjustment Mechanism Variance Account
LPSS	Load Profile Settlement System
MD&A	Management Discussion & Analysis
MIFRS	Modified International Financial Reporting Standards
MIST	Meter Inside the Settlement Timeframe
MTI	Midterm incentive
MSP	Meter Service Provider
OEA	Ontario Energy Association
OEB	Ontario Energy Board
OM&A	Operations, Maintenance and Administration
OMS	Outage Management Systems
OPG	Ontario Power Generation
P4P	Pay For Performance
P	Permanent
PCB	Polychlorinated Biphenyls
PILS	Payment in Lieu of Taxes
PP&E	Property, Plant, and Equipment
PSUP	Process and Systems Upgrades Program
RFSP	Ring-Fenced Solar Portfolio
RGCRP	Renewable Generation Credit Rate Protection
RPP	Regulated Price Plan
RSVA	Retail Settlement Variance Accounts
SCADA	Supervisory Control and Data Acquisition
Shared	Excludes RFSP
SLA	Service Level Agreement
SPN	Solar Power Network
SRE&D	Scientific Research Experimental and Development Tax credit
T	Temporary
UA	Util-Assist Inc.
VP	Vice President
WMS	Wholesale Market Service
YRT	York Region Transit

FORWARD LOOKING STATEMENTS AND INFORMATION

The Corporation's oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about the business and the industry in which the Corporation operates, and include beliefs and assumptions made by the management of the Corporation. Such statements include, but are not limited to:

- Statements about strategy, including strategic objectives;
- Statements regarding CDM programs and targets;
- The estimated impact of changes in the forecasted long-term Government of Canada bond yield (used in determining the regulated rate of return) on the results of operations;
- Statements related to economic conditions;
- Statements regarding liquidity and capital resources and operational requirements;
- Statements regarding credit facilities and other sources of corporate liquidity;
- Expectations regarding financing activities;
- Statements regarding ongoing and planned projects and/or initiatives including the expected results of these projects and/or initiatives and their completion dates;
- Expectations regarding the recoverability of large capital expenditures;
- Statements regarding expected future capital and development expenditures, the timing of these expenditures and investment plans;
- Statements regarding contractual obligations and other commercial commitments;
- Statements related to the OEB;
- Statements regarding future post-retirement benefit contributions, and actuarial valuations; and
- Statements related to the outlook and our approach to distribution rationalization.

Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions, risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. The Corporation does not intend, and disclaims any obligation, to update any forward-looking statements, except as required by law. These forward-looking statements are based on a variety of factors and assumptions including, but not limited to the following:

- No unforeseen changes in the legislative and operating framework for Ontario's electricity market;
- Decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications;
- No delays in obtaining required approvals;
- No unforeseen changes in rate orders or rate structures;
- A stable regulatory environment;
- No changes in environmental regulation; and
- No significant event occurring outside the ordinary course of business.

These assumptions are based on information currently available to the Corporation, including information obtained from third-party sources. Actual results may differ materially from those predicted by such forward-looking statements.
While the Corporation does not know what impact any of these differences may have, the business, results of operations, financial condition and credit stability may be materially adversely affected thereby.

Readers are cautioned that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail in the section "Risk Factors" in this Management's Discussion and Analysis. Readers should review this section in detail. In addition, the Corporation cautions the reader that information provided in this Management's Discussion and Analysis regarding the Corporation's outlook on certain matters, including future expenditures, is provided in order to give context to the nature of some of the Corporation's future plans and may not be appropriate for other purposes.

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INTRODUCTION

The following discussion and analysis of the consolidated financial condition and results of operations of Alectra Inc. (the "Corporation") should be read together with its consolidated financial statements and accompanying notes for the year ended December 31, 2018 (the "Consolidated Financial Statements") and comparatives for 11 months ended December 31, 2017.

The Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and in effect at December 31, 2018. All dollar amounts in the tables are in millions of Canadian dollars, which are presented in whole numbers.

CORPORATE OVERVIEW

Alectra Inc. is indirectly owned through holding companies by seven shareholders: – the City of Barrie; the City of Hamilton; the City of Markham; the City of Mississauga; the City of St. Catharines; the City of Vaughan and BPC Energy Corporation. Alectra Inc. was created by ("Merger Transaction"): i) the amalgamation ("Amalgamation Transaction") of the former entities: PowerStream Holdings Inc. ("PowerStream Holdings"); Enersource Holdings Inc. ("Enersource Holdings"); and Horizon Holdings Inc. ("Horizon Holdings") (collectively, the "Amalgamating Entities"); and ii) the acquisition of Hydro One Brampton Networks Inc. ("Brampton Hydro") and its subsequent amalgamation with Alectra Utilities Corporation ("AUC").

Alectra Inc. is an investment holding company that owns 100% of the common shares of each of: AUC; AES; and Horizon Solar Corporation ("Horizon Solar"). The Corporation also indirectly wholly owns AESI which, in turn, has wholly owned subsidiaries APSI and UA.

Alectra Utilities Corporation

AUC provides electricity distribution to approximately one million customers and is the second largest municipally-owned LDC in North America by customers.

In addition to its electricity distribution business, AUC also has a non-regulated commercial rooftop solar photovoltaic generation business ("Solar PV Business") under which it develops, constructs, owns, finances and operates rooftop photovoltaic generation equipment ("Solar PV Property"). The electricity generated by the Solar PV Business is sold to IESO under its FIT long term power purchase agreements ("FIT Agreements").

Alectra Energy Solutions Inc.

AES is an Ontario-based company that provides customers with non-regulated energy solutions through the use of innovative technologies. AES owns 100% of the common equity of each of AESI and APSI.

AESI provides wholesale metering and sub-metering services for condominium and commercial properties.

