ENMAX CORPORATION

Q1 2020 INTERIM REPORT

CAUTION TO READER

This document contains statements about future events and financial and operating results of ENMAX Corporation and its subsidiaries (ENMAX or the Corporation) that are forward-looking. By their nature, forward-looking statements require the Corporation to make assumptions and are subject to inherent risks and uncertainties. There is significant risk that predictions and other forward-looking statements will not prove to be accurate. Readers are cautioned not to place undue reliance on forward-looking statements as a number of factors could cause actual future results, conditions, actions or events to differ materially from financial and operating targets, expectations, estimates or intentions expressed in the forward-looking statements.

When used in this Financial Report, the words “may,” “would,” “could,” “will,” “intend,” “plan,” “anticipate,” “believe,” “seek,” “propose,” “estimate,” “expect” and similar expressions, as they relate to the Corporation or an affiliate of the Corporation, are intended to identify forward-looking statements. Such statements reflect the Corporation’s current views with respect to future events and are subject to certain risks, uncertainties and assumptions. Many factors could cause the Corporation’s actual results, performance or achievements to vary from those described in this Financial Report. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this Financial Report. Intended, planned, anticipated, believed, estimated or expected and other forward-looking statements included in this Financial Report herein should not be unduly relied upon. These statements speak only as of the date of this Financial Report. The Corporation does not intend, and does not assume any obligation, to update these forward-looking statements except as required by law, and reserves the right to change, at any time at its sole discretion, the practice of updating annual targets and guidance.

MANAGEMENT DISCUSSION AND ANALYSIS (MD&A)

This MD&A, dated May 21, 2020, is a review of the results of operations of ENMAX for the three months ended March 31, 2020, compared with 2019, and of the Corporation's financial condition and future prospects. This MD&A should be read in conjunction with the Q1 2020 Condensed Consolidated Interim Financial Statements and the 2019 ENMAX Financial Report, which is available on ENMAX's website at www.enmax.com, as information has been omitted from this MD&A if it remains substantially unchanged.

ENMAX's Condensed Consolidated Interim Financial Statements have been prepared in accordance with International Financial Reporting Standards (IFRS). The Condensed Consolidated Interim Financial Statements and MD&A were reviewed by ENMAX's Audit Committee and were approved by ENMAX's Board of Directors (the Board). All amounts are in millions of Canadian dollars unless otherwise specified.

The Corporation reports on certain non-IFRS financial performance measures that are used by management to evaluate performance of the Corporation and its business segments. Because non-IFRS financial measures do not have a standard meaning prescribed by IFRS, the Corporation has defined and reconciled them with their nearest IFRS measure. For the reader's reference, the definition, calculation and reconciliation of non-IFRS financial measures is provided in the Non-IFRS Financial Measures section.

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Glossary of terms can be found on page 46 of the Condensed Consolidated Interim Financial Statements.

MARKET CONDITIONS

The COVID-19 pandemic has created global economic uncertainty. The resulting drop in economic activity and other geopolitical factors has also caused an over-supply of oil, leading to record low oil prices. Canadian oil producers have announced drastic cuts to capital projects resulting in large reductions in capital spending. Further drops in oil prices may lead to shut-ins and even shutdowns of oilsands facilities. The impact on economic conditions and operations in Maine are not expected to be as significant as they are anticipated in Alberta. While there has not been significant reduction in electricity demand in Alberta yet, negative GDP growth will certainly affect future demand growth.

The Alberta power market pool price settled at $66.38 per megawatt hour (MWh) for the first quarter of 2020, representing a 7 per cent decrease over the same period in 2019 when the average was $70.73 per MWh. Spark spreads settled at $51.91 for the first quarter of 2020, compared to $52.43 for the same period in 2019. Prices for the first quarter of 2020 were generally low, with one cold period being the exception averaging $406.66 per MWh, with the rest of the quarter averaging only $38.74 per MWh. ENMAX's hedging strategy secures significant margins before entering the year, offering protection from decreasing power prices while maintaining some ability to capitalize on price increases.

Alberta demand (load) averaged 10,245 megawatt (MW) in the first quarter of 2020, which is less than a 0.5 per cent decrease over the same quarter in 2019. A new system peak load of 11,698 MW, up 1 MW from the previous record, was set on January 14, 2020 during the period of unseasonably cold temperatures. ENMAX generation facilities were fully available and operational during this time to assist in maintaining system reliability.

In January 2020, Alberta's Technology Innovation and Emissions Reduction (TIER) regulation took effect, which provides a mechanism to manage carbon pricing for Alberta's large industries, including electricity generation. The carbon cost for 2020 will match the federal carbon cost of $30.00 per tonne of CO_2 equivalent. Under TIER, all existing generating units, including coal, will be measured against a "good as best gas" intensity standard, which currently is Shepard Energy Centre (Shepard) for all generating plants in Alberta. Any changes to the provincial carbon tax structure in the near-term or the federal carbon tax structure in the long-term could impact electricity price outcomes and costs for power generation facilities.

Alberta natural gas prices averaged $1.93 per gigajoule (GJ) for the first quarter in 2020, which is a 27 per cent decrease compared to the average for the first quarter of 2019. Major maintenance of the Nova Gas Transmission Ltd. (NGTL) system is expected to continue until 2023 posing a gas delivery risk to ENMAX's assets, creating financial and operational challenges. ENMAX continues to acquire third party transportation to ensure that firm and reliable gas delivery requirements are met for our generation portfolio. We are also currently engaged in the ongoing process of planning and developing direct pipeline connections to surrounding natural gas supply sources. These connections would create long-term safe, secure and economic gas delivery to support the requirements of our generation portfolio.

FINANCIAL PERFORMANCE

Upon completion of its acquisition of Emera Maine (see Significant Events section) the Corporation's financial results include Emera Maine as a separate operating segment. Management believes that a measure of operating performance is more meaningful if the impact of specific items is excluded from the adjusted financial information. As a result, the table below presents ENMAX's adjusted earnings before interest, taxes, depreciation and amortization (Adjusted EBITDA), adjusted earnings before interest and taxes (Adjusted EBIT) and comparable net earnings. These financial metrics exclude foreign exchange gains (losses), unrealized gains (losses) on commodities where settlement on derivatives will occur in a future period and Emera Maine acquisition related costs (see Significant Events section). Refer to the Non-IFRS Financial Measures section on page 12 for definitions and further descriptions of the financial measures.

SELECTED CONSOLIDATED FINANCIAL INFORMATION

Three months ended March 31, *(millions of Canadian dollars)*	**2020**	**2019**
Total revenue	**719.2**	712.4
Adjusted EBITDA [1][2]		
Competitive Energy	**65.8**	71.8
Power Delivery	**61.0**	60.5
Emera Maine	**2.2**	-
Corporate and Eliminations	**(0.3)**	(0.7)
Consolidated	**128.7**	131.6
Adjusted EBIT [1][2]		
Competitive Energy	**31.8**	40.5
Power Delivery	**29.7**	31.1
Emera Maine	**1.0**	-
Corporate and Eliminations	**0.7**	0.3
Consolidated	**63.2**	71.9
Comparable net earnings [1][2]	**55.3**	55.9
Net earnings	**172.5**	74.2
Free cash flow (FCF) [1][3]	**49.5**	138.1
Capital expenditures [4]	**84.3**	101.0

(1) Non-IFRS financial measure. See discussion that follows in Non-IFRS Financial Measures section.

(2) Does not include:

- Realized and unrealized foreign exchange gains of $125.5 million (2019 - $0.7 million gains) for the three months ended March 31, 2020.
- Unrealized electricity and gas mark-to-market for the three months ended March 31, 2020 of $30.5 million gains (2019 - $31.3 million gains).
- Emera Maine acquisition related costs of $37.3 million (2019 – $4.9 million) for the three months ended March 31, 2020, including $15.2 million related to finance charges that are included in calculating Comparable net earnings.

(3) FCF is calculated for the twelve months ended March 31, 2020 and 2019 respectively.

(4) Capital expenditures excludes $1,392.9 million investment in the acquisition of Emera Maine (see Significant Events section).

ENMAX's Adjusted EBIT decreased by $8.7 million for the three months ended March 31, 2020, as compared with the three months ended March 31, 2019. The primary drivers were as follows:

- ENMAX Competitive Energy (Competitive Energy) – lower Power Services margin partially offset by higher realized margins due to increased electricity sales to customers.
- ENMAX Power Delivery (Power Delivery) – continued growth through investment and an increase in customer sites.
- Emera Maine – for the seven-days post acquisition, Emera Maine recorded $1.0 million in EBIT.
- ENMAX Corporate and Eliminations (Corporate and Eliminations) – higher adjusted EBIT primarily as a result of prior year non-recurring losses.

ENMAX's net earnings for the three months ended March 31, 2020 were $172.5 million as compared with net earnings of $74.2 million in the comparable period in 2019. The main driver for this increase is related to $125.5 million in foreign exchange gains in 2020 that were primarily realized on the settlement of forward contracts. Foreign exchange is not included in adjusted EBIT.

As at March 31, 2020, ENMAX's balance sheet continued to show strength as the Corporation carefully managed debt to cash flow ratios as well as capital investment. This prudent management enabled the Corporation to undertake strategic growth in regulated assets with the acquisition of Emera Maine (see Significant Events section).

Additional details on the financial performance of the Corporation are discussed in the ENMAX Financial Results section.

Results of operations are not necessarily indicative of future performance due to factors including fluctuating commodity prices, timing of receipt of regulatory decisions, the performance and retirement of existing generation facilities, the addition of new generation facilities, and the impact of government policies.

SIGNIFICANT EVENTS

CHIEF EXECUTIVE OFFICER ANNOUCEMENT

On May 20, 2020, the ENMAX Board of Directors announced that Wayne O'Conner has been appointed ENMAX President and Chief Executive Officer effective June 22, 2020. Wayne's appointment results from an extensive North American recruitment process undertaken by the Board following the June 2019 announcement of the planned departure of ENMAX President and Chief Executive Officer, Gianna Manes. To support a smooth and orderly transition following Wayne's arrival, Gianna will remain as a member of the Board until July 31, 2020.

Wayne comes to ENMAX with over 30 years of industry experience and leadership spanning multiple Canadian and North American electricity and energy markets. Most recently, Wayne has served as President and Chief Executive Officer of Nova Scotia Power leading a team of 1,700 employees and overseeing a portfolio of generation, transmission and distribution assets valued at over $4.0 billion. Prior to this role, Wayne has held a series of executive leadership positions across Emera Inc. companies and with TC Energy, formerly TransCanada Pipelines.

EMERA MAINE ACQUISITION

On March 24, 2020 the Corporation completed its acquisition of BHE Holdings Inc., the parent company of Emera Maine. This transaction is aligned with the Corporate strategy to grow regulated cash flows and diversify revenue streams within North America, increasing regulated rate base by approximately 50 per cent. The portion of future cash flows from regulated and non-commodity sources have risen to 70 per cent.

The Corporation acquired all the outstanding common shares of Emera Maine and the aggregate purchase price was approximately $1,394.0 million ($962.6 million USD), on closing, including the assumption of approximately $566.5 million ($391.2 million USD) of senior debt. The Corporation funded this transaction through a combination of cash, a two-year bank loan and issuance of private debentures.

The majority of Emera Maine's operations are subject to the rate-setting authority of the Federal Energy Regulatory Commission (FERC) and the Maine Public Utilities Commission (MPUC), and are accounted for pursuant to U.S. Generally Accepted Accounting Principles (U.S. GAAP), including the accounting guidance for regulated operations. Except for unregulated long-term debt acquired, construction work in progress and investments in corporate joint ventures, fair values of tangible and intangible assets and liabilities subject to these rate-setting provisions approximate their carrying values due to the fact that a market participant would not expect to recover any more or less than their net carrying value. Accordingly, assets acquired, liabilities assumed, and pro-forma financial information do not reflect any adjustments related to these amounts.

The transaction constitutes a business acquisition and as such has been accounted for using the acquisition method of accounting. The excess of the purchase price over estimated fair values of net assets acquired has been recognized as goodwill at the acquisition date of March 24, 2020. The goodwill reflects the value paid for access to regulated assets, net income and future cash flows, opportunities for adjacency growth, long-term potential for enhanced access to capital as a result of increased scale and business diversity, and an improved earnings risk profile.

Emera Maine acquisition costs, including one-time stipulated transaction costs have been excluded from the Corporations operating performance metrics (see Non-IFRS Measures section).

GENESEE 4/5 GENERATION PROJECT DEPARTURE

By letter dated March 24, 2020 to Capital Power, ENMAX made the decision not to proceed as a partner in the development of Genesee 4/5 Generation project. ENMAX provided notice of its departure from the Genesee 4/5 Generation project under the Joint Venture Agreement (the Notice). The Notice seeks, under the terms of the Joint Venture Agreement, payment from Capital Power of 90 per cent of ENMAX's share of the project costs upon closing, all as particularized in the Notice.

COVID-19 PANDEMIC

On March 11, 2020, the World Health Organization characterized the outbreak of a strain of the novel coronavirus (COVID-19) as a pandemic. Governments around the world have introduced public health and emergency measures to combat the spread of the virus. Combined with ongoing geopolitical factors, dramatic declines in oil prices created further economic uncertainty. By the end of March 2020, the Corporation implemented dramatic action against COVID-19, shifting to a remote operating environment to protect employees and customers and continue to operate as an essential service. Given the anticipated impact on the remainder of 2020, activities are underway to mitigate the effects on the business in Alberta and Maine.

On May 8, 2020, the Alberta Utility Payment Deferral Program Act (Bill 14) passed third and final reading. The legislation implements the Government of Alberta's utility deferral program. Under that program, residential, farm and small commercial customers can defer payments for electricity and natural gas services for the three-month period ending June 18, 2020. Customers who defer payments have 12 months to repay the deferred amounts. The legislation makes funds available, from the Government of Alberta and the Balancing Pool, to ENMAX and other electricity retailers to carry the cost of deferrals for customers enrolled in the program. These funds, if accessed, mitigate cash flow impacts connected with the utility bill deferral program. Under the legislation, there is no obligation for ENMAX to repay the Government of Alberta or the Balancing Pool any amounts that are not collected from customers.

ENMAX COMPETITIVE ENERGY BUSINESS AND UPDATE

ENMAX Competitive Energy is an integrated business providing customers with electricity, natural gas, distributed energy resource solutions, as well as engineering, procurement and construction services. Our competitive advantage is our ability to hedge our low-cost generation assets through our retail business – the largest in Alberta by number of customers and energy consumed. The competitive retail business provides customers with fixed-price electricity linked to our wind and gas-fueled generation assets, and provides opportunities to offer additional energy services, such as solar installations and thermal energy. As at March 31, 2020, Competitive Energy's capacity ownership interest was 1,509 MW of electricity generation: 1,289 MW from natural gas-fueled plants, 217 MW from wind power and 3 MW from combined heat and power (CHP) generation.

Natural gas retail contracts are backed by market transactions to provide supply certainty, margin stability, and risk mitigation. Natural gas fuel requirements for the portfolio are balanced through the purchase and sale of natural gas in the Alberta market.

KEY BUSINESS STATISTICS

Three months ended March 31,	2020	2019
Plant availability (%) (1)	**99.23**	97.56
Average flat pool price ($/MWh)	**66.38**	70.73
Spark spread ($) (2)	**51.91**	52.43

(1) Plant availability (%) reflects planned maintenance and forced outages.
(2) Based on market prices.

Plant availability was higher than the prior period due to a continued focus on safe and reliable operations. Minor outage events were undertaken as the same period in in 2019. ENMAX is well positioned in 2020, having completed two major maintenance outages in 2019 and have none scheduled for this year.

During the first three months of 2020, the average flat pool power price decreased compared to the same period in 2019. This was primarily due to the extreme temperatures Alberta experienced during the first quarter of 2019 which tightened the market supply-demand balance and provided prolonged upward pressure on pool prices.

Spark spread, which is the difference between the wholesale electricity price and the price of natural gas to produce the electricity, represents the gross margin contribution of a gas-fuelled power plant from generating an unhedged unit of electricity. The decline from 2019 levels was driven by a lower average pool price (as described above) which is partially offset by a decrease in the price of natural gas.

In the retail business our fixed price electricity volumes were higher than the prior year, maintaining our ability to hedge our generation assets. Our competitive products were positively impacted by higher margins, from the removal of the regulated rate option price cap of 6.8 cents per kilowatt hour (kWh) on electricity prices effective November 30, 2019.

During the first quarter of 2020 our electricity margins (see section ENMAX Financial Results) were slightly higher than 2019 due to the removal of the regulated rate option price cap (as described above) offsetting the decrease in market power and spark spreads over the prior year. To mitigate risk, ENMAX contracts most of our market position, delivering the majority of our margin with less exposure to the volatility of near-term spark spreads.

ENMAX manages its portfolio to deliver on our cash flow targets by using a combination of retail sales and forward market hedges. As a result, our hedging and contracting strategies temper the impact of in-year price movements, which reduces volatility of cash flows with respect to market prices. Public health actions to contain the COVID-19 pandemic have led to a significant decline in crude oil prices and production in Alberta and have reduced demand and price volatility for electricity. Entering the year, Competitive Energy has hedged a significant portion of its capacity. This has largely insulated commodity margins from the recent COVID-19 market impacts which has increased certainty on cashflows throughout the remainder of the year. Competitive Energy's remaining open positions have been impacted by the current market environment as power prices have significantly decreased combined with an increase in natural gas prices leading to lower expected spark spreads. We expect to see a rebound in electricity demand through the balance of year as COVID-19 containment actions are relaxed.

In response to the COVID-19 pandemic, the Government of Alberta passed Bill 14, providing a 90-day payment deferral for residential, farm and small business customers (see Significant Events section). This program may potentially affect our provision for allowance for doubtful accounts due to customer non-payment. Competitive Energy continues to actively manage credit and payments for large customers, while leveraging applicable and available credit facilities.

ENMAX POWER DELIVERY BUSINESS AND UPDATE

Power Delivery's highest priorities are providing safe, reliable and efficient delivery of electricity to customers. This is particularly important during the current COVID-19 pandemic.

Power Delivery continues to invest in its electricity transmission and distribution system infrastructure to meet Calgary's needs. This includes expansion of the distribution system, reinforcement of the transmission system, and replacement of aging infrastructure in both systems. Distribution projects include investments in system infrastructure to accommodate residential, commercial and industrial growth, as well as the replacement and modification of existing assets required to meet industry safety and reliability standards. Transmission projects can include capacity upgrades to existing substations, existing transmission lines, new substations, and new transmission lines to deliver reliable electricity that meets Calgary's demand.

Power Delivery submits applications to the Alberta Utilities Commission (AUC) to request approval for construction or replacement of utility-related facilities, and to set rates for providing electric energy delivery-related services to its customers, among other things.

- On December 16, 2019, the AUC issued a decision approving 2020 Performance Based Regulation (PBR) distribution rates on an interim basis, and distribution tariff terms and conditions for the period of January 1, 2020 to December 31, 2020. This decision is expected to increase the operating margin by 3.6 per cent.
- On December 2, 2019, the AUC approved the 2020 Interim Transmission Tariff Application of $99.8 million. Effective January 1, 2020, this approval resulted in $9.9 million higher revenue than the 2019 interim Transmission tariff that was previously in place.
- On March 19, 2020, the AUC suspended the General Cost of Capital proceeding due to the volatility in financial markets created by the COVID-19 pandemic. In a recent submission to the AUC, a group of Alberta utilities, including ENMAX, have proposed that the current Return on Equity (ROE) and capital ratios be extended into 2021 on a final basis. If adopted by the AUC, this extension would provide less uncertainty, reducing utility risk profiles and improving their creditworthiness.
- The AUC is also working with the Government and the broader community of stakeholders on the implementation of the utility payment deferral program reflected in Bill 14 (see Significant Events section). In parallel, the AUC has undertaken various outreach activities to understand the financial and operational issue facing utilities.

KEY BUSINESS STATISTICS

Three months ended March 31,	2020	2019
Distribution volumes in Gigawatt Hours (GWh)	**2,338**	2,431
System average interruption duration index (SAIDI) (1)	**0.05**	0.07
System average interruption frequency index (SAIFI) (2)	**0.07**	0.14

(1) SAIDI equals the total duration of a sustained interruption per average customer during a predefined period of time. A sustained interruption has a duration greater than or equal to one minute. The lower the SAIDI, the better the reliability.

(2) SAIFI equals how often the average customer experiences a sustained interruption over a predefined period of time. A sustained interruption has a duration greater than or equal to one minute. The lower the SAIFI, the better the reliability.

Total electricity delivered in GWh to the Calgary service area to date in 2020 was slightly lower than the prior year as a result of an overall decrease in customer usage over the first three months of 2020. We are continuously monitoring the impact the COVID-19 pandemic is having on energy delivered. We are witnessing a decrease in overall distribution volumes due to the continued closure of businesses which is partly offset by an increase in residential electricity usage.

When compared to the performance of other Canadian Electricity Association member utilities, ENMAX has remained one of the most reliable transmission and distribution utilities in Canada. Both SAIDI and SAIFI are favourable compared to the same period in 2019 due to a decrease in cable failures, animal/bird contacts and pole fires. ENMAX continues to monitor the cause of any outages to mitigate future occurrences.

ENMAX has continued to meet its SAIDI and SAIFI targets with the onset of the COVID-19 pandemic while assessing the impact for the remainder of the year. We continue to maintain our commitment to our customers, employees and safety during these unprecedented times.

EMERA MAINE BUSINESS AND UPDATE

Emera Maine is a public transmission and distribution utility operating in the Maine Public District (MPD) and Bangor Hydro District (BHD) covering six counties in the state of Maine. The total operating area is approximately 10,400 square miles (27,000 square kilometers), and it has approximately 160,000 customers. Emera Maine's business is focused around safe and reliable transmission and distribution of electricity to its customers and investments in the infrastructure to maintain the transmission and distribution system.

Emera Maine's regulated operations are subject to the regulatory authority of the MPUC relating to retail rates, service standards, territories served, the issuance of securities and other matters. Emera Maine is also subject to the jurisdiction of the FERC pertaining to various matters including rates for transmission services. The BHD is a member of the New England Power Pool (NEPOOL) and is interconnected with other New England utilities to the south and with New Brunswick Power Corporation to the north. The MPD is a member of the Northern Maine Independent System Administrator (NMISA).

Emera Maine earns revenue by charging customers for energy delivered across its transmission and distribution facilities. These retail revenues are divided into separate transmission, distribution and stranded cost rates. Currently, approximately 57 per cent of the company's electric revenue is from distribution operations, 34 per cent is associated with local transmission operations, and 9 per cent relates to stranded cost recoveries and conversion charges. The rates for each element are established in distinct regulatory proceedings. The distribution operations and stranded costs are regulated by the MPUC, which also regulates accounting, service standards, territories served and the issuance of securities. The transmission operations are regulated by the FERC.

ENMAX FINANCIAL RESULTS

With the addition of Emera Maine in the current year, ENMAX's financial results include an additional $1.0 million of EBIT for the one-week post acquisition.

ADJUSTED EARNINGS BEFORE INTEREST AND INCOME TAXES (ADJUSTED EBIT) COMPARED WITH THE SAME PERIOD IN 2019

For the three months ended March 31, *(millions of Canadian dollars)*	**Competitive Energy**	**Power Delivery**	**Emera Maine**	**Corporate**	**Consolidated**
Adjusted EBIT [1] for the period ended March 31, 2019	40.5	31.1	-	0.3	71.9
Increased (decreased) margins attributable to:					
Electricity	1.7	-	-	-	1.7
Natural gas	(0.3)	-	-	-	(0.3)
Transmission and distribution	-	1.7	4.3	-	6.0
Contractual services and other	(3.7)	0.2	0.1	0.2	(3.2)
Decreased (increased) expenses:					
Operations, maintenance & administration (OM&A) [2]	(3.7)	(1.4)	(2.2)	0.2	(7.1)
Depreciation and amortization	(2.7)	(1.9)	(1.2)	-	(5.8)
Adjusted EBIT [1] for the period ended March 31, 2020	31.8	29.7	1.0	0.7	63.2

(1) Adjusted EBIT is a non-IFRS measure. See Non-IFRS Financial Measures section.
(2) Normalized to exclude impact of intercompany transactions with no consolidated impact.

Electricity margins for the three months ended March 31, 2020 increased by $1.7 million or 2 per cent, compared to the same period in 2019. The favourable variance is due to the positive impact of the removal of the regulated rate option price cap of 6.8 cents per kWh on electricity prices effective November 30, 2019.

Natural gas margins for the three months ended March 31, 2020 decreased $0.3 million or 1 per cent compared to the first three months of 2019. The decrease was primarily due to lower retail consumption volumes combined with lower prices as a result of warmer temperatures compared to the prior year.

For the three months ended March 31, 2020, transmission and distribution margins increased $6.0 million or 7 per cent compared to the same period in 2019. The favourable variance from the prior year was largely due to the additional margins from Emera Maine as well as favourable changes resulting from the AUC approved 2020 interim Transmission Compliance filing.

Contractual services and other margins decreased $3.2 million or 14 per cent for the three months ended March 31, 2020 when compared to the same period in the prior year. The unfavourable variance was primarily due to decreased power services activity and lower customer penalty and interest revenues.

OM&A for the three months ended March 31, 2020 increased $7.1 million or 8 per cent when compared to the same period in 2019. Operational costs were higher due to increased staffing costs, increased technology support costs, increased building property tax and higher allowance for uncollectable receivables as a result of economic conditions in Alberta.

During the three months ended March 31, 2020, the Corporation recorded $37.3 million in Emera Maine acquisition related costs, of which $14.4 million are stipulated costs, and $15.2 million are related to finance charges, of which $1.1 million are stipulated costs. These costs are not included in Adjusted EBIT.

Depreciation and amortization expense increased $5.8 million or 10 per cent compared to the same period in 2019. The increase was driven by changes in the useful life of various assets.

OTHER NET EARNINGS ITEMS

Finance charges for the three months ended March 31, 2020 increased $6.8 million or 34 per cent compared to the same period in 2019, primarily driven by $15.2 million in financing costs related to the Emera Maine acquisition, offset by higher external interest revenues recognized in finance charges.

The calculation of the Corporation’s current and deferred income taxes involves a degree of estimation and judgment. The carrying value of deferred income tax assets is reviewed at the end of each reporting period. For the three months ended March 31, 2020, management adjusted the income tax provision utilizing its best estimate with considerations including management’s expectation of future operating results, interpretation of applicable tax regulations positions, allowances where uncertainty surrounding the realization of the tax benefit exists, and the settlement of various tax disputes.

OTHER COMPREHENSIVE INCOME AND SHAREHOLDER’S EQUITY

Other comprehensive income (OCI) illustrates earnings under the assumption of full income recognition of gains and losses on the market value of securities and derivatives, otherwise treated as hedges of future revenues and expenses, as well as remeasurement gains and losses on pension retirement benefits.

For the three months ended March 31, 2020, OCI had total losses of $28.3 million, compared with gains of $12.8 million for the same period in 2019. The OCI losses primarily reflect the unfavourable fair value changes in electricity and commodity positions. This is partially offset by the reclassification of gains on derivative instruments to net earnings.

Accumulated other comprehensive income (loss) is reflected in shareholder’s equity along with retained earnings and share capital. Retained earnings for the period increased $118.5 million largely from the net earnings recognized in 2020, partially offset by dividends on common shares.

NON-IFRS FINANCIAL MEASURES

The Corporation uses Adjusted EBITDA, Adjusted EBIT, comparable net earnings, and free cash flow (FCF) as financial performance measures. 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 shown below. These non-IFRS measures are consistently applied in the previous period.

ADJUSTED EBITDA

For the three months ended March 31, *(millions of Canadian dollars)*	**2020**	**2019**
Net earnings (IFRS financial measure)	**172.5**	74.2
Add (deduct):		
Unrealized (gains) on commodities	**(30.5)**	(31.3)
Foreign exchange (gains)	**(125.5)**	(0.6)
Emera Maine related acquisition costs (including finance charges) [1]	**37.3**	4.9
Net income tax expense on unrealized (gains) on commodities, foreign exchange (gains), and Emera Maine acquisition related costs	**1.5**	8.7
Comparable net earnings (non-IFRS financial measure)	**55.3**	55.9
Add (deduct):		
Depreciation and amortization	**65.5**	59.7
Finance charges (excludes Emera Maine related acquisition costs)	**11.8**	17.6
Remaining income tax expense (recovery)	**(3.9)**	(1.6)
Adjusted EBITDA (non-IFRS financial measure)	**128.7**	131.6

(1) For the three months ended March 31, 2020 - Includes $22.1 million in OM&A costs (of which $14.4 million are stipulated costs), and $15.2 financing charges (of which $1.1 million are stipulated costs).
For the three months ended March 31, 2019 – Includes $2.3 million OM&A and $2.6 million financing charges.

Management considers Adjusted EBITDA a useful measure of business performance, as it provides an indication of the cash flow results generated by primary business activities without consideration of how those activities are financed and amortized, or how the results are taxed. Adjusted EBITDA is also used to evaluate certain debt coverage ratios.

Adjusted EBITDA excludes the impact for unrealized (gains) on commodities, foreign exchange (gains), and Emera Maine acquisition related costs from the adjusted operating profit. Management believes that a measure of operating performance is more meaningful if results not related to normal operations, such as onerous provisions on long-term contracts, foreign exchange (gains), and unrealized (gains) on commodities, are excluded from the adjusted operating profit. Unrealized (gains) on commodities reflect the impact of changes in forward natural gas and power prices and the volume of the positions for these derivatives over a certain period of time. These unrealized (gains) do not necessarily reflect the actual gains and losses that will be realized on settlement. Furthermore, unlike commodity derivatives, ENMAX's generation capacity and future sales to retail customers are not marked to market under IFRS.

ADJUSTED EBIT

For the three months ended March 31, *(millions of Canadian dollars)*	2020	2019
Net earnings (IFRS financial measure)	**172.5**	74.2
Add (deduct):		
Unrealized (gains) on commodities	**(30.5)**	(31.3)
Foreign exchange (gains)	**(125.5)**	(0.6)
Finance charges (excludes Emera Maine related acquisition costs) (1)	**11.8**	17.6
Emera Maine related acquisition costs (including finance charges)	**37.3**	4.9
Income tax (recovery) expense	**(2.4)**	7.1
Adjusted EBIT (non-IFRS financial measure)	**63.2**	71.9

(1) For the three months ended March 31, 2020 - Includes $22.1 million in OM&A costs (of which $14.4 million are stipulated costs), and $15.2 financing charges (of which $1.1 million are stipulated costs).
For the three months ended March 31, 2019 – Includes $2.3 million OM&A and $2.6 million financing charges.

The Corporation focuses on Adjusted EBIT, which excludes the impact of foreign exchange (gains), unrealized (gains) on commodities, and Emera Maine acquisition related costs. Adjusted EBIT is a useful measure of business performance, which provides an indication of the operating results generated by primary business activities.

Management believes that this non-IFRS measure provides a better representation of the underlying operations of the Corporation.

FREE CASH FLOW (FCF)

ENMAX defines FCF as IFRS net cash provided by operating activities less capital expenditures, including the Emera Maine investment, funded from operations. Management believes that FCF is a liquidity measure that provides useful information regarding cash provided by operating activities, and operational cash used for investments in property and equipment that are required to maintain and grow the business over a twelve-month cycle.

For the twelve months ended March 31, *(millions of Canadian dollars)*	2020	2019
Net cash (used in) provided by operating activities (1)	**587.4**	335.5
Capital expenditures funded from operations (2)	**(241.1)**	(197.4)
Emera Maine acquisition funded from operations (3)	**(296.8)**	-
Free cash flow (non-IFRS financial measure)	**49.5**	138.1

(1) Refer to Liquidity and Capital Resources section.
(2) Includes cash provided to fund capital expenditures in Power Delivery that would otherwise be considered financing activities and excludes cash investment in the acquisition of Emera Maine (see Significant Events section).
(3) Emera Maine acquisition funds from operations includes $1,392.9 million invested in the acquisition of Emera Maine, reduced by incremental borrowings of $1,096.1 million for the acquisition.

ENMAX's FCF decreased $88.6 million for the twelve months ended March 31, 2020, as compared with the twelve months ended March 31, 2019. The decrease in FCF was primarily driven by net funds used to acquire Emera Maine, offset by favourable timing of working capital cashflows.

FINANCIAL CONDITION

SIGNIFICANT CHANGES IN THE CORPORATION'S FINANCIAL CONDITION

As at *(millions of Canadian dollars, except % change)*	**March 31, 2020**	**December 31, 2019**	**$ Change**	**% Change**	**Explanation for Change**
ASSETS					
Cash and cash equivalents	**19.0**	1,079.9	(1,060.9)	(98.2%)	Refer to Liquidity section.
Accounts receivable	**723.5**	689.4	34.1	4.9%	Increase mainly attributable to timing of receipts and seasonal fluctuations in revenue.
Property, plant and equipment (PPE)	**5,826.1**	4,495.2	1,330.9	29.6%	Acquisition of Emera Maine
Intangible assets	**277.3**	184.7	92.6	50.1%	Acquisition of Emera Maine
LIABILITIES AND SHAREHOLDER'S EQUITY					
Short-term financing	**196.1**	174.2	21.9	12.6%	Additional net credit facilities drawn in 2020.
Accounts payable	**497.9**	516.9	(19.0)	(3.7%)	Decrease mainly attributed to timing of disbursements.
Dividend payable	**40.5**	-	40.5	(100%)	Dividend declared in March to be paid in quarterly payments over the course of 2020.
Financial liabilities [1]	**23.2**	56.4	(33.2)	(58.9%)	Change in fair value of hedged and non-hedged derivatives.
Long-term debt [1]	**3,414.0**	2,622.0	792.0	30.2%	Additional $547.0 million debt assumed on acquisition of Emera Maine with $250.0 million term facility in 2020.
Asset retirement obligations and provisions [1]	**163.4**	122.2	41.2	33.7%	Fair value adjustment to Asset Retirement Obligations and additional provisions on acquisition of Emera Maine.

[1] Net current and long-term asset and liability positions.

LIQUIDITY

ENMAX actively monitors its cash position and anticipated cash flows to optimize funding levels. ENMAX finances working capital requirements, capital investments and any maturities of long-term debt, through a combination of cash flow from operations, drawings on the Corporation's bank credit facilities and long-term debt.

Our credit facility agreements and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. As at March 31, 2020, the Corporation was in compliance with all debt covenants and expects to continue to comply.

ENMAX's total debt balance at March 31, 2020 was $3,610.1 million (December 31, 2019 - $2,796.2 million) of which $250.0 million (December 31, 2019 – nil) has been drawn on syndicated facilities, and $196.1 million (December 31, 2019 - $174.2 million) is in Banker's Acceptances.

As at March 31, 2020 ENMAX has access to approximately $1,100.0 million (December 31, 2019 - $850.0 million) in credit facilities, of which $471.1 million (December 31, 2019 - $174.2 million) has been drawn upon. The Corporation's credit facilities mature between 2021 and 2022 and are provided by national and regional lenders.

On March 24, 2020 S&P updated their credit rating for ENMAX, reducing the Corporation's credit rating to BBB- with a stable outlook. On March 25, 2020 DBRS updated their credit rating for ENMAX, reducing the Corporation's credit rating to BBB (high) with a stable outlook. The updates were in response to ENMAX's closing of Emera Maine (see Significant Events section).

On April 28, 2020 the Corporation entered a $250.0 million, two-year syndicated revolving credit facility.

When prudent, ENMAX invests temporary surplus cash balances in short-term interest-bearing instruments to maximize investment income to fund future operating and maintenance costs. Short-term financing of $196.1 million as at March 31, 2020 reflects a temporary use of credit facilities to address timing of expenditures and acquisition of Emera Maine.

RISK MANAGEMENT AND UNCERTAINTIES

COVID-19 PANDEMIC RISK

In response to the COVID-19 pandemic, among other measures, the Government of Alberta has introduced legislation to provide residential, farm and small business customers the option of deferring utility bills for a three-month period (see Significant Events section). During this time, utilities cannot disconnect customers for non-payment of bills. In Maine, among other measures, similar customer relief has been implemented with disconnection activity for non-payment also being suspended for a period of time.

The Corporation continues to operate remotely as an essential service in Alberta and Maine. The duration and impact of COVID-19 is unknown at this time and it is not possible to reliably estimate the impact that the length and severity of these developments will have on the financial results and condition of the Corporation in future periods. The dramatic decrease in oil prices is expected to have less of an impact on the economic condition and operations in Maine as they are anticipated to be in Alberta. ENMAX continues to actively monitor these events while implementing activities to mitigate the impact to operations.

EMERA MAINE ACQUISITION

On March 24, 2020 the Corporation's business activities extended to include the operations of Emera Maine. ENMAX utilizes an Enterprise Risk Management (ERM) program to identify, analyze, evaluate, treat and communicate the Corporation's risk exposures in a manner consistent with ENMAX's business objectives and risk tolerance. With the new addition of Emera Maine, the Corporation has identified the following business and operational risks.

MARKET RISK

Emera Maine has significant financial market risk exposure to changing interest rates on its variable rate debt as well as the fair value of fixed rate debt. Interest rate risk is managed through a combination of both fixed and variable rate debt instruments with staggered maturities.

The cost of debt is a component of rates and prudently incurred debt costs that are recovered from customers. While regulatory ROE will generally follow the direction of interest rates, such that regulatory ROEs are likely to fall in times of reducing interest rates and rise in times of increasing interest rates, this relationship is indirect and generally has a lag period that reflects the regulatory process.

Emera Maine is affected by demand for energy based on changing customer patterns. General economic conditions, consumer focus on energy efficiency, and new technologies impact the demand for energy. Government policies promoting distributed generation and new technology developments enabling those policies have the potential to impact how electricity enters the system and how it is bought and sold. In addition, an increase in distributed generation may impact demand, resulting in lower load and revenues. These changes could negatively impact Emera Maine's operations, rate base, net earnings, and cash flows. Emera Maine is focused on understanding customer demand, energy efficiency, and government policy to ensure that the impact of these activities benefit customers, that they do not negatively impact the reliability of energy service, and that they are addressed by regulators and appropriately reflected in rates.

ENMAX has foreign exchange (FX) rate exposure arising from the addition of its U.S. operations. ENMAX has implemented various programs to reinforce internal controls over cash flow management to mitigate the exposure to extreme FX rate movements.

OPERATIONAL RISK

The company is exposed to commercial relationship risk with respect to its reliance on certain key partners, suppliers, and customers. The company manages its commercial relationship risk by monitoring credit risk and monitoring significant developments with its customers, partners, and suppliers.