AESI owns 100% of the shares of UA. UA provides consulting services with respect to Advanced Metering Infrastructure integration, customer information systems implementation, sync operation services, conservation initiatives, an outage management call centre under the name PowerAssist, and other smart grid applications.
APSI provides street lighting services including design, construction, and maintenance.

in millions of Canadian dollars

Credit Rating

The Corporations credit ratings are as follows:

	DBRS			S&P Global Ratings		
	Date Confirmed	Credit Rating	Trend	Date Confirmed	Credit Rating	Outlook
Issuer rating	June 29, 2018	A	Stable	January 24, 2018	A	Stable
Senior unsecured debentures	June 29, 2018	A	Stable	January 24, 2018	A	Stable
Short term (Commercial Paper)	October 2, 2018	R1(low)	Stable		-	-

Vision & Strategic Intent

The vision of the Corporation is to be Canada's leading electricity distribution and integrated energy solutions provider, creating a future where people, businesses and communities will benefit from energy's full potential. For further details on the values and the mission of the Corporation, please review the 2018 Annual Sustainability Report on the Corporation's website at: https://alectrautilities.com/about-alectra/investor-relations/

INDUSTRY REGULATION

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 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.

AUC is regulated by the 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 the Consolidated Financial Statements.

Rate Setting

The electricity distribution rates and other regulated charges of AUC are determined in a manner that provides shareholders with opportunity to earn a regulated Maximum Allowable Return on Equity ("MARE") on the amount of shareholder's 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 AUC, 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. These methods are described in more detail in the Consolidated Financial Statements.

The Incremental Capital Module ("ICM") is available to distributors under the Price Cap IR method. The ICM is intended to address capital investment needs arising during an incentive rate term that are incremental to a prescribed materiality threshold. 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 riders.

AUC is required to charge its customers for the following amounts (all of which, other than distribution rates, represent a pass-through of amounts payable to third parties):

- Commodity Charge - the commodity charge represents the market price of electricity consumed by customers and is passed through the IESO back to operators of generating stations. It includes the global adjustment, which primarily represents the difference between the market price of electricity and the rates paid to regulated and contracted generators;
- Retail Transmission Rate - the retail transmission rate represents the costs incurred in respect of the transmission of electricity from generating stations to local distribution networks. Retail transmission rates are passed through to operators of transmission facilities;
- WMS Charge - the WMS charge represents various wholesale market support costs, such as the cost of the IESO to administer the wholesale electricity system, operate the electricity market, and maintain reliable operation of the provincial grid. Wholesale charges are passed through to the IESO; and
- Distribution Rate - the distribution rate is designed to recover the costs incurred by AUC in delivering electricity to customers, including the OEB-allowed cost of capital. Distribution rates are regulated by the OEB and include fixed and variable (usage-based) components, based on a forecast of AUC's customers and electricity load.

Rate Applications

2018 Rates Application

On July 7, 2017, AUC 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 are 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%.

2019 Rates Application

AUC filed an application for the approval of electricity distribution rates effective January 1, 2019, with decisions received on January 31, 2019 as follows:

- Horizon Rate Zone - Fourth annual update to the Custom Incentive rate plan. The resulting change to the distribution portion of the bill for a typical residential customer consuming 750 kWh per month in the Horizon Rate Zone will be a decrease of approximately $0.28 or 1.03%;
- Brampton Hydro Rate Zone - Price Cap adjustment under the OEB's Price Cap IR. The resulting change to the distribution portion of the bill for a typical residential customer consuming 750 kWh per month in the Brampton Hydro Rate Zone will be an increase of approximately $0.39 or 1.58%;
- PowerStream Rate Zone - Price Cap adjustment and ICM rider under the OEB's Price Cap IR. The resulting change to the distribution portion of the bill for a typical residential customer consuming 750 kWh per month in the PowerStream Rate Zone will be an increase of approximately $0.23 or 0.83%, which excludes the impact of the ICM riders; and
- Enersource Rate Zone - Price Cap adjustment and ICM rider under the OEB's Price Cap IR. The resulting change to the distribution portion of the bill for a typical residential customer consuming 750 kWh per month in the Enersource Rate Zone will be a decrease of approximately $0.02 or 0.10% which excludes the impact of the ICM riders.

Select Energy Policies and Regulations Affecting the Corporation in 2019

A New Distribution Rate Design for Residential Electricity Customers:

On April 2, 2015, the OEB issued a policy providing for fully fixed distribution charges for residential electricity customers. The implementation of this New Distribution Rate Design for residential electricity customers will be phased in over a four year period commencing January 2016. This policy is focused on only the distribution rate component of electricity charges. Distribution rates are designed to recover the costs for the poles, wires, meters, transformer stations, trucks and computer systems that convey electricity from the high voltage transmission system to individual homes. Under the new policy, electricity distributors will structure residential rates so that all the costs for distribution service are collected through a fully fixed monthly charge. Current distribution rate design is a combination of a fixed monthly rate and a separate usage (i.e., variable rate) rate. The OEB’s general policy for rate design is to increase the amount of revenue collected through the fixed rate, and, ultimately, eliminate the amount of revenue collected through the usage rate. Electricity charges corresponding to the electricity generation, transmission and system operations are not affected by this policy. AUC will complete the transition to a fully fixed charge for the Horizon, Brampton Hydro and Enersource rate zones in 2019, and in 2020 for the PowerStream rate zone.

in millions of Canadian dollars

Please refer to the Consolidated Financial Statements for a full description of energy policies affecting the Corporation.

Please refer to https://www.alectrautilities.com/about-alectra/regulatory/ for the status of the Corporation's rate applications.