ENVIRONMENTAL RISK

Emera Maine is subject to regulation by federal, state, and municipal authorities with regard to environmental matters primarily related to its utility operations. Changes in environmental legislation could adversely affect utility operations. Emera Maine manages this risk through the development and application of environmental management systems. Emera Maine is committed to operating in a manner that is respectful and protective of the environment and is in full compliance with legal requirements and its own policy.

CLIMATE RISK

Emera Maine is subject to a number of risks that may arise from weather and climate change. Fluctuations in the amount of electricity used by customers can vary significantly in response to seasonal changes in weather and could impact the operations, results of operations, financial condition, and cash flows. In the absence of a regulatory recovery mechanism for unanticipated revenue losses, such events could have an adverse impact on operations.

Extreme weather events create a risk of physical damage to Emera Maine’s transmission and distribution infrastructure. Emera Maine has a program for storm hardening of transmission and distribution facilities to minimize damage, but there can be no assurance that these measures will fully mitigate the risk. This risk to transmission and distribution facilities is generally not insured, and as such the restoration cost is generally recovered through regulatory processes after the fact, through the establishment of regulatory assets. Recovery is not assured and is subject to prudency review.

REGULATORY RISK

Emera Maine operates as a cost-of-service utility, and oversight of operations is provided by the MPUC or FERC, and other agencies. Emera Maine is subject to regulations established to ensure it meets the obligation to serve customers.

Emera Maine must obtain regulatory approval to change general electricity rates. The recovery of costs and investments is subject to the approval of the MPUC or FERC through the adjustment of rates, which normally requires a public hearing process.

ENMAX cannot predict future government policies that may impact the development of Emera Maine’s business, or the ultimate impact that any changes to the regulatory environment may have on its business. Regulatory policies and decisions may cause delays, impact business planning transactions, increase costs, or restrict Emera Maine’s ability to grow earnings and recover costs.

This regulatory risk is managed through transparent regulatory disclosure, ongoing stakeholder and government consultation, and multi-party engagement on aspects such as utility operations, rate filings, and capital plans. Emera Maine employs a collaborative regulatory approach through technical conferences and, where appropriate, negotiated settlements.

HUMAN RESOURCE RISK

The ability to deliver service to customers and execute capital plans depends on attracting, developing, and retaining a skilled workforce. Emera Maine faces demographic challenges as it relates to trades, technical staff and engineers with an increasing number of employees expected to retire over the next several years. Failure to attract, develop, and retain an appropriately qualified workforce could adversely affect operations and financial results. Emera Maine seeks to manage this risk through maintaining competitive compensation programs and human resources programs, and practices including employee engagement surveys, succession planning for key positions, and apprenticeship programs.

Certain employees are subject to a collective labour agreement, which expires on June 30, 2022. Approximately 50 per cent of Emera Maine’s employees are represented by a local union affiliated with the International Brotherhood of Electrical Workers. The inability to maintain or negotiate future agreements on acceptable terms could result in higher labor costs and work disruptions, which could adversely affect service to customers and have an adverse effect on earnings, cash flows, and financial position. Emera Maine seeks to manage this risk through ongoing discussions and working to maintain positive relationships with the union.

TECHNOLOGY RISK

Emera Maine's reliance on information technology to manage its business exposes it to potential risks related to cyber security attacks and unauthorized access to the sensitive or confidential and credit information of its customers, suppliers, counterparties, and employees through hacking, viruses, and other risks (collectively "cyber security threats"). Emera Maine uses information technology systems and network infrastructure which include controls for interconnected systems of distribution and transmission, some of which is shared with third parties for operating purposes. Through the normal course of business, Emera Maine also collects, processes, and retains sensitive and confidential customer, supplier, counterparty, and employee information.

Despite security measures in place, Emera Maine's systems, assets and information could be vulnerable to cyber security attacks and other data security breaches that could cause system failures, disrupt operations, adversely affect safety, result in loss of service to customers, and release of sensitive or confidential information. Should such cyber security threats materialize, Emera Maine could suffer costs, losses and damages, all or some of which may not be recoverable through regulatory processes or otherwise.

Emera Maine relies on various information technology systems to manage operations. There are inherent costs and risks associated with maintaining, upgrading, replacing, and changing these systems. This includes impairment of its information technology, potential disruption of internal control systems, substantial capital expenditures, demands on management time and other risks of delays, difficulties in upgrading existing systems, as well as transitioning to new systems or integrating new systems into its current systems.

This risk is managed through regular IT asset lifecycle management, dedicated project teams, executive oversight and appropriate governance structures, and strong project management practices. Employees with extensive subject matter expertise assist in planning, project management, implementation, and training. Formal back up and critical incident response practices ensure that continuity is maintained in the event of any disruptions or incidents.

LIQUIDITY RISK

Liquidity risk relates to Emera Maine's ability to ensure sufficient funds are available to meet its financial obligations. The company manages this risk by forecasting cash requirements on a continuous basis to determine whether sufficient funds are available. Liquidity and capital needs will be financed through internally generated cash flows, short-term credit facilities, and ongoing access to capital markets. The company reasonably expects liquidity sources to exceed capital needs.

Emera Maine has a defined benefit (DB) pension plans that covers qualifying employees and retirees. All DB plans are closed to new entrants. Contributions to the pension plan are based on periodic actuarial valuations. The actual amount of contributions required in the future will depend on future investment returns and actuarial assumptions. Adverse global financial and capital markets, and changing interest rates may impact investment performance, and Emera Maine could be required to make larger contributions to fund this plan, which could affect the company's financial condition and operations. To manage this risk, Emera Maine engages expert investment managers and has investment policies and procedures in place to set out the investment framework of the plan assets.

CREDIT RISK

Emera Maine is exposed to credit risk with respect to amounts receivable from customers. Credit risk assessments are conducted on all new customers and deposits are requested on any high-risk accounts. Emera Maine also maintains provisions for potential credit losses, which are assessed on a regular basis.

REPORTING/DISCLOSURE RISK

With the addition of significant U.S. operations in the current year, the Corporation will be required to consider conversion of Emera Maine's transactions under U.S. GAAP to ENMAX's basis of presentation in accordance with IFRS. In addition, the difference in Emera Maine's functional currency and ENMAX's presentation currency must be translated in accordance with IAS 21. ENMAX has implemented various programs to reinforce its Internal Control over Financial Reporting, including quarterly certification of key controls facilitated by Internal Audit and review of certain disclosures by the Board.

CONSOLIDATED FINANCIAL STATEMENTS

Contents

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF FINANCIAL POSITION

As at *(unaudited)* *(millions of Canadian dollars)*	**March 31, 2020**	December 31, 2019
ASSETS		
Cash and cash equivalents (Notes 6)	**$ 19.0**	$ 1,079.9
Accounts receivable	**723.5**	689.4
Income taxes receivable	**7.8**	0.4
Current portion of financial assets (Note 8)	**109.8**	95.3
Other current assets (Note 14)	**92.6**	83.3
	952.7	1,948.3
Property, plant and equipment (Note 10)	**5,826.1**	4,495.2
Intangible assets (Note 11)	**279.5**	184.7
Goodwill (Note 5)	**681.0**	-
Deferred income tax assets (Note 15)	**35.8**	35.9
Financial assets (Note 8)	**54.8**	35.7
Other long-term assets (Note 14)	**219.0**	44.3
TOTAL ASSETS	**8,048.9**	6,744.1
REGULATORY DEFERRAL ACCOUNT DEBIT BALANCES (Note 9)	**208.7**	31.2
TOTAL ASSETS AND REGULATORY DEFERRAL ACCOUNT DEBIT BALANCES	**$ 8,257.6**	$ 6,775.3
LIABILITIES		
Short-term financing (Note 8)	**$ 196.1**	$ 174.2
Accounts payable and accrued liabilities	**497.9**	516.9
Income taxes payable (Note 15)	**4.1**	18.0
Dividend payable (Note 18)	**40.5**	-
Current portion of long-term debt (Notes 8)	**113.5**	73.3
Current portion of financial liabilities (Note 8)	**112.2**	114.4
Current portion of deferred revenue (Note 13)	**11.4**	10.5
Current portion of lease liabilities (Note 12)	**5.3**	5.4
Other current liabilities (Note 14)	**41.9**	32.0
Current portion of asset retirement obligations and other provisions	**23.5**	0.9
	1,046.4	945.6
Long-term debt (Notes 8)	**3,300.5**	2,548.7
Deferred income tax liabilities (Note 15)	**295.0**	31.6
Post-employment benefits	**170.2**	90.2
Financial liabilities (Note 8)	**75.6**	73.0
Deferred revenue (Note 13)	**554.2**	555.1
Lease liabilities (Note 12)	**53.8**	55.5
Other long-term liabilities (Note 14)	**17.1**	13.1
Asset retirement obligations and other provisions	**139.9**	121.3
TOTAL LIABILITIES	**5,652.7**	4,434.1
REGULATORY DEFERRAL ACCOUNT CREDIT BALANCES (Note 9)	**174.9**	1.5
SHAREHOLDER'S EQUITY		
Share capital	**280.1**	280.1
Retained earnings	**2,210.6**	2,092.1
Accumulated other comprehensive (loss) (Note 16)	**(60.7)**	(32.5)
	2,430.0	2,339.7
TOTAL LIABILITIES, REGULATORY DEFERRAL ACCOUNT CREDIT BALANCES AND SHAREHOLDER'S EQUITY	**$ 8,257.6**	$ 6,775.3

Commitments and contingencies (Note 21)
See accompanying Notes to Condensed Consolidated Interim Financial Statements.

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF EARNINGS

Three months ended March 31, *(unaudited)* *(millions of Canadian dollars)*	**2020**	**2019**
REVENUE (Note 7)		
Electricity	**$ 354.6**	$ 357.6
Natural gas	**102.6**	94.3
Transmission and distribution	**186.5**	182.5
Local access fees	**36.8**	35.6
Contractual services	**31.5**	33.7
Contributions in aid of construction (CIAC) revenue (Note 13)	**4.9**	4.7
Other revenue (Note 17)	**2.3**	4.0
TOTAL REVENUE	**719.2**	712.4
OPERATING EXPENSES (Note 7)		
Electricity and fuel purchases	**228.2**	232.1
Natural gas and delivery	**81.7**	73.1
Transmission and distribution	**119.3**	89.4
Local access fees	**36.8**	35.6
Depreciation and amortization	**65.4**	58.3
Other expenses (Note 17)	**13.3**	111.6
TOTAL OPERATING EXPENSES	**544.7**	600.1
OPERATING PROFIT	**174.5**	112.3
Finance charges	**27.0**	20.2
NET EARNINGS BEFORE TAX	**147.5**	92.1
Current income tax (recovery) expense (Note 15)	**(7.0)**	0.2
Deferred income tax expense (Note 15)	**4.6**	6.9
NET EARNINGS - BEFORE NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES	**149.9**	85.0
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES (Note 9)	**22.6**	(10.8)
NET EARNINGS	**$ 172.5**	$ 74.2

See accompanying Notes to the Condensed Consolidated Interim Financial Statements.

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF COMPREHENSIVE INCOME

Three months ended March 31, *(unaudited)* *(millions of Canadian dollars)*		**2020**		**2019**
NET EARNINGS	**$**	**172.5**	$	74.2
OTHER COMPREHENSIVE INCOME, NET OF INCOME TAX				
Items that will not be reclassified subsequently to statement of earnings				
Remeasurement (losses) on retirement benefits [1]		**-**		(0.2)
Cumulative (losses) on translation adjustment		**(17.1)**		-
Items that will be reclassified subsequently to statement of earnings				
Unrealized (loss) gains on derivative instruments [2]		**(6.1)**		17.3
Reclassification of (gains) on derivative instruments to net earnings [3]		**(5.0)**		(4.3)
Other comprehensive (loss) income, net of income tax		**(28.2)**		12.8
TOTAL COMPREHENSIVE INCOME	**$**	**144.3**	$	87.0

(1) Net deferred income tax expense of nil for the three months ended March 31, 2020 (2019 - $0.2 million expense).
(2) Net deferred income tax recovery of $3.4 million for the three months ended March 31, 2020 (2019 - $6.4 million expense).
(3) Net deferred income tax expense of $1.7 million for the three months ended March 31, 2020 (2019 - $1.9 million expense).

See accompanying Notes to the Condensed Consolidated Interim Financial Statements.

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY

(unaudited) *(millions of Canadian dollars)*		**Share Capital**		**Retained Earnings**		**Accumulated Other Comprehensive Income (Loss)**		**Total**
As at January 1, 2020	$	280.1	$	2,092.1	$	(32.5)	$	2,339.7
Net earnings		-		172.5		-		172.5
Other comprehensive loss, net of income tax		-		-		(28.2)		(28.2)
Total comprehensive income (loss)		-		172.5		(28.2)		144.3
Dividends (Note 18)		-		(54.0)		-		(54.0)
As at March 31, 2020	**$**	**280.1**	**$**	**2,210.6**	**$**	**(60.7)**	**$**	**2,430.0**

As at January 1, 2019	$	280.1	$	1,985.9	$	(4.7)	$	2,261.3
Net earnings		-		74.2		-		74.2
Other comprehensive income, net of income tax		-		-		12.8		12.8
Total comprehensive income		-		74.2		12.8		87.0
Dividends (Note 18)		-		(50.0)		-		(50.0)
As at March 31, 2019		280.1		2,010.1		8.1		2,298.3
Net earnings		-		82.0		-		82.0
Other comprehensive loss, net of income tax		-		-		(40.6)		(40.6)
As at December 31, 2019	**$**	**280.1**	**$**	**2,092.1**	**$**	**(32.5)**	**$**	**2,339.7**

See accompanying Notes to the Condensed Consolidated Interim Financial Statements.

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CASH FLOWS

Three months ended March 31, *(unaudited)* *(millions of Canadian dollars)*	**2020**	**2019**
CASH (USED IN) PROVIDED BY:		
OPERATING ACTIVITIES		
Net earnings	**$ 172.5**	$ 74.2
Items not involving cash:		
CIAC	**3.7**	6.1
CIAC revenue (Note 13)	**(4.9)**	(4.7)
Depreciation and amortization	**65.5**	58.3
Finance charges	**27.0**	20.2
Income tax expense (Note 15)	**(2.4)**	7.1
Change in unrealized market value of financial contracts (Note 8)	**(49.6)**	(33.4)
Post-employment benefits	**1.1**	1.5
Foreign exchange	**17.1**	-
Change in non-cash working capital (Note 19)	**(50.8)**	(157.2)
Cash flow provided by (used in) from operations	**179.2**	(27.9)
Interest paid [1]	**(8.7)**	(3.3)
Income taxes paid	**(12.7)**	(0.5)
Net cash flow provided by (used in) operating activities	**157.8**	(31.7)
INVESTING ACTIVITIES		
Purchase of property, plant and equipment and intangibles [1]	**(70.6)**	(101.0)
Acquisition of Emera Maine (Note 5)	**(1,392.9)**	-
Cash flow used in investing activities	**(1,463.5)**	(101.0)
FINANCING ACTIVITIES		
Repayment of short-term debt	**(1,377.3)**	(170.9)
Proceeds from short-term debt	**1,399.2**	272.9
Repayment of long-term debt	**(8.8)**	(8.6)
Proceeds from long-term debt	**247.0**	-
Repayment of lease liability	**(1.8)**	(0.8)
Dividend paid (Note 18)	**(13.5)**	(12.5)
Cash flow provided by financing activities	**244.8**	80.1
Decrease in cash and cash equivalents	**(1,060.9)**	(52.6)
Cash and cash equivalents, beginning of period	**1,079.9**	89.0
CASH AND CASH EQUIVALENTS, END OF PERIOD	**$ 19.0**	$ 36.4
Cash and cash equivalents consist of:		
Cash	**$ 10.3**	$ 30.2
Restricted cash (Note 6)	**8.7**	6.2
	$ 19.0	$ 36.4

[1] Total interest paid during the three months ended March 31, 2020 was $11.0 million (2019 - $4.5 million). Purchase of PPE and intangibles includes $2.3 million of capitalized borrowing costs (2019 - $1.2 million).

See accompanying Notes to Condensed Consolidated Interim Financial Statements.

NOTES TO THE CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
(unaudited)

1. DESCRIPTION OF THE BUSINESS

ENMAX Corporation and its subsidiaries (ENMAX or the Corporation), a wholly-owned subsidiary of the City of Calgary (the City), was incorporated under the *Business Corporations Act* (Alberta) in July 1997 to carry on the electric utility transmission and distribution operations previously carried on by the Calgary Electric System (CES), a former department of the City. Operations of the Corporation began on January 1, 1998, with the transfer of substantially all the assets and liabilities of the CES by the City into the Corporation at net book value, for consideration of one common share issued to the City. Since 1998, the Corporation has grown from its transmission and distribution roots to include electricity generation, commercial and residential solar, electricity and natural gas retail businesses.

On March 24, 2020, the Corporation closed the acquisition of BHE Holdings, Inc., the parent company of Emera Maine. The Corporation through its subsidiary, Emera Maine, engages in the transmission and distribution operations in the Bangor Hydro District (BHD) as well as the Maine Public District (MPD), in Maine, USA. Emera Maine's regulated operations are subject to the regulatory authority of Maine Public Utilities Commission (MPUC) and the Federal Regulatory Commission (FERC). BHD is a member of the New England Power Pool (NEPOOL) while MPD is a member of the Northern Maine Independent System Administrator (NMISA).

The Corporation's registered head office is at 141 - 50 Avenue SE, Calgary AB, T2G 4S7. The Corporation's principal place of business is Alberta.

2. BASIS OF PREPARATION

These unaudited condensed consolidated interim financial statements have been prepared in accordance with International Accounting Standards (IAS) 34, *Interim Financial Reporting*, and have been prepared following the same accounting policies and methods as those used in preparing the most recent consolidated financial statements, except as outlined in Notes 3 and 4. These unaudited condensed consolidated interim financial statements have been prepared under the historical costs basis, except for certain financial instruments which are stated at fair value. These unaudited condensed consolidated interim financial statements do not include all disclosures required for the preparation of audited annual financial statements. Accordingly, these unaudited condensed consolidated interim financial statements should be read in conjunction with the 2019 audited annual consolidated financial statements, which are available on ENMAX's website at www.enmax.com.

These condensed consolidated interim financial statements were authorized for issuance by ENMAX's Board of Directors (the Board) on May 21, 2020.

3. CRITICAL ACCOUNTING ESTIMATES AND JUDGMENTS

The preparation of these unaudited condensed consolidated interim financial statements requires management to select appropriate accounting policies and to make judgments, estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, as well as to disclose contingent assets and liabilities. These estimates and judgments concern matters that are inherently complex and uncertain. Judgments and estimates are continually evaluated and based on historical experience and expectations of future events. Changes to accounting estimates are recognized prospectively. Management has made significant assumptions in determining the fair value of the total assets acquired and liabilities assumed in the Emera Maine acquisition.

4. ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

The following standards and interpretations are not yet effective under International Financial Reporting Standards (IFRS) and have not been applied in preparing these condensed consolidated interim financial statements. The Corporation is currently assessing the impact of adopting these standards on its consolidated financial statements.

IAS 1 *Presentation of Financial Statements*

The amended International Accounting Standard (IAS) 1 provides detailed guidance on how an entity should disclose liabilities as either current or non-current, especially in circumstances where an entity has the right to defer settlement of the obligation past the 12-month operating cycle. The amended standard applies to entities with year-ends beginning on or after January 1, 2022 with early adoption, on a retrospective basis.

IFRS 10 *Consolidated Financial Statements*

The amended IFRS 10 provides guidance on loss of control in a subsidiary and remeasurement of the retained interest in the former subsidiary. The amended standard replaces the requirement to remeasure the retained interest at fair value while restricting the amount of gain or loss that could be recognized on the loss of control. The International Accounting Standards Board (IASB) have not set an implementation date for this amended standard but companies have the option of early adopting this standard on a prospective basis.

IAS 28 *Investments in Associates and Joint Ventures*

The amended IAS 28 provides guidance on gains and losses arising from both upstream and downstream transactions involving assets that do not constitute a business between the parent and its associate or joint venture. The proposed standard limits the amount of gains and losses that could be recorded on such transactions. The IASB have not set an implementation date for this amended standard but companies have the option of early adopting this standard on a prospective basis.

5. ACQUISITION

On March 24, 2020, the Corporation acquired all of the outstanding shares of BHE Holdings, Inc., the parent company of Emera Maine. Emera Maine is a public utility based in Bangor, Maine USA that is engaged in the transmission and distribution of electricity. Emera Maine serves an area of 10,400 square miles (27,000 square kilometers) throughout six counties across the state of Maine.

The aggregate purchase price was $1,394.0 million ($962.6 million USD), on closing, in addition to the assumption of approximately $566.5 million ($391.2 million USD) debt. The Corporation funded this transaction through a combination of cash, a two-year bank loan and issuance of private debentures.

The transaction constitutes a business acquisition and accordingly has been accounted for using the acquisition method of accounting. The excess of the purchase price over estimated fair values of net assets acquired has been recognized as goodwill at the acquisition date of March 24, 2020. The goodwill reflects the amount paid for access to regulated assets, net income and future cash flows, opportunities for adjacency growth, and an improved earnings risk profile.

The majority of Emera Maine's operations are subject to the rate-setting authority of the MPUC and FERC. Except for unregulated long-term debt acquired, construction work in progress, investments in corporate joint ventures, and fair values of assets and liabilities, subject to these rate-setting provisions, approximate their regulatory carrying values. This is due to the fact that a market participant would not expect to recover any more or less than the net carrying value. Accordingly, assets acquired and liabilities assumed do not reflect any adjustments related to these amounts.

The following table summarizes the allocation of the purchase consideration to the net assets acquired based on their fair values, using the March 24, 2020 exchange rate of $1.00 USD = $1.4482 CAD.

(millions of Canadian dollars)	
Purchase Consideration	1,394.0
Fair value assigned to net assets:	
Current assets	59.5
Regulatory assets and deferred charges	157.5
Net investment in utility plant	1,306.9
Construction work in progress	50.3
Intangible assets	94.0
Investments in corporate joint ventures and other investments [1]	175.3
Current liabilities	(47.0)
Assumed long-term debt (including current portion)	(566.5)
Accumulated deferred income taxes	(268.4)
Other regulatory liabilities	(176.2)
Accrued pension and postretirement benefit costs	(80.1)
Other regulatory and other long-term liabilities	(8.1)
Fair value of net assets acquired	697.2
Goodwill on acquisition	696.8
Foreign exchange adjustment	(15.8)
Goodwill	**681.0**

[1] Includes Maine Electric Power Company (MEPCo) as a corporation jointly owned by Central Maine Power and Emera Maine that owns a 182-mile (293-kilometer) transmission line from Wiscasset, Maine to the New Brunswick border. Emera Maine owns 21.7 per cent of the common stock of MEPCo and has one representative on MEPCo's Board.

Certain assets and liabilities have been measured on a provisional basis. If new facts and circumstances are obtained within one year from the date of acquisition that existed at the date of acquisition, any identified adjustments to the above amounts or additional provisions that existed at the date of acquisition, may result in a revision to the accounting for the acquisition.

Trade and other receivables included in current assets comprised gross contractual amounts due of $58.4 million, of which $2.6 million was determined to be uncollectible at the date of acquisition.

Goodwill is subject to an annual assessment for impairment at the reporting unit level.

During the three months ended March 31, 2020, the Corporation recorded $37.3 million (March 31, 2019 - $4.9 million) in total Emera Maine acquisition related costs, of which $15.2 million (March 31, 2019 - $2.6 million) are related to finance charges. Among the acquisition related costs there are $15.5 million (March 31, 2019 – nil) in one-time stipulated costs, of which $1.1 million are related to finance charges. These costs are not included in Adjusted EBIT.

In the seven-days post acquisition, Emera Maine contributed revenue of $5.8 million and net losses of $1.8 million to the Corporation's financial results for the three months ended March 31, 2020. If the acquisition had occurred on January 1, 2020 management estimates that consolidated revenue would have increased $69.1 million and consolidated profit would have increased $6.5 million before income taxes.

6. RESTRICTED CASH

As at March 31, 2020, the Corporation had $8.7 million of restricted cash (December 31, 2019 - $1,040.1 million). This consists primarily of $7.9 million (December 31, 2019 - $19.6 million) relating to margin posted with a financial institution, $0.8 million (December 31, 2019 – nil) in deposits with a financial institution to meet certain financial assurance obligations, and nil (December 31, 2019 - $1,020.5 million) related to funds held in escrow for the Emera Maine transaction (see Note 5).

7. SEGMENT INFORMATION

The Corporation operates in three main segments representing separately managed business units, each of which offers different products and services. The Corporation uses a shared service allocation model to allocate cost between segments.

ENMAX COMPETITIVE ENERGY (COMPETITIVE ENERGY)

Competitive Energy is an operating segment established to carry out competitive energy supply and retail functions and the Calgary Regulated Rate Option (RRO) retail function through various legal entities and affiliated companies. Competitive Energy is an integrated business providing customers with electricity, natural gas, distributed energy resource solutions, as well as engineering, procurement and construction services. The competitive retail business provides customers with fixed-price electricity linked to our wind and gas-fueled generation assets, and provides opportunities to offer additional energy services, such as solar installations and thermal energy. Competitive Energy also delivers project execution for customer infrastructure in areas such as power infrastructure, light rail transit, and commercial and residential development.

ENMAX POWER DELIVERY (POWER DELIVERY)

Power Delivery is a regulated operating segment established to own and operate electricity transmission and distribution assets in the Calgary service area through various legal entities and affiliated companies. Power Delivery's objective is to safely and efficiently operate and maintain the high reliability of its transmission and distribution system while meeting Calgary's power delivery infrastructure needs.

EMERA MAINE

Emera Maine is a regulated operating segment that carries on the business of electricity transmission and distribution in the Bangor Hydro District and Maine Public District. The segment operates in the Maine counties of Penobscot, Hancock, Washington, Waldo, Piscataquis and Aroostook. All of the Corporation's operations conducted in the USA are included in this segment.

The final segment is ENMAX Corporate and Eliminations (Corporate and Eliminations), which is responsible for providing shared services and financing for Competitive Energy, Power Delivery and Emera Maine.

SEGMENTED TOTAL ASSETS AND REGULATORY DEFERRAL ACCOUNT BALANCES

As at *(millions of Canadian dollars)*	**March 31, 2020**	**December 31, 2019**
Competitive Energy	**2,792.6**	2,791.2
Power Delivery	**2,813.9**	2,802.3
Emera Maine	**2,332.9**	-
Corporate and Eliminations	**109.5**	1,150.6
Total assets	**8,048.9**	6,744.1
Regulatory deferral account debit balances	**208.7**	31.2
Total assets and regulatory deferral account debit balances	**8,257.6**	6,775.3

COMPARATIVE SEGMENT INFORMATION

Segment information reflects the presentation regularly reviewed by the chief operating decision maker. The chief operating decision maker uses adjusted operating profit as the basis for making decisions around asset allocation or assessing performance. Adjusted operating profit accounts for items such as unrealized gains and losses on commodities, foreign exchange, onerous provision recoveries on long-term contracts, and Emera Maine acquisition related costs, which are reflected in the column "Adjusted Consolidated Totals" below.

Segment information as at March 31, 2020 has been reclassified to conform with the current year's presentation. The presentation change had no impact on reported consolidated net earnings.

Three months ended March 31, 2020 *(millions of Canadian dollars)*	**Competitive Energy**	**Power Delivery**	**Emera Maine**	**Corporate and Eliminations**	**Adjusted Consolidated Totals**	**Regulatory Deferral Movement**	**Other Presentation Reclass**	**Consolidated Totals**
REVENUE								
Electricity	386.5	-	-	(31.9)	354.6	-	-	354.6
Natural gas	102.7	-	-	(0.1)	102.6	-	-	102.6
Transmission and distribution	-	178.4	5.7	-	184.1	2.4	-	186.5
Local access fees	-	36.8	-	-	36.8	-	-	36.8
Other revenue	36.4	8.6	0.1	(1.1)	44.0	(5.3)	-	38.7
TOTAL REVENUE	525.6	223.8	5.8	(33.1)	722.1	(2.9)	-	719.2
OPERATING EXPENSES								
Electricity and fuel purchases	290.5	-	-	(31.8)	258.7	-	(30.5)	228.2
Natural gas and delivery	81.6	-	-	0.1	81.7	-	-	81.7
Transmission and distribution	-	93.7	1.4	-	95.1	24.2	-	119.3
Local access fees	-	36.8	-	-	36.8	-	-	36.8
Depreciation and amortization	34.0	31.3	1.2	(1.0)	65.5	(0.1)	-	65.4
Other expenses	87.7	32.3	2.2	(1.1)	121.1	(4.4)	(103.4)	13.3
TOTAL OPERATING EXPENSES	493.8	194.1	4.8	(33.8)	658.9	19.7	(133.9)	544.7
OPERATING PROFIT	31.8	29.7	1.0	0.7	63.2	(22.6)	133.9	174.5
Unrealized gain on commodities					(30.5)	-	30.5	-
Foreign exchange gain					(125.5)	-	125.5	-
Emera Maine acquisition costs [1]					22.1	-	(22.1)	-
Finance charges [2]					27.0	-	-	27.0
NET EARNINGS BEFORE TAX					170.1	(22.6)	-	147.5
Current income tax recovery					(7.0)	-	-	(7.0)
Deferred income tax expense					4.6	-	-	4.6
NET EARNINGS (LOSS) BEFORE NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES					172.5	(22.6)	-	149.9
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES					-	22.6	-	22.6
NET EARNINGS					172.5	-	-	172.5

[1] During the three months ended March 31, 2020, ENMAX recognized other expenses related to the acquisition of Emera Maine (see Note 5) of $22.1 million, of which $15.5 million are stipulated costs.

[2] During the three months ended March 31, 2020, ENMAX recognized finance charges related to the acquisition of Emera Maine (see Note 5) of $15.2 million, of which $1.1 million are stipulated costs.

Three months ended March 31, 2019 *(millions of Canadian dollars)*	Competitive Energy	Power Delivery	Emera Maine	Corporate and Eliminations	Adjusted Consolidated Totals	Regulatory Deferral Movement	Other Presentation Reclass	Consolidated Totals
REVENUE								
Electricity	391.7	-	-	(34.1)	357.6	-	-	357.6
Natural gas	94.4	-	-	(0.1)	94.3	-	-	94.3
Transmission and distribution	-	179.7	-	-	179.7	2.8	-	182.5
Local access fees	-	35.6	-	-	35.6	-	-	35.6
Other revenue	42.4	8.9	-	(1.3)	50.0	(7.6)	-	42.4
TOTAL REVENUE	528.5	224.2	-	(35.5)	717.2	(4.8)	-	712.4
OPERATING EXPENSES			-					
Electricity and fuel purchases	297.4	-	-	(34.0)	263.4	-	(31.3)	232.1
Natural gas and delivery	73.0	-	-	0.1	73.1	-	-	73.1
Transmission and distribution	-	96.7	-	-	96.7	(7.3)	-	89.4
Local access fees	-	35.6	-	-	35.6	-	-	35.6
Depreciation and amortization	31.3	29.4	-	(1.0)	59.7	(1.4)	-	58.3
Other expenses	86.3	31.4	-	(0.9)	116.8	(6.9)	1.7	111.6
TOTAL OPERATING EXPENSES	488.0	193.1	-	(35.8)	645.3	(15.6)	(29.6)	600.1
OPERATING PROFIT	40.5	31.1	-	0.3	71.9	10.8	29.6	112.3
Unrealized gain on commodities					(31.3)	-	31.3	-
Foreign exchange gain					(0.6)	-	0.6	-
Emera Maine acquisition costs [(1)]					2.3	-	(2.3)	-
Finance charges					20.2	-	-	20.2
NET EARNINGS BEFORE TAX					81.3	10.8	-	92.1
Current income tax expense					0.2	-	-	0.2
Deferred income tax expense					6.9	-	-	6.9
NET EARNINGS BEFORE NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES					74.2	10.8	-	85.0
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES					-	(10.8)		(10.8)
NET EARNINGS					74.2	-	-	74.2

(1) During the three months ended March 31, 2019, ENMAX recognized other expenses related to the acquisition of Emera Maine (see Note 5) of $2.3 million.

REVENUE

Types of Customers and Sales Channel	Nature and significant payment terms
Mass market	Mass market is comprised of residential and small business customers who consume less than 250,000 (kilowatt hour) kWh/year. These customers can be supplied electricity through competitive contracts or the Regulated Rate Option. Natural gas is always supplied under a competitive contract.
Commercial market	Commercial market is business to business competitive contracting for electricity and/or natural gas. A small number of commercial customers who do not negotiate a contract are supplied electricity on a regulated default supply.
Government and institutional	ENMAX receives revenue from governments and municipalities (counties, cities and towns), entities backed by the government, universities, colleges and school boards.
Non-government and non-institutional	ENMAX receives revenue from individual consumers to large corporations who in turn receive credit and terms based on their respective products and their credit history.
Transmission	ENMAX receives revenue from Alberta Electric System Operator (AESO) specifically for the use of its transmission grid system.
Distribution	ENMAX receives revenue from electricity retailers specifically for the use of its electricity distribution system to deliver electricity to the end customers.
City of Calgary local access fees	ENMAX receives revenue from electricity end users to offset municipal levies by the City in lieu of property taxes.
U.S. Operations	ENMAX receives revenues from the distribution companies, for the use of its transmission grid system, based on a rate approved by the MPUC.

REVENUE – MAJOR CUSTOMERS AND SALES CHANNELS

(millions of Canadian dollars)	Mass Market	Commercial Market	Government and Institutional	Non-Government and Non-Institutional	Transmission	Distribution	City of Calgary Local Access Fees	U.S. Operations	Total
Three months ended March 31, 2020									
Electricity									
Competitive Energy	64.9	253.8	-	-	-	-	-	-	**318.7**
Regulated	30.1	5.8	-	-	-	-	-	-	**35.9**
Natural gas	74.9	27.7	-	-	-	-	-	-	**102.6**
Transmission & distribution	-	-	-	-	24.9	155.9	-	5.7	**186.5**
Local access fees	-	-	-	-	-	-	36.8	-	**36.8**
Contractual services	-	-	12.2	19.3	-	-	-	-	**31.5**
Other revenue & CIAC	-	-	-	7.1	-	-	-	0.1	**7.2**
TOTAL REVENUE	**169.9**	**287.3**	**12.2**	**26.4**	**24.9**	**155.9**	**36.8**	**5.8**	**719.2**

(millions of Canadian dollars)	Mass Market	Commercial Market	Government and Institutional	Non-Government and Non-Institutional	Transmission	Distribution	City of Calgary Local Access Fees	U.S. Operations	Total
Three months ended March 31, 2019									
Electricity									
Competitive Energy	61.8	257.9	-	-	-	-	-	-	**319.7**
Regulated	29.9	8.0	-	-	-	-	-	-	**37.9**
Natural gas	69.9	24.4	-	-	-	-	-	-	**94.3**
Transmission & distribution	-	-	-	-	20.3	162.2	-	-	**182.5**
Local access fees	-	-	-	-	-	-	35.6	-	**35.6**
Contractual services	-	-	10.1	23.6	-	-	-	-	**33.7**
Other revenue & CIAC	-	-	-	8.7	-	-	-	-	**8.7**
TOTAL REVENUE	**161.6**	**290.3**	**10.1**	**32.3**	**20.3**	**162.2**	**35.6**	**-**	**712.4**

8. FINANCIAL INSTRUMENTS, HEDGES AND RISK MANAGEMENT MARKET RISK

MARKET RISK

The Corporation manages its exposure to market risk (interest rate risk, foreign currency exchange risk, and commodity price risk) on a portfolio basis. This includes managing its positions arising from interests in generation facilities, liability positions arising from commitments to customers, and transacting positions arising from hedging activities.

VALUATION OF DERIVATIVE ASSETS AND LIABILITIES

Financial derivative instruments are recorded at fair value on the condensed consolidated interim statement of financial position. As at March 31, 2020, the fair values of derivatives were as follows:

As at	**March 31, 2020**		**December 31, 2019**	
(millions of Canadian dollars)	**Hedge Instruments**	**Non-Hedge Derivatives**	**Hedge Instruments**	**Non-Hedge Derivatives**
Assets				
Current	**9.8**	**100.0**	23.8	71.5
Non-current	**7.1**	**47.7**	7.7	28.0
Liabilities				
Current	**14.6**	**97.6**	12.2	102.2
Non-current	**4.6**	**71.0**	5.2	67.8

For cash flow hedges, gains and losses are reclassified immediately to net earnings when anticipated hedged transactions are no longer likely to occur.

For non-hedge derivatives, there were unrealized gains of $49.6 million for the three months ended March 31, 2020 (2019 - $33.4 million gain), primarily recorded in electricity and fuel purchases. The anticipated non-hedge derivatives are expected to settle in 2020 through 2032. The mark-to-market adjustments do not consider the impact of any interrelationship among the factors such as the underlying position and the optionality of the Corporation’s integrated business. Generation capacity or future sales to customers are not fair valued, which creates a mismatch in the timing of earnings.

On March 23, 2020, the Corporation settled the forward contracts relating to the purchase price of Emera Maine. The contracts had an aggregate notional amount of $959 million USD and upon settlement, ENMAX recognized $105.2 million in foreign exchange gains.

NON-DERIVATIVE FINANCIAL ASSETS AND LIABILITIES

Fair values for cash and cash equivalents, accounts receivable, short-term financing, accounts payable and accrued liabilities are not materially different from their carrying amounts due to their short-term nature.

The Corporation estimated the fair value of its long-term debt based on quoted market prices for the same or similar debt instruments. When such information was not available, future payments of interest and principal were discounted at estimated interest rates for comparable entities.

CARRYING AMOUNTS AND FAIR VALUES OF LONG-TERM DEBT

As at	March 31, 2020		December 31, 2019	
(millions of Canadian dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt [(1)] consisting of:				
Debentures, with remaining terms of:				
Less than 5 years	**38.1**	**38.9**	44.1	44.7
5–10 years	**27.6**	**30.1**	27.6	29.5
10–15 years	**216.2**	**250.8**	216.3	247.8
15–20 years	**575.2**	**626.3**	575.2	625.4
20–25 years	**420.2**	**424.6**	420.2	432.5
General and refunding mortgage bonds [(2)]				
10.25% series	**40.0**	**43.1**	-	-
8.98% series	**26.7**	**31.9**	-	-
Private debentures				
Series 3 (3.81%)	**196.6**	**200.8**	196.4	207.6
Series 4 (3.84%)	**293.6**	**296.6**	293.4	310.7
Series 5 (2.92%)	**298.9**	**299.2**	298.8	303.4
Series 6 (3.33%)	**298.5**	**294.2**	298.5	305.3
Series 7 (3.88%)	**248.6**	**245.2**	248.6	256.8
Senior notes [(2)]				
Unsecured note (3.61%)	**82.5**	**88.2**	-	-
Unsecured note (4.34%)	**146.6**	**145.7**	-	-
Unsecured note (4.36%)	**66.6**	**63.9**	-	-
Unsecured note (4.71%)	**66.6**	**67.4**	-	-
Unsecured note (3.79%)	**80.0**	**68.8**	-	-
Non-revolving term facility [(3)]	**250.0**	**250.0**	-	-
Revolving Debt [(2)]	**38.1**	**38.0**	-	-
Promissory note	**2.9**	**2.9**	2.9	3.1
Debt Instrument [(2)]	**0.5**	**0.5**	-	-
	3,414.0	**3,507.1**	2,622.0	2,766.8

(1) Includes current portion of $113.5 million (December 31, 2019 – $73.3 million). Maturity dates range from June 2020 to December 2049.

(2) As part of the March 24, 2020 acquisition, the Corporation assumed debt which includes:

- $30.0 million USD of General and Refunding mortgage bonds maturing 2020 with a coupon rate of 10.25 per cent.
- $20.0 million USD of General and Refunding mortgage bonds maturing 2022 with a coupon rate of 8.89 per cent.
- $70.0 million USD of Senior unsecured notes maturing 2022 with a coupon rate of 3.61 per cent.
- $110.0 million USD of Senior unsecured notes maturing 2044 with a coupon rate of 4.34 per cent.
- $50.0 million USD of Senior unsecured notes maturing 2047 with a coupon rate of 4.36 per cent.
- $50.0 million USD of Senior unsecured notes maturing 2048 with a coupon rate of 4.71 per cent.
- $60.0 million USD of Senior unsecured notes maturing 2049 with a coupon rate of 3.79 per cent.
- Revolving credit facility maturing 2023 with a variable rate.
- Debt instrument with 7.00 per cent cumulative rate.

(3) On March 26, 2020 the Corporation fully drew on a $250.0 million non-recourse 2-year term facility with a coupon rate of 1.63 per cent.

As at March 31, 2020 ENMAX had nil commercial paper (December 31, 2019 - $53.0 million, fair value of $53.0 million, and average interest rates of 2.15 per cent).

As at March 31, 2020 ENMAX had drawn $446.1 million on existing credit facilities with an average rate of 1.48 per cent (December 31, 2019 - $121.2 million).

9. REGULATORY DEFERRAL ACCOUNT BALANCES

NATURE AND ECONOMIC EFFECT OF RATE REGULATION

ENMAX Canadian Operations

ENMAX Transmission and ENMAX Distribution (the Divisions) are divisions ENMAX Power Delivery. The Divisions are regulated operations established to carry out all electrical transmission and distribution service functions. The Alberta Utilities Commission (AUC) approves Transmission and Distribution Tariffs (rates and terms and conditions of service) pursuant to Sections 37 and 102 of the Electric Utilities Act.

With respect to Distribution, the 2018-2022 Distribution Access Service (DAS) rates are subject to the Performance Based Regulation (PBR) mechanism. In December 2018, the AUC approved formula-based rates for the period effective January 1, 2019, which replaced approved interim rates that had been in place since April 1, 2018.

Transmission division rates are set based on an AUC approved revenue requirement and are regulated under a traditional cost of service framework. Interim rates are currently in place pending a decision on the 2018-2020 General Tariff Application, which was filed in December 2018.

ENMAX U.S. Operations

ENMAX through its wholly owned subsidiary Emera Maine, has distribution and transmission operations in the state of Maine, USA. Emera Maine's distribution and stranded cost recoveries are regulated by the MPUC while its transmission operations are regulated by the FERC. Rates for these operations are established in distinct regulatory proceedings. Tax benefits arising from U.S. tax reforms were reflected in distribution and transmission rates effective July 1, 2018, while other components being deferred are to be addressed in future regulatory proceedings.

Emera Maine's distribution service operates under a traditional cost of service regulatory structure and distribution rates are set by the MPUC. Emera Maine's transmission operations are split between two districts: BHD and MPD. BHD's transmission rates are regulated by the FERC and set annually on June 1, based on a formula that utilizes prior year actual transmission investment and forecasted transmission investment. BHD's bulk transmission assets are managed by ISO-New England (ISO-NE) as part of a region-wide pool of assets. MPD's transmission rates are regulated by the FERC and are set annually on June 1 for wholesale and July 1 for retail customers, based on a formula that utilizes prior year actual transmission investments and expenses.

REGULATORY BALANCES

The timing of recognition of certain regulatory debits, credits, revenues and expenses may differ from what is otherwise expected under IFRS for non-regulated operations.

The Corporation has recorded the following regulatory deferral account debit and credit balances:

As at *(millions of Canadian dollars)*	Accounts Receivable (a)	Un-Eliminated Inter-Company Profit (b)	Other Regulatory Debits (c)	U.S. Operations (e)	Total Regulatory Deferral Account Debit Balances
Regulatory deferral account debit balances					
January 1, 2020	21.0	6.6	3.6	-	31.2
Balances arising in the period (1)	76.8	0.8	2.2	(0.3)	79.5
Emera Maine balance acquired	-	-	-	157.5	157.5
Recovery (reversal) (2)	(55.4)	(0.1)	(0.5)	-	(56.0)
Foreign exchange	-	-	-	(3.5)	(3.5)
March 31, 2020	**42.4**	**7.3**	**5.3**	**153.7**	**208.7**
Expected recovery/reversal period	3 Months	25 Years	12 Months		
January 1, 2019	62.8	10.8	8.4	-	82.0
Balances arising in the period (1)	43.4	0.2	3.0	-	46.6
Recovery (reversal) (2)	(54.9)	(1.4)	(2.0)	-	(58.3)
March 31, 2019	51.3	9.6	9.4	-	70.3
Balances arising in the period (1)	132.5	(2.8)	3.7	-	133.4
Recovery (reversal) (2)	(162.8)	(0.2)	(9.5)	-	(172.5)
December 31, 2019	**21.0**	**6.6**	**3.6**	**-**	**31.2**
Expected recovery/reversal period	3 Months	25 Years	12 Months		

(1) "Balances arising in the period" row consists of new additions to regulatory deferral debits and credit balances.
(2) "Recovery (reversal)" row consists of amounts collected/refunded through rate riders or transactions reversing existing regulatory balances.

As at *(millions of Canadian dollars)*	Accounts Payable (a)	Other Regulatory Credits (d)	U.S. Operations (e)	Total Regulatory Deferral Account Credit Balances
Regulatory deferral account credit balances				
January 1, 2020	-	1.5	-	1.5
Balances arising in the period (2)	-	2.2	(0.1)	2.1
Emera Maine balance acquired	-	-	176.2	176.2
Recovery (reversal) (1)	-	(1.0)	-	(1.0)
Foreign exchange	-	-	(3.9)	(3.9)
March 31, 2020	**-**	**2.7**	**172.2**	**174.9**
Expected recovery/reversal period		18 Months		
January 1, 2019	-	5.0	-	5.0
Recovery (reversal) (1)	-	(0.9)	-	(0.9)
March 31, 2019	-	4.1	-	4.1
Balances arising in the period (2)	-	1.2	-	1.2
Recovery (reversal) (1)	-	(3.8)	-	(3.8)
December 31, 2019	**-**	**1.5**	**-**	**1.5**
Expected recovery/reversal period		18 Months		

(1) "Recovery (reversal)" row consists of amounts collected/refunded through rate riders or transactions reversing existing regulatory balances.
(2) "Balances arising in the period" row consists of new additions to regulatory deferral debits and credit balances.

The following describes each of the circumstances in which rate regulation affects the accounting for a transaction or event. Regulatory deferral account debit balances represent costs incurred in the current period or in prior periods, that are expected to be recovered from customers in future periods through the rate-setting process. Regulatory deferral account credit balances represent future reductions or limitations of increases in revenues associated with amounts that are expected to be returned to customers as a result of the rate-setting process.

(a) Accounts receivable and payable

Accounts receivable and payable represents a deferral account for transmission charges from the AESO. In the absence of rate regulation and the standard, IFRS 14 would require that actual costs be recognized as an expense when incurred.

(b) Inter-company profit

A subsidiary of the Corporation performs construction work for the regulated operations of Power Delivery at a profit. Such profit is deemed to be realized to the extent that the transfer price is recognized for rate-making purposes by the regulator and included in the capital cost of distribution assets. In the absence of rate regulation and the standard, IFRS would require that inter-company profits be eliminated upon consolidation.

(c) Other regulatory debits

Other regulatory debits primarily relate to the AUC flow-through items and other costs that will be collected from customers via future rates such as access service charges. The timing of the decision on collection of these items can result in significant fluctuation in balances from year to year.

(d) Other regulatory credits

Other regulatory credits primarily relate to items that will be refunded to customers through future rates.

For certain regulatory items identified above, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties including those inherent in rate-setting regulatory processes. There is a risk that the regulator may disallow a portion of certain costs incurred in the current period for recovery through future rates or disagree with the proposed recovery period. Any impairment related to regulatory deferral account debit balances are recorded in the period in which the related regulatory decisions are received.

(e) U.S. Operations

Regulatory assets and liabilities for Emera Maine's operations consist of the following:

As at *(millions of Canadian dollars)*	March 31, 2020	December 31, 2019
Regulatory assets		
Deferred income tax asset	**58.6**	-
Pension and post-retirement medical plan	**54.5**	-
Storm reserve	**18.4**	-
Stranded cost recovery	**0.5**	-
Other	**21.7**	-
	153.7	-
Current	**20.6**	-
Long-term	**133.1**	-
Total regulatory assets	**153.7**	-
Regulatory liabilities		
Deferred income tax liabilities	**151.9**	-
FERC transmission liability	**6.5**	-
Maine Yankee Department of Energy proceeds	**3.4**	-
Stranded cost	**4.4**	-
Other	**6.0**	-
	172.2	-
Current	**10.4**	-
Long-term	**161.8**	-
Total regulatory liabilities	**172.2**	-

Unfunded Deferred Income Tax Asset and Liability

In accordance with IFRS 14, Emera Maine is required to flow through to customers benefits/expenses of certain book vs. tax timing differences including State of Maine excess tax depreciation, allowance for funds used during construction (AFUDC), and the excess of deferred taxes. Emera Maine records the balance sheet impact for the temporary differences flowed through to customers as regulatory assets or liabilities and deferred income tax liabilities.

Pension and post-retirement medical plan

The asset relates to the deferred costs of pension and post-retirement benefits and is included in the rate base and earns a rate of return as permitted by the MPUC. The balance is amortized over the remaining service life of the plan participants.

Storm reserves

In December 2013 and November 2014, Emera Maine experienced major storms in its service territory, resulting in over one-third of its customer base experiencing power outages. Due to the severity of the outages and damages to the electrical system, significant resources were utilized to restore service to the affected areas. Total incremental costs related to the 2013 and 2014 storms were $4.8 million USD and $4.6 million USD, respectively. For the 2013 storm, the MPUC approved the recovery of the incremental costs incurred, through a rate increase effective July 1, 2014 over 5 years. Of the 2014 storm related costs, $4.6 million USD is being amortized over 5 years beginning January 2017.

In October 2017, Emera Maine experienced a windstorm resulting in power outages to more than half its customer base. The incremental cost incurred in restoring power to its affected customers was $7.2 million USD of which $6.1 million USD will be recovered through rate adjustments.

In October 2019, Emera Maine experienced two major storms resulting in power outages to approximately 99,000 of customers, cumulatively. The incremental cost incurred in restoring power to its affected customers was $3.5 million USD. Given the significance of the storm related costs and the regulatory precedent set for rate recovery in similar events, Emera Maine will be making a filing with the MPUC in 2020 seeking approval for recovery of these costs.

Stranded cost recoveries

Stranded cost recoveries in the State of Maine are set by the MPUC. These recoveries primarily related to the full recovery of net costs associated with purchase power contracts that the utility has been directed to purchase and resell by the MPUC.

Other

The Corporation through its wholly owned subsidiary, Emera Maine, has various other regulatory assets and liabilities recorded on its consolidated financial statements where Emera Maine's regulated rates are designed to recover/return these deferred costs/revenue to/from customers, including a return on unamortized assets.

10. PROPERTY, PLANT AND EQUIPMENT (PPE)

(millions of Canadian dollars)	**Transmission, Distribution and Substation Equipment**	**Generation Facilities and Equipment**	**Buildings and Site Development**	**Tools, Systems and Equipment**	**Land**	**Capital Spares and Other**	**Vehicles**	**Work in Progress**	**Government Grants**	**Total**
Cost										
As at January 1, 2019	2,444.5	2,277.5	475.6	87.3	49.3	48.5	41.8	113.7	(20.0)	5,518.2
Additions	-	36.7	17.6	0.1	-	3.4	10.1	390.1	-	458.0
Transfers	196.6	31.8	13.8	11.3	-	-	6.1	(259.6)	-	-
Disposals	(7.1)	(17.9)	(8.3)	(3.3)	-	-	(5.9)	(7.3)	-	(49.8)
Changes to asset retirement costs	-	14.5	-	-	-	-	-	-	-	14.5
Impairment	-	-	-	-	-	-	-	(1.1)	-	(1.1)
As at December 31, 2019	2,634.0	2,342.6	498.7	95.4	49.3	51.9	52.1	235.8	(20.0)	5,939.8
Emera Maine acquisition	1,144.7	0.5	56.1	21.5	33.4	10.2	40.5	48.5	-	1,355.4
Additions	1.3	4.6	3.0	2.7	-	2.2	-	54.6	-	68.4
Transfers	13.8	0.8	-	1.4	0.1	-	0.3	(15.6)	-	0.8
Disposals	(2.8)	(4.1)	(3.6)	(1.5)	-	-	-	(0.3)	-	(12.3)
Adjustments	-	-	-	-	-	-	-	(13.7)	-	(13.7)
Changes to asset retirement costs	-	18.6	-	-	-	-	-	-	-	18.6
Foreign exchange	(25.8)	-	(1.3)	(0.5)	(0.7)	(0.2)	(0.9)	(1.1)	-	(30.5)
As at March 31, 2020	**3,765.2**	**2,363.0**	**552.9**	**119.0**	**82.1**	**64.1**	**92.0**	**308.2**	**(20.0)**	**7,326.5**
Accumulated Depreciation										
As at January 1, 2019	(346.2)	(772.8)	(105.1)	(43.3)	-	-	(9.8)	-	12.9	(1,264.3)
Depreciation	(94.5)	(98.6)	(16.0)	(8.1)	-	-	(5.3)	-	0.4	(222.1)
Disposals	13.3	16.7	3.5	3.3	-	-	5.0	-	-	41.8
As at December 31, 2019	(427.4)	(854.7)	(117.6)	(48.1)	-	-	(10.1)	-	13.3	(1,444.6)
Depreciation	(25.2)	(27.0)	(4.4)	(2.4)	-	-	(1.6)	-	0.1	(60.5)
Disposals	2.8	0.1	0.3	1.5	-	-	-	-	-	4.7
As at March 31, 2020	**(449.8)**	**(881.6)**	**(121.7)**	**(49.0)**	**-**	**-**	**(11.7)**	**-**	**13.4**	**(1,500.4)**
Net Book Value										
As at December 31, 2019	2,206.6	1,487.9	381.1	47.3	49.3	51.9	42.0	235.8	(6.7)	4,495.2
As at March 31, 2020	**3,315.4**	**1,481.4**	**431.2**	**70.0**	**82.1**	**64.1**	**80.3**	**308.2**	**(6.6)**	**5,826.1**

Real property, including land and buildings, with a carrying amount of $513.3 million as at March 31, 2020 (December 31, 2019 - $430.4 million), was subject to a right of first refusal to purchase held by the City.

For the period ended March 31, 2020, capitalized borrowing costs amounted to $2.3 million (2019 - $8.2 million), with capitalization rates ranging from 3.18 per cent to 3.93 per cent (2019 - 3.15 to 3.91 per cent). Interest is capitalized based on the actual cost of debt used to finance the capital construction projects. Interest rates ranged from 1.63 to 5.02 per cent (2019 – 1.95 to 5.02 per cent).

11. INTANGIBLE ASSETS

(millions of Canadian dollars)	Computer Systems	Renewable Energy Certificates and Water Licenses	Land Easements, Rights and Lease Options	Work in Progress	Total
Cost					
As at January 1, 2019	248.4	12.4	33.9	9.1	303.8
Additions	-	-	-	28.3	28.3
Transfers	18.5	-	-	(18.5)	-
As at December 31, 2019	266.9	12.4	33.9	18.9	332.1
Emera Maine acquisition	43.4	-	50.6	2.1	96.1
Additions	-	-	-	5.8	5.8
Transfers	6.1	-	-	(6.0)	0.1
Foreign exchange	(0.9)	-	(1.1)	-	(2.0)
As at March 31, 2020	**315.5**	**12.4**	**83.4**	**20.8**	**432.1**
Accumulated amortization					
As at January 1, 2019	(106.0)	(12.3)	(7.7)	-	(126.0)
Amortization	(20.1)	-	(1.3)	-	(21.4)
As at December 31, 2019	(126.1)	(12.3)	(9.0)	-	(147.4)
Amortization	(4.7)	(0.1)	(0.4)	-	(5.2)
As at March 31, 2020	**(130.8)**	**(12.4)**	**(9.4)**	**-**	**(152.6)**
Net book value					
As at December 31, 2019	140.8	0.1	24.9	18.9	184.7
As at March 31, 2020	**184.7**	**-**	**74.0**	**20.8**	**279.5**

12. LEASES

ENMAX leases several assets categorized as: generation facilities and equipment, buildings and site development, land, tools, systems and equipment and vehicles. The average term remaining on the leases is 4.8 years.

Right-of-use assets

The changes in the net book value for the Corporation's right-of-use assets during the three months ended March 31, 2020 were as follows:

(millions of Canadian dollars)	Generation Facilities and Equipment	Buildings and Site Development	Land	Tools, Systems and Equipment	Vehicles	Total
Cost						
As at January 1, 2019	5.1	-	-	-	-	5.1
Opening balance adjustment IFRS 16	27.9	13.3	8.8	0.1	7.7	57.8
Net changes	(0.1)	0.1	-	-	1.9	1.9
As at December 31, 2019	32.9	13.4	8.8	0.1	9.6	64.8
Net changes	-	(0.5)	0.5	0.1	-	0.1
As at March 31, 2020	**32.9**	**12.9**	**9.3**	**0.2**	**9.6**	**64.9**
Accumulated Depreciation						
As at January 1, 2019	(1.7)	-	-	-	-	(1.7)
Net changes	(1.2)	(1.2)	(0.3)	(0.1)	(2.6)	(5.4)
As at December 31, 2019	(2.9)	(1.2)	(0.3)	(0.1)	(2.6)	(7.1)
Net changes	(0.3)	(0.2)	-	-	(0.8)	(1.3)
As at March 31, 2020	**(3.2)**	**(1.4)**	**(0.3)**	**(0.1)**	**(3.4)**	**(8.4)**
Net Book Value						
As at December 31, 2019	30.0	12.2	8.5	-	7.0	57.7
As at March 31, 2020	**29.7**	**11.5**	**9.0**	**0.1**	**6.2**	**56.5**

Amounts recognized in profit and loss

Three months ended March 31, *(millions of Canadian dollars)*	2020	2019
Depreciation expense	**1.3**	1.4
Lease expense on short-term leases	**0.2**	0.1
Interest expense on lease liabilities	**0.9**	0.9
Amounts expensed in profit and loss	**2.4**	2.4

Lease payments

The required lease payments of the lease liability at March 31, 2020, are as follows:

As at March 31, *(millions of Canadian dollars)*	2020
Less than 1 year	**7.1**
1–5 years	**23.1**
More than 5 years	**56.9**

The total cash outflow for leases amounts to $2.9 million for the three months ended March 31, 2020. ENMAX does not face a significant liquidity risk with regards to its lease liabilities. Lease liabilities are monitored through ENMAX's treasury function.

13. DEFERRED REVENUE

As at *(millions of Canadian dollars)*	CIAC	Other	Total
January 1, 2020	544.1	21.5	565.6
Additions	3.7	2.5	6.2
Recognized as revenue	(4.8)	(1.4)	(6.2)
March 31, 2020	**543.0**	**22.6**	**565.6**
Less: current portion	-	(11.4)	(11.4)
	543.0	11.2	554.2
January 1, 2019	533.6	21.8	555.4
Additions	4.2	2.2	6.4
Recognized as revenue	(4.7)	(0.3)	(5.0)
March 31, 2019 (1)	533.1	23.7	556.8
Additions	27.8	6.8	34.6
Movements to PPE	(2.4)	-	(2.4)
Recognized as revenue	(14.4)	(9.0)	(23.4)
December 31, 2019	**544.1**	**21.5**	**565.6**
Less: current portion	-	(10.5)	(10.5)
	544.1	11.0	555.1

(1) Includes current portion of $9.2 million in other deferred revenue as at March 31, 2019.

14. OTHER ASSETS AND LIABILITIES

As at *(millions of Canadian dollars)*	March 31, 2020	December 31, 2019
Other current assets		
Prepaid expenses	**14.0**	17.8
Collateral paid	**30.5**	18.4
Deferred asset	**0.5**	0.5
Emission offsets	**40.3**	39.9
Other	**7.3**	6.7
	92.6	83.3
Other long-term assets		
Prepaid expenses	**5.5**	6.1
Long-term accounts receivable	**22.5**	18.0
Deferred asset	**5.4**	5.5
Equity Investments	**159.3**	-
Other	**26.3**	14.7
	219.0	44.3
Other current liabilities		
Deposits	**15.7**	25.0
Other	**26.2**	7.0
	41.9	32.0
Other long-term liabilities		
Other	**17.1**	13.1
	17.1	13.1

15. INCOME TAXES

The calculation of the Corporation's current and deferred income taxes involves a degree of estimation and judgment. The carrying value of deferred income tax assets is reviewed at the end of each reporting period. For the three months ended March 31, 2020, management adjusted the income tax provision using its best estimate with considerations including management's expectation of future operating results and interpretation of applicable tax positions and allowances, where uncertainty surrounding the realization of the tax benefit exists.

16. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

As at *(millions of Canadian dollars)*	**March 31, 2020**	**December 31, 2019**
Net unrealized (losses) gains on derivatives designated as cash flow hedges, including deferred income tax expense of $0.5 million (December 31, 2019 - expense of $5.7 million)	**(2.8)**	8.3
Net actuarial losses on defined benefit plans, including deferred income tax recovery of $0.7 million (December 31, 2019 - recovery of $0.7 million)	**(40.8)**	(40.8)
Cumulative Translation Adjustment on Consolidation of Foreign Entity	**(17.1)**	-
Accumulated other comprehensive (loss), including deferred income tax recovery of $0.2 million (December 31, 2019 - expense of $5.0 million)	**(60.7)**	(32.5)

17. OTHER REVENUE AND EXPENSES

OTHER REVENUE

Three months ended March 31, *(millions of Canadian dollars)*	**2020**	**2019**
Interest and penalty revenue	**1.8**	2.4
Miscellaneous	**0.5**	1.6
	2.3	4.0

OTHER EXPENSES

Three months ended March 31, *(millions of Canadian dollars)*	**2020**	**2019**
Contractual services cost	**19.1**	20.1
Staff costs	**62.4**	51.2
Consulting costs	**4.3**	5.7
Advertising and promotion	**4.8**	1.6
Administrative and office expenses	**16.7**	19.9
Operating costs	**9.2**	7.7
Building and property costs	**11.4**	6.1
Other costs (recoveries)	**10.9**	(0.1)
Foreign exchange (gains)	**(125.5)**	(0.6)
	13.3	111.6

18. DIVIDENDS

On March 19, 2020, the Corporation declared a total dividend of $54.0 million to the City (2019 – $50.0 million). The dividend is paid in equal quarterly instalments during 2020.

19. CHANGE IN NON-CASH WORKING CAPITAL

Three months ended March 31, *(millions of Canadian dollars)*	2020	2019
Accounts receivable	**20.4**	(86.1)
Regulatory deferral account debit balances	**(23.5)**	11.7
Other assets	**(12.7)**	19.5
Accounts payable and accrued liabilities	**(37.9)**	(95.5)
Regulatory deferral account credit balances	**1.2**	(0.9)
Other liabilities	**(14.9)**	(5.5)
Deferred revenue (non-CIAC)	**1.2**	2.0
Provisions	**15.4**	(0.4)
Change in non-cash working capital	**(50.8)**	(155.2)

20. RELATED PARTY TRANSACTIONS

The City is the sole shareholder of the Corporation. The following tables summarize the related party transactions between the Corporation and the City.

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF EARNINGS

Three months ended March 31, *(millions of Canadian dollars)*	2020	2019
Revenue [1]	**34.1**	42.2
Local access fees and other expenses [2]	**37.0**	36.8

[1] The significant components include contract sales of electricity, construction of infrastructure, provision of non-regulated power distribution services, and billing and customer care services relating to the City's utilities departments.
[2] This cost is passed through the Corporation directly to transmission and distribution customers.

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF FINANCIAL POSITION

As at *(millions of Canadian dollars)*	March 31, 2020	December 31, 2019
Accounts receivable	**22.9**	32.4
Property, plant and equipment [1]	**3.2**	3.2
Accounts payable and accrued liabilities	**15.8**	13.7
Long-term debt [2]	**1,277.3**	1,283.3
Other long-term liabilities [3]	**6.1**	6.2

[1] Assets under lease.
[2] Interest and principal payments for the three months ended March 31, 2020 were $0.4 million (2019 - $0.8 million) and $6.1 million (2019 - $8.5 million) respectively. In addition, for the three months ended March 31, 2019, the Corporation paid a management fee of $0.8 million (2019 - $0.7 million) to the City.
[3] Includes finance lease obligation.

Transactions between the Corporation and the City have been recorded at the exchange amounts, as outlined by the contracts in effect between the Corporation and the City.

The Corporation has committed to a water supply agreement, whereby the City supplies a specified amount of water annually to facilitate Shepard Energy Centre's operations.

21. COMMITMENTS AND CONTINGENCIES

The Corporation is committed to expenditures for capital additions, rent for premises, vehicles and equipment under multiple lease contracts with varying expiration dates.

The Corporation commits to the purchase of renewable energy certificates and carbon offset credits and to long-term service arrangements on certain generating assets.

HISTORICAL TRANSMISSION LINE LOSS CHARGES

ENMAX has participated in various proceedings regarding the AESO's Line Loss Rule (LLR). The LLR establishes the loss factors that form the basis for certain transmission charges paid by Alberta generators, including ENMAX. Proceedings relating to the LLR address the AUC's authority to order retroactive adjustments (Module A); the replacement of the 2006-2016 methodology (Module B); and the calculation and invoicing of retroactive loss charges and credits for the 2006-2016 period (Module C). The AUC issued its decision on the last module, Module C, on December 18, 2017. The AUC's decisions in each of Module A and C have been the subject of permission to appeal applications before the Alberta Court of Appeal as well as review and variance applications before the AUC.

The permission to appeal applications were heard by the Alberta Court of Appeal in the second quarter of 2018. On December 20, 2018, the Court issued a decision denying permission to appeal the AUC's decision on Module A and further reserving its decision on permission to appeal Module C and related matters. On June 3, 2019, the Court of Appeal of Alberta issued a decision denying permission to appeal the AUC's Model C decision. Since the Court did not grant permission to appeal Module A or Module C, the decision of the AUC will stand unless the Court's decision is further challenged.

Based on the Court's decision in Module A and Module C, management believes that ENMAX may be required to make material payments to the AESO for historical amounts. Because the AUC's previous decisions do not require the AESO to consider commercial agreement terms and service transfer circumstances when the AESO determines which party to invoice, ENMAX could be invoiced for amounts for which it may not ultimately, in whole or in part, be responsible. Moreover, the invoices may not reflect the benefit of credits to which ENMAX is entitled nor any of ENMAX's rights to subsequently seek compensation, including under commercial agreements from other parties such as the Balancing Pool.

The AESO had expected to be in a position to issue charges or credits in April 2021, with initial settlement to occur in June 2021. In December 2019, the AESO filed an application to review and vary the Module C decision. If approved, the application would result in the AESO issuing charges or reimbursements to market participants once the AESO calculates loss factors for one or more of the years in the historic period. The AESO would repeat the process sequentially until all historical years have been settled. Approval of the application would commence the settlement process for historical line losses earlier than had been expected. ENMAX expects the AUC will issue a decision on the AESO's application before the end of Q2 2020.

Management does not have the information necessary to calculate a reliable range of expected charges and credits across the portfolio of generation held during the relevant periods and the impact to ENMAX of such amounts. ENMAX believes it has sufficient access to cash to satisfy any amounts which may be required to be paid.

LEGAL AND REGULATORY PROCEEDINGS

In the normal course of business, the Corporation is, and may be named as, a defendant or party in lawsuits and regulatory proceedings related to various matters. The Corporation currently believes the outcome of these lawsuits and regulatory proceedings will not have a material impact on the operating results or financial position of the Corporation.

The Corporation, along with other market participants in the province of Alberta, is subject to decisions, market rules, regulations, regulatory proceedings and/or jurisdiction of the AUC, AESO, Market Surveillance Administrator (MSA) and other authorities. The financial impact of decisions, market rules, regulations and regulatory proceedings is reflected in the condensed consolidated interim financial statements when the amount can be reasonably estimated.

From 2011 to 2016, four separate complaints were filed with the FERC to challenge the base Return on Equity (ROE) for public utility transmission assets subject to the ISO-NE Open Access Transmission Tariff (OATT), including those of Emera Maine. All four complaints remain outstanding at the FERC at various stages of review, rehearing, and/or remand from appeal. Provisions have been recorded for complaints II & III.

On October 16, 2018, the FERC issued an order that addresses all four complaint proceedings. The FERC order proposes a new methodology to set ROEs. Based on the new methodology, the FERC's preliminary finding is a 10.41 per cent base ROE for transmission subject to the ISO-NE OATT for most of the period covered by the four complaints. In January and February 2019, various parties commented on FERC's proposal and its application to the pending complaint proceedings.

On November 21, 2019, the FERC issued an order affecting transmission ROEs in the Midcontinent ISO (MISO) region that adopts a methodology for analyzing the base return on equity component of a jurisdictional public utility's rates that differ from that proposed in the October 18, 2018 order. Although the methodology was applied to MISO, it may be used in the pending ISO-NE cases. No date for a decision has been made yet, but the FERC is expected to rule on these outstanding ISO-NE cases in 2020. Additionally, both the MISO case, and a decision in the ISO-NE cases, will be subject to further appeal rights, and if appealed, a final decision would be unlikely to occur before Q4 2020. No reserves have been made with respect to the fourth ISO-NE OATT complaint as it is not possible to determine the impact at this time.

COVID-19 PANDEMIC

On March 11, 2020 the World Health Organization characterized the outbreak of a strain of the novel coronavirus (COVID-19) as a pandemic which has resulted in a series of public health and emergency measures that have been put in place to combat the spread of the virus. In response to the COVID-19 pandemic, the Government of Alberta passed the Utility Payment Deferral Program (Bill 14) providing a 90-day payment deferral for residential, farm and small businesses. Similarly, the MPUC has directed all electrical utilities not to engage in disconnection activity in Maine until further notice is received; this direction applies equally to residential and business customers.

The duration and impact of COVID-19 is unknown at this time and it is not possible to reliably estimate the impact that the length and severity of these developments will have on the financial results and condition of the Corporation in future periods.

22. SUBSEQUENT EVENTS

Under the terms of the acquisition, Emera Maine was legally renamed to Versant Power effective, May 11, 2020. A public announcement was issued virtually on May 14, 2020 in light of COVID-19 pandemic health and safety protocols. A staged and orderly implementation of the name change will occur over the new few months to ensure there are no disruptions to customers and operations.

GLOSSARY OF TERMS

AESO	Alberta Electric System Operator
AFUDC	Allowance for funds used during construction
AUC	Alberta Utilities Commission
Bill 14	Alberta Utility Payment Deferral Program Act
BHD	Bangor Hydro District
CES	Calgary Electric System
CHP	Combined Heat and Power
CIAC	Contributions in aid of construction
Competitive Energy	ENMAX Competitive Energy
Corporate and Eliminations	ENMAX Corporate and Eliminations
Corporation	ENMAX Corporation and its subsidiaries
COVID-19	Strain of the novel coronavirus
EBIT	Earnings before interest and income taxes
EBITDA	Earnings before interest, income tax and depreciation and amortization
ENMAX	ENMAX Corporation and its subsidiaries
ERM	Enterprise Risk Management
FCF	Free Cash Flow
FERC	Federal Regulatory Commission
FX	Foreign exchange
GJ	Gigajoule
GWh	Gigawatt hour
IAS	International Accounting Standards
IASB	International Accounting Standards Board
ISO-NE	ISO-New England
kWh	Kilowatt hour
LLR	Line Loss Rule
MD&A	Management's Discussion and Analysis
MEPCo	Maine Electric Power Company
MISO	Midcontinent ISO
MPD	Maine Public District
MPUC	Maine Public Utilities Commission
MSA	Market Surveillance Administrator
MW	Megawatt
MWh	Megawatt hour
NEPOOL	New England Power Pool
NGTL	Nova Gas Transmission Ltd.
NMISA	Northern Maine Independent System Administrator
OATT	Open Access Transmission Tariff
OCI	Other comprehensive income
OM&A	Operations, maintenance and administration
PBR	Performance based regulation
Power Delivery	ENMAX Power Delivery
PPE	Property, plant and equipment
ROE	Return on equity
RRO	Regulated Rate Option
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
Shepard	Shepard Energy Centre
the Board	ENMAX's Board of Directors
the City	The City of Calgary
the Divisions	ENMAX Transmission and ENMAX Distribution
the Notice	Notice of departure from the Genesee 4/5 generation project
TIER	Alberta's Technology Innovation and missions Reduction regulation
U.S. GAAP	United States Generally Accepted Accounting Principles

ADDITIONAL INFORMATION

ENMAX welcomes questions from stakeholders.
Additional information relating to ENMAX can be found at enmax.com.

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FINANCIAL REVIEW

ENMAX 2019

CAUTION TO READER

This document contains statements about future events and financial and operating results of ENMAX Corporation and its subsidiaries (ENMAX or the Corporation) that are forward-looking. By their nature, forward-looking statements require the Corporation to make assumptions and are subject to inherent risks and uncertainties. There is significant risk that predictions and other forward-looking statements will not prove to be accurate. Readers are cautioned not to place undue reliance on forward-looking statements, as a number of factors could cause actual future results, conditions, actions or events to differ materially from financial and operating targets, expectations, estimates or intentions expressed in the forward-looking statements.

When used in this Financial Report, the words “may,” “would,” “could,” “will,” “intend,” “plan,” “anticipate,” “believe,” “seek,” “propose,” “estimate,” “expect” and similar expressions, as they relate to the Corporation or an affiliate of the Corporation, are intended to identify forward-looking statements. Such statements reflect the Corporation’s current views with respect to future events and are subject to certain risks, uncertainties and assumptions. Many factors could cause the Corporation’s actual results, performance or achievements to vary from those described in this Financial Report. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this Financial Report. Intended, planned, anticipated, believed, estimated or expected and other forward-looking statements included in this Financial Report herein should not be unduly relied upon. These statements speak only as of the date of this Financial Report. The Corporation does not intend, and does not assume any obligation, to update these forward-looking statements except as required by law, and reserves the right to change, at any time at its sole discretion, the practice of updating annual targets and guidance.

For further information, see the Management’s Discussion & Analysis (MD&A) section, Risk Management and Uncertainties.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This MD&A, dated March 19, 2020, is a review of the results of operations of ENMAX Corporation and its subsidiaries (ENMAX or the Corporation) for the year ended December 31, 2019, compared with 2018, and of the Corporation's financial condition and future prospects. This discussion contains forward-looking information that is qualified by reference to and should be read in light of the Caution to Reader previously set out.

ENMAX's Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards (IFRS). The Consolidated Financial Statements and MD&A were reviewed by ENMAX's Audit Committee (AC), and the Consolidated Financial Statements were approved by ENMAX's Board of Directors (the Board). All amounts are in millions of Canadian dollars unless otherwise specified.

The Corporation reports on certain non-IFRS financial performance measures that are used by management to evaluate performance of business segments. Because non-IFRS financial measures do not have a standard meaning prescribed by IFRS, the Corporation has defined and reconciled them with their nearest IFRS measure. For the reader's reference, the definition, calculation and reconciliation of non-IFRS financial measures is provided in the Non-IFRS Financial Measures section.

Contents

Glossary of terms can be found on page 89 of the Consolidated Financial Statements.

BUSINESS OVERVIEW

ENMAX is a wholly owned subsidiary of the City of Calgary (the City), and is headquartered in Calgary, Alberta, Canada. ENMAX's mission is to power the potential of people, businesses and communities by safely and responsibly providing electricity and energy services in ways that matter to them today and tomorrow. ENMAX has a proud history of providing Albertans with electricity and continues to explore ways to improve the province's electricity system and provide progressive solutions for its customers.

As a result of significant transformation of the electricity industry both within and outside of Alberta, ENMAX adjusted its strategic direction in 2017 and continued this direction throughout 2019. Our strategy is to develop a business with strong regulated and contracted cash flows and diverse revenue streams within North America via services and customer focussed businesses built upon an efficient platform.

ENMAX has core operations through two main business segments, **ENMAX Competitive Energy** (Competitive Energy) and **ENMAX Power Delivery** (Power Delivery). Competitive Energy includes the competitive generation and sale of electricity across Alberta as well as power project services and solutions. Power Delivery includes the regulated transmission and distribution of electricity within the City of Calgary.

- Competitive Energy carries out competitive energy supply and retail functions including the Calgary Regulated Rate Option (RRO) through various affiliated legal entities. Competitive Energy is an integrated business providing customers with electricity, natural gas, and distributed energy resource solutions, as well as engineering, procurement and construction services. Our competitive advantage is our ability to hedge our low-cost generation assets through our retail business – the largest in Alberta by number of customers and energy consumed. The competitive retail business provides customers with fixed-price electricity linked to our wind and gas-fueled generation assets, and provides opportunities to offer additional energy services, such as solar installations and thermal energy. Our risk mitigation strategies, which result in contracting most of our market position, deliver the majority of our margin with reduced exposure to the volatility of near-term spark spreads. Competitive Energy manages its portfolio to deliver cash flow targets by using a combination of retail sales and forward markets with hedges. As a result, our hedging program tempers the impact of in-year price movements, which reduces volatility of cash flows with respect to market prices.
- Power Delivery owns and operates electricity transmission and distribution assets in the Calgary service area. Power Delivery's objective is to safely and efficiently operate and maintain the high reliability of its transmission and distribution system while meeting Calgary's power delivery infrastructure needs. In addition to safe, reliable and efficient delivery, cost and capital management are key priorities. Other priorities include minimizing regulatory lag and updating critical technology as a platform for future initiatives. The need to replace aging infrastructure in Calgary provides a significant and predictable growth opportunity for ENMAX.