Key Business Statistics

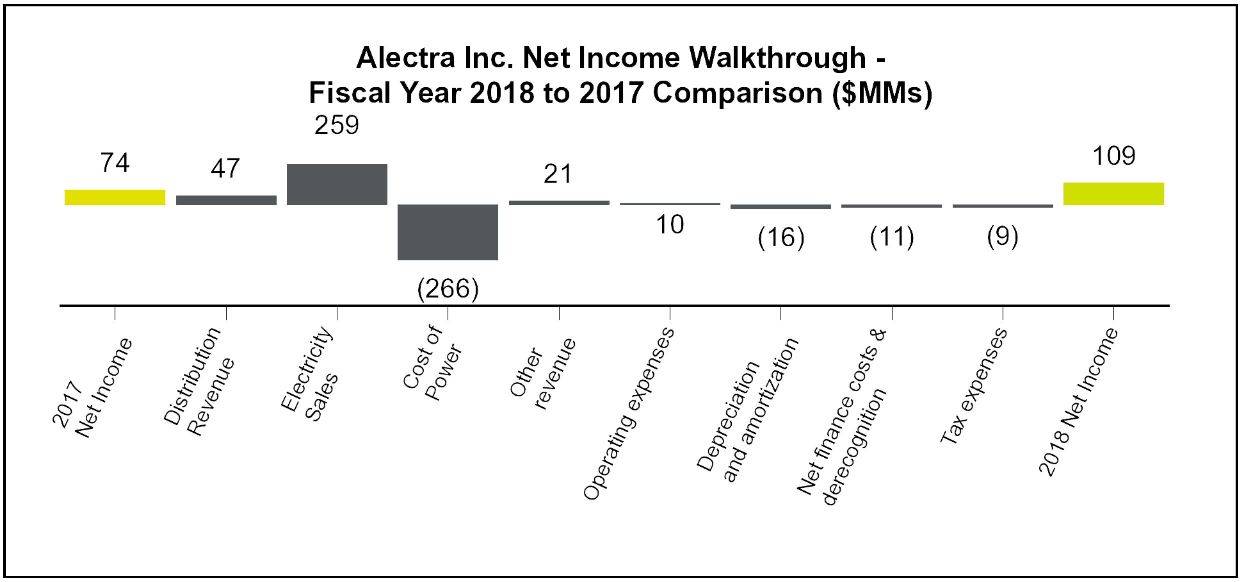
	2018	2017	2017 OEB Benchmark[1]
System average interruption duration index (SAIDI) (2)	1.08	0.83	1.03
System average interruption frequency index (SAIFI) (3)	1.37	1.12	1.00

(1) The 2017 OEB benchmark is based on the average SAIDI and SAIFI index (excluding Hydro One Networks and rural distribution utilities) from the 2017 yearbook of Ontario electricity distributors.

(2) SAIDI equals the average duration of a sustained interruption per customer during a predefined period of time. A sustained interruption has a duration greater than or equal to one minute, adjusted for loss of supply and major events. The lower the SAIDI, the better the reliability. SAIDI figures presented in the table above are in hours.

(3) SAIFI equals the average number of times a customer experiences a sustained interruption over a predefined period of time. A sustained interruption has a duration greater than or equal to one minute, adjusted for loss of supply and major events. The lower the SAIFI, the better the reliability.

RESULTS OF OPERATIONS

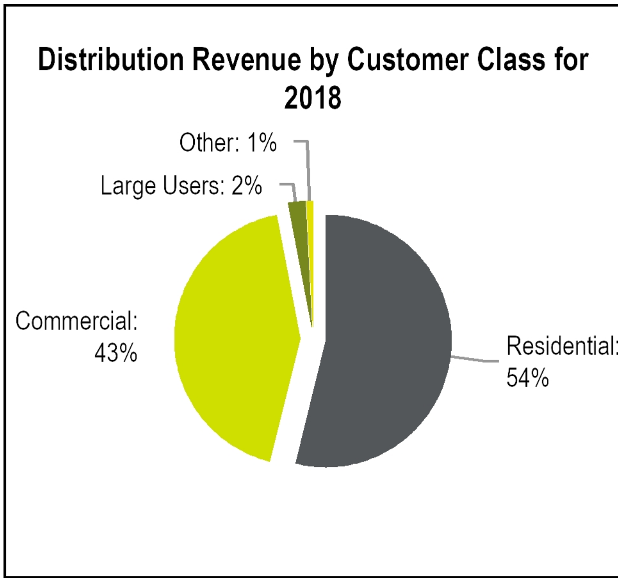


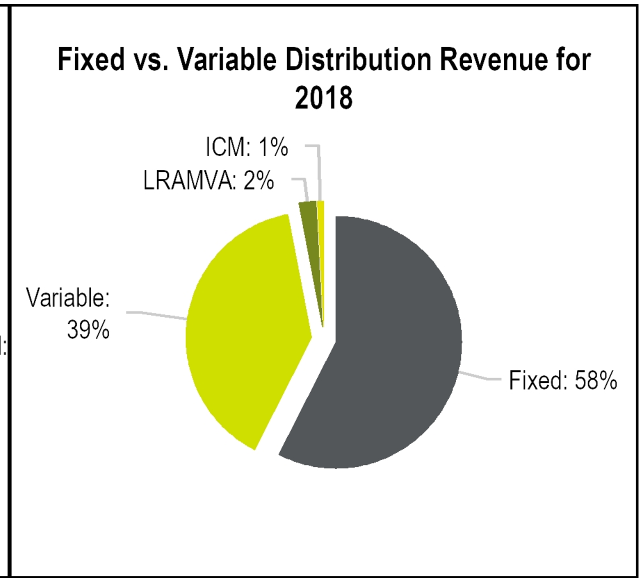
Net income for the year ended December 31, 2018 was $109 which is $35 higher than 2017 net income of $74. The increase in net income is principally attributable to: (i) higher distribution revenue from the recognition of twelve months of distribution revenue compared to eleven months in 2017 ($47); (ii) higher other revenue related to the recognition of the CDM mid-term incentive received from higher energy savings achieved ($21); (iii) lower operating expenses principally as a result of lower merger transition costs ($13); partially offset by (iii) higher depreciation, net finance costs and tax as a result of twelve months of activity in the fiscal year compared to eleven months in 2017 ($36).

in millions of Canadian dollars

	2018	2017	Change
Distribution Revenue	505	458	47

Distribution revenue is recorded based on OEB-approved distribution rates to recover the costs incurred by AUC in delivering electricity to customers. The increase in distribution revenue comprises: (i) twelve months of distribution revenue compared to eleven months for 2017 ($50); (ii) higher fixed and volumetric distribution revenue as a result of higher distribution rates, customer growth, combined with higher consumption from residential and GS<50 kW and higher demand from GS>50kW customers due to favourable weather ($12); partially offset by (ii) a decrease in settlements of net regulatory liabilities accruing to customers of the Corporation arising from regulatory accounting treatments that differ from IFRS ($15).