The final segment of the business is ENMAX Corporate and Eliminations (Corporate), which is responsible for providing shared services and financing to Competitive Energy and Power Delivery.

MARKET CONDITIONS

Power prices and spark spreads were stronger in 2019 than in the prior year. The Alberta power market pool price settled at $55.28 per Megawatt hour (MWh) for 2019, representing an increase of 10 per cent over the prior year's average of $50.19 per MWh. Average power prices for the year were particularly affected by the extended cold weather in February 2019. Spark spreads settled at $42.67 per MWh for 2019 compared to $39.38 per MWh the prior year. ENMAX's hedging strategy secures significant margins before entering the year, offering protection from fluctuating power prices while maintaining some ability to capitalize on price increases.

In 2016, the Alberta government tabled the Technology Innovation and Emissions Reduction (TIER) regulation, which provides a mechanism to manage carbon pricing for Alberta's large industries, including electricity generation. The carbon cost for 2020 will match the federal carbon cost of $30.00 per tonne of CO2 equivalent. Under TIER, all existing generating units, including coal, will be measured against a "good-as-best" intensity, which currently for ENMAX is Shepard Energy Centre. Any changes to the provincial carbon tax structure in the near-term or the federal carbon tax structure in the long-term could impact electricity price outcomes and costs for power generation facilities.

Electricity demand averaged 9,695 Megawatt (MW) for 2019, representing a decline of less than 1 per cent over the prior year's average demand of 9,744 MW. Economic indicators moved between stagnant and mild recovery as conventional oil activity continued to be affected by limited market access. These factors weighed on electricity demand growth, which was essentially flat year-over-year. ENMAX's unique vertically integrated business model, which includes making, moving and marketing electricity, benefits from demand growth through increases in generator revenue, retail sites, and distribution network size.

Alberta natural gas prices averaged $1.68 per gigajoule (GJ) for 2019, representing a 17 per cent increase compared to 2018's average natural gas price of $1.44 per GJ. The implementation of a Temporary Service Protocol (TSP) adjusted how gas curtailments during maintenance on the Nova Gas Transmission Ltd. system (NGTL) are managed, prioritizing demand service over supply service thus increasing access to natural gas storage deliveries. This had the effect of modestly increasing gas prices towards the latter half of 2019. Maintenance of the NGTL system is expected to continue until 2023 posing a gas delivery risk to ENMAX's assets, creating financial and operational challenges. ENMAX continues to acquire third party transportation to ensure that firm and reliable gas delivery requirements are met for our generation portfolio. We are also currently engaged in the process of planning and developing direct pipeline connections to surrounding natural gas supply sources. These connections would create long-term safe, secure and economic gas delivery to support the requirements of our generation portfolio.

Since the cancellation of the Capacity Market in July 2019, several generation projects have been announced, including coal-to-gas conversions and new gas, wind and solar projects. ENMAX will continue to monitor the progress of these projects and the likelihood of completion as some of these projects are exposed to market risks and economics. The Alberta government has also requested that Alberta Electric System Operator (AESO) recommend any changes that may be required to ensure enough incentive for future generation investment in the Energy Only market. The impact of these initiatives is expected to be felt in the Alberta power market over the next few years.

FINANCIAL PERFORMANCE

Management believes that a measure of operating performance is more meaningful if the impacts of specific items are excluded from the adjusted financial information. As a result, the table below presents ENMAX's adjusted earnings before interest, taxes, depreciation and amortization (Adjusted EBITDA), adjusted earnings before interest and taxes (Adjusted EBIT), and comparable net earnings (CNE). These financial metrics exclude impairment, onerous provision charges (recoveries) on long-term contracts, foreign exchange gains (losses), and unrealized gains (losses) on commodities where settlement on derivatives will occur in a future period.

In addition, the effect of the Emera Maine transaction has been excluded from 2019 results. Refer to the Non-IFRS Financial Measures section on page 12 for definitions and further descriptions of the financial measures.

SELECTED CONSOLIDATED FINANCIAL INFORMATION

Year ended December 31, *(millions of Canadian dollars)*	**2019**	**2018**
Total revenue	**2,524.9**	2,378.4
Adjusted EBITDA [1][2]		
Competitive Energy	**213.9**	221.2
Power Delivery	**238.1**	207.8
Corporate and Eliminations	**(0.3)**	5.7
Consolidated	**451.7**	434.7
Adjusted EBIT [1][2]		
Competitive Energy	**86.6**	100.2
Power Delivery	**118.0**	98.2
Corporate and Eliminations	**3.7**	5.7
Consolidated	**208.3**	204.1
Comparable net earnings [1][2][3]	**160.6**	149.2
Net earnings	**156.2**	5.1
Free cash flow (FCF) [1]	**126.4**	308.5
Capital expenditures	**443.9**	342.5

[1] Non-IFRS financial measure. See discussion that follows in Non-IFRS Financial Measures section.

[2] Does not include:

- Realized and unrealized foreign exchange loss of $21.8 million (2018 - $10.6 million gain) for the year ended December 31, 2019.
- Unrealized electricity and gas mark-to-market for the year ended December 31, 2019 of $106.7 million gains (2018 - $6.5 million gains).
- Impairment charges of $1.1 million (2018 - $26.9 million) for the year ended December 31, 2019.
- Onerous provision of $nil (2018 - $12.5 million recovery) for the year ended December 31, 2019.
- Emera Maine acquisition costs of $35.1 million (2018 - $nil) for the year ended 2019, including $13.6 million related to finance charges that are included in calculating comparable net earnings.

[3] Does not include tax adjustments of $26.6 million (2018 - $144.3 million).

ENMAX's Adjusted EBIT increased by $4.2 million for the year ended December 31, 2019 as compared with the prior year. The primary drivers for the change in Adjusted EBIT are as follows:

- ENMAX Power Delivery – The regulated business continues to grow through investment and an increase in customer sites. This is largely a result of continued growth in the Calgary service area and the need to replace the City's aging infrastructure. The increase in regulatory margins over 2018 resulted from the Alberta Utilities Commission's (AUC) approved 2019 revenue rates for both Distribution and Transmission systems.
- ENMAX Competitive Energy – For the year ended December 31, 2019, Competitive Energy had lower Adjusted EBIT compared to the prior year primarily due to the impact of unplanned asset outages, in addition to lower offset sales and lower Power Services margins. Competitive Energy was able to realize higher natural gas margins due to increased customer sales. However, operational costs were higher due to increased staffing costs across the business, increased technology support costs and higher allowance for uncollectable receivables as a result of economic conditions in Alberta.
- ENMAX Corporate and Eliminations – For the year ended December 31, 2019, Corporate and Eliminations incurred higher staffing and managed service costs.

ENMAX's net earnings for the year ended December 31, 2019 were $156.2 million as compared to $5.1 million in the prior year. A one-time tax adjustment was recorded in 2018, as a result of the Alberta Court of Appeal decision.

Adjusting for events not related to normal operations as well as the unrealized gains on commodities and foreign exchange losses, ENMAX's comparable net earnings for the year December 31, 2019 increased by $11.4 million from the prior year.

ENMAX closed the year with a healthy balance sheet despite challenging market conditions. ENMAX's credit and collections activities have made significant efforts in continuing this trend in 2020. ENMAX's balance sheet and cash flow enable the Corporation to continue to achieve growth and profitability in Alberta's uncertain economic environment.

Additional details on the financial performance of the Corporation are discussed in the ENMAX Financial Results section.

Results of operations are not necessarily indicative of future performance, due to factors including fluctuating commodity prices, timing of receipt of regulatory decisions, the performance and retirement of existing generation facilities, the addition of new generation facilities, and the impact of government policies.

SIGNIFICANT EVENTS

EMERA MAINE ACQUISITION

On March 25, 2019, the Corporation announced that it had entered into a definitive agreement to acquire Emera Maine, a regulated electric transmission and distribution company in Maine, for a purchase price of $1,286 million. Including assumed debt, the aggregate enterprise value is expected to be approximately $1,800 million. This transaction is aligned with the Corporate strategy to grow regulated cash flows and diversify revenue streams within North America. The acquisition will raise ENMAX's regulated rate base by approximately 50 per cent and increase the portion of future cash flows from regulated and non-commodity sources to approximately 70 per cent. ENMAX intends to finance this transaction using approximately 85 per cent debt and 15 per cent equity. The debt is expected to consist of a two-year bank loan, which is intended to be repaid before maturity, and private notes. The remaining balance will be funded in cash.

On March 17, 2020 the Commissioners of Maine Public Utilities Commission (MPUC) deliberated approved the acquisition of Emera Maine by ENMAX. Closing will take place following issuance by the MPUC of the written order.

TAX LITIGATION UPDATE

On April 26, 2018, the Alberta Court of Appeal issued its decision relating to interest expense deductions by ENMAX Energy Corporation and ENMAX PSA Corporation. ENMAX had filed an application with the Supreme Court of Canada seeking leave to appeal. On February 28, 2019 the Supreme Court of Canada dismissed the application (see Income Tax Section). In the year, ENMAX substantially settled all outstanding tax matters with Alberta Finance, Tax and Revenue Administration (Alberta Finance) under the Payment In Lieu of Tax (PILOT) Regulation of the Electric Utilities Act (Alberta). However, there remains an outstanding matter with respect to the calculation of interest on the income tax payable amount. ENMAX is discussing the matter with Alberta Finance and is optimistic that this matter will be resolved in early 2020.

ENMAX COMPETITIVE ENERGY BUSINESS AND UPDATE

ENMAX Competitive Energy is an integrated business providing customers with electricity, natural gas, distributed energy resource solutions, as well as engineering, procurement and construction services. Our competitive advantage is our ability to hedge our low-cost generation assets through our retail business – the largest in Alberta by number of customers and energy consumed. The competitive retail business provides customers with fixed-price electricity linked to our wind and gas-fueled generation assets, and provides opportunities to offer additional energy services, such as solar installations and thermal energy. As at December 31, 2019, Competitive Energy's capacity ownership interest was 1,509 MW of electricity generation: 1,289 MW from natural gas-fueled plants, 217 MW from wind power and 3 MW from combined heat and power (CHP) generation.

Natural gas retail contracts are backed by market transactions to provide supply certainty, margin stability, and risk mitigation. Natural gas fuel requirements for the portfolio are balanced through the purchase and sale of natural gas in the Alberta market.

KEY BUSINESS STATISTICS

	2019	2018
Plant availability (%) [(1)]	**93.89**	93.90
Average flat pool price ($/MWh)	**55.28**	50.19
Spark spread ($) [(2)]	**42.67**	39.38

(1) Plant availability includes planned maintenance and forced outages.
(2) Based on market prices.

In 2019 our plant availability was lower than the prior period, at 93.89 per cent, reflecting unplanned outages at the Shepard Energy Centre and Calgary Energy Centre in 2019. Unplanned outages at our generation facilities precipitate the need to source electricity from the open market, exposing our costs of supplying power to our retail customers to prevailing market prices.

During 2019 the average flat pool power price increased from 2018 levels, primarily due to extreme cold temperatures in February, which tightened the market supply-demand balance. Various industry participant outages across Alberta over the course of the year also influenced an increased pool price.

Spark spread, which is the difference between the wholesale electricity price and the price of natural gas used to produce electricity, represents the gross margin contribution of a gas-fueled power plant from generating an unhedged unit of electricity. The market improvement from 2018 levels was driven by a higher average flat pool price (as described above) as the change in the price of natural gas had a minimal impact on spark spread.

In the retail business our fixed price electricity volumes were in line with the prior year, maintaining our ability to hedge our generation assets. Our competitive products were negatively impacted by higher cost of goods sold, combined with the impact of Bill 16 (an Act to Cap Regulated Electricity Rates, implemented June 1, 2017), which ended November 30, 2019.

During 2019 our electricity margins (see section ENMAX Financial Results) were slightly lower than 2018 due to the impact of unplanned asset outages offsetting the increase in market power and spark spreads over the prior year. To mitigate risk, ENMAX contracts most of our market position, delivering the majority of our margin with less exposure to the volatility of near-term spark spreads.

ENMAX manages its portfolio to deliver on our cash flow targets by using a combination of retail sales and forward markets with hedges. As a result, our hedging and contracting strategies temper the impact of in-year price movements, which reduces volatility of cash flows with respect to market prices.

ENMAX POWER DELIVERY BUSINESS AND UPDATE

Power Delivery's highest priorities are providing safe, reliable and efficient delivery of electricity to customers.

Power Delivery continues to invest in its electricity transmission and distribution system infrastructure to meet Calgary's needs. This includes expansion of the distribution system, reinforcement of the transmission system, and replacement of aging infrastructure in both systems. Distribution projects include investments in system infrastructure to accommodate residential, commercial and industrial growth, as well as the replacement and modification of existing assets required to meet industry safety and reliability standards. Transmission projects can include capacity upgrades to existing substations, existing transmission lines, new substations, and new transmission lines to deliver reliable electricity that meets Calgary's demand.

Power Delivery submits applications to the AUC to request approval for construction or replacement of utility-related facilities, and setting rates for providing electric energy delivery-related services to its customers, among other things.

- On December 16, 2019, the AUC issued a decision approving 2020 Performance Based Regulation (PBR) distribution rates on an interim basis, and distribution tariff terms and conditions for the period of January 1, 2020 to December 31, 2020. This decision is expected to increase the operating margin by 3.6 per cent.
- On December 2, 2019, the AUC approved the 2020 Interim Transmission Tariff Application of $99.8 million. Effective January 1, 2020, this approval resulted in $9.9 million higher revenue than the 2019 interim Transmission tariff that was previously in place.
- On March 1, 2019, the AUC issued a decision disallowing recovery of capital costs incurred for conductors and underground cables during 2015 and 2016. On December 3, 2019, the AUC issued a Compliance filling decision disallowing recovery of capital costs incurred in 2017 for conductors and underground cables. These decisions resulted in $5.1 million of unrecovered revenue in 2019.
- On February 12, 2019, the AUC approved the 2019 Interim Transmission Tariff Application of $89.9 million. Effective May 1, 2019, this approval resulted in $8.7 million higher revenue than the 2017 interim Transmission tariff that was previously in place.
- On December 21, 2018, the AUC issued a decision approving 2019 PBR distribution rates on an interim basis and distribution tariff terms and conditions for the period of January 1, 2019 to December 31, 2019. It was expected that this decision would increase the operating margin from 2018 by 2.7 per cent.
- On December 12, 2018, the 2018-2020 Transmission General Tariff Application was filed with the AUC, requesting final approval of forecast revenue requirements of $85.7 million, $95.7 million, and $106.4 million in 2018, 2019 and 2020, respectively. On November 8, 2019, a Negotiated Settlement Agreement (NSA) was filed with the AUC. This NSA is currently under review.

Power Delivery continues its efforts to reduce regulatory lag, focus on prudent capital expenditures and promote operational and capital cost efficiencies.

KEY BUSINESS STATISTICS

	2019	2018
Distribution volumes in Gigawatt Hours (GWh)	**9,332**	9,520
System average interruption duration index (SAIDI) [(1)]	**0.41**	0.54
System average interruption frequency index (SAIFI) [(2)]	**0.72**	0.80

(1) SAIDI equals the total duration of a sustained interruption per average customer during a predefined period of time. A sustained interruption has a duration greater than or equal to one minute. The lower the SAIDI, the better the reliability.

(2) SAIFI equals how often the average customer experiences a sustained interruption over a predefined period of time. A sustained interruption has a duration greater than or equal to one minute. The lower the SAIFI, the better the reliability.

Total electricity delivered in GWh to the Calgary service area in 2019 was slightly lower than in 2018 as a result of decreased energy usage in 2019 compared to prior year. This slightly lower volume is due to lower customer usage from a combination of milder summer weather, weaker economic conditions and energy efficiency in 2019. Partially offsetting this decrease are increased sites mainly from residential homes in 2019 compared to the 2018 comparative periods.

When compared to the performance of other Canadian Electricity Association member utilities, ENMAX has remained one of the most reliable transmission and distribution utilities in Canada. Both SAIDI and SAIFI are favourable compared to the same period in 2018, due to lower pole fires and equipment failures. ENMAX continues to monitor the cause of any outages to mitigate future occurrences.

ENMAX FINANCIAL RESULTS

ADJUSTED EARNINGS BEFORE INTEREST AND INCOME TAXES (ADJUSTED EBIT) COMPARED WITH THE SAME PERIOD IN 2018

Year ended December 31, *(millions of Canadian dollars)*	Competitive Energy	Power Delivery	Corporate	Consolidated
Adjusted EBIT [(1)(3)] for the year ended December 31, 2018	100.2	98.2	5.7	204.1
Increased (decreased) margins attributable to:				
Electricity	(0.5)	-	(0.4)	(0.9)
Natural gas	2.0	-	(0.1)	1.9
Transmission and distribution	-	18.8	-	18.8
Contractual services and other	(5.9)	(0.7)	-	(6.6)
Decreased (increased) expenses:				
Operations, maintenance & administration (OM&A) [(2)]	(2.9)	12.2	(5.5)	3.8
Depreciation and amortization	(6.3)	(10.5)	4.0	(12.8)
Adjusted EBIT [(1)(3)] for the year ended December 31, 2019	86.6	118.0	3.7	208.3

(1) Adjusted EBIT is a non-IFRS measure. See Non-IFRS Financial Measures section.

(2) Normalized to exclude impact of intercompany transactions with no consolidated impact.

(3) Does not include Emera Maine acquisition costs of $35.1 million (2018 - $nil) for the year ended 2019, including $13.6 million related to finance charges that are included in calculating Adjusted EBIT.

Electricity margins for the year ended December 31, 2019 decreased $0.9 million or 0.3 per cent compared to the same period in 2018, primarily due to the impact of unplanned asset outages that offset the positive impact of spark spreads on our uncontracted positions.

Natural gas margins for the year ended December 31, 2019 increased by $1.9 million or 3.4 per cent compared to the same period in 2018. The increase was primarily due to higher retail consumption volumes as a result of increased site acquisitions.

For the year ended December 31, 2019 Distribution and Transmission margins increased by $18.8 million or 6.0 per cent compared to the same period in 2018. The favourable variance was largely due to the AUC's approval of the 2019 interim rates for Distribution's Performance Based Regulation and Transmission's 2019 interim rates.

Contractual services and other margins for the year ended December 31, 2019 decreased by $6.6 million or 7.0 per cent, compared to the prior year, primarily due to lower emission offset sales and lower Power Services margins.

OM&A for 2019 decreased by $3.8 million or 1.0 per cent from the prior year due to a decrease in salary costs that resulted from strategic restructuring at the end of 2018.

Depreciation and amortization expense increased by $12.8 million or 5.6 per cent compared to the same period in 2018, consistent with an increase in capital assets in 2019.

During 2019 the Corporation recorded $35.1 million in Emera Maine acquisition costs, of which $13.6 million were finance related charges. Acquisition costs are not included in adjusted EBIT.

OTHER NET EARNINGS ITEMS

Finance charges for the year ended December 31, 2019 were $80.6 million or 18.2 per cent higher compared to the prior year, due to $850.0 million of Private Debentures issued with a weighted coupon rate of 3.35 per cent. These debentures were issued in support of the Emera Maine acquisition and the funds are currently being held in escrow.

The calculation of the Corporation's current and deferred income taxes involves a degree of estimation and judgment. The carrying value of deferred income tax assets is reviewed at the end of each reporting period. For the year ended December 31, 2019 management adjusted the income tax provision utilizing its best estimate with considerations including management's expectation of future operating results, interpretation of applicable tax regulations positions, allowances where uncertainty surrounding the realization of the tax benefit exists, and the settlement of various tax disputes.

The Corporation recorded a current and deferred income tax expense of $33.8 million (2018 - $133.5 million) for the year ended December 31, 2019. The change in the income tax expense is primarily due to the reversal of provisions for the PILOT program recorded in prior periods.

OTHER COMPREHENSIVE INCOME AND SHAREHOLDER'S EQUITY

Other comprehensive income (OCI) illustrates earnings under the assumption of full income recognition of gains and losses on the market value of securities and derivatives, otherwise treated as hedges of future period revenues and expenses, as well as remeasurement gains and losses on pension retirement benefits.

For the year ended December 31, 2019 OCI had total losses of $27.8 million compared with losses of $16.4 million for the same period in 2018. The OCI losses primarily reflect the unfavourable change in re-measurement on retirement benefits caused by investment returns being less than the returns implied by the discount rate, and unfavourable fair value change in forward foreign exchange (FX) rates. These negative impacts are offset by favourable fair value changes in electricity and commodity positions.

Accumulated other comprehensive loss is reflected in shareholder's equity along with retained earnings and share capital. Retained earnings for the period increased $106.2 million, largely from earnings during the year, partially offset by the recognition of 2019 dividends on common shares.

NON-IFRS FINANCIAL MEASURES

The Corporation uses Adjusted EBITDA, Adjusted EBIT, comparable net earnings, and free cash flow (FCF) as financial performance measures. 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 shown below. These non-IFRS measures are consistently applied in the previous period and excludes the impact of the Emera Maine operations in the consolidated non-IFRS financial measures.

ADJUSTED EBITDA

Year ended December 31, *(millions of Canadian dollars)*	**2019**	**2018**
Net earnings (IFRS financial measure)	**156.2**	5.1
Add (deduct):		
Unrealized gains on commodities	**(106.7)**	(6.5)
Foreign exchange losses (gains)	**21.8**	(10.6)
Impairment	**1.1**	26.9
Onerous provision recovery	**-**	(12.5)
Emera Maine related acquisition costs (including finance charges)	**35.1**	-
Net income tax expense on unrealized (gains) on commodities, foreign exchange losses (gains), and impairment	**26.5**	2.5
Tax adjustments	**26.6**	144.3
Comparable net earnings (non-IFRS financial measure)	**160.6**	149.2
Add (deduct):		
Depreciation and amortization (excludes regulatory deferral)	**243.4**	230.6
Finance charges (excludes Emera Maine related acquisition costs)	**67.0**	68.2
Remaining income tax recovery	**(19.3)**	(13.3)
Adjusted EBITDA (non-IFRS financial measure)	**451.7**	434.7

Management considers Adjusted EBITDA a useful measure of business performance, as it provides an indication of the cash flow results generated by primary business activities without consideration as to how those activities are financed and amortized, or how the results are taxed. Adjusted EBITDA is also used to evaluate certain debt coverage ratios.

Adjusted EBITDA excludes the impact for unrealized (gains) losses on commodities, foreign exchange (gains) losses, impairments, and (recoveries) charges of onerous provisions from the adjusted operating profit. Management believes that a measure of operating performance is more meaningful if results not related to normal operations, such as impairment, onerous provisions on long-term contracts, foreign exchange (gains) losses, and unrealized gains (losses) on commodities, are excluded from the adjusted operating profit. Unrealized (gains) losses on commodities reflect the impact of changes in forward natural gas and power prices and the volume of the positions for these derivatives over a certain period of time. These unrealized (gains) losses do not necessarily reflect the actual gains and losses that will be realized on settlement. Furthermore, unlike commodity derivatives, ENMAX's generation capacity and future sales to retail customers are not marked to market under IFRS.

ADJUSTED EBIT

Year ended December 31, *(millions of Canadian dollars)*	2019	2018
Net earnings (IFRS financial measure)	**156.2**	5.1
Add (deduct):		
Unrealized gains on commodities	**(106.7)**	(6.5)
Foreign exchange losses (gains)	**21.8**	(10.6)
Finance charges (excludes Emera Maine related acquisition costs)	**67.0**	68.2
Impairment	**1.1**	26.9
Emera Maine related acquisition costs (including finance charges)	**35.1**	-
Onerous provision (recovery) charge	**-**	(12.5)
Income tax expense	**33.8**	133.5
Adjusted EBIT (non-IFRS financial measure)	**208.3**	204.1

The Corporation focuses on Adjusted EBIT, which excludes the impact of foreign exchange (gains) losses, unrealized (gains) losses on commodities and (recoveries) charges of onerous provisions. Adjusted EBIT is a useful measure of business performance, which provides an indication of the operating results generated by primary business activities.

Management believes that this non-IFRS measure provides a better representation of the underlying operations of the Corporation.

FREE CASH FLOW

ENMAX defines free cash flow as IFRS net cash provided by operating activities less capital expenditures funded from operations. Management believes that FCF is a liquidity measure that provides useful information regarding cash provided by operating activities, and cash used for investments in property and equipment that are required to maintain and grow the business.

Year ended December 31, *(millions of Canadian dollars)*	2019	2018
Net cash provided by operating activities [1]	**397.9**	473.5
Capital expenditures funded from operations [2]	**(271.5)**	(165.0)
Free cash flow (non-IFRS financial measure)	**126.4**	308.5

[1] Refer to Liquidity and Capital Resources section.

[2] Includes cash provided to fund capital expenditures in Power Delivery that would otherwise be considered financing activities.

Free cash flow for the year ended December 31, 2019 decreased by $182.1 million compared to the same period in 2018, primarily due to reduction of the trade payables and increased capital expenditures in 2019. Reduction of trade payable balances coupled with increase interest paid resulted in decrease in cash flow from operations of $75.6 million. Capital expenditures funded from operations for 2019 were $101.4 million higher than in 2018 due to capacity upgrades and additions to substations and transmission lines, as well as construction of the first hybrid gas turbine generation plant.

FINANCIAL CONDITION

SIGNIFICANT CHANGES IN THE CORPORATION'S FINANCIAL CONDITION

As at December 31, *(millions of Canadian dollars, except % change)*	**2019**	**2018**	**$ Change**	**% Change**	**Explanation for Change**
ASSETS					
Cash and cash equivalents	**1,079.9**	89.0	990.9	1,113.4	Increased due to issuance of private debentures
Accounts receivable	**689.4**	716.4	(27.0)	(3.8)	Decrease is mainly attributable to the timing of receipts and seasonal fluctuations in revenue
Property, plant and equipment (PPE)	**4,495.2**	4,253.9	241.3	5.7	General capital additions partially offset by amortization
LIABILITIES AND SHAREHOLDER'S EQUITY					
Short-term financing	**174.2**	18.0	156.2	867.8	Refer to Liquidity section
Accounts payable	**516.9**	624.6	(107.7)	(17.2)	Decrease mainly attributable to timing of disbursements
Financial liabilities [1]	**56.4**	155.4	(99.0)	(63.7)	Change in fair value of hedged and non-hedged derivatives
Lease liabilities [1]	**60.9**	4.2	56.7	1,350.0	Increase is due to prospective adoption of IFRS 16
Long-term debt [1]	**2,622.0**	1,685.9	936.1	55.5	Receipt of $172.4 million in new Alberta Capital Finance Authority (ACFA) debt and $847.2 million from issuance of private debentures offset by regular principal repayments. The proceeds from the private debentures is to be applied to the purchase price of Emera Maine

[1] Net current and long-term asset and liability positions.

LIQUIDITY AND CAPITAL RESOURCES

TOTAL LIQUIDITY AND CAPITAL RESERVES

As at December 31, *(millions of Canadian dollars)*	**2019**	**2018**
Committed and available bank credit facilities	**850.0**	850.0
Letters of credit issued:		
Power pool purchases	**180.2**	171.8
Energy trading	**47.0**	55.5
Regulatory commitments	**128.0**	146.0
Asset commitments	**3.0**	1.1
PPAs [1]	**-**	2.0
	358.2	376.4
Remaining available bank facilities	**491.8**	473.6
Cash and cash equivalents	**1,079.9**	89.0
Short term financing	**(174.2)**	(18.0)
Total liquidity and capital reserves	**1,397.5**	544.6

[1] ENMAX terminated the Battle River PPA on January 1, 2016 and the Keephills PPA on May 5, 2016.

Cash and cash equivalents increased to $1,079.9 million as at December 31, 2019 compared to $89.0 million at the same time last year due to funds held in escrow for the Emera Maine acquisition. Short-term financing of $174.2 million at year end reflects a temporary use of credit facilities to address timing of expenditures.

CAPITAL STRATEGY

The business is funded with a view to maintaining a capital structure in line with ENMAX's strategy of maintaining a stable, investment-grade credit rating. As a result of holding funds in reserve to pay for the Emera Maine acquisition, as at December 31, 2019 the long-term debt-to-total capitalization ratio is 54 per cent, compared with 43 per cent at year end 2018. On October 3, 2019 S&P Global changed the Corporation's credit rating to BBB and has placed the ratings on CreditWatch with negative implications while DBRS continues to maintain ENMAX's current rating of A(low) and has placed the Corporation under review (-negative). The change in credit rating arose from the issuance of additional debt to fund the Emera Maine acquisition during the year. Management intends to use free cash flow to reduce outstanding acquisition debt and improve credit metrics. These ratings continue to provide ENMAX with reasonable access to debt capital markets.

The principal financial covenant in ENMAX's credit facilities is debt-to-capitalization not to exceed 65 per cent and as at December 31, 2019 the debt-to-capitalization ratio is 54 per cent.

CASH PROVIDED BY OPERATING ACTIVITIES

Cash provided by operating activities for the year ended December 31, 2019 is $397.9 million, compared to $473.5 million in the same period in 2018, due to reduction of trade payables and increase in the amount of interest paid in 2019.

INVESTING ACTIVITIES

The following table outlines investment in capital additions and other changes for the year ended December 31, 2019.

Year ended December 31, *(millions of Canadian dollars)*	**2019**	**2018**
Property, plant and equipment	**427.7**	359.6
Intangibles	**28.3**	18.6
Impairment to property, plant and equipment and intangibles	**(1.1)**	(26.9)
Capital accruals	**(19.2)**	(15.1)
Capitalized interest	**8.2**	6.3
Total	**443.9**	342.5

During the year ended December 31, 2019 ENMAX continued to execute its capital plans to expand the distribution system, reinforce the transmission system and replace aging infrastructure in both systems.

FINANCING ACTIVITIES

During the year ended December 31, 2019 ENMAX made regularly scheduled debt repayments of $74.8 million, compared with $70.9 million in the same period in 2018.

ENMAX's total credit facilities remain at $850.0 million, compared to $850.0 million in the same period in 2018, with similar pricing and terms ranging from 2021 to 2022.

During 2019 as part of its normal course financing plans, the Corporation requested additional ACFA borrowings and drew $172.4 million during the year. To fund the Emera Maine acquisition, on October 15, 2019 ENMAX completed the issuance of Series 5, 6 and 7 unsecured private debentures for a total of $850.0 million. The net proceeds of $847.2 million will be applied towards the acquisition price of Emera Maine at closing. The proceeds are held under escrow and as such, have been classified as restricted cash. The Series 5 debentures of $300.0 million have a 3-year term and bear interest at 2.92 per cent. The Series 6 debentures of $300.0 million have a 5-year term and bear interest at 3.33 per cent, and the Series 7 debentures of $250.0 million have a 10-year term and bear interest at 3.88 per cent.

On March 13, 2019 ENMAX declared a dividend of $50.0 million payable to the City in quarterly instalments throughout 2019. All quarterly instalments of this dividend were paid by the end of 2019. On March 19, 2020 a total dividend of $54.0 million was declared payable to the City in four quarterly instalments payable throughout 2020.

ENMAX has historically paid the City annual dividends of the greater of 30 per cent of the prior year's net earnings, or $30.0 million. Dividends for a fiscal year are established in the first quarter of the same fiscal year. As per normal course, the payment and level of dividends is affected by such factors as financial performance and ENMAX's liquidity requirements.

RISK MANAGEMENT AND UNCERTAINTIES

ENMAX's approach to risk management addresses risk exposures across the Corporation's entire business activities and risk types. ENMAX utilizes an Enterprise Risk Management (ERM) program to identify, analyze, evaluate, treat and communicate the Corporation's risk exposures in a manner consistent with ENMAX's business objectives and risk tolerance.

Risk exposures are managed within levels approved by the Board and the Chief Executive Officer, and monitored by personnel in the business units, the planning and risk department, and the senior management team. At a management level, each accountability area is responsible for assessing its risk exposures and implementing risk management plans. An enterprise risk assessment process and consolidated risk reporting is coordinated. Risk oversight is provided through the Board's Governance Committee, the Risk Management Committee (RMC), and the Commodity Risk Management Committee (CRMC) which are comprised of members of the Board of Directors and the Executive Team members. Together, the RMC, CRMC and the Board oversee identified risk exposures and risk management programs, including the ERM program.

ENMAX's overall risk control environment includes:

- Clearly articulated corporate values, principles of business ethics
- Published enterprise-wide policies and standards in key risk areas, such as delegation of authority
- Documented commodity trading and position limits
- An internal audit function to test compliance with internal controls and policies
- Regular reporting of risk exposures and mitigations, including insurance programs, to the RMC, CRMC, and Board, as appropriate
- Regular monitoring of ENMAX's financial exposure to changing market conditions
- The use of industry-accepted tools and methodologies for assessing risk exposures
- A Safety and Ethics Line for employees to anonymously report suspected illegal or unethical behaviour

These risk management programs and governance structures are designed to manage and mitigate several risk factors affecting ENMAX's business. In addition, by its nature, a discussion of enterprise risks typically focuses on mitigation of downside risk, as many of the risks ENMAX faces also present opportunities. The following discussion focuses predominantly on the mitigation of risks as opposed to leveraging of opportunities. The following discussion does not consider the result of any interrelationship among the factors.

MARKET RISK

ENMAX has inherent risk in electricity and natural gas commodity positions arising from owned and controlled supply assets and demand obligations. ENMAX also purchases and sells these commodities in wholesale markets to manage such positions. While ENMAX's business model is designed to achieve a balanced portfolio, in the near-term, electricity and natural gas positions may experience periodic imbalances and result in exposures to price volatility from spot or short-term contract markets. In the longer term, if ENMAX had fewer fixed-price retail contracts, there would be greater exposure to market prices.

ENMAX Competitive Energy utilizes numerous tools to forecast electricity consumption and generation, as well as the pattern of consumption and generation between hours (load shape). However, it is not possible to hedge all positions every hour. As such, there is exposure to volume and load shape risk. ENMAX actively manages its supply to match generation and market purchases to consumption volumes and has facilities that allow for quick reaction to unexpected supply and demand factors.

ENMAX may have future earnings variability as it relates to the sustainability and diversification of its portfolio, valuation modelling errors, commodity price levels, as well as demand volatility from retail residential, small business, industrial, commercial and institutional customers that could reduce retail margins or decrease renewal and acquisition rates. ENMAX Competitive Energy uses derivative instruments, such as swaps and forwards, to manage exposure to commodity price risk. Financial gains and losses could be recognized as a result of volatility in the market values of these contracts. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these derivative instruments may involve management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts. The inability or failure to effectively hedge its portfolio and prevent financial losses from derivative instruments could adversely affect ENMAX's business, results of operations, financial condition or prospects of the Corporation. ENMAX's hedging strategies control and mitigate these commodity price risks. Occasionally, hedging is ineffective as it may require a minimum level of market liquidity to actively manage positions.

ENMAX has foreign exchange (FX) rate exposures arising from certain procurement and energy commodity business activity. ENMAX hedges the majority of its FX risk exposures as such exposures arise. However, such hedges may not be sufficient to cover FX exposure in the event of timing mismatches or extreme FX rate movements.

Changes in interest rates can impact borrowing costs. Substantially all of ENMAX's long-term debt is comprised of debentures and private debentures. This structure effectively mitigates exposure to interest rate fluctuations in the near-term. Short-term debt is generally variable rate, and long-term debt will need to be replaced at maturity leading to longer-term exposure.

For additional details on ENMAX's market risk exposures and sensitivities, refer to Note 8 in the Notes to the Consolidated Financial Statements.

OPERATIONAL RISK

ENMAX owns, controls or operates several electricity generation, district energy, transmission and distribution assets and facilities. The operation of such assets and facilities involves many risks, including: public safety incidents, start-up risks, breakdown or failure of generation, transmission or distribution facilities or pipelines, use of new technology, dependence on a specific fuel source, including the transportation of fuel, impact of unusual or adverse weather conditions, including natural disasters, and performance below expected or contracted levels of output or efficiency. Renewable energy resource operating facilities are subject to weather-driven risks such as wind availability. There is risk of inadequate or failed internal processes, people and systems within the competitive and regulated businesses, shared services departments, and certain outsourced service organizations.

Breakdown or failure of a facility may prevent it from performing as expected under applicable agreements, which, in certain situations, could result in terminating the agreements or incurring a liability for damages. Unanticipated transmission and distribution outages can cause interruptions in service. Unanticipated generation facility outages or operations at lower-than-full capacity can cause periodic imbalances in ENMAX's electricity and natural gas positions. Weather conditions can materially affect the level of demand for electricity and natural gas, the prices for these commodities and the generation of electricity at certain facilities. In addition, demand obligations may fluctuate based on commodity prices, season, day and time of use, and specific customer requirements.

Events that could result from war, terrorism, global pandemic, civil unrest or vandalism may cause damage to ENMAX and its assets and have an impact on its generation, transmission and distribution operations or administrative functions in unpredictable ways.

These operational risks may affect ENMAX's ability to execute its strategy in an effective and efficient manner, affect the quality of customer service, and result in lost revenues and/or increased costs. These risks are actively managed using asset management plans, site planning, controls, safety, security and insurance programs, and incentives. In addition to several other measures within certain critical areas, ENMAX has implemented security measures and emergency response plans within certain critical areas.

ENMAX has obtained property, business interruption and other insurance coverage to mitigate some of these risk exposures, although such programs and measures may not prevent or cover the occurrence of any or all of these events and the adverse effects they may generate. There can be no assurance that ENMAX will be able to obtain or maintain adequate insurance in the future at rates the Corporation considers reasonable, that insurance will continue to be available on terms as favourable as the existing arrangements, or that insurance companies will pay claims.

Earnings could be affected by a regulated transmission or distribution blackout/brownout, failure of metering equipment or loss of communication services. Fuel supply shortages, failure of third-party services or infrastructure, human error, labour disruption, hazards to facilities and regulatory decisions could cause earnings variability. Earnings variability could also be seen as a result of the non-performance of contracted physical electricity or natural gas by counterparties.

ENVIRONMENTAL RISK

ENMAX is subject to regulation by federal, provincial and local authorities regarding air, land and water quality and other environmental matters. The generation, transmission and distribution of electricity results in and requires disposal of certain hazardous materials, which are subject to these laws and regulations. In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for non-compliance, including fines, injunctive relief and other sanctions. New environmental laws and regulations affecting ENMAX operations may be adopted and new interpretations of existing laws and regulations could be invoked or become applicable, which may substantially impact operations in the future. New facilities or modifications of existing facilities may require new environmental permits or amendments to existing permits. Delays in the environmental permitting process, denials of permit applications, and conditions imposed in permits may materially affect the cost and timing of projects. Non-compliance with environmental laws and regulations or incurrence of new costs or liabilities could adversely affect the business, results of operations, financial condition or prospects of the Corporation. ENMAX has implemented various programs to manage environmental risk exposures, many of which focus on prevention of and preparedness for adverse events. Overall, moderate earnings variability exposure is possible if ENMAX fails to comply with its Environmental Management System. Exposure to further moderate volatility is possible due to potential of spills, releases and fire from hazardous materials, or as a result of greenhouse gas (GHG) emissions policy changes.

Public interest in climate change and greenhouse gases is growing, and ENMAX expects regulation of greenhouse gases to become more restrictive over time. ENMAX also expects tightening restrictions on criteria air contaminants and mercury. Utilities around the world are grappling with the challenge of meeting reliability targets while reducing air pollution. Industry best practice for minimizing air pollution currently involves increasing intermittent renewable generation, backed by clean-burning, flexible natural gas-fueled generation. Since renewable generation is highly variable, it must be supplemented by flexible generation sources. Power storage will play a bigger role in the future as costs decline. ENMAX also expects demand-side management to increase in the future, especially with the growing penetration of smart meters. However, power storage and demand management are currently too small to replace firm, flexible natural gas-fueled generation as backup for renewables. Therefore, the best large-scale, economical alternative is clean-burning natural gas generation. ENMAX's wholesale generation portfolio is comprised entirely of wind power and natural gas-fueled generation, so ENMAX is well positioned for Alberta's green future.

Current provincial regulations seek to reduce emissions from large emitters by increasing their exposure to carbon prices. Recent amendments to the federal coal-fueled and natural-gas-fueled electricity regulations largely align with provincial regulations in requiring coal plants either to retire on or before December 31, 2029 or convert to natural gas- fueled power plants. The approach to large emitters indirectly rewards efficient natural gas facilities by raising coal facilities' variable costs, forcing them to offer their electricity output at higher prices.

Besides investing in clean, environmentally friendly generation technology, ENMAX manages climate change regulatory risk by advocating for well-designed and cost-effective policy at the provincial and federal levels. ENMAX also has internal compliance procedures in place to monitor and control our plants' emissions. ENMAX purchases emissions offsets as required.

REGULATORY RISK

ENMAX operates in competitive and regulated sectors of the electricity and natural gas industries. It is subject to regulation by federal, provincial and municipal regulatory and market authorities. Oversight of ENMAX's operations is provided by the Alberta Department of Energy, the AUC, the Market Surveillance Administration (MSA), AESO, the National Energy Board, the North American Electric Reliability Corporation, and the U.S. Federal Energy Regulatory Commission and other agencies.

ENMAX Competitive Energy and ENMAX Power Delivery are subject to regulations established to help ensure Alberta's electric and natural gas markets operate in a fair, efficient and openly competitive manner.

ENMAX Power Delivery is a transmission and distribution system owner that is regulated by the AUC. Regulations and regulatory decisions may affect: ENMAX Power Delivery's allowed rate of return and deemed capital structure; rate structure; the development and operation of transmission and distribution assets; acquisitions, disposal, depreciation and amortization; service quality and reliability levels; and recovery of operating costs.

ENMAX Power Delivery is also subject to AUC regulatory oversight for the provision of the RRO. ENMAX Power Delivery has arranged for ENMAX Competitive Energy to provide the RRO service within the ENMAX Power Corporation service territory. ENMAX Competitive Energy is an affiliated retailer of ENMAX Power Delivery and must comply with general energy marketing regulations and the Code of Conduct Regulation.

ENMAX cannot predict future municipal, provincial or federal government policies that may impact the development of regulation over ENMAX's business, or the ultimate impact that any changes to the regulatory environment may have on its business. Regulatory policies and decisions may cause delays in or impact business planning and transactions, increase costs or restrict ENMAX's ability to grow earnings, recover costs, and achieve a targeted Return on Equity (ROE) in certain parts of its competitive and regulated businesses.

Non-compliance with laws or regulations or changes to the regulatory environment could adversely impact the business, results of operations, financial condition or prospects of the Corporation.

The timing of regulatory decisions may result in delays to revenue recognition, and therefore earnings, although this may be partially mitigated with approved interim rates.

ENMAX actively participates in various regulatory processes that influence its business environment and operations. ENMAX actively monitors the business activities that are subject to regulation and has implemented compliance programs to mitigate regulatory risk exposures.

ENMAX is potentially exposed to the financial impact from changes to existing, new or upcoming policies, protocols, standards, administrative orders or regulations that can have an impact on ENMAX activities and operations. ENMAX is also potentially exposed to financial impact from regulatory decisions and matters related to generation operations.

HUMAN RESOURCES RISK

ENMAX is subject to workforce factors, including: loss or retirement of key executives or other employees, availability of and ability to attract, develop and retain qualified personnel, collective bargaining agreements with union employees, who represent over 60 per cent of our workforce, and performance of key suppliers and service providers. Certain personnel with highly specialized knowledge, skills and experience are required to lead and operate competitive and regulated businesses and shared services departments. Failure to manage human resources risk could adversely affect the business, results of operations, financial condition or prospects of the Corporation. ENMAX has mitigated this risk by implementing various programs to attract, develop and retain personnel, including recruitment, talent development, recognition and competitive compensation and benefits programs.

ENMAX is committed to maintaining effective relationships with the Corporation's unions. There are risks that successful negotiations will not be completed with collective bargaining units on mutually agreeable terms. Difficulties in negotiating these agreements or continuing these programs could lead to higher employee costs, a work stoppage or strike, and attraction or retention rates below expectations. ENMAX has two collective bargaining agreements covering its workforce. The Canadian Union of Public Employees (CUPE) collective bargaining agreement has a three-year term that expired on December 31, 2019. Negotiations began on November 14, 2019 and continue to progress. The International Brotherhood of Electrical Workers (IBEW) collective bargaining agreement expires on December 31, 2021. Exposure in relation to a breakdown in labour relations with either of the two unions is possible.

TECHNOLOGICAL RISK

ENMAX operates a variety of complex technology systems across the business, from operational technology in transmission and distribution, generation plants, to enterprise data and information technology. Ongoing investments are required to ensure reliable and efficient technologies to support current operations and enable strategic company initiatives. Such investments include upgrading, replacing and modernizing our technology landscape as well as improving our redundancy and disaster recovery capabilities.

ENMAX has implemented a governance framework to mitigate inherent risks associated with our complex technical ecosystem, including the need to embrace industry disruptions triggered by digital innovations. At the strategic level, this framework aligns to ENMAX'S Enterprise Risk Management guidelines and risk mitigation mandates. Operationally, the framework includes investment and technology oversight to apply appropriate control and management of technology risks. This ensures technology management decisions align with corporate strategic objectives and are compliant with legal and regulatory requirements.

Cyber Security is a key business risk associated with technology advancements and increasing operational reliance on technology platforms. ENMAX has a vigilant, risk-based Cyber Security program that focuses on prevention, detection and response of cyber incidents. The program is based on industry standards with the objective to safeguard ENMAX assets, technology infrastructure, customer and enterprise data.

The potential imbalance of risk and reward in technology innovation adoption can be a risk to ENMAX. The rapid and sometimes exponential advancement in technology within the utilities industry is transforming the traditional energy generation, transmission and distribution business models. From one view, keeping up with new technology innovation is key to a future ready utility organization. The risk of not investing in innovation and modernizing the technology landscape means reduced competitive advantage for ENMAX. From a regulatory perspective, ENMAX's obligation requires us to balance investment risks between protecting customer values and achieving our long term corporate strategy. This risk is mitigated through the technology investment governance framework noted above.

LIQUIDITY RISK

A need to raise additional capital may occur if cash flow from operations and sources of liquidity are insufficient to fund activities. Such additional capital may not be available when it is needed or on favourable terms for a number of potential reasons, including changes in market conditions or perceptions of the investment community. ENMAX may be required to post collateral to support certain contracts that were executed to hedge commodity positions. Downgrades to credit ratings by credit rating agencies could affect ENMAX's ability to access capital on favourable terms and within a desired time frame and could also increase the amount of collateral required to be provided to counterparties. ENMAX actively monitors its cash position and anticipated flows to achieve adequate funding levels and communicates regularly with credit rating agencies and the investment community regarding its capital position. ENMAX also strives to maintain an investment grade credit rating from credit rating agencies.

ENMAX offers a defined benefit (DB) pension plan for qualifying employees. Our contributions to the pension plan are based on periodic actuarial valuations, the most recent being completed for December 31, 2018. For accounting purposes, as at December 31, 2019 the pension plan had an accrued benefit liability of $75.3 million ($39.2 million at December 31, 2018). The actual amount of contributions required in the future will depend on future investment returns, changes in benefits and actuarial assumptions. Failure to effectively manage financial resources and related exposures could affect the business, results of operations, financial condition or prospects of the Corporation. To manage this risk, ENMAX engages expert investment managers and has investment policies and procedures in place to set out the investment framework of the funds, including permitted investments and various investment constraints. These policies and procedures are approved annually by the Safety and Human Resources Committee of the Board, which also monitors the performance of the pension plan. ENMAX's contribution to its pension plan satisfy, and are expected to continue to satisfy, minimum funding requirements.

For additional details on ENMAX's liquidity risk exposures, refer to Note 8 in the Notes to the Consolidated Financial Statements. For additional details on its pension plan, refer to Note 18 in the Notes to the Consolidated Financial Statements.

CREDIT RISK

ENMAX enters into agreements and engages in transactions with a number of external parties, including suppliers, service providers, customers and other counterparties. In such arrangements, exposure exists to counterparty credit risks and the risk that one or more counterparties may fail to fulfill their obligations, including paying for or delivery of commodities. These risks are often exacerbated during periods of sustained low commodity prices, which may negatively affect some of our customers or counterparties, and tighter credit markets.

ENMAX has implemented a credit risk management program to mitigate its exposures to credit risk. While it seeks to manage credit exposure by evaluating creditworthiness before and after entering into such agreements, monitoring business activity and obtaining collateral when prudent to do so, ENMAX may not be able to identify and avoid all counterparties that are not creditworthy. Defaults by suppliers, service providers, customers and other counterparties could adversely affect the business, results of operations, financial condition or prospects of the Corporation.

ENMAX's credit and collections activities include monitoring credit risk exposures and initiating mitigation measures to protect against any future losses. In specific situations, this includes but is not limited to a reduction of credit limits, requests for credit assurances in the form of additional collateral, as well as requirements for performance bonds on significant projects or restriction of new transaction terms.

Financial results could be affected as a result of industrial, commercial or institutional customer default or as a result of default by residential, small commercial and wholesale customers. This risk will increase during the COVID-19 pandemic. For additional details on ENMAX's credit risk exposures, refer to Note 8 in the Notes to the Consolidated Financial Statements.

DEVELOPMENT RISK

ENMAX's asset ownership strategy requires the development and construction of transmission and distribution projects, as well as capital improvements to existing assets. Its ability to complete these projects in a timely manner and within established budgets is contingent upon many variables and subject to a variety of risks, some of which are beyond the Corporation's control. Should any such risks occur, ENMAX could be subject to additional costs, delays to the in-service dates of these projects, termination payments under committed contracts and/or the write-off of the investment. In addition, while ENMAX's business model is designed to mitigate exposure to risks, the Corporation's strategy is to manage construction costs by seeking fixed price contracts with vendors.

ENMAX's ability to successfully identify, value, evaluate, complete and integrate new acquisition or organic growth opportunities and major capital projects is subject to risk. These include increased competition for acquisition targets, capital and other resources, the performance of the Alberta economy, regulatory or legislative intervention by the Government of Alberta. Such business development challenges could adversely affect the business, operations, financial condition, and growth prospects of the Corporation.

ENMAX budgets for capital programs and projects on an annual basis and funding for specific approved capital programs and projects on an ongoing basis. ENMAX performs risk assessments and develops risk mitigation plans for major capital programs and projects and uses a phase gate approval process on developments and acquisitions to mitigate risks. Project performance relative to expectations is regularly reported to senior management and the Board, and any corrective measures are taken as required. Delays and overspending in the development and construction of capital projects could affect ENMAX's financial results.

LEGAL RISK

ENMAX is subject to costs and other effects of legal and administrative proceedings, settlements, investigations, claims and actions. New or revised tax laws, rates or policies, accounting standards, securities laws and corporate governance requirements may also impact ENMAX. Non-compliance with existing laws, resolution of legal actions and changes to the legal environment could adversely impact the business, results of operations, financial condition or prospects of the Corporation.

ENMAX reviews and actively monitors business activity that could be subject to public or private legal actions, including changes to certain legislation, contracts with outside parties, and incidents or claims allegedly involving the Corporation. Programs have been implemented to mitigate ENMAX's legal risk exposures. The Corporation could experience earnings variability as it relates to matters including: legal or regulatory action; litigation; a breach of a material contract; or a material non-compliance with legislation, regulation or rules.

The Corporation is occasionally named as a party in various claims and legal proceedings that arise during the normal course of its business. The Corporation reviews each of these claims, including the nature of the claim and the amount in dispute. Although there is no assurance that each claim will be resolved in favour of the Corporation, the Corporation does not believe that the outcome of any claims or potential claims it is currently aware of will have a material adverse effect on the financial results or position of the Corporation, after taking into account amounts previously reserved by the Corporation. For further information, refer to Note 27 in the Notes to the Consolidated Financial Statements.

CORPORATE STRUCTURE RISK

ENMAX conducts a significant amount of business through subsidiaries and joint arrangements. The ability to meet and service debt obligations is dependent on the operational results of these investments and their ability to distribute funds to ENMAX. Any restrictions on the ability of these investments to distribute funds to ENMAX may affect the ability to service the corporate debt. ENMAX closely monitors the financial performance of these entities, has full control over its subsidiaries and is the operator of the largest joint arrangement.

REPORTING/DISCLOSURE RISK

The application of critical accounting policies reflects complex judgments and estimates. These policies include industry-specific accounting applicable to regulated public utilities, to pensions and to derivative instruments. The adoption of new accounting standards, or changes to current accounting policies or interpretations of such policies, could adversely affect the business, results of operations, financial condition or prospects of the Corporation. ENMAX has implemented various programs to reinforce its Internal Control over Financial Reporting, including quarterly certification of key controls facilitated by Internal Audit and review of certain disclosures by the Board.

INCOME TAX RISK

Prior to January 1, 2001, the legal entities comprising the ENMAX group of companies were not subject to federal or provincial income taxes based on an exemption for municipally owned corporations in the Canadian Income Tax Act (ITA). The exemption generally requires corporations to be wholly owned by a municipality, with all or substantially all income be derived from sources within the geographic boundaries of the municipality. Entities that do not meet these requirements are subject to income tax.

In 2001, the Government of Alberta introduced a payment in lieu of tax regulation under the Electric Utilities Act (“PILOT”) in conjunction with the deregulation of the Alberta energy market. The purpose of this regulation was to level the playing field between municipally owned tax-exempt entities and non-tax-exempt organizations participating in the competitive part of the electricity market, by requiring tax-exempt organizations to make a payment in lieu of taxes equal to what they would have had to pay if they were not tax-exempt. This regulation required municipally owned retailers and municipally owned PPA holders to remit PILOT payments to the Balancing Pool, based on the retail and commodity components of their electricity operations. PILOT regulations do not apply to those entities subject to tax under the ITA.

All legal entities comprising the ENMAX group of companies are potentially subject to audit by the applicable tax authority it operates in. However, the legal entities subject to PILOT are administered and audited exclusively by the Department of Finance-Alberta Treasury Board & Finance-Tax & Revenue Administration (“Alberta Finance”) for the Balancing Pool. All compliance tax filings including PILOT returns are based on the current interpretation of the ITA.

With respect to the PILOT dispute, regards to what constitutes a reasonable interest expense, on April 26, 2018 the Court of Appeals of Alberta rendered its decision in favour of Alberta Finance. The decision however was not based solely on the interpretation and jurisprudence found in Income Tax Act and as a result ENMAX’s PILOT compliance filings face higher uncertainty. ENMAX had filed an application seeking leave to apply to the Supreme Court of Canada. The Supreme Court of Canada dismissed the application on February 28, 2019. In the following months, all or substantially all tax disagreements were settled between ENMAX and Alberta Finance.

The Alberta Electric Utilities Act precludes municipally owned corporations competing in the electricity generation business from realizing a tax subsidy or financing advantage as a result of their association with the municipality. Accordingly, ENMAX holds generation assets in entities that do not qualify for the income tax exemptions noted above.

The determination of the income tax provision is an inherently complex process, requiring management to interpret continually changing regulations and to make certain judgments. Tax filings are subject to audit by taxation authorities, and the outcome of such audits may increase tax liabilities. Issues in dispute for audited years and audits for subsequent years are ongoing and in various stages of completion. The Corporation estimates and monitors any uncertain tax position and recognizes an income tax expense if and when it is probable that the disputes will result in some changes to the tax liability. As a consequence, earnings variability in relation to reassessments from Alberta Finance in regard to prior years' returns and other contingent tax liabilities is possible. Considering the above, tax risk is considered to be moderate to low for the Corporation in the one-year time frame.

STRATEGIC RISK

ENMAX's business model and strategic direction are predicated on certain assumptions, including the long-term viability of the competitive and regulated businesses, benefits associated with holding each of these businesses, evolution of technology used in the industry and attractiveness of growth opportunities. While ENMAX believes these assumptions will remain valid in the future, significant changes to the overall business environment or other factors could cause ENMAX to re-evaluate its business model or strategic direction. ENMAX routinely monitors industry trends and the business environment.

ENMAX has several competitors that operate in the electricity and natural gas markets where it serves customers. Competitors vary in size from small companies to large corporations with significant financial, marketing and procurement resources. ENMAX Competitive Energy must also compete with the RRO service provided by various parties throughout Alberta. Failure to attract and retain customers could adversely affect the business, results of operations, financial condition or prospects of the Corporation. ENMAX could potentially see earnings variability as it relates to constraints on its growth targets for market share. To mitigate this risk, ENMAX continually monitors the market and adjusts its offerings and marketing to remain competitive.

ENMAX faces considerable risk with respect to its strategy due to changing government policies. Political uncertainties and changing provincial governments with different perspectives and ideologies could potentially impact ENMAX's ability to deliver on its strategy. ENMAX's strategy factors in these uncertainties and attempts to mitigate this risk by focusing resources on regulated businesses and industries. By focusing on stable predictable cash flows and contracted revenue ENMAX helps reduce the exposure to market risk and unfavourable consequences of changes in government policy.

ENVIRONMENTAL, SOCIAL AND GOVERNANCE

ENMAX has publicly disclosed its environmental, social and governance (ESG) performance in alignment with the Global Reporting Initiative's (GRI) Standards for Sustainability Reporting and its accompanying Electric Utility Sector Supplement for 12 years. ENMAX continuously strives to enhance the robustness of the disclosures and currently reports on over 100 environment, safety, social and governance indicators. Our most recent GRI report can be found on the corporate website. The following section outlines our ongoing commitment to ESG performance monitoring and enhancement as well as outcomes.

In 2019 ENMAX achieved the Canadian Electricity Association's (CEA) designation as a Sustainable Electricity Company™, which recognizes the importance member companies place on sustainability over and above standard compliance and performance. ENMAX adheres to the CEA's Sustainable Development Corporate Responsibility Policy and updates their industry sustainability report with our ESG performance. Membership requires that ENMAX maintain an environmental management system that aligns with ISO14001.

ENMAX is committed to accelerating sustainable-energy sector technology solutions that will meet customer electricity needs today and in the future. We readily embark on innovative research and demonstration pilot projects, such as the installation of Canada's first hybrid electric gas turbine at Crossfield Energy Centre, one of 11 winners in Emissions Reductions Alberta's Industrial Efficiency Challenge. We also initiated a pilot project to research how innovative modifications to Calgary's highly specialized electricity grid can enable two-way power flow and the opportunity for customers in urban centres to generate solar electricity and sell that power back to the grid.

ENVIRONMENTAL

Customers are becoming more attuned to the source of their energy and as a result, the demand for energy from alternative production methods and renewable resources is increasing. Based on ENMAX's asset portfolio, it is positioned to offer consumers choices and progressive technologies that will help increase revenues from renewable resources should this trend continue to develop. Several examples include ENMAX's distributed solar products, combined heat and power systems, and district energy heating.

ENMAX is committed to reducing emissions and using resources responsibly. Fifteen years ago, 90 per cent of ENMAX's generation capacity was coal-fired. The 2017 termination of our Power Purchase Agreements associated with coal-fired generation reduced the intensity of our generation capacity by 60 per cent, and today, ENMAX holds no coal-fired generation facilities in its portfolio. In 2019 we further advanced our commitment to reduce emissions through an upgrade at the Shepard Energy Centre, which added 15 MW to its total generation capacity without an increase in GHG emissions. Optimizing water use at our generation facilities is also part of our environmental commitment. Shepard Energy Centre uses reclaimed water exclusively, the first use of reclaimed water for power production in Alberta. ENMAX also prioritizes continuous improvement within our operations and in 2019, implemented engineering innovations that reduced the amount of wastewater disposed at Shepard by 29 per cent.

Environmental liabilities recorded in ENMAX's financial statements include GHG liabilities which relate to electricity generated from certain ENMAX-owned generation facilities. These items have been reflected as liabilities in the Consolidated Financial Statements as at December 31, 2019. ENMAX continues to actively monitor and comply with environmental regulations. ENMAX currently has no outstanding litigation for environmental matters. There are no other material environmental liabilities at this time.

Refer to the Risk Management and Uncertainties section for discussion regarding environmental risks.

SOCIAL

Our community investment program creates positive social change in the neighbourhoods we live and work in and forms a key part of our employee experience through active engagement, volunteerism and giving back. In 2019, ENMAX engaged with a range of community partners, and investing over $3.0 million and contributing over 4,000 employee volunteer hours. We meet Imagine Canada's Caring Company criteria through a 1 per cent investment of pre-tax profits in charitable and non-profit organizations over a five-year rolling average, and we undergo annual third-party verification of our adherence via the London Benchmarking Group Canada.

GOVERNANCE

ENMAX's Board of Directors and the Executive Team are committed to strong and effective standards of corporate governance and ethical conduct. Although ENMAX is not required to publicly file an annual information circular, for the past 10 years we have released an annual disclosure document regarding our governance and executive compensation practices that is informed by the requirements applicable to public companies. ENMAX's most recent Annual Report on Governance and Compensation is available on the Corporate website.

ENMAX recognizes that having a majority independent, highly qualified Board of Directors from diverse backgrounds is essential to effective decision-making. In 2019, ENMAX made a series of enhancements to its governance framework with the City of Calgary, its sole Shareholder, including an increase in the frequency of meetings with the Shareholder while removing City Councillors from the Board of Directors. For the year ended December 31, 2019: (i) all of our Directors were independent, other than our President and CEO; and (ii) 44 per cent of the Board of Directors were women. As a further reflection of ENMAX's commitment to diversity, in 2017 ENMAX became a signatory to the Leadership Accord on Gender Diversity, headed by Electricity Human Resources Canada.

As ENMAX continues to move forward in the advancement of our long-term strategy, our ongoing commitment to both the monitoring and enhancement of our ESG performance remains a core element of our overall business planning processes and practices.

INTEREST OF EXPERTS

INDEPENDENT AUDITOR

ENMAX's external auditor is Deloitte LLP, Chartered Professional Accountants, Suite 700, 850 – 2 Street SW, Calgary, Alberta, T2P 0R8. Deloitte LLP is independent with respect to ENMAX within the meaning of the Rules of Professional Conduct of the Institute of Chartered Professional Accountants of Alberta.

ACTUARY

ENMAX utilizes external professional services in relation to its employee benefits from Willis Towers Watson, Suite 1600, 111 – 5 Avenue SW, Calgary, Alberta, T2P 3Y6. Willis Towers Watson is independent with respect to ENMAX, as it has no equity interest in the Corporation and is compensated at a contracted fixed rate, regardless of the outcome of its reports.

CONSOLIDATED FINANCIAL STATEMENTS

Contents

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The preparation and presentation of the accompanying consolidated financial statements of ENMAX Corporation are the responsibility of management and have been approved by the Board of Directors (the Board). In management's opinion, the consolidated financial statements have been prepared within reasonable limits of materiality in accordance with International Financial Reporting Standards (IFRS). The preparation of financial statements necessarily requires judgment and estimation when events affecting the current year depend on determinations to be made in the future. Management has exercised careful judgment where estimates were required, and these consolidated financial statements reflect all information available to March 19, 2020. Financial information presented elsewhere in this report is consistent with that in the consolidated financial statements.

To discharge its responsibility for financial reporting, management maintains systems of internal controls designed to provide reasonable assurance that the Corporation's assets are safeguarded, that transactions are properly authorized, and that reliable financial information is relevant, accurate and available on a timely basis. The internal control systems are monitored by management and evaluated by an internal audit function that regularly reports its findings to management and the Audit Committee of the Board.

The consolidated financial statements have been audited by Deloitte LLP, the Corporation's external auditor. The external auditor is responsible for examining the consolidated financial statements and expressing an opinion on the fairness of the financial statements in accordance with IFRS. The auditor's report outlines the scope of their audit examination and states the opinion.

The Board, through the Audit Committee, is responsible for ensuring management fulfills its responsibilities for financial reporting and internal controls. The Audit Committee, which is comprised of independent directors, meets regularly with management, the internal auditors and the external auditor to ensure each group is discharging its responsibilities with respect to internal controls and financial reporting. The Audit Committee reviews the consolidated financial statements and annual financial report and recommends their approval to the Board. The external auditor has full and open access to the Audit Committee, with and without the presence of management. The Audit Committee is also responsible for reviewing and recommending the annual appointment of the external auditor and approving the annual external audit plan.

On behalf of management,

Gianna Manes
President and Chief Executive Officer

Helen Wesley
Executive Vice President and
Chief Financial Officer

March 19, 2020

Deloitte.

Deloitte LLP
700, 850 2 Street SW
Calgary, AB T2P 0R8
Canada

Tel: 403-267-1700
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INDEPENDENT AUDITOR'S REPORT

To the Shareholder of ENMAX Corporation

OPINION

We have audited the consolidated financial statements of ENMAX Corporation and its subsidiaries (the "Corporation"), which comprise the consolidated statements of financial position as at December 31, 2019 and 2018, and the consolidated statements of earnings, comprehensive income (loss), changes in shareholder's equity and cash flows for the years then ended, and notes to the consolidated financial statements, including a summary of significant accounting policies (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2019 and 2018, and its financial performance and its cash flows for the years 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 ("Canadian GAAS"). Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are independent of the Corporation in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

OTHER INFORMATION

Management is responsible for the other information. The other information comprises the information, other than the financial statements and our auditor's report thereon, in the Financial Report.

Our opinion on the financial statements does not cover the other information and we do not express any form of assurance conclusion thereon. In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

We obtained the Financial Report prior to the date of this auditor's report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in this auditor's report. We have nothing to report in this regard.

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 Corporation’s ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Corporation or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Corporation’s financial reporting process.

AUDITOR’S RESPONSIBILITIES FOR THE AUDIT OF THE FINANCIAL STATEMENTS

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor’s report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian GAAS will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian GAAS, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

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

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

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

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

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

Deloitte LLP

Chartered Professional Accountants
March 19, 2020

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As at *(millions of Canadian dollars)*	**December 31, 2019**	December 31, 2018
ASSETS		
Cash and cash equivalents (Note 6)	**$ 1,079.9**	$ 89.0
Accounts receivable (Note 8)	**689.4**	716.4
Income taxes receivable (Note 9)	**0.4**	45.6
Current portion of financial assets (Note 8)	**95.3**	58.3
Other current assets (Note 11)	**83.3**	118.9
	1,948.3	1,028.2
Property, plant and equipment (Notes 12 and 15)	**4,495.2**	4,253.9
Intangible assets (Note 13)	**184.7**	177.8
Deferred income tax assets (Note 9)	**35.9**	52.2
Financial assets (Note 8)	**35.7**	29.9
Other long-term assets (Notes 8 and 11)	**44.3**	27.1
TOTAL ASSETS	**6,744.1**	5,569.1
REGULATORY DEFERRAL ACCOUNT DEBIT BALANCES (Note 10)	**31.2**	82.0
TOTAL ASSETS AND REGULATORY DEFERRAL ACCOUNT DEBIT BALANCES	**$ 6,775.3**	$ 5,651.1
LIABILITIES		
Short-term financing (Note 14)	**$ 174.2**	$ 18.0
Accounts payable and accrued liabilities	**516.9**	624.6
Income taxes payable (Note 9)	**18.0**	0.1
Current portion of long-term debt (Notes 8 and 14)	**73.3**	71.3
Current portion of financial liabilities (Note 8)	**114.4**	108.4
Current portion of deferred revenue (Note 19)	**10.5**	12.0
Current portion of lease liabilities (Note 5 and 15)	**5.4**	0.1
Other current liabilities (Note 11)	**32.0**	24.8
Current portion of asset retirement obligations and other provisions (Note 16)	**0.9**	1.7
	945.6	861.0
Long-term debt (Notes 8 and 14)	**2,548.7**	1,614.6
Deferred income tax liabilities (Note 9)	**31.6**	57.3
Post-employment benefits (Note 18)	**90.2**	51.1
Financial liabilities (Note 8)	**73.0**	135.2
Deferred revenue (Note 19)	**555.1**	543.4
Lease liabilities (Notes 5 and 15)	**55.5**	4.1
Other long-term liabilities (Note 11)	**13.1**	12.1
Asset retirement obligations and other provisions (Note 16)	**121.3**	106.0
TOTAL LIABILITIES	**4,434.1**	3,384.8
REGULATORY DEFERRAL ACCOUNT CREDIT BALANCES (Note 10)	**1.5**	5.0
SHAREHOLDER'S EQUITY		
Share capital (Note 17)	**280.1**	280.1
Retained earnings	**2,092.1**	1,985.9
Accumulated other comprehensive loss (Note 20)	**(32.5)**	(4.7)
	2,339.7	2,261.3
TOTAL LIABILITIES, REGULATORY DEFERRAL ACCOUNT CREDIT BALANCES AND SHAREHOLDER'S EQUITY	**$ 6,775.3**	$ 5,651.1

Commitments and contingencies (Note 27)

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31, *(millions of Canadian dollars)*	**2019**	2018
REVENUE (Note 7)		
Electricity	**$ 1,254.8**	$ 1,242.1
Natural gas	**199.6**	167.6
Transmission and distribution	**744.0**	664.6
Local access fees	**142.4**	137.1
Contractual services	**146.2**	124.9
Contributions in aid of construction (CIAC) revenue (Note 19)	**19.1**	17.9
Other revenue (Note 21)	**18.8**	24.2
TOTAL REVENUE	**2,524.9**	2,378.4
OPERATING EXPENSES (Note 7)		
Electricity and fuel purchases	**808.4**	894.8
Natural gas and delivery	**141.1**	111.0
Transmission and distribution	**367.6**	360.4
Local access fees	**142.4**	137.1
Depreciation and amortization	**241.8**	230.6
Impairment (Notes 7 and 12)	**1.1**	26.9
Other expenses (Note 21)	**504.6**	421.0
TOTAL OPERATING EXPENSES	**2,207.0**	2,181.8
OPERATING PROFIT	**317.9**	196.6
Finance charges (Note 24)	**80.6**	68.2
NET EARNINGS BEFORE TAX	**237.3**	128.4
Current income tax expense (Note 9)	**30.2**	115.0
Deferred income tax expense (Note 9)	**3.6**	18.5
NET EARNINGS (LOSS) - BEFORE NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES	**203.5**	(5.1)
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES (Notes 7 and 10)	**(47.3)**	10.2
NET EARNINGS	**$ 156.2**	$ 5.1

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

Year ended December 31, *(millions of Canadian dollars)*		**2019**		**2018**
NET EARNINGS	**$**	**156.2**	$	5.1
OTHER COMPREHENSIVE INCOME, NET OF INCOME TAX				
Items that will not be reclassified subsequently to statement of earnings				
Remeasurement (losses) gains on retirement benefits (Note 18) (1)		**(36.8)**		2.2
Items that will be reclassified subsequently to statement of earnings				
Unrealized gains (loss) on derivative instruments (2)		**24.1**		(4.0)
Reclassification of losses on derivative instruments to net earnings (3)		**(15.1)**		(14.6)
Other comprehensive loss net of income tax		**(27.8)**		(16.4)
TOTAL COMPREHENSIVE INCOME (LOSS)	**$**	**128.4**	$	(11.3)

(1) Net deferred income tax recovery of $0.3 million for the year ended December 31, 2019 (2018 - $nil).
(2) Net deferred income tax expense of $9.3 million for the year ended December 31, 2019 (2018 - $1.5 million tax recovery).
(3) Net deferred income tax expense of $6.6 million for the year ended December 31, 2019 (2018 - $7.0 million tax expense).

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY

(millions of Canadian dollars)	Share Capital	Retained Earnings	Accumulated Other Comprehensive (Loss) Income	Total
As at January 1, 2019	$ 280.1	$ 1,985.9	$ (4.7)	$ 2,261.3
Net earnings	-	156.2	-	156.2
Other comprehensive (loss), net of income tax	-	-	(27.8)	(27.8)
Total comprehensive income (loss)	280.1	2,142.1	(32.5)	2,389.7
Dividends (Note 23)	-	(50.0)	-	(50.0)
As at December 31, 2019	**$ 280.1**	**$ 2,092.1**	**$ (32.5)**	**$ 2,339.7**
As at January 1, 2018	280.1	2,020.8	11.7	2,312.6
Net earnings	-	5.1	-	5.1
Other comprehensive (loss), net of income tax	-	-	(16.4)	(16.4)
Total comprehensive (loss) income	-	5.1	(16.4)	(11.3)
Dividends (Note 23)	-	(40.0)	-	(40.0)
As at December 31, 2018	$ 280.1	$ 1,985.9	$ (4.7)	$ 2,261.3

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31, *(millions of Canadian dollars)*	2019	2018
CASH PROVIDED BY (USED IN):		
OPERATING ACTIVITIES		
Net earnings	**$ 156.2**	$ 5.1
Items not involving cash:		
CIAC	**29.6**	50.0
CIAC revenue (Note 19)	**(19.1)**	(17.9)
Depreciation and amortization	**241.8**	230.6
Impairment	**1.1**	26.9
Finance charges	**80.6**	68.2
Income tax expense (Note 9)	**33.8**	133.5
Change in unrealized market value of financial contracts	**(87.1)**	(6.4)
Post-employment benefits	**0.3**	1.5
Changes in non-cash working capital (Note 25)	**20.5**	118.7
Cash flow from operations	**457.7**	610.2
Interest paid [1]	**(77.3)**	(63.7)
Income taxes recovered (paid)	**17.5**	(73.0)
Net cash flow provided by operating activities	**397.9**	473.5
INVESTING ACTIVITIES		
Purchase of property, plant and equipment and intangibles [1] (Notes 12 and 13)	**(443.9)**	(342.5)
Cash flow used in investing activities	**(443.9)**	(342.5)
FINANCING ACTIVITIES		
Repayment of short-term debt	**(383.1)**	(919.3)
Proceeds from short-term debt	**539.3**	729.6
Repayment of long-term debt	**(75.1)**	(370.9)
Proceeds from long-term debt	**1,010.9**	477.4
Repayment of lease liabilities	**(5.1)**	-
Dividend paid (Note 23)	**(50.0)**	(40.0)
Cash flow from (used in) financing activities	**1,036.9**	(123.2)
Increase (decrease) in cash and cash equivalents	**990.9**	7.8
Cash and cash equivalents, beginning of year	**89.0**	81.2
CASH AND CASH EQUIVALENTS, END OF YEAR	**$ 1,079.9**	$ 89.0
Cash and cash equivalents consist of:		
Cash	**$ 39.8**	$ 76.6
Restricted cash (Note 6)	**1,040.1**	12.4
	$ 1,079.9	$ 89.0

[1] Total interest paid during the year was $85.5 million (2018 - $70.3 million). Purchase of property, plant and equipment (PPE) and intangibles includes $8.2 million of capitalized borrowing costs (2018 - $6.3 million).

See accompanying Notes to the Consolidated Financial Statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. DESCRIPTION OF THE BUSINESS

ENMAX Corporation (ENMAX or the Corporation), a wholly-owned subsidiary of The City of Calgary (the City), was incorporated under the *Business Corporations Act* (Alberta) in July 1997 to carry on the electric utility transmission and distribution operations previously carried on by the Calgary Electric System (CES), a former department of the City. Operations of the Corporation began on January 1, 1998, with the transfer of substantially all the assets and liabilities of CES by the City into the Corporation at net book value, for consideration of one common share issued to the City. Since 1998, the Corporation has grown from its transmission and distribution roots to include electricity generation, commercial and residential solar, electricity and natural gas retail, and engineering, procurement and construction businesses.

The Corporation's registered and head office is at 141 - 50 Avenue SE, Calgary, Alberta, T2G 4S7. The Corporation's principal place of business is Alberta.

2. BASIS OF PREPARATION

These consolidated financial statements have been prepared by management in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and interpretations of the International Financial Reporting Interpretations Committee (IFRIC).

These consolidated financial statements were approved and authorized for issuance by the Board of Directors on March 19, 2020.

BASIS OF MEASUREMENT

These consolidated financial statements have been prepared on the historical cost basis except for the revaluation of financial derivative instruments to fair value and to reflect asset impairment (if any).

FUNCTIONAL AND PRESENTATION CURRENCY

These consolidated financial statements are presented in millions of Canadian dollars, which is the Corporation's functional currency.

3. CRITICAL ACCOUNTING ESTIMATES AND JUDGMENTS

The preparation of these consolidated financial statements requires management to select appropriate accounting policies and make judgments, estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, as well as to disclose contingent assets and liabilities. These estimates and judgments involve matters that are inherently complex and uncertain. Judgments and estimates are continually evaluated and are based on historical experience and expectations of future events. Changes to accounting estimates are recognized prospectively.