	2018	2017	Change
Electricity Sales	2,850	2,591	259

Electricity sales arise from the responsibility of the Corporation 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 amounts that the Corporation is billed by such third parties often differ from the amount that the Corporation recovers from its customers. The difference between sales of energy and the corresponding cost of power is a timing difference ultimately recoverable from or repayable to ratepayers prospectively through annual applications to the OEB to adjust the rates of the Corporation to settle such timing differences. Such differences as at the end of the prior fiscal year are generally settled over a twelve month period as of the effective date of such annual applications; or more generally, the thirteenth to twenty-fourth month following the end of the prior fiscal year.

Electricity sales were $2,850 compared to $2,591 in the previous year. This change is principally driven by twelve months of electricity sales as compared to eleven months in the previous year.

in millions of Canadian dollars

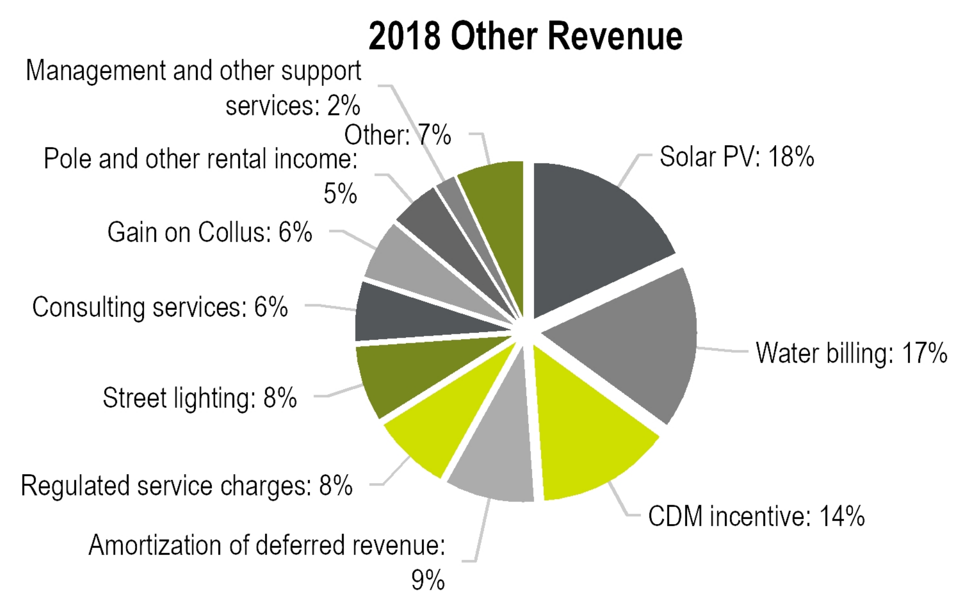
	2018	2017	Change
Other Revenue	97	76	21

Other revenue is earned from regulated electricity distribution activities as well as non-regulated activities. Other revenue from regulated activities includes:

- the amortization of deferred revenue related to capital contributions from developers;
- rates charged to customers for: connections, reconnections, late payments, and ancillary services; customer contributions;
- pole attachment charges to other utility service providers that attach equipment to poles owned by AUC; and
- CDM incentives and gains on sale of investments.

Non-regulated activities include: sub-metering services; water billing services; consulting services; street lighting services; and generation revenue from the Solar PV Business.

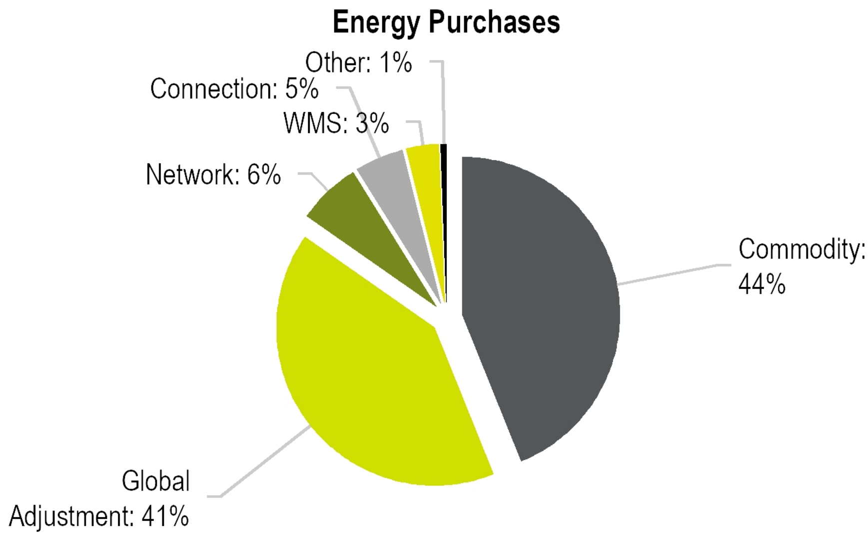
The increase in other revenue for 2018 as compared to 2017 primarily relates to the incentive received as result of achieving energy savings in the CDM program ($13) and the gain received on the sale of the investment in Collus PowerStream ($6).



	2018	2017	Change
Cost of Power	2,833	2,567	(266)

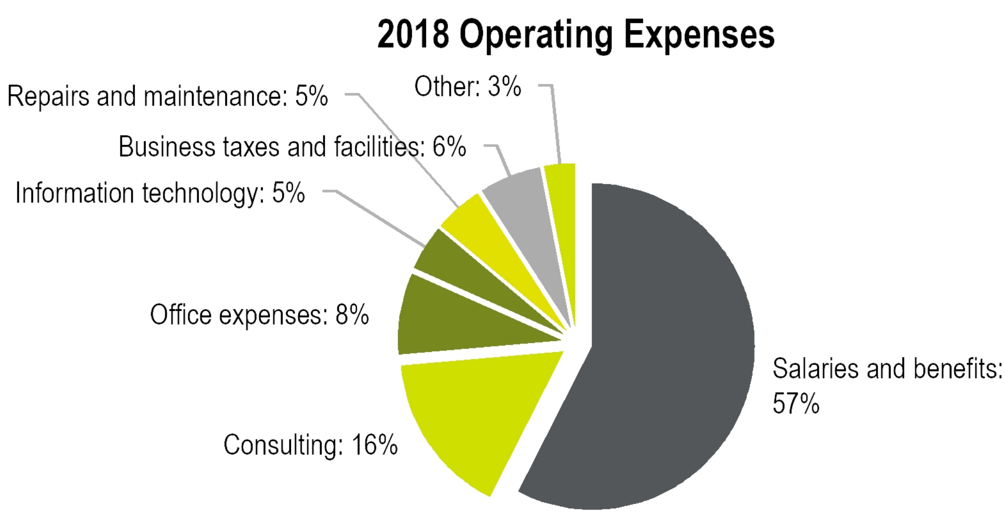
Cost of Power represents actual charges for electricity generated by third parties, which are delivered by AUC and passed through to customers in the form of energy sales. Refer to the discussion under *Electricity Sales*.

in millions of Canadian dollars



	2018	2017	Change
Operating Expenses	261	271	10

Operating expenses principally include salaries and benefits, materials and other third party service costs in support of the activities underlying the business of the Corporation including: (i) operation and maintenance of the distribution system; (ii) billing and collection; (iii) general administration costs; and (iv) costs in support of the non-regulated business activities. The decrease in operating expense in 2018 as compared to 2017 is principally the result of: (i) lower transition costs related to the amalgamation in 2018 as compared to 2017 ($13); partially offset by (ii) higher outside service provider expenditures as a result of 2018 being twelve months compared to eleven months in 2017 ($3).



in millions of Canadian dollars

	2018	2017	Change
Depreciation and Amortization	140	124	(16)

The increase in depreciation and amortization expense for the year ended December 31, 2018 was primarily due to new in-service asset additions in 2018, as well as the additional month of depreciation in 2018 as compared to 2017.

	2018	2017	Change
Income Taxes	39	30	(9)

The Corporation and its subsidiaries, other than AESI and UA, are currently exempt from taxes under the *Income Tax Act (Canada)* and the *Ontario Corporations Tax Act* (collectively the "Tax Acts"). As a consequence of this 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. AESI and UA are subject to the payment of tax under the Tax Acts.

The increase in income taxes relates to higher net income before tax in 2018 compared to 2017.

in millions of Canadian dollars

FINANCIAL CONDITION

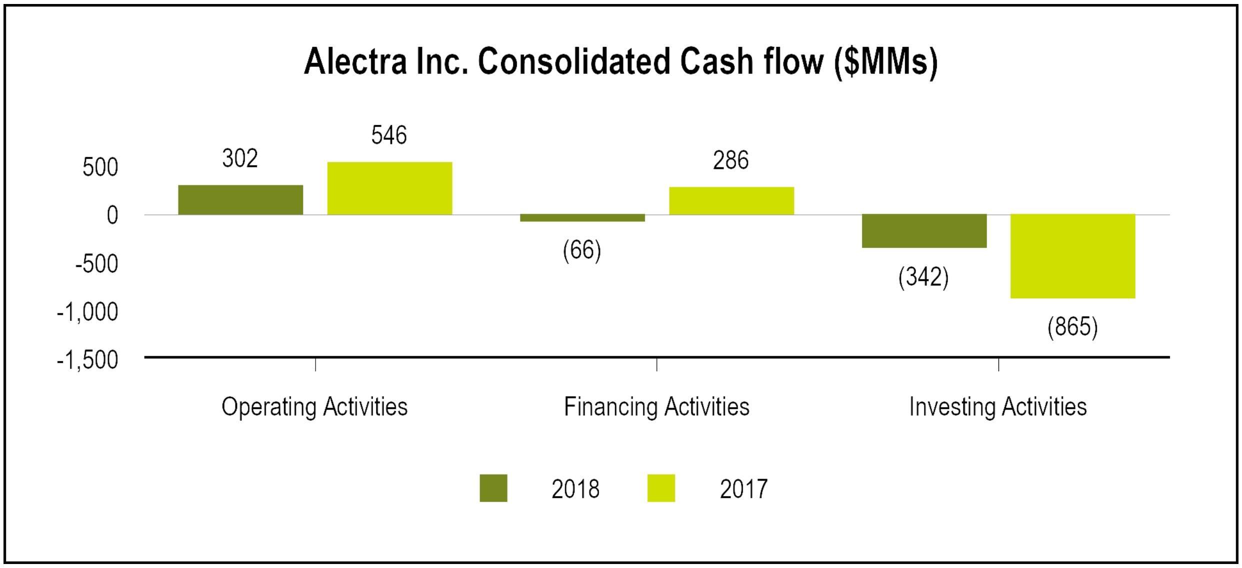
Significant changes in the Corporation's Financial Condition:

	2018	2017	$ Change	% Change	Explanation
ASSETS					
Accounts receivable and unbilled revenue	596	523	73	14%	Increase primarily driven by higher unbilled revenue due to timing of customer payments.
Assets held for sale	—	16	(16)	(100%)	Decrease in assets held for sale due to: i) the sale of Collus PowerStream that occurred during the year; and ii) the transfer of land that was held for sale back into PP&E.
PP&E	3,052	2,892	160	6%	Increase was principally due to capital expenditures, partially offset by depreciation and derecognition.
Goodwill and other intangible assets	936	879	57	6%	Increase was principally due to the capitalization of new software as a result of the implementation of the new CIS system.
LIABILITIES					
Accounts payable and accrued liabilities	368	414	(46)	(11%)	Decrease in accounts payable is primarily due to lower energy purchases as compared to prior year.
Short term debt	250	176	74	42%	Higher short term debt due to the Corporation's investment in its capital program.
Deferred revenue	361	300	61	20%	Increase in deferred revenue relates to higher deposits in aid of the capital cost of construction received during the year in relation to new subdivisions and transit projects.
Deferred tax liabilities	45	15	30	200%	Increase in deferred tax liabilities as a result of PP&E timing differences between depreciation and CCA.

LIQUIDITY AND CAPITAL RESOURCES

Sources of Liquidity and Capital Resources

The principal sources of liquidity and capital resources comprise funds generated from operations and the financing activities of the Corporation.



Operating Activities

Cash from operating activities is $302 (2017 - $546). The decrease in net cash provided in operating activities was principally due to timing differences in relation to the settlement of receivable and payables (see note 27 in Consolidated Financial Statements); partially offset by higher net income and higher financing costs.