Significant judgments and estimates are required in the application of accounting policies. These are referenced in the following tables:

SIGNIFICANT ACCOUNTING JUDGMENTS

Financial Statement Area	Accounting Policy	Judgment Areas
Property, plant and equipment	Note 4 (h)	Determination of components and useful lives
Long-lived assets and intangible assets impairment	Note 4 (m)	Assessment of impairment indicators and grouping of cash-generating units (CGUs)
Leases	Note 4 (o)	Assessment of contracts for lease arrangements
Provisions	Note 4 (q)	Determination of probability of outflow of resources
Income taxes	Note 4 (u)	Interpretation of uncertain tax positions and application tax regulations

SIGNIFICANT ACCOUNTING ESTIMATES

Financial Statement Area	Accounting Policy	Judgment Areas
Regulatory deferral accounts	Note 4 (d)	Estimates related to regulatory proceedings or decisions
Accounts receivable	Note 4 (e)	Assumptions as input to calculate the expected loss rates
Fair value measurements and valuation	Note 4 (e)	Estimates of fair value for financial assets and liabilities
Property, plant and equipment	Note 4 (h)	Determination of components and useful lives
Long-lived assets and intangible assets impairment	Note 4 (m)	Assessment of impairment indicators and grouping of cash-generating units (CGUs)
Post-employment benefits	Note 4 (n)	Estimates of key assumptions used to calculate post-retirement benefits
Leases	Note 4 (o)	Assessment of contracts for lease arrangements
Asset retirement obligation	Note 4 (p)	Estimates of amount and timing of asset retirements
Provisions	Note 4 (q)	Determination of probability of outflow of resources
Revenue	Note 4 (r)	Contributions In Aid of Construction are contributions received for work performed under various statutory requirements, therefore is determined not to contain significant financing component; and Principal vs. Agent consideration for each revenue stream
Income taxes	Note 4 (u)	Interpretation of uncertain tax positions and application tax regulations

4. SIGNIFICANT ACCOUNTING POLICIES

(a) CONSOLIDATION

The consolidated financial statements include the accounts of the Corporation and its subsidiaries. All intercompany transactions, balances, and unrealized gains and losses from intercompany transactions are eliminated on consolidation, except as disclosed under Note 10 (Regulatory Deferral Account Balances). The consolidated financial statements of the subsidiaries are prepared for the same reporting period and apply accounting policies consistent with the Corporation.

Subsidiaries are fully consolidated from the date on which control is obtained by the Corporation until the date that control ceases. Control exists when the Corporation possesses power over the investee, has exposure or rights to variable returns from its involvement with the investee, and has the ability to use its power over the investee to affect returns.

(b) JOINT ARRANGEMENT

A joint arrangement is an arrangement in which two or more parties have joint control and must act together to direct the activities that significantly affect the returns of the arrangement. The Corporation classifies its interest in joint arrangements as either joint operations or joint ventures depending on the Corporation's rights to the assets and obligations for the liabilities. When making this assessment, the Corporation exercises judgments and considers the structure and contractual terms of the arrangement, as well as the legal form of any separate vehicles in addition to all other relevant facts and circumstances.

Joint arrangements that provide all parties with rights to the assets and obligations for the liabilities are classified as joint operations. The Corporation's consolidated financial statements include its share of assets, liabilities, revenues, expenses, and other comprehensive income (OCI) from the joint operations.

Joint arrangements that provide all parties with rights to the net assets of the entities under the arrangements are classified as joint ventures. Joint ventures are accounted for under the equity method of accounting. Under this method, the Corporation's interests in joint ventures are initially recognized at cost and are adjusted thereafter to recognize the Corporation's share of profits or losses, movements in other comprehensive income, and dividends or distributions received.

When a corporation transacts with a jointly controlled entity of the Corporation, unrealized profits and losses are eliminated to the extent of the Corporation's interest in the joint venture.

(c) BUSINESS COMBINATIONS AND GOODWILL

The Corporation applies the acquisition method of accounting for acquisition of businesses. The determination of whether or not an acquisition meets the definition of a business, under IFRS, requires judgment, and is assessed on a case-by-case basis. The cost of acquisition is measured as the aggregate of the fair values at the date of exchange of the assets given and liabilities incurred or assumed. The consideration paid does not include the amounts related to the settlement of pre-existing relationships. The transaction costs incurred in connection with an acquisition are expensed as incurred.

Identifiable assets, liabilities and contingent liabilities acquired or assumed are measured at fair value at the acquisition date, as are any contingent consideration payable. Subsequent remeasurement of the fair value of the contingent liability is recorded in net earnings.

Goodwill is determined as the excess of the fair value of consideration paid over ENMAX's interest in the fair value of the identifiable net assets, liabilities and contingent liabilities of the acquired subsidiary, jointly controlled entity, or associate recognized at the date of acquisition. In conformity with IFRS 3 *Business Combinations*, goodwill is recorded at cost and not amortized. Goodwill is tested for impairment on an annual basis, and whenever there are conditions that the cash generating unit (CGU) to which goodwill has been allocated to may be impaired. Impairment is determined by assessing the recoverable amount of the cash generating unit to which goodwill relates. When the recoverable amount of the CGU is less than the carrying amount, an impairment loss is recognized.

If ENMAX's interest in the net fair value of the identifiable assets, liabilities and contingent liabilities assumed exceeds the cost of the consideration, such excess is recognized immediately in the Statements of Earnings. Expenditures on internally generated goodwill is expensed as incurred.

(d) REGULATORY DEFERRAL ACCOUNTS

In accordance with IFRS 14 *Regulatory Deferral Accounts*, the Corporation continues to recognize amounts that qualify as regulatory deferral balances in accordance with the basis of accounting used immediately before transition to IFRS. A regulatory deferral account balance is any expense (or income) account that:

- Is included, or expected to be included, by the rate regulator in establishing the rate(s) that can be charged to the customers; and
- Would not otherwise be recognized as an asset or liability in accordance with other IFRS.

In accordance with this standard, the Corporation has presented regulatory deferral account debits and credits on a separate line in the consolidated statements of financial position. As well, the net movement in regulatory deferral accounts is presented on a separate line in the statements of earnings (Note 10).

(e) FINANCIAL INSTRUMENTS

Recognition

Financial assets and liabilities are initially recognized at fair value when the Corporation becomes a party to the contractual provisions of the instrument. However, where the fair value differs on initial recognition from the transaction price and the fair value is not measured using entirely observable inputs, the instrument is recognized at the transaction price. Fair value of a financial instrument is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. See Note 8 for disclosures of the fair value of financial instruments. In the case of instruments not measured at fair value through profit or loss (FVTPL), incremental directly attributable transaction costs are accounted for as an adjustment to the carrying amount, and in all other cases such transaction costs are expensed as incurred.

The Corporation evaluates contracts to purchase non-financial items, which are subject to net settlement, to determine whether such contracts should be considered derivatives or if they were entered into and continue to be held for the purpose of the receipt or delivery of a non-financial item in accordance with the entity's expected purchase, sale or usage requirements ("own use"). If such contracts qualify as own use, they are considered executory contracts outside the scope of financial instrument accounting.

The Corporation evaluates financial and non-financial contracts not measured at FVTPL to determine whether they contain embedded derivatives. An embedded derivative is a component of a hybrid (combined) instrument that also includes a non-derivative host contract, with the effect that some of the cash flows of the combined instrument vary in a way similar to a stand-alone derivative. For such instruments, an embedded derivative is separated where the economic characteristics and risks of the embedded derivative are not closely related to the economic characteristics and risks of the host contract and a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative.

Derecognition

Financial assets are derecognized when the rights to receive cash flows from the assets have expired or it transfers the financial instrument in a manner that qualifies for derecognition through transfer of substantially all risks and rewards or transfer of control.

Financial liabilities are derecognized upon extinguishment. A modification of a financial liability with an existing lender is evaluated to determine whether the amendment results in substantially different terms in which case it is accounted for as an extinguishment.

Classification

The classification of the Corporation's financial instrument depends on the nature and purpose of the financial instrument and is determined at the time of initial recognition.

The financial assets of the Corporation are classified in the following categories:

- **Amortized cost:** assets that are held for collection of contractual cash flows where those cash flows represent solely payments of principal and interest are measured at amortized cost. Financial assets of the Corporation included in this category are cash and cash equivalents, and current and long-term accounts receivables.
- **Fair value through other comprehensive income (FVOCI):** assets that are held for collection of contractual cash flows and for selling the financial assets, where the assets' cash flows represent solely payments of principal and interest, are measured at FVOCI. Financial assets of the Corporation included in this category are equity investments.
- **FVTPL:** assets that do not meet the criteria for amortized cost or FVOCI are measured at fair value through earnings. Financial assets of the Corporation included in this category are derivative instruments.

The financial liabilities of the Corporation are classified either as amortized cost or at FVTPL. Financial liabilities of the Corporation included under amortized cost are accounts payable, current and long-term debt and other current and other long-term liabilities. Financial liabilities of the Corporation included under FVTPL are derivative instruments.

Other financial liabilities include accounts payable and accrued liabilities, long-term debt, other current liabilities and other long-term liabilities. Financial instruments in this category are initially recorded at fair value, net of any transaction costs incurred, and subsequently carried at amortized cost using the effective interest method.

Derivatives and hedging activities

Derivatives are initially recognized at fair value on the date a derivative contract is entered into, and are subsequently remeasured to their fair value at the end of each reporting period. The accounting for subsequent changes in fair value depends on whether the derivative is designated as a hedging instrument, and if so, the nature of the item being hedged and the type of hedge relationship designated.

The fair values of various derivative financial instruments used for hedging purposes are disclosed in Note 8. Movements in the hedging reserve in shareholder's equity are shown in Note 20. The full fair value of a hedging derivative is classified as a non-current asset or liability when the remaining maturity of the hedged item is more than 12 months; it is classified as a current asset or liability when the remaining maturity of the hedged item is less than 12 months. Trading derivatives are classified as current assets or liabilities.

Cash flow hedges

The Corporation utilizes forward and swap contracts as hedging instruments to manage the commodity price risk associated with its highly probable commodity sales and purchases. At the inception of the hedging transaction, the Corporation documents the economic relationship between hedging instruments and hedged items, including whether the hedging instrument is expected to offset changes in cash flows of hedged items.

Sources of hedge ineffectiveness can occur as a result of credit risk, change in hedge ratio, and forecast adjustments leading to over-hedging. If the hedge ratio for risk management purposes is no longer optimal but the risk management objective remains unchanged and the hedge continues to qualify for hedge accounting, the hedge relationship will be rebalanced by adjusting either the volume of the hedging instrument, or the volume of the hedged item so that the hedge ratio aligns with the ratio used for risk management purposes. Any hedge ineffectiveness is calculated and accounted for in earnings at the time of the hedge relationship rebalancing.

The Corporation can only discontinue hedge accounting prospectively if there is no longer an economic relationship between the hedged item and hedging instrument, the risk management objective changes, the derivative no longer is designated as a hedging instrument, or the underlying hedged item is derecognized. If the Corporation discontinues hedge accounting, the cumulative gain or loss in accumulated other comprehensive income (AOCI) is transferred to earnings at the same time as the hedged item affects earnings. The amount in AOCI is immediately transferred to earnings if the hedged item is derecognized or it is probable that a forecast transaction will not occur in the originally specified time frame.

Estimation Uncertainty

In estimating the fair value of financial assets or liabilities, the Corporation uses market-observable data when available. When observable data is not available, the Corporation determines fair value using inputs other than quoted prices observable for the asset or liability, or valuation techniques with inputs based on historical data.

Presentation

Financial assets and liabilities are not offset unless they are with a counterparty for which the Corporation has a legally enforceable right to settle the financial instruments on a net basis and the Corporation intends to settle on a net basis.

Impairment of Financial Assets

The impairment provisions for accounts receivable disclosed at Note 8(b) are based on assumptions on expected loss rates. The Corporation uses judgment in making these assumptions and selecting the inputs to the impairment calculation based on the Corporation's history, existing market conditions, as well as forward looking estimates at the end of each reporting period.

Estimation Uncertainty

Estimates are made to set up the impairment provision for accounts receivable, which reflects the amount of accounts receivable that are ultimately expected to be non-collectible based on their expected credit losses.

Hedges

In conducting its business, the Corporation uses derivatives and other financial instruments, including swaps, futures, options and forwards to manage its exposure to certain market risks. Certain derivatives are designated as hedging instruments for accounting purposes when meeting certain effectiveness and documentation requirements at inception of the hedging relationship and on an ongoing basis. Effectiveness is measured with reference to the risk management objective and strategy for the hedged item.

Cash flow hedges are used to manage the variability of cash flows resulting from the purchase and sale of electricity, natural gas and foreign exchange exposure.

For cash flow hedges, changes in the fair value of the effective portion of the derivative designated in a hedging relationship are accumulated in OCI and recognized in earnings during the periods when the cash flows of the hedged item are realized. Gains and losses on cash flow hedges are reclassified immediately to earnings when a hedged anticipated transaction is no longer probable.

Where the hedged item continues to be probable of occurring but is no longer highly probable of occurring, the hedging relationship terminates. The accumulated amount in other comprehensive income is retained until the hedged transaction occurs or it is no longer probable of occurring.

For cash flow hedges, ineffectiveness is measured based on comparing the cumulative change in the fair value of the hedged item with the cumulative change in the fair value of the hedging instrument in absolute terms. If the cumulative change in fair value of the hedging instrument exceeds the cumulative change in fair value of the hedged item, ineffectiveness is recorded in profit or loss for the excess.

Changes in fair value of de-designated or discontinued hedges are recorded in earnings from the date of de-designation or discontinuation. The unrealized changes in fair value recorded prior to de-designation or discontinuation are reclassified from accumulated other comprehensive income to earnings when the relating hedged item is recognized in earnings.

(f) FOREIGN CURRENCY

Foreign currency transactions

Transactions in foreign currencies are translated into the functional currency using the exchange rates prevailing at the transaction date. Receivables, payables, and other monetary assets and liabilities are translated into the functional currency using the exchange rate at the balance sheet date. The foreign exchange gains and losses resulting from the settlement of such transactions, and from the translation at balance sheet date exchange rates are recognized in the statements of earnings, except when deferred in equity as qualifying cash flow hedges.

Foreign operations

The assets and liabilities of foreign operations, including goodwill and fair value adjustments arising on acquisition, and intercompany loans are translated into the functional currency using the exchanges rate at the balance sheet date. The income and expenses of foreign operations are translated into the functional currency at exchange rates approximating the exchange rates at the transaction date. Foreign currency differences are recognized in OCI and are presented as equity.

(g) CASH AND CASH EQUIVALENTS

Cash and cash equivalents consist of cash-on-hand balances with banks and investments in money market instruments with original maturities of three months or less from the date of acquisition.

(h) PROPERTY, PLANT AND EQUIPMENT

Items of property, plant and equipment are measured at cost less accumulated depreciation and any impairment losses. Cost includes contracted services, materials, direct labour, applicable taxes, overhead, borrowing costs on qualifying assets, and decommissioning costs. Subsequent costs are included in the assets' carrying amount or recognized as a separate asset, as appropriate, only when it is probable that the future economic benefits associated with the items will flow to the Corporation and the costs can be measured reliably. The carrying amount of a replaced asset is derecognized when replaced. Major overhauls and inspections are capitalized. Repairs and maintenance are charged to the statement of earnings in the period in which they are incurred.

Depreciation of PPE is recorded on a straight-line basis over the estimated useful life of the asset class at the following rates:

Asset Class	Depreciation Rates		
Buildings and site development equipment	0.61%	to	4.60%
Generation facilities and equipment	2.00%	to	20.00%
Generation overhauls and inspections	9.02%	to	67.11%
Tools, systems and equipment	4.53%	to	25.00%
Vehicles	2.36%	to	8.00%

Construction in progress represents assets that are not yet available for use and therefore not subject to depreciation. Capital spares and inventory are not amortized until they are put into service.

Gains or losses on disposal of an item of PPE are determined by comparing the proceeds from disposal with the carrying amount of PPE and are recognized in earnings.

For transmission, distribution, and substation equipment depreciated using the group life depreciation method (regulated depreciable assets) with depreciation rates ranging from 0.00 per cent to 20.00 per cent, gains or losses on the disposal of regulated depreciable assets are typically deferred and amortized over the estimated remaining service life of the related regulated depreciable assets. Gains or losses on the disposal and retirement of regulated depreciable assets outside the course of normal business are charged or credited to other expenses, with the offset recorded as net movement in regulatory deferral account balances in the statement of earnings under IFRS 14.

Significant Judgment

Where significant parts of an item of PPE have different useful lives in relation to the total cost of the item, they are accounted for as separate items of PPE and are depreciated separately. Useful lives are determined based on past experience and current facts, taking into account future expected usage and potential for technological obsolescence. Depreciation methods, useful lives, and residual values are reviewed annually and adjusted if appropriate.

(i) DEFERRED REVENUE

Under various statutory requirements and agreements with customers and developers, the Corporation receives CIAC in the form of cash contributions. Such contributions are recorded as deferred revenue when funds are received and recognized into revenue over the useful life of the underlying asset to which the contribution related. In addition to CIAC, the Corporation receives fixed capacity charges and warranty deposits on long-term contracts in the form of cash. Such contributions are recorded as deferred revenue when funds are received and recognized into revenue over the term of the underlying contract.

(j) GOVERNMENT GRANTS

Government grants are not recognized until there is reasonable assurance that the Corporation will comply with the conditions attached to them and that the grants will be received. Government grants received for the purchase of certain items of PPE are deducted from the carrying amount of the related asset. Amounts received related to expense reimbursement reduce the expense in the period in which it is incurred.

(k) CAPITALIZATION OF BORROWING COSTS

Borrowing costs directly attributable to the construction of a qualifying asset are eligible for capitalization. Qualifying assets are assets for which a substantial period of time is required to prepare the asset for its intended use. The Corporation borrows funds to finance its capital construction projects. The borrowing costs are capitalized until construction is completed, at a rate based on the actual costs of debt used to finance the capital construction projects. Capitalized borrowing costs cannot exceed the actual cost incurred to borrow the funds.

(l) INTANGIBLE ASSETS

Intangible assets are recorded at cost and amortization is recorded on a straight-line basis over the estimated useful life of the assets at the following rates:

Asset Class	Depreciation Rates		
Renewable energy certificates and water license	11.00%	to	11.00%
Computer systems	2.81%	to	25.00%
Land easements, rights and lease options	1.73%	to	25.86%

The useful lives of intangible assets are based on past experience, current facts, and formal amortization studies. Intangible assets with indefinite lives including land easements, renewable energy certificates and water licenses, are not subject to amortization. These assets are assessed annually for impairment or more frequently if events or changes in circumstances indicate that the asset may be impaired.

(m) ASSET IMPAIRMENT

The carrying amount of long-lived assets, intangible assets, and goodwill are reviewed at each reporting date to determine if there is any indication of impairment. For long-lived assets and intangible assets with definite useful lives, the recoverable amounts are estimated when an indicator of impairment exists. For goodwill and intangible assets with indefinite useful lives, or those that are not available for use, the recoverable amount is estimated at least once a year.

Testing for impairment is performed at the CGU level. The recoverable amount of a CGU is the greater of the fair value less costs of disposal and value in use (VIU). The VIU is calculated based on the net present value of cash flow projections incorporating estimates of annual revenues, expenses and capital expenditures to the asset's useful life. These estimates incorporate past experience and the Corporation's current view of future cash flow generated by the CGU. The Corporation gives consideration to externally available information related to future commodity pricing and current economic conditions within the province when developing certain pricing assumptions. The discount rate used reflects market weighted average cost of capital (WACC) using the capital asset pricing model (CAPM), giving consideration to risks specific to the CGU and risks embedded in the net cash flow projections. Impairment loss is recognized in the statement of earnings if the recoverable amount of a CGU is estimated to be less than its carrying amount.

Impairment losses recognized in prior periods are assessed at each reporting date for indications that the loss has decreased or no longer exists. The impairment loss can be reversed up to the original carrying value of the asset that would have been determined, net of depreciation, had no impairment loss been recognized. A reversal of impairment is recognized immediately in the statements of earnings.

Significant Judgment and Estimation Uncertainty

Impairment indicator assessment and the grouping of CGUs are significant judgments in the process of asset impairment analysis. The determination of CGU recoverable amounts involves significant estimates, including timing of cash flows, expected future prices for inputs and outputs, expected usage of the assets, and appropriate discount rates.

During the year, the Corporation recorded an impairment loss of $nil (2018 - $20.3 million) as related to a CGU.

(n) POST-EMPLOYMENT BENEFITS

The Corporation sponsors pension plans that contain both defined contribution (DC) and defined benefits (DB) provisions.

For DC pension plans, the Corporation's obligations for contributions are recognized as other expenses in the statement of earnings when services are rendered by employees.

For DB pension plans and other post-employment benefits, the level of benefit provided is based on years of service and earnings of the person entitled. The service cost of DB pension and other post-employment benefits earned by employees is actuarially determined using the projected unit credit method prorated on service and management's best estimate of expected health care costs. The related pension liability recognized in the statement of financial position is the present value of the DB and post-retirement benefit obligation at the statement of financial position date less the market value of the plan assets.

Actuarial valuations for defined benefit plans are carried out every three years at December 31. The discount rate applied in arriving at the present value of the pension liability represents yields on high-quality Canadian corporate bonds that have terms to maturity approximating the terms of the related pension liability.

Components of DB costs include service cost, net interest on the net DB liability and re-measurements of the net DB liability. Service cost is recognized as other expenses in the statement of earnings. Net interest is calculated by applying the discount rate to the net DB liability at the beginning of the annual period, taking into account projected contributions and benefit payments during the period. The net interest is recognized as interest expense in the statement of earnings. Re-measurement gains and losses, resulting from experience adjustments and changes in assumptions used to measure the accrued benefit obligation, are recognized in full in the period in which they occur through other comprehensive income.

Estimation Uncertainty

Significant assumptions and estimates are used in the accounting for DB pension plans. The Corporation consults with an actuarial specialist when setting the key assumptions used to estimate the post-employment benefits and the costs of providing post-retirement benefits. Key assumptions include future return on plan assets, retirement age, mortality rates, discount rates, future health care costs, salary escalation rates and claims experiences.

(o) LEASES

When an arrangement is entered into for the use of items of PPE, the Corporation evaluates the arrangement to determine whether it contains a lease. The Corporation recognizes an arrangement as a lease when a lessee has the right to direct the use of the asset. The Corporation recognizes the right-of-use (ROU) assets and corresponding lease liabilities on the consolidated statements of financial position for operating lease arrangements with a term of 12 months or longer. Lease of low-value assets are accounted for as an operating lease.

Assets under financing leases are amortized on a straight-line basis over the term of the underlying leases (see Note 15) and are tested for impairment using the same approach as is applied for long-lived assets.

Significant Judgment

Lease liabilities and ROU assets require the use of judgment and estimates, which are applied in determining the term of a lease, appropriate discount rates, whether an arrangement contains a lease, and whether there are any indicators of impairment for ROU assets.

(p) ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations (ARO) are provisions for legal and constructive obligations for decommissioning and restoring the Corporation’s generation assets and the Corporation’s share of jointly-operated generation assets.

The estimated future cash flows of the asset retirement costs are risk adjusted and discounted using a pre-tax, risk-free rate that reflects the time value of money. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset and then amortized over its estimated useful life. Changes due to revisions of discount rates, the timing or the amount of the original estimate of the provision are reflected on a prospective basis by adjusting the carrying amount of the related PPE.

Estimation Uncertainty

Significant assumptions and estimates are used in the accounting of ARO that include the amount and timing of asset retirements, the extent of site remediation required, and related future cash flows, inflation rates, and discount rates.

(q) PROVISIONS AND CONTINGENCIES

A provision is a liability of uncertain timing or amount. Provisions are recognized when the Corporation has a present legal or constructive obligation as a result of past events, it is probable that an outflow of resources will be required to settle the obligation, and the amount can be reliably estimated. Provisions are measured at management's best estimate of the expenditure required to settle the obligation at the end of the reporting period and are discounted to present value where the effect of discounting is significant. A pre-tax, risk-free rate is used to discount estimated future risk-adjusted cash outflows. The unwinding of the discount (accretion) is recognized as a finance charge. The Corporation remeasures provisions each reporting period, taking into account changes in the likelihood and timing of future outflows and changes in discount rates.

The Corporation performs evaluations to identify onerous contracts and, where applicable, records provisions for such contracts.

Significant Judgment

Judgment is involved to determine the probability of outflow of resources.

(r) REVENUE RECOGNITION

Revenue is recognized to the extent that it is probable that the economic benefits will flow to the Corporation and the revenue can be reliably measured. Revenue is measured at the fair value of the consideration received and is reduced for rebates and other similar allowances.

Electricity and gas

Contracts with customers within the Competitive Energy operation mainly consist of contracts to provide and deliver supplies of electricity and/or natural gas (the commodity) to customers' specified locations.

Performance obligations

Typical commodity contracts with customers include two performance obligations, which are to provide supplies of the commodity and to arrange for the delivery of these supplies to the customers' specified locations. These performance obligations are considered to be a series of performance obligations satisfied over time as the customers simultaneously consume the commodity and generate benefits upon receipt. The method of recognition of revenue for the commodity is an output method, which is based on volume of commodity delivered to the customers.

Delivery charges collected within the Calgary city limit as ENMAX is the principal for the provision of supplies of the commodity, with these charges reflected as gross revenue on ENMAX's consolidated financial statements. For delivery charges outside the Calgary city limit, ENMAX is an agent in relation to the performance obligation to arrange for delivery of the commodity and therefore the payment and recovery of the flow-through costs are presented on a net basis.

Transaction price

The transaction price for the commodity contract involves consideration from customers that is variable and constrained due to unknown volume of the commodity that will be consumed. Certain commodity contracts may also include a price constraint as the relevant commodity price would be based on the commodity pool price at the time of the consumption. The variable consideration is no longer constrained when the volume and/or price of the commodity consumed by customers become known at each period. The resolved transaction price for the commodity delivered to customer at each billing period will be allocated to the single performance obligation to provide the commodity.

Revenue recognition

The method utilized to recognize revenue for a commodity contract is an output method, which is based on actual volume of commodity distributed each period.

Estimation Uncertainty

By regulation, wire service providers are not required to submit final load settlement data on customer electricity usage until four months after the month in which such electricity was consumed. The Corporation uses processes and systems to estimate electricity revenues and costs, including unbilled consumption. Any changes to electricity revenues and costs arising from these estimation processes will be accounted for as a change in estimate in the period they occur.

Transmission and distribution

Contracts with customers under transmission and distribution operations are ENMAX's promises to provide transmission and distribution services to end customers through collaboration with electricity retailers. The customer for transmission service is the Alberta Electric System Operator (AESO), while the customers for the distribution service are electricity retailers.

Performance obligation

The transmission contract includes one performance obligation, which is a stand-ready obligation to provide transmission service for the period. This performance obligation is satisfied when the stand-ready obligation to provide transmission service has been performed each month. The distribution contract includes one performance obligation, which is to provide distribution services. This performance obligation is satisfied when the end customer receives electricity. ENMAX’s promises to provide transmission and distribution services to the customer are performance obligations that are satisfied over time as the customer is able to simultaneously consume the electricity transmitted and distributed to the customer's location.

Transaction price

The transaction price for the transmission service involves consideration that is variable and constrained. The variable consideration is no longer constrained when Alberta Utilities Commission (AUC) approves the Cost of Service, which allows the Corporation to recover the cost to build, operate and maintain the transmission lines.

The transaction price for the distribution contract involves consideration that is variable and constrained. The variable consideration is no longer constrained when the actual number of customers serviced during each billing period becomes known.

Revenue recognition

The method utilized to recognize revenue for the transmission contract is an input method, which is based on the passage of time as the stand-ready performance obligation is completed each period. The method utilized to recognize revenue for the distribution contract is an output method, which is based on actual volume of electricity distributed and actual number of customers serviced each period.

Estimation Uncertainty

Estimates are necessary given that the regulatory environment in which the Corporation operates often requires amounts to be recorded at estimated values until finalization and adjustment, pursuant to subsequent regulatory proceedings or decisions.

Contractual services

Contracts with a customer where ENMAX promises to render services mainly consist of services to maintain customer’s assets or to develop specific assets.

Performance obligation

The rendering of a service contract includes one performance obligation, which is to either maintain customer's assets or to develop an asset. This performance obligation is satisfied over time either because the customer simultaneously benefits from the maintenance services completed, or because they either enhance the customer's assets, or the new assets are highly specific for the customer and ENMAX has the right to receive payment for all the services performed at the end of each reporting period.

Transaction price

The transaction price for the rendering of a service contract includes consideration from the customer that is fixed.

Certain contracts may also include variable considerations that are constrained, hence are not included in the transaction prices. The transaction price for all services rendered to the customer at each billing period will be allocated to the single performance obligation to provide a service to the customer.

Revenue recognition

Both input and output methods are used to recognize revenue for the rendering of service contracts depending on which method more accurately depicts ENMAX’s promise to transfer services to the customer. For contracts where an input method is used, revenue is recognized based on actual labor cost and materials consumed to perform the required service during each billing period. For contracts where an output method is used, the revenue is recognized based on actual services delivered to the customer during each billing period.

(s) EMISSION CREDITS AND ALLOWANCES

On July 1, 2007, the Climate Change and Emissions Management Amendment Act (CCEMA Act) was enacted into law in Alberta. This Act and its current regulation, Carbon Competitiveness Incentive Regulation (CCIR), establishes baseline emission intensity levels, and emissions over this baseline are subject to a surcharge. Effective January 1, 2020, the CCEMA Act replaced the Emissions Management and Climate Resilience Act (EMCRA) and Technology, Innovation and Emissions Reduction (TIER) regulation replaced the CCIR.

Purchased emission allowances are recorded on the statement of financial position as part of other assets, at historical cost, and are carried at the lower of weighted average cost and net realizable value. Allowances granted to the Corporation or internally generated from approved projects are accounted for as other assets.

The Corporation has recorded emissions liabilities on the statement of financial position, as a component of accounts payable and accrued liabilities, using the best estimate of the amount required to settle the obligation in excess of government established emission intensity levels. These amounts are recognized as cost of electricity services provided and charged to the statement of earnings in the period they are levied.

(t) DIVIDENDS

Dividends on common shares are recognized in the Corporation’s consolidated financial statements as a reduction of retained earnings in the period in which the dividends are approved by the Board of Directors of the Corporation.

(u) INCOME TAXES

Income tax in Canada is determined on a legal entity basis. All legal entities of the Corporation are subject to income tax as determined under the *Income Tax Act* and *Alberta Corporate Tax Act* (collectively to be referred to as "Act"), unless the legal entities are exempt. The exemption generally requires corporations to be wholly owned by a municipality, with all or substantially all income be derived from sources within the geographic boundaries of the municipality. Those subsidiaries exempt may instead have to estimate the income tax based on the payment in lieu of tax regulation (PILOT) and the *Electric Utilities Act* (EUA). The PILOT payments are remitted to the Balancing Pool of Alberta. Any further reference to income tax recognizes the combined obligations under PILOT and the Act.

The Corporation recognizes current and deferred income tax in the profit or loss for the period, except to the extent that it relates to a business combination or other transactions that are directly recognized in equity or other comprehensive income.

Current tax liabilities or assets are measured at the amount expected to be paid to or recovered from the taxation authorities or the Balancing Pool of Alberta for the current and prior periods, using the tax rates that have been enacted or substantively enacted by the end of the reporting period.

Deferred income tax assets and liabilities are recognized for temporary differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases, using the tax rates that are expected to apply in the period in which the deferred tax asset or liability is expected to be realized or settled, based on the laws that have been enacted or substantively enacted by the reporting date.

A deferred tax asset is recognized for all deductible temporary differences to the extent that it is probable that taxable profit will be available against which the deductible temporary difference can be utilized, with the exception that the deferred tax asset arises from the initial recognition of assets or liabilities in a transaction (other than in a business combination) that affects neither accounting income nor taxable income.

A deferred tax liability is recognized for all taxable temporary differences, unless the deferred tax liability arises from the initial recognition of goodwill, or the initial recognition of other assets or liabilities in a transaction (other than in a business combination) that affects neither accounting income nor taxable income.

The Corporation recognizes deferred tax liabilities for the taxable temporary differences associated with investments in subsidiaries, and interests in joint arrangements, unless the Corporation is able to control the timing of the reversal of the temporary difference and it is probable the temporary difference will not reverse in the foreseeable future. The Corporation recognizes deferred tax assets for the deductible temporary differences arising from investments in subsidiaries, and interests in joint arrangements only under circumstances where the temporary differences are expected to reverse in the foreseeable future and there is sufficient taxable income available against which the temporary differences can be utilized. Unrecognized deferred tax assets are reassessed at each reporting date and are recognized to the extent that it has become probable that future taxable profits will allow the deferred tax asset to be recovered.

Deferred tax assets and liabilities are offset when there is a legally enforceable right to set off current tax assets against current tax liabilities and when they relate to income taxes levied by the same taxation authority and the Corporation and its subsidiaries intend to settle their current tax assets and liabilities on a net basis.

Significant Judgment and Estimation Uncertainty

The calculation of the Corporation's total income tax expense involves a degree of estimation and judgment, and management periodically evaluates positions taken in tax returns with respect to situations in which applicable tax regulation is subject to interpretation and establishes provisions where appropriate on the basis of amounts expected to be paid to the tax authorities or the Balancing Pool of Alberta. The calculation includes consideration of whether it is more likely than not for a contingent liability to be recognized in the financial statements.

The carrying amounts of deferred tax assets are reviewed at the end of each reporting period and are reduced to the extent that it is no longer probable that sufficient taxable income will be available to allow the benefit of part or all of that deferred tax asset to be realized. Unrecognized deferred tax assets are reassessed at each reporting date and are recognized to the extent that it has become probable that future taxable profits will allow the deferred tax asset to be recovered.

5. ACCOUNTING PRONOUNCEMENTS

ADOPTION OF NEW ACCOUNTING STANDARDS

ENMAX adopted the following new accounting standard for the first time for the financial year beginning on January 1, 2019.

IFRS 16, *Leases*

IFRS 16 introduces new or amended requirements with respect to lease accounting. It introduces significant changes to lessee accounting by removing the distinction between operating and finance leases, requiring the recognition of a right-of-use asset and a lease liability at commencement for all leases, except for short-term leases (leases with a term of less than 12 months) and leases of low-value assets. In contrast to lessee accounting, the requirements for lessor accounting have remained largely unchanged. The impact of the adoption of IFRS 16 on ENMAX's consolidated financial statements is described below and in Note 15.

ENMAX has adopted IFRS 16 on a modified retrospective basis with any adoption impacts recorded as an adjustment to opening balances on January 1, 2019. There was no impact to opening retained earnings on adoption.

In the initial recognition calculation of lease liabilities, ENMAX used a weighted average rate of 3.8 per cent to determine the net present value of future lease payments. As at December 31, 2018, $69.5 million was included in the commitment and contingency note related to future lease payments that have now been included in the initial finance lease obligations. ENMAX has recognized $57.8 million of lease liabilities on initial application of IFRS 16 on January 1, 2019.

(millions of Canadian dollars)	**As at January 1, 2019**
Operating lease commitment as at December 31, 2018	**69.5**
Present value impact	**(20.5)**
Discounted using the incremental borrowing rate at January 1, 2019	**49.0**
Extension and termination options reasonably certain to be exercised	**8.8**
Lease liabilities on adoption of IFRS 16	**57.8**
Lease liabilities recognized as at December 31, 2018	**4.2**
Lease liabilities as at January 1, 2019	**62.0**

Impact of the new definition of a lease

IFRS 16 determines whether a contract contains a lease on the basis of whether the customer has the right to control the use of an identified asset for a period of time in exchange for consideration.

ENMAX applies the definition of a lease and related guidance set out in IFRS 16 to all lease contracts entered or modified on or after January 1, 2019. In preparation for the initial application of IFRS 16, ENMAX has carried out an implementation project.

Impact on lease accounting

IFRS 16 changes how ENMAX accounts for leases previously classified as operating leases under IAS 17 and IFRIC 4.

ENMAX accounts for leases as follows:

a. Recognizes right-of-use assets and lease liabilities in the consolidated statements of financial position, initially measured at the present value of future lease payment;

b. Recognizes depreciation of right-of-use assets and interest on lease liabilities in the consolidated statements of earnings; and

c. Separates the total amount of cash paid into a principal portion and interest in the consolidated statements of cash flows.

Lease incentives are recognized as part of the measurement of the right-of-use assets and lease liabilities whereas under IAS 17 they resulted in the recognition of a lease incentive, amortized as a reduction of rental expense on a straight-line basis.

Under IFRS 16, right-of-use assets are tested for impairment in accordance with IAS 36 *Impairment of Assets*. This replaces the previous requirement to recognize a provision for onerous lease contracts.

ELECTED PRACTICAL EXPEDIENTS

Single discount rate

To apply a single discount rate to a portfolio of leases with reasonably similar characteristics (remaining term, class of underlying asset, and economic environment).

Onerous leases

Prior to adoption, the Corporation assessed all leases under IAS 37 as an alternative to performing an impairment review subsequent to adoption. The right-of-use asset at the date of initial application will be adjusted by the amount of any provision for onerous leases recognized in the statements of financial position immediately before the date of initial application.

Short-term leases

Exclude leases from initial recognition for which the lease term ends within 12 months of the date of initial application or lease commencement.

Indirect costs

To exclude initial direct costs from the measurement of the right-of-use asset at the date of initial application.

Hindsight

To use hindsight, such as in determining the lease term if the contract contains options to extend or terminate the lease.

CHANGES TO SIGNIFICANT ACCOUNTING POLICIES DUE TO ADOPTION OF NEW ACCOUNTING STANDARDS

ENMAX as Lessee

ENMAX assesses whether a contract is or contains a lease, at inception of the contract. ENMAX recognizes a right-of-use asset and a corresponding lease liability with respect to all lease arrangements in which it is the lessee, except for short-term and low-value leases. For these, ENMAX recognizes the lease payments as an operating expense on a straight-line basis over the term of the lease, unless another systemic basis is more representative of the time pattern in which economic benefits from the leased assets are realized.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted by using the rate implicit in the lease. If this rate cannot be readily determined, ENMAX uses the incremental borrowing rate.

Lease payments included in the measurement of the lease liability comprise of the following:

- Fixed lease payments (including in-substance fixed payments), less any lease incentives;
- Variable lease payments that depend on an index or rate, initially measured using the index or rate at the commencement date;
- The amount expected to be payable by ENMAX under residual value guarantees;
- The exercise price of purchase options, if ENMAX is reasonably certain to exercise the options; and
- Payments of penalties for terminating the lease, if the lease term reflects the exercise of an option to terminate the lease.

The lease liability is presented as a separate line in the consolidated statements of financial position.

The lease liability is subsequently remeasured by increasing the carrying amount to reflect interest on the lease liability (using the effective interest method) and by reducing the carrying amount to reflect the lease payments made.

ENMAX remeasures the lease liability and makes a corresponding adjustment to the related right-of-use asset under the following conditions:

- The lease term changes or there is a change in the assessment of exercise of a purchase option, in which case the lease liability is remeasured by discounting the revised lease payments using a revised discount rate;
- The lease payments change due to movements in an index or rate or a change in expected payment under a guaranteed residual value. In such cases the lease liability is remeasured by discounting the revised lease payments using the initial discount rate (unless the lease payments change is due to a change in a floating interest rate, in which case a revised discount rate is used); and
- A lease contract is modified, and the lease modification is not accounted for as a separate lease, in which case the lease liability is remeasured by discounting the revised lease payments using a revised discount rate.