Financing Activities

Cash used in financing activities is $66 (2017 - $286). Cash from financing was lower in 2018 principally due to the fact the Corporation issued debt in 2017 but not in 2018.

In October 2018, the Corporation entered into a Commercial Paper ("CP") program. The program has a maximum authorized amount of $300 and is supported by the Corporation's $500 committed credit facility. The Corporation also has a $100 uncommitted credit facility and a $1 secured demand facility. The Corporation may draw on the credit facilities for working capital and general corporate purposes. Interest on drawn amounts under the credit facilities would apply based on Canadian benchmark rates.

Short-term loans at December 31, 2018 consist of CP issued under the Corporation's CP program. These short-term loans are denominated in Canadian dollars and are issued with varying maturities of no more than one year. CP issuances bear interest based on the prevailing market conditions at the time of issuance.

Short-term loans at December 31, 2017 consist of Bankers Acceptances ("BA") issued under the committed credit facility. These borrowings bear interest at short-term floating rates plus a negotiated spread. Negotiated standby fees are applied to undrawn amounts of the committed credit facility, in accordance with the credit agreement.

Long-term liquidity is available through the Corporation's ability to issue senior unsecured debentures under an established trust indenture. The rates of interest on such debentures comprise: government of Canada bond yields with terms of maturity corresponding to the terms of issued debentures; market-based credit spreads determined with reference to comparably rated entities; and costs of issuance. Details of the Corporation's long-term borrowings are provided in the Consolidated Financial Statements.

Dividend Requirements

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

- Common share dividends aggregating $60 or $6.06 per share (2017 - $28 or $2.78 per share); and
- Class S share dividends aggregating $9 or $87.02 per share (2017 - $8 or $81.00 per share).

In addition, $5 of return of capital on Class S shares were paid during the year.

The Class S dividends, other than return on capital, are subject to Part VI.1 tax under the *Income Tax Act (Canada)* at a rate of 25% based on the amount of dividend paid. The Corporation is also eligible for a corresponding deduction equal to a specified multiple of the dividend. The deduction does not fully offset the Part VI.1 tax, resulting in a net effective tax rate of 1.8% on the Class S share dividends.

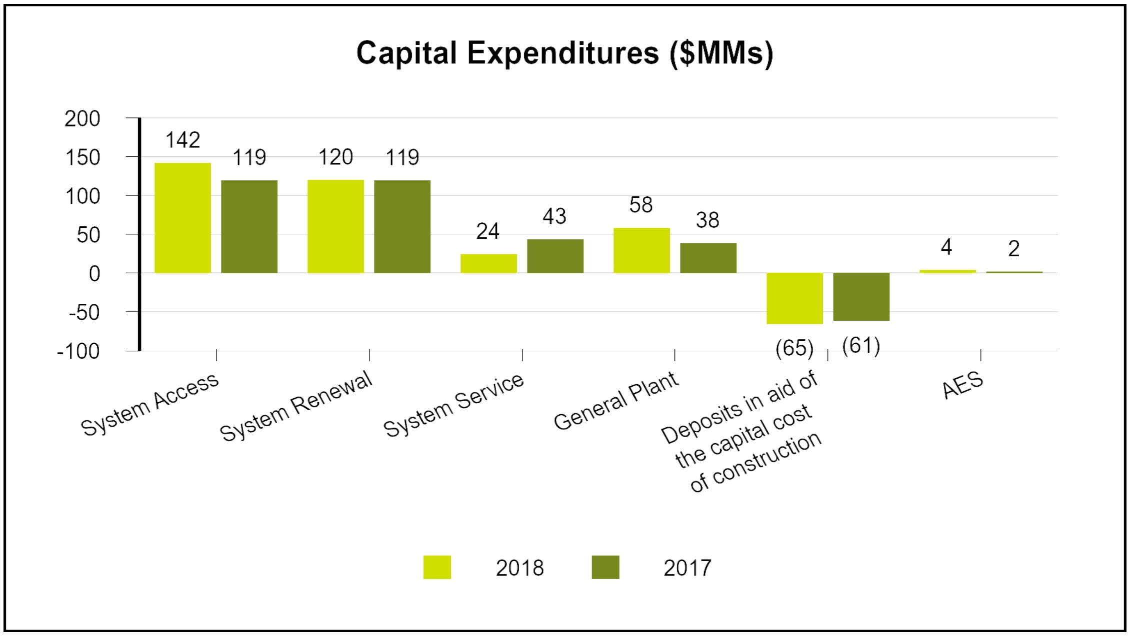
Investing Activities

Cash used in investing activities was $342 (2017 - $865). The cash used in investing activities is lower compared to 2017 with the variance principally attributable to the purchase of Brampton Hydro by the Corporation in 2017, which was the main use of cash for investing activities in 2017. There were no acquisitions in 2018.

During the year ended December 31, 2018, the Corporation continued to execute its capital plans to expand the distribution system, and replace aging infrastructure.

Capital Expenditures

The Corporations gross capital investments are presented by activity in the table below:



System access expenditures relate to projects required to meet customer service obligations in accordance with the Distribution System Code of the OEB and corporate Conditions of Service. Projects in this category include: connecting new customers; building new subdivisions; and relocating system plant for roadway reconstruction work. Capital expenditures in this category have increased by $23 compared to 2017, principally as a result of: (i) higher expenditures on transit projects ($12); and (ii) a payment under a CCRA to Hydro One Networks in 2018 ($7). CCRA payments represent contributions made to Hydro One Networks for building dedicated infrastructure to accommodate the Corporation's distribution system requirements.

System renewal expenditures relate to long-term plans to replace assets that are at the end, or nearing the end, of their useful lives. Replacement strategies are prioritized based on both age and condition of assets, as well as the impact on system reliability. Capital expenditures in this category are substantially the same as 2017.

System service expenditures relate to projects required to support the expansion, operation and reliability of the distribution system. System service expenditures have decreased by $19 compared to 2017, principally explained by: (i) a large project for the expansion of distribution lines in 2017 ($11); and (ii) a significant transformer station was energized in 2017 ($7).

General plant expenditures relate to information systems projects, facilities, and fleet. Capital expenditures have increased by $20 as compared to 2017, principally due to: (i) higher expenditures related to the harmonization of predecessor ERP and CIS systems into common respective systems ($15); and (ii) higher fleet expenditures in 2018 as compared to 2017 ($3).

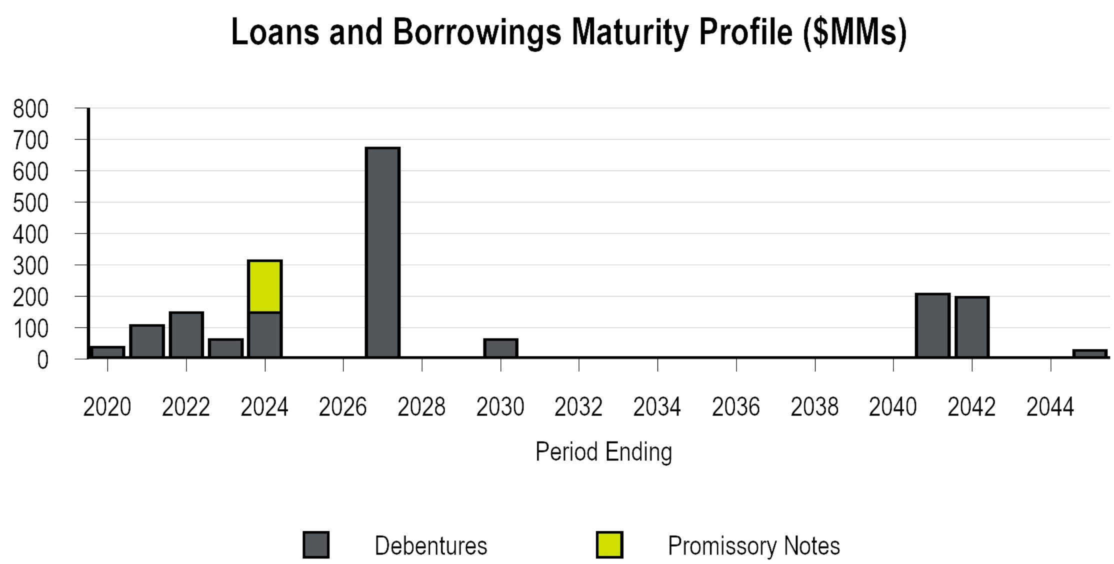
AES capital expenditures are principally attributable to the purchase of sub-metering assets.

Requirements for liquidity and capital resources

The Corporation's principal liquidity and capital resource requirements comprise its ongoing commitment to maintain, improve and expand its distribution business and the Solar PV Business, and invest in other infrastructure assets on a sustainable basis and in accordance with: governing statutes and regulations; working capital requirements; cost of power expense; the servicing and repayment of debt obligations; and the payment of dividends to its shareholders.

Summary of loans and borrowings

The following table presents a summary of the Corporations loans and borrowings.



in millions of Canadian dollars

NON-IFRS FINANCIAL MEASURES

EBITDA

The Corporation uses earnings before interest, taxes, depreciation and amortization ("EBITDA"), comparable net earnings, and funds from operations ("FFO") as financial performance measures under MIFRS. MIFRS adjusts IFRS results for the effect of rate regulation. These measures do not have any standard meaning prescribed by IFRS and may not be comparable to similar measures presented by other companies. The purpose of these financial measures and their reconciliation to IFRS financial measures are provided below. These non-IFRS measures are consistently applied in the previous period, except where otherwise noted.

($MMs)	2018	2017
EBITDA (MIFRS)	356	269
Add adjustments to remove regulatory accounting:		
Revenue	(3)	12
Operating expenses	(1)	1
Loss on derecognition	(1)	—
Net income from joint venture	—	(1)
EBITDA (IFRS)	351	281

Management believes that a measure of operating performance is more meaningful when including regulatory accounting in the results of operations as this truly reflects the Corporation's normal operations.

AFFO (Adjusted Funds from Operations)

AFFO is used as an additional metric of cash flow without regard to changes in the Corporation’s non-cash working capital and adjusted for contributions in aid of construction.

Adjusted Funds From Operations (MIFRS - $MMs)	2018	2017
Net income (IFRS measure)	109	74
Adjustment for regulatory activities	31	9
MIFRS Net income	140	83
Depreciation (MIFRS)	131	120
Net gain / loss on disposal (MIFRS)	3	6
Amortization of deferred revenue	(9)	(6)
Net change in employee future benefits	5	2
Net change in non-cash operating working capital (MIFRS)	(123)	55
Net change in deferred revenue	70	56
Net change in taxes	21	13
Total changes	98	246
Adjusted funds from operations[1]	238	329

[1]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.

SUBSEQUENT EVENT

Merger

On January 1, 2019, the Corporation amalgamated with Guelph Hydro Electric Systems Inc. ("GHESI"). The Corporation 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 the Corporation 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 new shareholder ownership structure as a result of this merger is as follows: Barrie Hydro Holdings - 8.4%; Enersource Corporation - 29.6%; Hamilton Utilities Corporation - 17.3%; Markham Enterprises Corporation - 15.0%; St. Catharines Hydro Inc. - 4.6%; Vaughan Holdings Inc. - 20.5%; and GMHI - 4.6%.

The accounting and valuation for the amalgamation is still being finalized. Consequently, disclosures regarding the purchased assets and liabilities cannot be provided at this time.

RISK MANAGEMENT AND RISK FACTORS

The ability to identify, manage and mitigate risk and uncertainty, maintain effective operations and respond appropriately to changes in the external and internal business environment is crucial to the continued success of the Corporation. The Corporation has established and implemented an Enterprise Risk Management ("ERM") System, as defined by its ERM Framework, to provide a coordinated approach to assessing and responding to risks and opportunities that have an impact on the achievement of strategic objectives.

During 2018, the Corporation completed an enterprise-wide review of risks. The potential impact of risks to the Corporation were assessed based on assessments of various outcomes and probability of occurrence. Internal risk owners were identified and strategies were developed to mitigate potential impacts. The most significant risks are elaborated below.