ENMAX did not make any such adjustments during the year presented.

Right-of-use assets are comprised of the initial measurement of the corresponding lease liability, lease payments made at or before the commencement day and any initial direct costs. They are subsequently measured at cost less accumulated depreciation and impairment losses.

Whenever ENMAX incurs an obligation for costs to dismantle and remove a leased asset, restore the site on which it is located, or restore the underlying asset to the condition required by the terms and conditions of the lease, a provision is recognized and measured under IAS 37. The cost is included in the related right-of-use asset, unless those costs are incurred to produce inventories.

Right-of-use assets are depreciated over the shorter period of the lease term and useful life of the underlying asset. If a lease transfers ownership of the underlying asset or the cost of the right-of-use asset reflects that ENMAX expects to exercise a purchase option, the related right-of-use asset is depreciated over the useful life of the underlying asset. The depreciation starts at the commencement date of the lease.

ENMAX applies IAS 36 to determine whether a right-of-use asset is impaired and accounts for any identified impairment loss as described in the 'Property, Plant and Equipment' policy.

Variable rents that do not depend on an index or rate are not included in the measurement of the lease liability and the right-of-use asset. The related payments are recognized as an expense in the period in which the event or condition that triggers those payments occurs and are included in the line 'Other expenses' in the statement of earnings or loss.

6. RESTRICTED CASH

Restricted cash consists of $1,020.5 million (December 31, 2018 - $nil) related to funds held in escrow for the previously announced Emera Maine transaction (see Note 28) as well as $19.6 million (December 31, 2018 - $12.4 million) relating to margin posted with a financial institution. This margin is required as part of the Corporation's commodity trading activity. Total restricted cash balance was $1,040.1 million (December 31, 2018 - $12.4 million).

7. SEGMENT INFORMATION

The Corporation operates in two segments representing separately managed business units, each of which offers different products and services.

The Corporation uses a shared service allocation model to allocate cost between segments.

ENMAX COMPETITIVE ENERGY (COMPETITIVE ENERGY)

Competitive Energy is an operating segment established to carry out competitive energy supply and retail functions and the Calgary Regulated Rate Option (RRO) retail function through various legal entities and affiliated companies. Competitive Energy is an integrated business providing customers with electricity, natural gas, distributed energy resource solutions, as well as engineering, procurement and construction services. The competitive retail business provides customers with fixed-price electricity linked to our wind and gas-fueled generation assets, and provides opportunities to offer additional energy services, such as solar installations and thermal energy. Competitive Energy also delivers project execution for customer infrastructure in areas such as power infrastructure, light rail transit and commercial and residential development.

ENMAX POWER DELIVERY (POWER DELIVERY)

Power Delivery is a regulated operating segment established to own and operate electricity transmission and distribution assets in the Calgary service area through various legal entities and affiliated companies. Power Delivery's objective is to safely and efficiently operate and maintain the high reliability of its transmission and distribution system while meeting Calgary's power delivery infrastructure needs.

The final segment is ENMAX Corporate and Eliminations (Corporate and Eliminations), which is responsible for providing shared services and financing to ENMAX Competitive Energy and ENMAX Power Delivery. Certain comparative figures have been reclassified to conform to the current period's presentation.

SEGMENTED TOTAL ASSETS AND REGULATORY DEFERRAL ACCOUNT BALANCES

As at *(millions of Canadian dollars)*	**December 31, 2019**	**December 31, 2018**
Competitive Energy	**2,791.2**	2,854.2
Power Delivery	**2,802.3**	2,551.4
Corporate and eliminations	**1,150.6**	163.5
Total Assets	**6,744.1**	5,569.1
Regulatory deferral account debit balances	**31.2**	82.0
Total assets and regulatory deferral account debit balances	**6,775.3**	5,651.1

COMPARATIVE SEGMENT INFORMATION

Segment information reflects the presentation regularly reviewed by the chief operating decision maker. The chief operating decision maker uses adjusted operating profit as the basis for making decisions around asset allocation or assessing performance. Adjusted operating profit adjusts for items such as impairment, foreign exchange, onerous provision charges on long-term contracts, and unrealized gains and losses on commodities is reflected in the column 'Adjusted Consolidated Totals' below.

Segment information as at and for the year ended December 31, 2019 and 2018 have been reclassified to conform with the current year's presentation. The reclassification of RRO revenues and operating expenses and assets from Power Delivery to Competitive Energy had no impact on reported consolidated net earnings.

Year Ended December 31, 2019 *(millions of Canadian dollars)*	**Competitive Energy**	**Power Delivery**	**Corporate and Eliminations**	**Adjusted Consolidated Totals**	**Regulatory Deferral Movement**	**Other Presentation Reclass**	**Consolidated Totals**
REVENUE							
Electricity	1,387.3	-	(132.4)	1,254.9	(0.1)	-	1,254.8
Natural gas	199.8	-	(0.2)	199.6	-	-	199.6
Transmission and distribution	-	734.0	-	734.0	10.0	-	744.0
Local access fees	-	142.4	-	142.4	-	-	142.4
Other revenue	191.6	35.9	(5.5)	222.0	(37.9)	-	184.1
TOTAL REVENUE	1,778.7	912.3	(138.1)	2,552.9	(28.0)	-	2,524.9
OPERATING EXPENSES							
Electricity and fuel purchases	1,047.1	-	(132.0)	915.1	-	(106.7)	808.4
Natural gas and delivery	140.9	-	0.2	141.1	-	-	141.1
Transmission and distribution	-	401.6	-	401.6	(34.0)	-	367.6
Local access fees	-	142.4	-	142.4	-	-	142.4
Depreciation and amortization	127.3	120.1	(4.0)	243.4	(1.6)	-	241.8
Impairment [1]	-	-	-	-	-	1.1	1.1
Other expenses	376.8	130.2	(6.0)	501.0	(39.7)	43.3	504.6
TOTAL OPERATING EXPENSES	1,692.1	794.3	(141.8)	2,344.6	(75.3)	(62.3)	2,207.0
OPERATING PROFIT	86.6	118.0	3.7	208.3	47.3	62.3	317.9
Unrealized gain on commodities				(106.7)	-	106.7	-
Foreign exchange loss				21.8	-	(21.8)	-
Emera Maine acquisition costs				21.5	-	(21.5)	-
Impairment [1]				1.1	-	(1.1)	-
Finance charges				80.6	-	-	80.6
NET EARNINGS BEFORE TAX				190.0	47.3	-	237.3
Current income tax expense				30.2	-	-	30.2
Deferred income tax expense				3.6	-	-	3.6
NET EARNINGS BEFORE NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES				156.2	47.3	-	203.5
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES				-	(47.3)	-	(47.3)
NET EARNINGS				156.2	-	-	156.2

[1] During the year ended December 31, 2019, the ENMAX Competitive Energy segment recognized an impairment loss of $1.1 million associated with certain property, plant and equipment.

Year Ended December 31, 2018 *(millions of Canadian dollars)*	**Competitive Energy**	**Power Delivery**	**Corporate and Eliminations**	**Adjusted Consolidated Totals**	**Regulatory Deferral Movement**	**Other Presentation Reclass**	**Consolidated Totals**
REVENUE							
Electricity	1,371.0	-	(129.0)	1,242.0	0.1	-	1,242.1
Natural gas	167.7	-	(0.1)	167.6	-	-	167.6
Transmission and distribution	-	661.4	-	661.4	3.2	-	664.6
Local access fees	-	137.1	-	137.1	-	-	137.1
Other revenue	169.7	36.4	(4.1)	202.0	(35.0)	-	167.0
TOTAL REVENUE	1,708.4	834.9	(133.2)	2,410.1	(31.7)	-	2,378.4
OPERATING EXPENSES							
Electricity and fuel purchases	1,030.3	-	(129.0)	901.3	-	(6.5)	894.8
Natural gas and delivery	110.8	-	0.2	111.0	-	-	111.0
Transmission and distribution	-	347.8	-	347.8	12.6	-	360.4
Local access fees	-	137.1	-	137.1	-	-	137.1
Depreciation and amortization	121.0	109.6	-	230.6	-	-	230.6
Impairment [(1)]	-	-	-	-	-	26.9	26.9
Other expenses	346.1	142.2	(10.1)	478.2	(34.1)	(23.1)	421.0
TOTAL OPERATING EXPENSES	1,608.2	736.7	(138.9)	2,206.0	(21.5)	(2.7)	2,181.8
OPERATING PROFIT	100.2	98.2	5.7	204.1	(10.2)	2.7	196.6
Unrealized gain on commodities				(6.5)	-	6.5	-
Foreign exchange gain				(10.6)	-	10.6	-
Impairment [(1)]				26.9	-	(26.9)	-
Onerous provision [(1)]				(12.5)	-	12.5	-
Finance charges				68.2	-	-	68.2
NET EARNINGS BEFORE TAX				138.6	(10.2)	-	128.4
Current income tax expense				115.0	-	-	115.0
Deferred income tax expense				18.5	-	-	18.5
NET EARNINGS LOSS BEFORE NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES				5.1	(10.2)	-	(5.1)
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES				-	10.2		10.2
NET EARNINGS				5.1	-	-	5.1

(1) During the year ended December 31, 2018, the ENMAX Competitive Energy segment recognized an impairment loss of $26.9 million associated with certain property, plant and equipment. During the year, the segment also recognized a recovery of its onerous provision by $12.5 million to reflect changes in circumstances associated with the expected timing and amounts of certain longer-term onerous contracts.

REVENUE

Types of Customers and Sales Channel	Nature and significant payment terms
Mass market	Mass Market is comprised of residential and small business customers who consume less than 250,000 kWh/year. These customers can be supplied electricity through competitive contracts or through the Regulated Rate Option. Natural gas is always supplied under a competitive contract.
Commercial market	Commercial Market is business to business competitive contracting for electricity and/or natural gas. A small number of commercial customers that do not negotiate a contract are supplied electricity on a regulated Default supply.
Government and institutional	ENMAX receives revenue from governments and municipalities (counties, cities and towns), entities backed by the government, universities, colleges and school boards.
Non-government and non-institutional	ENMAX receives revenue from individual consumers to large corporations; these individuals and corporations receive credit and terms based on the revenue product and their credit history.
Transmission	ENMAX receives revenue from Alberta Electric System Operator (AESO) specifically for the use of its transmission grid system.
Distribution	ENMAX receives revenue from electricity retailers specifically for the utilization of its electricity distribution system in delivering electricity to the end customers.
City of Calgary local access fees	ENMAX receives revenue from electricity end users to offset municipal levies by the City of Calgary in lieu of property taxes.

REVENUE – MAJOR CUSTOMERS AND SALES CHANNELS

(millions of Canadian dollars)	Mass Market	Commercial Market	Government and Institutional	Non-Government and Non-Institutional	Transmission	Distribution	City of Calgary Local Access Fees	Total
Year Ended December 31, 2019								
Electricity								
Competitive Energy	225.9	888.4	-	-	-	-	-	**1,114.3**
Regulated	111.5	29.0	-	-	-	-	-	**140.5**
Natural gas	148.7	50.9	-	-	-	-	-	**199.6**
Transmission & distribution	-	-	-	-	89.9	654.1	-	**744.0**
Local access fees	-	-	-	-	-	-	142.4	**142.4**
Contractual services	-	-	54.6	91.6	-	-	-	**146.2**
Other revenue & CIAC	-	-	-	37.9	-	-	-	**37.9**
TOTAL REVENUE	**486.1**	**968.3**	**54.6**	**129.5**	**89.9**	**654.1**	**142.4**	**2,524.9**

(millions of Canadian dollars)	Mass Market	Commercial Market	Government and Institutional	Non-Government and Non-Institutional	Transmission	Distribution	City of Calgary Local Access Fees	Total
Year Ended December 31, 2018								
Electricity								
Competitive Energy	223.7	879.0	-	-	-	-	-	1,102.7
Regulated	112.5	26.9	-	-	-	-	-	139.4
Natural gas	123.8	43.8	-	-	-	-	-	167.6
Transmission & distribution	-	-	-	-	92.6	572.0	-	664.6
Local access fees	-	-	-	-	-	-	137.1	137.1
Contractual services	-	12.9	37.0	75.0	-	-	-	124.9
Other revenue & CIAC	-	-	-	42.1	-	-	-	42.1
TOTAL REVENUE	460.0	962.6	37.0	117.1	92.6	572.0	137.1	2,378.4

8. FINANCIAL INSTRUMENTS, HEDGES AND RISK MANAGEMENT MARKET RISK

MARKET RISK

The Corporation manages its exposure to market risk (interest rate risk, foreign currency exchange risk, commodity price risk and equity price risk) on a portfolio basis. This includes managing its positions arising from interests in generation facilities, liability positions arising from its commitments to customers, and transacting positions arising from its hedging activities.

The sensitivities provided in each of the following risk discussions disclose how earnings and OCI would have been affected by changes in relevant risk variables that were reasonably possible at the reporting date. These sensitivities are based on financial instruments carried at fair value, which include derivative contracts. The impact of a change in one factor may be compounded or offset by changes in other factors. Those sensitivities do not consider tax nor the impact of any interrelationship among the factors such as the underlying position and the optionality of the Corporation's integrated business. Generation capacity or future sales to customers are not mark-to-market, which creates an earnings mismatch. The sensitivities are hypothetical and should not be considered to be indicative of actual future results.

Certain assumptions have been made in arriving at the sensitivity analysis. These assumptions are as follows:

- The same fair value methodologies have been used as were used to obtain actual fair values in the fair values section of this note.
- Changes in the fair value of derivative instruments that are effective cash flow hedges are recorded in OCI.
- Changes in the fair value of derivative instruments that are not designated as hedges, that are fair value hedges or that are ineffective cash flow hedges are recorded in earnings.
- Foreign currency balances, principal and notional amounts are based on amounts as at December 31, 2019 and 2018.

COMMODITY PRICE RISK

The Corporation uses electricity and gas forward contracts to manage its exposure to certain market risks. Forward prices of natural gas and electricity fluctuations impact the fair value of these commodity derivatives. As at December 31, 2019, holding all other variables constant, an unrealized mark-to-market adjustment on outstanding gas forward contracts related to a 10 per cent increase or decrease in the forward price of natural gas would increase or decrease earnings by $59.5 million, respectively (2018 - $44.5 million) and no change in OCI (2018 - $nil). As at December 31, 2019, holding all other variables constant, an unrealized mark-to-market adjustment on outstanding electricity forward contracts related to a 10 per cent increase or decrease in the forward price of electricity would increase or decrease earnings by $0.5 million, respectively (2018 – $0.6 million) and increase or decrease OCI by $15.5 million, respectively (2018 - $29.7 million). These gas and electricity forward contracts extend out to 2025, respectively.

FOREIGN EXCHANGE AND INTEREST RATE RISK

Foreign exchange and interest rate risks are created by fluctuations in the fair values or cash flows of financial instruments due to changes in foreign exchange rates and/or changes in the market interest rates.

The Corporation is not exposed to significant interest rate risk and volatility as a result of the issuance of fixed-rate long-term debt. The fair value of the Corporation's long-term debt changes as interest rates change, assuming all other variables remain constant.

Changes in the value of the Canadian dollar relative to the U.S. dollar could impact the Canadian dollar cost of natural gas, which affects the input cost of the Corporation's natural gas-fuelled generation capacity, as well as the cost to the Corporation of offering fixed price gas contracts to customers. The foreign exchange impact on these gas purchases is offset, when possible, by foreign exchange contracts. Foreign exchange exposure resulting from procurement contracts has also been mitigated by foreign exchange contracts. As at December 31, 2019, a 10 per cent strengthening in the Canadian dollar in relation to the U.S. dollar, holding all other variables constant, would decrease earnings by $122.6 million (2018 – increase earnings by $1.0 million), and vice versa.

CREDIT RISK

The Corporation is exposed to credit risk primarily through its wholesale and retail energy sales business. Credit risk is the loss that may result from counterparties' non-performance. The Corporation evaluates the credit risk of wholesale and retail competitive supply activities separately as discussed below. The Corporation's maximum financial statement exposure to credit risk is the carrying value of the financial assets, as set out in the table below. This maximum exposure does not necessarily reflect losses expected by management nor does it necessarily reflect losses experienced in the past.

FINANCIAL ASSETS

As at *(millions of Canadian dollars)*	**December 31, 2019**	**December 31, 2018**
Cash and cash equivalents (a)	**1,079.9**	89.0
Accounts receivable (b)	**689.4**	716.4
Current portion of financial assets (c)	**95.3**	58.3
Financial assets (c)	**35.7**	29.9
Long-term accounts receivable (b)	**18.0**	2.5

(a) Cash and Cash Equivalents

Credit risk associated with cash and cash equivalents is minimized by ensuring these financial assets are placed with governments, well-capitalized financial institutions, and other credit-worthy counterparties. Continuous reviews are performed to evaluate changes in the credit quality of counterparties.

(b) Current and Long-Term Accounts Receivable

The majority of the Corporation's accounts receivable are exposed to credit risk. Exposure to credit risk occurs through competitive electricity and natural gas supply activities that serve residential, commercial and industrial customers. The risk represents the loss that may occur due to the non-payment of a customer's accounts receivable balance, as well as the loss that may be incurred from the resale of energy previously allocated to serve the customer.

Charges to earnings as a result of credit losses for the Corporation for the year ended December 31, 2019 totalled $16.7 million (2018 - $7.0 million). Management monitors credit risk exposure and has implemented measures to mitigate losses. In specific situations, this includes, but is not limited to, a reduction of credit limits, requests for additional collateral or restrictions on new transaction terms.

AGING ANALYSIS OF TRADE RECEIVABLES PAST DUE

As at *(millions of Canadian dollars)*	**December 31, 2019**	**December 31, 2018**
1-30 days past due	**17.9**	14.7
31-60 days past due	**3.6**	3.5
61 days or more past due	**32.5**	21.1
Total past due	**54.0**	39.3

CHANGES IN THE ALLOWANCE FOR DOUBTFUL ACCOUNTS

As at *(millions of Canadian dollars)*	**December 31, 2019**	**December 31, 2018**
Provision at the beginning of the year	**16.5**	18.6
Increase to allowance	**16.7**	7.0
Recoveries	**(9.3)**	(9.1)
Provision at end of the year	**23.9**	16.5

The remainder of the accounts receivable balance outstanding at December 31, 2019 consists of current trade receivables and unbilled revenue accruals. No provision has been recorded due to the minimal credit risk at the statement of financial position date.

(c) Current and Non-Current Financial Assets

The Corporation measures wholesale credit risk as the replacement cost for open energy commodity and derivative transactions (both mark-to-market and accrual), adjusted for amounts owed to or due from counterparties for settled transactions and all other amounts owing but not yet due. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where the Corporation has a legally enforceable right of offset and intends to settle on a net basis. The Corporation monitors and manages the credit risk of wholesale operations through credit policies and procedures that include an established credit approval process, daily monitoring of counterparty credit limits, and the use of credit mitigation measures such as margin, collateral, letters of credit and/or prepayment arrangements.

Due to the possibility of extreme volatility in the prices of energy commodities and derivatives, the market value of contractual positions with individual counterparties could exceed established credit limits or collateral provided by those counterparties. In such cases, the Corporation would make a margin call for additional collateral. The Corporation deems that the risk of a material loss from a counterparty failing to perform its obligations under its contract is low.

Additionally, if a counterparty were to default and the Corporation were to liquidate all contracts with that entity, the credit loss would include the loss in value of mark-to-market contracts, the amount owed for settled transactions, and unbilled deliveries and additional payments, if any, that would have to be made to settle unrealized losses on accrual contracts. The majority of counterparties enabled for wholesale transactions are rated investment grade (BBB- or higher) by recognized rating agencies.

LIQUIDITY RISK

Liquidity risk is the risk that the Corporation will not be able to meet its financial obligations as they fall due. The Corporation's approach to managing liquidity risk is to ensure that it always has sufficient cash and credit facilities to meet its obligations when due.

The following table details the remaining contractual maturities for the Corporation's current and long-term non-derivative financial liabilities, including both the principal and interest cash flows:

CONTRACTUAL MATURITIES OF NON-DERIVATIVE FINANCIAL LIABILITIES

As at *(millions of Canadian dollars)*	**December 31, 2019**	**December 31, 2018**
Less than 1 year (includes accounts payable)	**871.3**	801.1
1–3 years	**618.7**	253.4
3–5 years	**476.0**	218.0
More than 5 years	**2,159.8**	1,693.5

The following table details the remaining contractual maturities for the Corporation's derivative financial liabilities:

CONTRACTUAL MATURITIES OF DERIVATIVE FINANCIAL LIABILITIES

As at *(millions of Canadian dollars)*	**December 31, 2019**	**December 31, 2018**
Less than 1 year	**114.4**	108.4
1–3 years	**54.1**	97.6
3–5 years	**17.9**	30.4
More than 5 years	**1.0**	7.2

VALUATION OF DERIVATIVE ASSETS AND LIABILITIES

Financial derivative instruments are recorded at fair value on the statement of financial position. As at December 31, 2019, the fair values of derivatives were as follows:

As at	**December 31, 2019**		**December 31, 2018**	
(millions of Canadian dollars)	**Hedge Instruments**	**Non-Hedge Derivatives**	**Hedge Instruments**	**Non-Hedge Derivatives**
Assets				
Current	**23.8**	**71.5**	22.2	36.1
Non-current	**7.7**	**28.0**	15.7	14.2
Liabilities				
Current	**12.2**	**102.2**	14.9	93.5
Non-current	**5.2**	**67.8**	20.8	114.4

For cash flow hedges, gains and losses are reclassified immediately to net earnings when anticipated hedged transactions are no longer likely to occur.

During 2019, the Corporation designated a cash flow hedging relationship to mitigate a proportion of the foreign exchange risk relating to the purchase price of Emera Maine, which is denominated in US dollars. As at December 31, 2019 the Corporation has entered into forward contracts with an aggregate notional amount of $959.0 million US dollars to be exchanged in 2020, of which $400.0 million were previously designated as hedging instruments. In November 2019, ENMAX de-designated these forwards from being a hedge relationship. At the time of de-designation, a $3.5 million unrealized loss relating to these forwards was recorded in OCI and will remain there until these forwards settle.

For non-hedge derivatives, there were unrealized gains of $87.1 million for the year ended December 31, 2019 (2018 - $6.4 million gain), primarily recorded in electricity and fuel purchases. The anticipated non-hedge derivatives are expected to settle in 2020 through 2031. The mark-to-market adjustments do not consider the impact of any interrelationship among the factors such as the underlying position and the optionality of the Corporation's integrated business. Generation capacity or future sales to customers are not mark-to-market, which creates a mismatch in the timing of earnings.

FAIR VALUE

Fair value of financial instruments and derivatives is determined by reference to quoted bid or asking price, as appropriate, in active markets at reporting dates. In the absence of an active market, the Corporation determines fair value by using valuation techniques that refer to observable market data or estimated market prices. Fair values determined using valuation models require the use of assumptions about the amount and timing of estimated future cash flows and discount rates. In making these assumptions, the Corporation gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level I) and the lowest priority to unobservable inputs (Level III), as applicable.

Level Determination and Classifications

The Level I, II and III classifications in the fair value hierarchy used by the Corporation are defined as follows:

Level I

Fair values are determined using inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Corporation has the ability to access. In determining Level I, the Corporation uses quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange and the Natural Gas Exchange.

Level II

Fair values are determined using inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly.

Fair values are determined using inputs including interest rate yield curves, forward market rates, quoted commodity prices or credit spreads that are readily observable and reliable, or for which unobservable inputs are deemed to be insignificant to the fair values.

Commodity contracts' fair values falling within the Level II category are determined through the use of quoted prices in active markets adjusted for factors specific to the asset or liability. Level II fair values include those determined using pricing applications for creating power curves where the inputs are readily observable, including commodity prices for similar assets or liabilities in active markets.

Level III

The fair values are determined using significant unobservable data or inputs.

In certain circumstances, the Corporation enters into commodity transactions with non-standard features for which market-observable data is not available. In these cases, Level III fair values are determined using valuation techniques with inputs that are based on historical data.

FAIR VALUES OF THE CORPORATION'S DERIVATIVES

As at December 31, 2019 *(millions of Canadian dollars)*	Quoted Prices in Active Markets (LEVEL I)	Significant Other Observable Inputs (LEVEL II)	Significant Unobservable Inputs [(1)] (LEVEL III)	TOTAL
Financial assets measured at fair value:				
Energy trading forward contracts	**70.3**	**58.5**	**2.2**	**131.0**
Financial assets total	**70.3**	**58.5**	**2.2**	**131.0**
Financial liabilities measured at fair value:				
Energy trading forward contracts	**(61.9)**	**(89.7)**	**(10.0)**	**(161.6)**
Foreign currency forward contracts	**-**	**(25.8)**	**-**	**(25.8)**
Financial liabilities total	**(61.9)**	**(115.5)**	**(10.0)**	**(187.4)**
Net derivative (liabilities) assets	**8.4**	**(57.0)**	**(7.8)**	**(56.4)**

(1) Market-observable data are not available. Fair values are determined using valuation techniques.

As at December 31, 2018 *(millions of Canadian dollars)*	Quoted Prices in Active Markets (LEVEL I)	Significant Other Observable Inputs (LEVEL II)	Significant Unobservable Inputs [(1)] (LEVEL III)	TOTAL
Financial assets measured at fair value:				
Energy trading forward contracts	16.2	67.8	3.5	87.5
Foreign currency forward contracts	-	0.5	-	0.5
Available for sale securities	0.2	-	-	0.2
Financial assets total	16.4	68.3	3.5	88.2
Financial liabilities measured at fair value:				
Energy trading forward contracts	(45.0)	(163.0)	(32.3)	(240.3)
Foreign currency forward contracts	-	(3.3)	-	(3.3)
Financial liabilities total	(45.0)	(166.3)	(32.3)	(243.6)
Net derivative (liabilities) assets	(28.6)	(98.0)	(28.8)	(155.4)

(1) Market-observable data are not available. Fair values are determined using valuation techniques.

CHANGE IN FAIR VALUE OF LEVEL III RISK MANAGEMENT ASSETS AND LIABILITIES

The following table summarizes the key factors impacting the change in the fair value of the Corporation's Level III net risk management assets and liabilities separately by source of valuation during the year:

(millions of dollars)	**Hedges**
Net derivative assets as at January 1, 2018	(31.4)
Changes attributable to:	
Commodity price changes	(2.1)
Commodity price changes (de-designated)	-
New contracts entered	(0.3)
Transfers in/out of Level III	5.0
Net derivative (liabilities) as at December 31, 2018	(28.8)
Changes attributable to:	
Commodity price changes	**9.3**
Commodity price changes (de-designated)	**-**
New contracts entered	**0.3**
Transfers in/out of Level III	**11.4**
Net derivative (liabilities) as at December 31, 2019	**(7.8)**
Total change in fair value included in OCI	**(0.2)**
Total change in fair value included in pre-tax earnings	**21.2**

NON-DERIVATIVE FINANCIAL ASSETS AND LIABILITIES

Fair values for cash and cash equivalents, accounts receivable, short-term financing, accounts payable and accrued liabilities are not materially different from their carrying amounts due to their short-term nature.

The Corporation estimated the fair value of its long-term debt based on quoted market prices for the same or similar debt instruments. When such information was not available, future payments of interest and principal were discounted at estimated interest rates for comparable entities.

CARRYING AMOUNTS AND FAIR VALUES OF LONG-TERM DEBT

As at	**December 31, 2019**		**December 31, 2018**	
(millions of Canadian dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt [(1)] consisting of:				
Debentures, with remaining terms of:				
Less than 5 years	**44.1**	**44.7**	57.8	58.9
5–10 years	**27.6**	**29.5**	21.1	22.0
10–15 years	**216.3**	**247.8**	150.4	166.3
15–20 years	**575.2**	**625.4**	507.9	537.4
20–25 years	**420.2**	**432.5**	448.1	447.0
Private debentures				
Series 3 (3.81%)	**196.4**	**207.6**	199.0	203.0
Series 4 (3.84%) [(2)]	**293.4**	**310.7**	298.3	301.2
Series 5 (2.92%) [(3)]	**298.8**	**303.4**	-	-
Series 6 (3.33%) [(4)]	**298.5**	**305.3**	-	-
Series 7 (3.88%) [(5)]	**248.6**	**256.8**	-	-
Promissory note	**2.9**	**3.1**	3.3	3.4
	2,622.0	**2,766.8**	1,685.9	1,739.2

(1) Includes current portion of $73.3 million (December 31, 2018–$71.3 million). Maturity dates range from June 2020 to June 2044.
(2) On June 5, 2018, $300.0 million of Series 4 Private debentures were issued for a 10-year term with a coupon rate of 3.84 per cent.
(3) On October 15, 2019, $300.0 million of Series 5 Private debentures were issued for a 3-year term with a coupon of 2.92 per cent.
(4) On October 15, 2019, $300.0 million of Series 6 Private debentures were issued for a 5-year term with a coupon of 3.33 per cent.
(5) On October 15, 2019, $250.0 million of Series 7 Private debentures were issued for a 10-year term with a coupon of 3.88 per cent.

As at December 31, 2019 ENMAX issued $53.0 million in commercial paper, with a fair value of $53.0 million, and average interest rates of 2.15 per cent (December 31, 2018 - $18.0 million, fair value of $18.0 million, and average interest rates of 2.25 per cent).

As at December 31, 2019, ENMAX had drawn $121.2 million on existing credit facilities with an average rate of 2.04 per cent (December 31, 2018 - $nil).

Financial Assets and Financial Liabilities Subject to Offsetting

Information about the Corporation's financial assets and liabilities that are subject to enforceable master netting arrangements or similar agreements is as follows:

As at	**December 31, 2019**		**December 31, 2018**	
(millions of Canadian dollars)	**Accounts Receivable**	**Accounts Payable and Accrued Liabilities**	**Accounts Receivable**	**Accounts Payable and Accrued Liabilities**
Gross amounts recognized	**-**	**(70.3)**	-	(38.2)
Gross amounts set-off	**-**	**32.9**	-	13.7
Net amounts as presented in the Consolidated Statement of Financial Position	**-**	**(37.4)**	-	(24.5)

9. INCOME TAXES

Year ended December 31, *(millions of Canadian dollars)*	**2019**	**2018**
Current income tax expense		
Expense for current year	**6.5**	0.3
Other	**23.7**	114.7
Total current income tax expense	**30.2**	115.0
Deferred income tax expense		
Origination and reversal of temporary differences	**0.5**	(12.8)
Adjustment in respect of prior years	**(1.2)**	(1.2)
Other	**4.3**	32.5
Total deferred income tax expense	**3.6**	18.5
Total income tax expense	**33.8**	133.5

THE RECONCILIATION OF STATUTORY AND EFFECTIVE INCOME TAX EXPENSE

Year ended December 31, *(millions of Canadian dollars)*	**2019**	**2018**
Net earnings before tax	**237.3**	128.4
Income not subject to tax	**(230.2)**	(163.5)
	7.1	(35.1)
Federal and provincial tax rates	**26.5%**	27.0%
Expected income tax expense (recovery)	**1.9**	(9.4)
Non-deductible expense	**0.6**	6.0
Adjustment for deferred tax reversal and other estimate revisions	**31.3**	136.9
Total income tax expense	**33.8**	133.5

The changes in deferred income tax assets and liabilities during the years ended December 31, 2019 and 2018 were as follows:

(millions of Canadian dollars)	January 1, 2019	Recognized In Net Income	Recognized In Other Comprehensive Income	December 31, 2019
Deferred income tax assets				
Property, plant and equipment	(31.7)	14.6	-	**(17.1)**
Loss carried forward	42.0	(17.8)	-	**24.2**
Unused capital losses	-	0.3	-	**0.3**
Unrealized derivatives	41.8	(30.3)	-	**11.5**
Other comprehensive income	(2.5)	-	(2.4)	**(4.9)**
Other	2.6	19.3	-	**21.9**
	52.2	(13.9)	(2.4)	**35.9**
Deferred income tax liabilities				
Property, plant and equipment	96.7	(50.3)	-	**46.4**
Loss carried forward	(14.1)	4.3	-	**(9.8)**
Unrealized derivatives	(0.7)	0.3	-	**(0.4)**
Other comprehensive income	(0.1)	-	0.1	**-**
Other	(24.5)	19.9	-	**(4.6)**
	57.3	(25.8)	0.1	**31.6**
Net deferred tax assets (liabilities)	(5.1)	11.9	(2.5)	**4.3**

(millions of Canadian dollars)	January 1, 2018	Recognized In Net Income	Recognized In Other Comprehensive Income	December 31, 2018
Deferred income tax assets				
Property, plant and equipment	(32.0)	0.3	-	**(31.7)**
Loss carried forward	75.2	(33.2)	-	**42.0**
Unrealized derivatives	43.6	(1.8)	-	**41.8**
Other comprehensive income	(11.0)	7.0	1.5	**(2.5)**
Other	5.5	(2.9)	-	**2.6**
	81.3	(30.6)	1.5	**52.2**
Deferred income tax liabilities				
Property, plant and equipment	110.5	(13.8)	-	**96.7**
Loss carried forward	(13.2)	(0.9)	-	**(14.1)**
Unrealized derivatives	(0.8)	0.1	-	**(0.7)**
Other comprehensive income	(0.1)	-	-	**(0.1)**
Other	(21.8)	(2.7)	-	**(24.5)**
	74.6	(17.3)	-	**57.3**
Net deferred tax (liability) assets	6.7	(13.3)	1.5	**(5.1)**

The Corporation has the following tax losses carry-forward and deductible temporary differences for which no deferred tax assets have been recognized:

Year ended December 31, *(millions of Canadian dollars)*	2019	2018
Non-capital loss	**15.8**	14.5
Property, plant and equipment	**62.5**	62.5
Contingent liabilities	**19.0**	19.9
	97.3	96.9

The changes in income taxes receivable and income taxes payable during the years ended December 31, 2019 and 2018 were as follows:

(millions of Canadian dollars)	**Income Taxes Receivable**	**Income Taxes Payable**	**Net Position**
January 1, 2018	87.5	(1.8)	85.7
Installment and refunds	(59.9)	-	(59.9)
Current year provision	(0.2)	(0.1)	(0.3)
Other	18.2	1.8	20.0
December 31, 2018	45.6	(0.1)	45.5
Prior period adjustments	(31.1)	(3.7)	(34.8)
Instalments and refunds	0.1	(22.0)	(21.9)
Current year provision	-	(6.4)	(6.4)
Other	(14.2)	14.2	-
December 31, 2019	**0.4**	**(18.0)**	**(17.6)**

As at December 31, 2019, the Corporation has non-capital loss carry-forwards that can be used to offset taxes in future years. These non-capital loss carry-forwards expire as follows:

NON-CAPITAL LOSS CARRY FORWARD

(millions of dollars)	**2019**
2030	0.1
2031	1.3
2032	4.9
2033	1.0
2034	20.8
2035	13.2
2036	17.0
2037	22.0
2038	10.8
2039	66.1

10. REGULATORY DEFERRAL ACCOUNT BALANCES

NATURE AND ECONOMIC EFFECT OF RATE REGULATION

ENMAX Transmission and ENMAX Distribution (the Divisions) are divisions ENMAX Power Delivery. The Divisions are regulated operations established to carry out all electrical transmission and distribution service functions. The AUC approves Transmission and Distribution Tariffs (rates and terms and conditions of service) pursuant to Sections 37 and 102 of the Electric Utilities Act.

With respect to Distribution, the 2018-2022 Distribution Access Service (DAS) rates are subject to the Performance Based Regulation (PBR) mechanism. In December 2018, the AUC approved formula-based rates for the period effective January 1, 2019, which replaced approved interim rates that had been in place since April 1, 2018.

Transmission division rates are set based on an AUC approved revenue requirement and are regulated under a traditional cost of service framework. Interim rates are currently in place pending a decision on the 2018-2020 General Tariff Application, which was filed in December 2018.

REGULATORY BALANCES

The timing of recognition of certain regulatory debits, credits, revenues and expenses may differ from what is otherwise expected under IFRS for non-regulated operations. The Corporation has recorded the following regulatory deferral account debit and credit balances:

As at *(millions of Canadian dollars)*	**Accounts Receivable (a)**	**Un-Eliminated Inter-Company Profit (b)**	**Other Regulatory Debits (c)**	**Total Regulatory Deferral Account Debit Balances**
Regulatory deferral account debit balances				
January 1, 2019	62.8	10.8	8.4	82.0
Balances arising in the period [1]	175.9	(2.6)	6.7	180.0
Reversal [2]	(217.7)	(1.6)	(11.5)	(230.8)
December 31, 2019	**21.0**	**6.6**	**3.6**	**31.2**
Expected recovery/reversal period	3 Months	25 Years	12 Months	
January 1, 2018	34.4	9.9	31.9	76.2
Balances arising in the period [1]	167.7	0.9	3.7	172.3
Reversal [2]	(139.3)	-	(27.2)	(166.5)
December 31, 2018	62.8	10.8	8.4	82.0
Expected recovery/reversal period	3 Months	25 Years	12 Months	

(1) "Balances arising in the period" row consists of new additions to regulatory deferral debits and credit balances.
(2) "Recovery (reversal)" row consists of amounts collected/refunded through rate riders or transactions reversing existing regulatory balances.

As at *(millions of Canadian dollars)*	**Accounts Payable (a)**	**Other Regulatory Credits (d)**	**Total Regulatory Deferral Account Credit Balances**
Regulatory deferral account credit balances			
January 1, 2019	-	5.0	5.0
Balances arising in the period [1]	-	1.2	1.2
Recovery (reversal) [2]	-	(4.7)	(4.7)
December 31, 2019	**-**	**1.5**	**1.5**
Expected recovery/reversal period		18 Months	
January 1, 2018	-	9.4	9.4
Balances arising in the period [1]	-	0.1	0.1
Recovery (reversal) [2]	-	(4.5)	(4.5)
December 31, 2018	-	5.0	5.0
Expected recovery/reversal period		12 Months	

(1) "Balances arising in the period" row consists of new additions to regulatory deferral debits and credit balances.
(2) "Recovery (reversal)" row consists of amounts collected/refunded through rate riders or transactions reversing existing regulatory balances.

The following describes each of the circumstances in which rate regulation affects the accounting for a transaction or event. Regulatory deferral account debit balances represent costs incurred in the current period or in prior periods, which are expected to be recovered from customers in future periods through the rate-setting process. Regulatory deferral account credit balances represent future reductions or limitations of increases in revenues associated with amounts that are expected to be returned to customers as a result of the rate-setting process.