Culture

The Corporation continues with its integration efforts with respect to the 2017 Merger Transaction including the establishment of a unified high-performing corporate culture. During this transition from legacy cultures, there is a potential risk associated with resistance to cultural change and conformance. The Corporation may experience some level of employee disengagement or loss of key employees. A failure to attract and retain qualified personnel could have a significant adverse effect on the Corporation. The Corporation has been working diligently through various means to establish a resilient culture including: the establishment of core values; employee engagement and communication initiative; and employee involvement in culture initiatives.

Regulatory/Political

The electricity distribution business in Ontario is highly regulated, which poses risks to the financial and operational aspects of the Corporation’s rate regulated business. The Province and/or the OEB could implement a regulatory framework or issue directives or decisions that restrict the electricity distribution business from achieving an acceptable rate of return that permits the financial sustainability of its operations. All requests for changes in electricity distribution charges require the approval of the OEB.

The Corporation files applications to the OEB on an ongoing basis for rate adjustments in support of the sustainment and growth of its electricity distribution system. OEB decisions on current and future applications could have a significant impact on the distribution revenue of the Corporation in the future. The Corporation has an experienced management team dealing with these regulatory matters and continues to mitigate regulatory and political risk through participation in stakeholder groups, industry associations and other affiliations that are designed to inform the development of the legislative and regulatory environment.

Safety

The Corporation is engaged in the construction, operation and maintenance of high voltage electrical infrastructure throughout the communities it serves and, as such, is exposed to significant safety risks associated with this work. These risks include the potential for a major impact on the health and safety of the Corporation’s staff or a member of the public. The failure to keep members of the public and employees safe could have a material adverse effect on the Corporation. The Corporation has recognized the high level of safety excellence achieved at the four legacy utilities and is building upon that foundation to implement an enterprise-wide safety management system. Safety is one of the Corporation’s core values and, as such, the organization is focused on continual improvement of its safety performance.

Integration Projects

The Corporation is currently in the planning and/or implementation phase of several large operating/network system convergence projects. These projects include the Customer Information System (“CIS”), Enterprise Resource Planning System (“ERP”), and Graphical Information System/ Operations Management System (“GIS/OMS”). These large, complex projects pose risks related to cost overruns, scope changes and timeline delays that have the potential to impact the synergies, savings and operational and customer benefits identified within the Corporation’s business plan for the Merger Transaction. Failure to successfully implement these projects could have an adverse financial, operational and/or reputational impact on the Corporation.

In order to mitigate these risks, dedicated teams of functional and technical experts have been, or are in the process of being, developed along with appropriate third party assistance from knowledgeable system integrators. These teams are supported by the Corporation’s internal project management and change management expertise. These projects include the development of formal project charters and governance structures as well as regular review of project status, milestones, risks and issues to mitigate potential risks before or as they arise.

Cyber Security

All businesses are at risk of cyber-attacks and are vulnerable to unauthorized access due to computer viruses, hacking, or other causes. A cyber-attack has the potential to cause service disruptions or system failure, or could result in the disclosure of confidential customer or business information. Any such cyber-attack could have an adverse financial, operational and/or reputational impact on the Corporation. Due to the rapid change in technology and infrastructure security requirements of operating systems, the Corporation uses specialized internal resources and outside cybersecurity services to mitigate the potential for cyber security events. Policies, procedures and employee cyber security education programs are in place to reduce the risk of security breach. The Corporation is in the process of standardizing security tools across the enterprise as networks and systems from the legacy utilities are consolidated. These security enhancements include hardware, software, as well as physical security at all facilities.

Although the Corporation has implemented security controls and other preventative measures to protect information and technology against cyber-attacks, there can be no assurance that such measures will be effective in protecting the Corporation's electricity distribution infrastructure or other assets from a cyber-attack or the effects thereof.

Collective Agreement

Unionized employees at the four legacy utilities were previously represented by different unions and, as a result, had separate collective agreements in place. In, 2017, unionized employees selected the Power Workers Union ("PWU") as their new collective bargaining agent. The Corporation is in the process of negotiating a unified collective agreement with the PWU for all represented employees. In the event of a labour dispute, the Corporation could face operational risks related to its ability to provide service to customers. The Corporation and PWU are working towards a mutually satisfactory collective agreement that will benefit represented employees and also create an environment in which the organization can achieve its strategic goals. It is anticipated that a new collective agreement will be in place in 2019. The Corporation is confronted by financial and operational risks related to its ability to negotiate a collective agreement.

Credit risk

Credit risk is the risk that one party to a financial instrument will fail to discharge an obligation and cause the other party to incur a financial loss.

The principal source of credit risk for the Corporation corresponds to the realization of its customer receivables. The legislation governing the operation of Ontario’s electricity industry exposes the Corporation, through its electricity distribution operations, to credit risk of several multiples of its means to generate revenue. Pursuant to Provincial regulation, electricity distribution companies in Ontario are required to act as the billing agent for all industry participants and must remit billed amounts accruing to these participants irrespective of whether such amounts are ultimately collected. With the exception of the debt retirement charge, electricity distribution companies are exposed to losses for entire amounts billed to customers. Electricity distribution companies are not compensated for assuming this level of risk nor is there a clear and mechanistic regulatory means to recover losses for non-distribution charges.

Management has implemented credit and collection policies in compliance with OEB regulation to mitigate the exposure of the Corporation to credit risk, although such regulation is inadequate to effectively mitigate such risk. OEB regulation continues to impose certain restrictions on credit policy that exposes electricity distribution Corporations to unmitigated and uncompensated credit risk of several multiples of their means to generate revenue.

Management actively monitors and manages its exposure to credit risk, within regulatory constraints, and records credit losses in the period in which, in management's opinion, the collection of related receivables becomes doubtful.

As at year end, approximately $23 (2017 - $20) 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.

Risk Associated with Debt Financing

The Corporation relies on debt financing or the availability of credit facilities to repay existing indebtedness and to finance its ongoing business operations including capital expenditures. The Corporation's ability to arrange sufficient and cost-effective debt financing could be adversely affected by a number of factors, including financial market conditions, the regulatory environment in Ontario affecting its businesses, the Corporation's results of operations and financial condition, the ratings assigned to the Corporation and its debt securities by credit rating agencies, the current timing of debt maturities, and general economic conditions.