(a) Accounts receivable and payable

Accounts receivable and payable represent a deferral account for transmission charges from the AESO. In the absence of rate regulation and the standard, IFRS 14 would require that actual costs be recognized as an expense when incurred.

(b) Inter-company profit

A subsidiary of the Corporation performs construction work for the regulated operations of Power Delivery at a profit. Such profit is deemed to be realized to the extent that the transfer price is recognized for rate-making purposes by the regulator and included in the capital cost of distribution assets. In the absence of rate regulation and the standard, IFRS would require that intercompany profits be eliminated upon consolidation.

(c) Other regulatory debits

Other regulatory debits primarily relate to the AUC flow-through items and other costs that will be collected from customers via future rates such as access service charges. The timing of the decision on collection of these items can result in significant fluctuation in balances from year to year.

(d) Other regulatory credits

Other regulatory credits primarily relate to items that will be refunded to customers through future rates.

For certain regulatory items identified above, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties including those inherent in rate-setting regulatory processes. There is a risk that the regulator may disallow a portion of certain costs incurred in the current period for recovery through future rates or disagree with the proposed recovery period. Any impairment related to regulatory deferral account debit balances are recorded in the period in which the related regulatory decisions are received.

11. OTHER ASSETS AND LIABILITIES

As at *(millions of Canadian dollars)*	**December 31, 2019**	**December 31, 2018**
Other current assets		
Prepaid expenses	**17.8**	9.2
Collateral paid	**18.4**	71.9
Deferred asset	**0.5**	0.3
Emission offsets	**39.9**	32.3
Other	**6.7**	5.2
	83.3	118.9
Other long-term assets		
Prepaid expenses	**6.1**	8.2
Long-term accounts receivable	**18.0**	2.5
Deferred asset	**5.5**	3.3
Other	**14.7**	13.1
	44.3	27.1
Other current liabilities		
Deposits	**25.0**	17.9
Other	**7.0**	6.9
	32.0	24.8
Other long-term liabilities		
Other	**13.1**	12.1
	13.1	12.1

12. PROPERTY, PLANT AND EQUIPMENT (PPE)

(millions of Canadian dollars)	**Transmission, Distribution and Substation Equipment**	**Generation Facilities and Equipment**	**Buildings and Site Development**	**Tools, Systems and Equipment**	**Land**	**Capital Spares and Other**	**Vehicles**	**Work in Progress**	**Government Grants**	**Total**
Cost										
As at January 1, 2018	2,228.2	2,261.5	438.3	122.4	49.3	44.5	32.2	113.5	(20.0)	5,269.9
Additions	-	-	-	0.1	-	4.0	-	335.4	-	339.5
Transfers	224.3	36.1	37.3	17.9	-	-	13.3	(328.9)	-	-
Disposals	(8.0)	(20.1)	-	(53.1)	-	-	(3.7)	(1.6)	-	(86.5)
Impairment	-	-	-	-	-	-	-	(4.7)	-	(4.7)
As at December 31, 2018	2,444.5	2,277.5	475.6	87.3	49.3	48.5	41.8	113.7	(20.0)	5,518.2
Additions	-	36.7	17.6	0.1	-	3.4	10.1	390.1	-	458.0
Transfers	196.6	31.8	13.8	11.3	-	-	6.1	(259.6)	-	-
Disposals	(7.1)	(17.9)	(8.3)	(3.3)	-	-	(5.9)	(7.3)	-	(49.8)
Changes to asset retirement costs	-	14.5	-	-	-	-	-	-	-	14.5
Impairment	-	-	-		-	-	-	(1.1)	-	(1.1)
As at December 31, 2019	**2,634.0**	**2,342.6**	**498.7**	**95.4**	**49.3**	**51.9**	**52.1**	**235.8**	**(20.0)**	**5,939.8**
Accumulated Depreciation										
As at January 1, 2018	(265.3)	(680.1)	(84.2)	(86.7)	-	-	(9.9)	-	5.0	(1,121.2)
Depreciation	(89.3)	(92.6)	(13.0)	(9.7)	-	-	(2.7)	-	0.6	(206.7)
Transfers	-	-	-	-	-	-	-	-	-	-
Disposals	8.4	19.5	0.1	53.1	-	-	2.8	-	-	83.9
Impairment	-	(19.6)	(8.0)	-	-	-	-	-	7.3	(20.3)
As at December 31, 2018	(346.2)	(772.8)	(105.1)	(43.3)	-	-	(9.8)	-	12.9	(1,264.3)
Depreciation	(94.5)	(98.6)	(16.0)	(8.1)	-	-	(5.3)	-	0.4	(222.1)
Disposals	13.3	16.7	3.5	3.3	-	-	5.0	-	-	41.8
As at December 31, 2019	**(427.4)**	**(854.7)**	**(117.6)**	**(48.1)**	**-**	**-**	**(10.1)**	**-**	**13.3**	**(1,444.6)**
Net book value										
As at December 31, 2018	2,098.3	1,504.7	370.5	44.0	49.3	48.5	32.0	113.7	(7.1)	4,253.9
As at December 31, 2019	**2,206.6**	**1,487.9**	**381.1**	**47.3**	**49.3**	**51.9**	**42.0**	**235.8**	**(6.7)**	**4,495.2**

Real property, including land and buildings, with a carrying amount of $430.4 million as at December 31, 2019 (December 31, 2018 - $419.8 million), was subject to a right of first refusal to purchase held by the City.

For the year ended December 31, 2019, capitalized borrowing costs amounted to $8.2 million (2018 - $6.3 million), with capitalization rates ranging from 3.15 per cent to 3.91 per cent (2018 - 3.15 to 5.32 per cent). Interest is capitalized based on the actual cost of debt used to finance the capital construction projects. Interest rates ranged from 1.95 per cent to 5.02 per cent (2018 – 1.80 to 6.31 per cent).

During 2019, the Corporation performed an impairment test on a CGU where circumstances indicated possible impairment (Note 4(m)). An impairment loss was recognized for $nil (2018 - $20.3 million).

During the year ended December 31, 2019 ENMAX recognized an impairment loss of $1.1 million (2018 - $6.6 million) associated with certain property, plant and equipment (prior to the project being completed and included in one of ENMAX's CGU's). ENMAX no longer expects to bring the project to market due to changes in market conditions.

13. INTANGIBLE ASSETS

(millions of Canadian dollars)	Computer Systems	Renewable Energy Certificates and Water Licenses	Land Easements, Rights and Lease Options	Work in Progress	Total
Cost					
As at January 1, 2018	273.8	12.4	33.5	44.1	363.8
Additions	-	-	-	20.6	20.6
Transfers	53.3	-	0.4	(53.7)	-
Impairment	-	-	-	(1.9)	(1.9)
Disposals	(78.7)	-	-	-	(78.7)
As at December 31, 2018	248.4	12.4	33.9	9.1	303.8
Additions	-	-	-	28.3	28.3
Transfers	18.5	-	-	(18.5)	-
As at December 31, 2019	**266.9**	**12.4**	**33.9**	**18.9**	**332.1**
Accumulated amortization					
As at January 1, 2018	(162.4)	(12.3)	(6.2)	-	(180.9)
Amortization	(22.3)	-	(1.5)	-	(23.8)
Disposals	78.7	-	-	-	78.7
As at December 31, 2018	(106.0)	(12.3)	(7.7)	-	(126.0)
Amortization	(20.1)	-	(1.3)	-	(21.4)
As at December 31, 2019	**(126.1)**	**(12.3)**	**(9.0)**	**-**	**(147.4)**
Net book value					
As at December 31, 2018	142.4	0.1	26.2	9.1	177.8
As at December 31, 2019	**140.8**	**0.1**	**24.9**	**18.9**	**184.7**

14. LONG-TERM DEBT

As at *(millions of Canadian dollars)*	December 31, 2019	Weighted Average Interest Rates	December 31, 2018	Weighted Average Interest Rates
City debentures [(1)] with remaining terms of:				
Less than 5 years	**44.1**	**3.19%**	57.8	3.54%
5 – 10 years	**27.6**	**3.79%**	21.1	3.69%
10 – 15 years	**216.3**	**4.62%**	150.4	4.58%
15 – 20 years	**575.2**	**3.63%**	507.9	3.86%
20 – 25 years	**420.2**	**2.95%**	448.1	3.23%
Private debentures [(1)]	**1,335.7**	**3.52%**	497.3	3.82%
Promissory note	**2.9**	**5.00%**	3.3	5.00%
	2,622.0		1,685.9	
Less: current portion	**(73.3)**		(71.3)	
	2,548.7		1,614.6	

[(1)] Unsecured debentures. See note 8 for further detail.

CITY DEBENTURES

Debentures were initially issued by the City on behalf of the CES, pursuant to City bylaw authorizations prior to January 1, 1998. Pursuant to the master agreement between the Corporation and the City, the debentures were included in the assumed liabilities upon transfer of substantially all the assets and liabilities of the CES from the City to the Corporation at January 1, 1998. In accordance with a debt management service level agreement between the Corporation and the City, the City continues to administer the new and existing debentures on behalf of the Corporation. During 2019, the Corporation drew down on $172.4 million of additional Alberta Capital Finance Authority (ACFA) borrowings.

The Corporation is required to reimburse the City for all principal repayments and interest payments with respect to the debentures on the same day as the City disburses the payments to ACFA. In addition, the Corporation is required to pay a loan guarantee and administration fee to the City of 0.25 per cent on the average monthly outstanding ACFA debenture balance held by the City on behalf of the Corporation.

PRIVATE DEBENTURES

On June 5, 2018, a Series 4 Private Debenture of $300.0 million at 3.84 per cent was issued. As at December 31, 2019 the outstanding unsecured private debentures of $200.0 million and $300.0 million bear interest at a rate of 3.81 per cent and 3.84 per cent respectively, payable semi-annually, and mature on December 5, 2024, and June 5, 2028, respectively.

On October 15, 2019, ENMAX completed the issuance of Series 5, 6 and 7 unsecured private debentures for a total of $850 million. The Series 5 debentures of $300.0 million have a 3-year term and bear interest at 2.92 per cent, the Series 6 debentures of $300.0 million have a 5-year term and bear interest at 3.33 per cent, and the Series 7 debentures of $250.0 million have a 10-year term and bear interest at 3.88 per cent.

PROMISSORY NOTE

The promissory note was issued in the fourth quarter of 2006 and represents an amortizing loan from the Board of Trustees of Westwind School Division No. 74, acting as agent for the Wind Participation Consortium (WPC), which is comprised of three school divisions. The 20-year note, in the amount of $6.3 million with interest at a fixed rate of 5.00 per cent is repayable in monthly instalments. The Corporation provided a fixed charge over two wind turbines located at Taber, Alberta, as security for the loan. Concurrent with execution of the loan, WPC executed a 20-year electricity services agreement with ENMAX Competitive Energy.

PRINCIPAL REPAYMENTS

The required repayments of principal on the long-term debt at December 31, 2019, are as follows:

REQUIRED REPAYMENTS OF PRINCIPAL

As at December 31, *(millions of Canadian dollars)*	**2019**
Less than 1 year	**73.3**
1–3 years	**428.9**
3–5 years	**324.9**
More than 5 years	**1,809.2**

SHORT TERM FINANCING

As at December 31, 2019 ENMAX had $174.2 million (December 31, 2018 - $18.0 million) of commercial paper and bankers acceptances outstanding. The interest rate averaged 2.08 per cent (2018 – 2.25 per cent); management expects this balance to be repaid within a year.

15. LEASES

ENMAX leases several assets categorized as: generation facilities and equipment, buildings and site development, land, tools, systems and equipment, and vehicles. As at December 31, 2019, the average term remaining on the leases is 4.3 years.

Generation Facilities and Equipment

ENMAX leases a pipeline to supply the necessary water to one of its generation facilities. The term of this lease is 30 years with fixed payments over the life of the lease.

Buildings and Site Development

ENMAX has entered into building leases to house various operations. As at December 31, 2019 the leases that were capitalized have 3 to 9 years remaining.

Land

In relation to several of ENMAX's generating facilities, additional land surrounding the facilities is leased to allow for the installation of substations and water reservoirs. The contracted lengths and terms of payments of the leases vary. As at December 31, 2019 ENMAX expects all land leases to be renewed until the end of the useful life of each respective generating facility.

Tools, Systems and Equipment

ENMAX has entered into a lease for various copiers and printers at its facilities. The lease term is for one year. At adoption, it could not be reasonably determined if this lease would be renewed.

Vehicles

ENMAX leases vehicles that are mainly used by its field services crews for the installation and maintenance of the electrical system. The lease terms of the vehicles vary based on the specific use of the vehicle but are typically for five years.

Right-of-use assets

The cost and accumulated depreciation related to the right-of-use assets have been included in property, plant and equipment (see Note 12). The changes in the net book value for the Corporation's right-of-use assets, during the year ended December 31, 2019 were as follows:

(millions of Canadian dollars)	**Generation Facilities and Equipment**	**Buildings and Site Development**	**Land**	**Tools, Systems and Equipment**	**Vehicles**	**Total**
Cost						
As at January 1, 2019	5.1	-	-	-	-	5.1
Opening balance adjustment IFRS 16	27.9	13.3	8.8	0.1	7.7	57.8
Net Changes	(0.1)	0.1	-	-	1.9	1.9
As at December 31, 2019	**32.9**	**13.4**	**8.8**	**0.1**	**9.6**	**64.8**
Accumulated Depreciation						
As at January 1, 2019	1.7	-	-	-	-	1.7
Opening balance adjustment IFRS 16	-	-	-	-	-	-
Net Changes	1.2	1.2	0.3	0.1	2.6	5.4
As at December 31, 2019	**2.9**	**1.2**	**0.3**	**0.1**	**2.6**	**7.1**
Net book value						
As at January 1, 2019	3.4	-	-	-	-	3.4
As at December 31, 2019	**30.0**	**12.2**	**8.5**	**-**	**7.0**	**57.7**

Amounts recognized in profit and loss

(millions of Canadian dollars)	**Year ended December 31, 2019**
Depreciation expense	6.0
Lease expense on short-term leases	0.3
Interest expense on finance leases	2.4
Amounts expensed in profit and loss	**8.7**

Lease payments

The required lease payments of the lease liability at December 31, 2019, are as follows:

As at December 31, *(millions of Canadian dollars)*	**2019**
Less than 1 year	**7.8**
1–5 years	**27.6**
More than 5 years	**55.1**

The total cash outflow for leases amounts to $7.5 million for the year ended December 31, 2019. ENMAX does not face a significant liquidity risk with regards to its lease liabilities. Lease liabilities are monitored through ENMAX's treasury function**.**

16. ASSET RETIREMENT OBLIGATIONS AND OTHER PROVISIONS

(millions of Canadian dollars)	**Asset Retirement Obligations**	**Onerous Contracts and Other**	**Total**
As at January 1, 2018	87.3	36.0	123.3
Recoveries	-	(12.5)	(12.5)
Settled in the year	-	(4.9)	(4.9)
Accretion expense	1.8	-	1.8
As at December 31, 2018	89.1	18.6	107.7
Additions	14.5	-	14.5
Settled in the year	-	(2.0)	(2.0)
Accretion expense	2.0	-	2.0
As at December 31, 2019	105.6	16.6	122.2
Less: current portion	-	(0.9)	(0.9)
	105.6	**15.7**	**121.3**

Asset Retirement Obligations

The Corporation has estimated the net present value of the decommissioning liabilities associated with the assets of ENMAX Competitive Energy based on a total undiscounted future liability of $195.1 million (December 31, 2018 - $195.1 million) calculated using an inflation rate of 2 per cent (December 31, 2018 - 2 per cent). These payments are expected to be made between 2039 and 2071. The Corporation calculated the present value of the obligations using discount rates ranging from 1.75 per cent to 1.79 per cent (December 31, 2018 - between 1.89 per cent and 2.23 per cent) to reflect the market assessment of the time value of money.

Onerous contracts and Other

The Corporation decreased its onerous contracts and other provision by $2.0 million (December 31, 2018 - $17.4 million) due to settlement and to reflect changes in the expected timing and amounts of certain longer-term onerous contracts.

17. SHARE CAPITAL

(millions of Canadian dollars, except share amounts)	Number of Shares	Amount
Authorized:		
Unlimited number of common shares		
Issued and outstanding:		
Balance, December 31, 2018 and 2019:		
Issued on incorporation	1	-
Issued on transfer of net assets from CES	1	278.2
Issued on transfer of billing and customer care assets from the City in 2001	1	1.9
Balance, December 31, 2018 and 2019	**3**	**280.1**

18. POST-EMPLOYMENT BENEFITS

The Corporation has a registered pension plan that substantially covers all employees and includes both Defined Benefit (DB) and Defined Contribution (DC) provisions. The DB provisions provide a pension based on years of service and highest average earnings over five consecutive years of employment. DB pension benefits under the registered plan will increase annually by at least 60.00 per cent of the consumer price index for Alberta. Under the DC provisions, the employer provides a base level of contributions and additional employer contributions are matched based on the participating members' contribution levels and points (age plus service) calculation.

The Corporation also sponsors a supplemental pension plan providing an additional DC or DB pension to members whose benefits are limited by maximum pension rules under the ITA. The supplemental pension plan benefits do not automatically increase. In addition, the Corporation provides employees with post-retirement benefits other than pensions, including extended health benefits beyond those provided by government-sponsored plans, life insurance, Health Care Spending accounts and a lump-sum allowance payable at retirement, up to age 65.

Total cash payments for employee future benefits for the year ended December 31, 2019, consisting of cash contributed by the Corporation under the DB and DC provisions of the registered pension plan and cash payments directly to beneficiaries of the Corporation's unfunded other benefit plans, were $22.4 million (2018 - $22.4 million).

For the year ended December 31, 2019, the total expense for the DC provisions of the plan is $10.3 million (2018 - $10.2 million).

Information about the DB provisions of the plan, including the supplemental pension plan and the post-retirement non-pension benefit plan, is as follows:

	December 31, 2019			December 31, 2018		
(millions of Canadian dollars)	**Pension Benefit Plan**	**Other Benefit Plan**	**Total**	**Pension Benefit Plan**	**Other Benefit Plan**	**Total**
Change in defined benefit obligation:						
Balance, beginning of year	**336.1**	**11.6**	**347.7**	355.5	12.8	368.3
Current service cost	**11.2**	**0.9**	**12.1**	12.5	0.9	13.4
Interest cost	**12.3**	**0.4**	**12.7**	12.1	0.4	12.5
Employee contributions	**3.5**	**-**	**3.5**	3.6	-	3.6
Actuarial losses (gains)	**60.6**	**2.4**	**63.0**	(15.7)	(1.9)	(17.6)
Benefits paid	**(25.7)**	**(0.7)**	**(26.4)**	(31.9)	(0.6)	(32.5)
Defined benefit obligation, end of year	**398.0**	**14.6**	**412.6**	336.1	11.6	347.7
Change in plan assets:						
Fair value, beginning of year	**296.9**	**-**	**296.9**	317.9	-	317.9
Interest income	**11.0**	**-**	**11.0**	11.1	-	11.1
Return on plan assets, excluding amounts included in interest expense	**25.7**	**-**	**25.7**	(15.1)	-	(15.1)
Employer contributions	**10.1**	**-**	**10.1**	10.2	-	10.2
Employee contributions	**3.5**	**-**	**3.5**	3.7	-	3.7
Benefits paid	**(24.2)**	**-**	**(24.2)**	(30.5)	-	(30.5)
Non-investment expenses	**(0.3)**	**-**	**(0.3)**	(0.4)	-	(0.4)
Plan assets at fair value, end of year	**322.7**	**-**	**322.7**	296.9	-	296.9
Funded status-plan deficit						
Accrued benefit asset (liability)	**(75.3)**	**(14.6)**	**(89.9)**	(39.2)	(11.6)	(50.8)

DEFINED BENEFIT COST – STATEMENT OF EARNINGS

	December 31, 2019			December 31, 2018		
(millions of Canadian dollars)	**Pension Benefit Plan**	**Other Benefit Plan**	**Total**	**Pension Benefit Plan**	**Other Benefit Plan**	**Total**
Current service costs	**11.3**	**0.8**	**12.1**	12.5	0.9	13.4
Net interest on net benefit liability	**1.2**	**0.4**	**1.6**	1.0	0.4	1.4
Admin costs	**0.3**	**-**	**0.3**	0.3	-	0.3
Net benefit plan expense	**12.8**	**1.2**	**14.0**	13.8	1.3	15.1

DEFINED BENEFIT COST – STATEMENT OF COMPREHENSIVE INCOME

	December 31, 2019			December 31, 2018		
(millions of Canadian dollars)	**Pension Benefit Plan**	**Other Benefit Plan**	**Total**	**Pension Benefit Plan**	**Other Benefit Plan**	**Total**
Return on plan assets (greater) less than discount rate	**(25.7)**	**-**	**(25.7)**	15.3	0.1	15.4
Actuarial (gains) losses						
Experience adjustments	**10.6**	**(0.2)**	**10.4**	(0.4)	(0.4)	(0.8)
Changes in assumptions (1)	**50.1**	**2.7**	**52.8**	(15.4)	(1.4)	(16.8)
Re-measurement effects recognized in OCI (2)	**35.0**	**2.5**	**37.5**	(0.5)	(1.7)	(2.2)

(1) See changes in assumptions – Note 18(a).
(2) A prior period adjustment for $0.4 million was recognized in 2019 related to the last actuarial valuation – Note 18(b).

The defined pension benefits plan's assets are comprised as follows:

As at	December 31, 2019				December 31, 2018			
(millions of Canadian dollars)	**Quoted**	**Un-quoted**	**Total**	**In %**	**Quoted**	**Un-quoted**	**Total**	**In %**
Canadian equity securities			**142.0**	**44.1%**			78.0	26.1%
Small company equity fund	**6.5**	**-**			9.4	-		
World equity fund	**39.8**	**-**			-	-		
Global infrastructure LP	**15.0**	**-**			-	-		
Canadian equity fund	**80.7**	**-**			68.6	-		
Foreign equity securities			**72.6**	**22.6%**			92.7	31.1%
U.S. large company equity fund	**65.8**	**-**			53.8	-		
Developed country equity fund	**6.8**	**-**			38.9	-		
Fixed-income securities			**79.7**	**24.7%**			101.0	33.9%
Canadian fixed-income fund	**2.9**	**-**			5.5	-		
Canadian long-duration bond fund	**24.3**	**-**			33.9	-		
Real return bond fund	**15.3**	**-**			16.0	-		
Long duration credit bond fund	**21.6**	**-**			29.2	-		
U.S. high yield bond fund	**15.6**	**-**			16.4	-		
Real estate investments	**-**	**27.2**	**27.2**	**8.4%**	-	25.2	25.2	8.5%
Cash and cash equivalents	**-**	**0.4**	**0.4**	**0.1%**	-	0.9	0.9	0.3%
Non-investment asset	**-**	**0.3**	**0.3**	**0.1%**	-	0.4	0.4	0.1%
Total plan assets			**322.2**	**100.0%**			298.2	100.0%

(a) Assumptions

The significant weighted-average actuarial assumptions adopted in measuring the Corporation's defined benefit obligations and net benefit plan expense are as follows:

	December 31, 2019		December 31, 2018	
(millions of Canadian dollars)	**Pension Benefit Plan**	**Other Benefit Plan**	**Pension Benefit Plan**	**Other Benefit Plan**
Defined benefit obligation:				
Discount rate	**3.00%**	**3.00%**	3.75%	3.50%
Inflation rate	**1.80%**	**n/a**	1.80%	n/a
Rate of compensation increase	**2.80%**	**2.80%**	2.80%	2.80%
Health care cost trend rate for next year	**n/a**	**7.00%**	n/a	6.50%
Decreasing gradually to 5% in the year	**n/a**	**2025**	n/a	2025
Average life expectancy [(1)]				
Male	**21.8**	**n/a**	21.7	n/a
Female	**24.2**	**n/a**	24.1	n/a
Net benefit plan expense:				
Discount rate	**3.75%**	**3.50%**	3.50%	3.25%
Inflation rate	**1.80%**	**n/a**	1.80%	n/a
Rate of compensation increase	**2.80%**	**2.80%**	2.80%	2.80%
Health care cost trend rate for next year	**n/a**	**6.50%**	n/a	6.50%
Decreasing gradually to 5% in the year	**n/a**	**2026**	n/a	2021

(1) The average life expectancy for a 65-year-old based on the mortality tables used for year-end disclosures.

The per capita cost of covered dental benefits was assumed to increase by 4.5 per cent per year (2018 – 4.50 per cent).

The sensitivity of the defined benefit obligation (DBO) to changes in assumptions is set out below. The effects on each plan of a change in an assumption are weighted proportionately to the total plan obligations to determine the total impact for each assumption presented.

SENSITIVITIES OF ASSUMPTIONS

	December 31, 2019		
(millions of Canadian dollars)	**Change in assumption**	**Increase**	**Decrease**
Impact on Pension Benefit Plan DBO			
Discount rate	**1%**	**(53.1)**	**68.3**
Rate of compensation increase	**1%**	**10.5**	**(10.8)**
Inflation rate	**1%**	**34.8**	**(31.7)**
Life expectancy	**1 year**	**9.7**	**(9.9)**
Impact on Other Benefit Plan DBO			
Discount rate	**1%**	**(1.4)**	**1.7**
Rate of compensation increase	**1%**	**0.7**	**(0.6)**
Health care cost trend rate	**1%**	**0.5**	**(0.4)**
Life expectancy	**1 year**	**(0.1)**	**n/a**

Each sensitivity analysis disclosed in this note is based on changing one assumption while holding all other assumptions constant. In practice, this is unlikely to occur, and changes in some of the assumptions may be correlated. When calculating the sensitivity of the defined benefit obligation to variations in significant actuarial assumptions, the same method (present value of the DBO calculated with the projected unit credit method at the end of the reporting period) has been applied for calculating the liability recognized in the statement of financial position.

(b) Maturity analysis

An actuarial valuation was performed as of December 31, 2018. The aggregate solvency deficit in the Corporation's funded pension plans amounted to $16.8 million. The Corporation will make special payments for past service of $3.3 million annually to fund the defined pension benefits plans' deficit over 10 years. Current agreed service contributions are 9.81 per cent of pensionable salaries and continue to be made in the normal course. Total expected contributions to post-employment benefit plans for the year ending December 31, 2019 (including the past service contributions) are $2.4 million.

The weighted average duration of the defined benefit obligation for the pension benefit plan and the other benefit plan is 15.2 years and 10.9 years respectively (2018 – 16.2 years and 8.5 years).

Expected maturity analysis of undiscounted pension and other benefit plans:

	Less than 1 year	**1 - 3 years**	**3 - 5 years**	**More than 5 years**	**Total**
Defined pension benefit plan	18.9	38.3	40.3	107.2	204.7
Other benefit plans	1.0	2.0	2.0	5.4	10.4
At December 31, 2019	**19.9**	**40.3**	**42.3**	**112.6**	**215.1**

(c) Risk assessment

Funding risk

The primary risk associated with the DB pension for the plan sponsor is the risk that investment asset growth and contribution rates will not be sufficient to cover pending funding obligations, resulting in unfunded liabilities.

Alberta registered plans are required to file funding valuations on a triennial basis with a few exceptions. If the going concern funded status is less than 85 per cent, a plan may be required to file an annual valuation.

Based on the 2018 pension valuation, the DB Provisions are 132.6 per cent funded on a going-concern basis and 94.6 per cent on a solvency basis. The funding ratio is monitored on an ongoing basis.

Investment risk

The Corporation makes investment decisions for its funded plan based on an asset-liability matching analysis reflecting the results of its aforementioned funding valuations. The Corporation attempts to achieve investment returns in excess of its liabilities by setting an asset-allocation target based on risks and returns. This targeted asset allocation is recorded in ENMAX Pension Plan Statement of Investment Policies and Procedures (SIPP). The plan's asset portfolio is regularly monitored to ensure compliance to the SIPP, as well as its performance as compared to a liability benchmark intended to approximate the growth in the plan's future obligations. Given the likely significant shortening of the liability structure with the passage of time, the continuing appropriateness of the plan's asset allocation is evaluated at least once every three years.

19. DEFERRED REVENUE

(millions of Canadian dollars)	**CIAC**	**Other**	**Total**
As at December 31, 2018	533.6	21.8	555.4
Net additions	32.0	13.7	45.7
Movements to PPE	(2.4)	-	(2.4)
Recognized as revenue	(19.1)	(14.0)	(33.1)
As at December 31, 2019	544.1	21.5	565.6
Less: current portion	-	(10.5)	(10.5)
	544.1	**11.0**	**555.1**

20. ACCUMULATED OTHER COMPREHENSIVE (LOSS) INCOME

As at *(millions of Canadian dollars)*	**December 31, 2019**	**December 31, 2018**
Net unrealized gains (losses) on derivatives designated as cash flow hedges, including deferred income tax expense of $5.7 million (December 31, 2018- expense of $2.9 million)	**9.1**	(0.8)
Net actuarial losses on defined benefit plans, including deferred income tax recovery of $0.7 million (December 31, 2018- recovery of $0.4 million)	**(36.9)**	(3.9)
Accumulated other comprehensive losses, including deferred income tax expense of $5.0 million (December 31, 2018- expense of $2.5 million)	**(27.8)**	(4.7)

21. OTHER REVENUE AND EXPENSES

OTHER REVENUE

Year ended December 31, *(millions of Canadian dollars)*	2019	2018
Interest and penalty revenue	**8.4**	8.0
Miscellaneous	**10.4**	16.2
	18.8	24.2

OTHER EXPENSES

Year ended December 31, *(millions of Canadian dollars)*	2019	2018
Contractual services cost	**100.7**	79.3
Staff costs	**188.0**	200.5
Consulting costs	**32.6**	24.3
Advertising and promotion	**10.3**	7.7
Administrative and office expenses	**86.5**	69.1
Operating costs	**39.1**	38.7
Building and property costs	**24.6**	26.2
Other costs (recoveries)	**1.0**	(14.2)
Foreign exchange losses (gains)	**21.8**	(10.6)
	504.6	421.0

22. JOINT ARRANGEMENTS

Significant joint operations included in the consolidated financial statements at December 31, 2019 are listed below.

Significant Joint Operations	Operating Jurisdiction	Ownership Percent	Principal Activity
McBride Lake Wind Facility	Canada	50%	Wind turbine generating facility
Shepard Energy Centre	Canada	50%	Gas-fueled generating facility
Balzac Power Station	Canada	50%	Gas-fueled generating facility
Genesee 4 and 5	Canada	50%	Gas-fueled generating development project

23. DIVIDENDS

On March 15, 2019, the Corporation declared a dividend of $50.0 million to the City (2018 – $40.0 million). The dividend was paid in equal quarterly instalments during 2019.

24. FINANCE CHARGES

Year ended December 31, *(millions of Canadian dollars)*	2019	2018
Accretion expense	**2.0**	1.8
Interest expense – pension	**1.6**	1.4
Interest on long-term debt	**73.6**	68.9
Interest on finance leases	**2.4**	-
Short-term interest and other financing charges	**9.2**	2.4
Less: capitalized borrowing costs	**(8.2)**	(6.3)
	80.6	68.2

25. CHANGES IN NON-CASH WORKING CAPITAL

Year ended December 31, *(millions of Canadian dollars)*	**2019**	**2018**
Accounts receivable	**27.0**	(60.1)
Regulatory deferral account debit balances	**52.5**	(5.8)
Other assets	**18.4**	(10.5)
Accounts payable and accrued liabilities	**(77.4)**	211.1
Regulatory deferral account credit balances	**(3.5)**	(4.4)
Other liabilities	**5.8**	(2.5)
Deferred revenue (non-CIAC)	**(0.3)**	8.3
Provisions	**(2.0)**	(17.4)
Changes in non-cash working capital	**20.5**	118.7

26. RELATED PARTY TRANSACTIONS

The City is the sole shareholder of the Corporation. The following tables summarize the related party transactions between the Corporation and the City.

STATEMENTS OF EARNINGS

Year ended December 31, *(millions of Canadian dollars)*	**2019**	**2018**
Revenue (1)	**151.4**	152.7
Local access fees and other expenses (2)	**149.2**	144.4

(1) The significant components include contract sales of electricity, construction of infrastructure, provision of non-regulated power distribution services, and billing and customer care services relating to the City's utilities departments.
(2) This cost is passed through the Corporation directly to transmission and distribution customers.

STATEMENTS OF FINANCIAL POSITION

As at December 31, *(millions of Canadian dollars)*	**2019**	**2018**
Accounts receivable	**32.4**	30.8
Property, plant and equipment (1)	**3.2**	3.4
Accounts payable and accrued liabilities	**13.7**	14.4
Long-term debt (2)	**1,283.3**	1,185.4
Other long-term liabilities (3)	**6.2**	6.4

(1) Assets under lease.
(2) Interest and principal payments for the year ended December 31, 2019 were $45.4 million (2018 - $43.0 million) and $74.5 million (2018 - $70.6 million) respectively. In addition, for the year ended December 31, 2019, the Corporation paid a management fee of $3.1 million (2018 - $2.9 million) to the City.
(3) Finance lease obligation.

Transactions between the Corporation and the City have been recorded at the exchange amounts, as outlined by the contracts in effect between the Corporation and the City.

The Corporation has committed to a water supply agreement, whereby the City supplies a specified amount of water annually to facilitate Shepard Energy Centre operations.

Compensation of key management

The Corporation's key management personnel are members of the Board of Directors and the executive management team. Key management personnel have the authority and the responsibility for planning, directing and controlling the activities of the Corporation.

The total compensation and remuneration paid by the Corporation and its subsidiary companies to key management personnel is presented below:

Year ended December 31, *(millions of Canadian dollars)*	**2019**	**2018**
Salaries and other short-term employee benefits	**5.6**	6.0
Other long-term benefits	**2.4**	2.3
Retirement and post-employment benefits	**0.6**	0.6
	8.6	8.9

27. COMMITMENTS AND CONTINGENCIES

The Corporation is committed to expenditures for capital additions, rent for premises, vehicles and equipment under multiple lease contracts with varying expiration dates.

The Corporation commits to the purchase of renewable energy certificates and carbon offset credits. The Corporation commits to long-term service arrangements on certain generating assets.

The aggregated minimum payments under these arrangements over the next five years and thereafter are as follows:

(millions of Canadian dollars)	
2020	202.6
2021	10.8
2022	8.8
2023	5.5
2024	3.4
Thereafter	5.9

HISTORICAL TRANSMISSION LINE LOSS CHARGES

ENMAX has participated in various proceedings regarding the AESO's Line Loss Rule (LLR). The LLR establishes the loss factors that form the basis for certain transmission charges paid by Alberta generators, including ENMAX. Proceedings relating to the LLR address the AUC's authority to order retroactive adjustments (Module A); the replacement of the 2006-2016 methodology (Module B); and the calculation and invoicing of retroactive loss charges and credits for the 2006-2016 period (Module C). The AUC issued its decision on the last module, Module C, on December 18, 2017. The AUC's decisions in each of Module A and C have been the subject of permission to appeal applications before the Alberta Court of Appeal as well as review and variance applications before the AUC.

The permission to appeal applications were heard by the Alberta Court of Appeal in the second quarter of 2018. On December 20, 2018, the Court issued a decision denying permission to appeal the AUC's decision on Module A and further reserving its decision on permission to appeal Module C and related matters. On June 3, 2019, the Court of Appeal of Alberta issued a decision denying permission to appeal the AUC's Model C decision. Since the Court did not grant permission to appeal Module A or Module C, the decision of the AUC will stand unless the Court's decision is further challenged.

Based on the Court's decision in Module A and Module C, management believes that ENMAX may be required to make material payments to the AESO for historical amounts. Because the AUC's previous decisions do not require the AESO to consider commercial agreement terms and service transfer circumstances when the AESO determines which party to invoice, ENMAX could be invoiced for amounts for which it may not ultimately, in whole or in part, be responsible. Moreover, the invoices may not reflect the benefit of credits to which ENMAX is entitled nor any of ENMAX's rights to subsequently seek compensation, including under commercial agreements from other parties such as the Balancing Pool.

The AESO had expected to be in a position to issue charges or credits in April 2021, with initial settlement to occur in June 2021. In December 2019, the AESO filed an application to review and vary the Module C decision. If approved, the application would result in the AESO issuing charges or reimbursements to market participants once the AESO calculates loss factors for one or more of the years in the historic period. The AESO would repeat the process sequentially until all historical years have been settled. Approval of the application would commence the settlement process for historical line losses earlier than had been expected. ENMAX expects the AUC will issue a decision on the AESO's application before the end of Q1 2020.

Management does not have the information necessary to calculate a reliable range of expected charges and credits across the portfolio of generation held during the relevant periods and the impact to ENMAX of such amounts. ENMAX believes it has sufficient access to cash to satisfy any amounts which may be required to be paid.

INCOME TAX

Alberta Finance, Tax and Revenue Administration (Alberta Finance) is responsible for assessing the income tax returns filed under the PILOT regulation of the EUA, which became effective January 1, 2001.

When Alberta Finance conducted its 2006 audit of ENMAX Energy Corporation and ENMAX PSA Corporation, it disagreed with the interest expense deducted on the PILOT returns. ENMAX Corporation entered into intercompany loans with its affiliates ENMAX Energy Corporation in 2004 and ENMAX PSA Corporation in 2006 and 2007. ENMAX has received reassessments and communications from Alberta Finance in respect of the taxation years from 2004 through 2013. This matter was heard before the Court of Queen's Bench of Alberta with a decision rendered in favour of ENMAX on June 17, 2016. Following this decision, the Crown appealed, and the appeal was heard by the Court of Appeals of Alberta on October 12, 2017. On April 26, 2018, the Alberta Court of Appeal issued its decision allowing the Crown's appeal and reinstating the Notices of Reassessment previously issued by Alberta Finance. On June 21, 2018, ENMAX filed an application seeking leave to appeal to the Supreme Court of Canada. On February 28, 2019, the Supreme Court of Canada dismissed the application.

During 2019, ENMAX and Alberta Finance settled all remaining issues thereby forsaking the appeal and litigation process commenced.

The Corporation regularly reviews the potential for adverse outcomes in respect of tax matters and believes it has adequate provisions for these tax matters. The determination of the income tax provision is an inherently complex process, requiring management to interpret continually changing regulations and to make certain judgments. Although there can be no assurance that the disputes will be resolved in the Corporation's favor, the Corporation believes that the outcome of these disputes will not have a material adverse effect on its financial position.

LEGAL AND REGULATORY PROCEEDINGS

In the normal course of business, the Corporation is, and may be named as, a defendant or party in lawsuits and regulatory proceedings related to various matters. The Corporation currently believes the outcome of these lawsuits and regulatory proceedings will not have a material impact on the operating results or financial position of the Corporation.

The Corporation, along with other market participants in the province of Alberta, is subject to decisions, market rules, regulations, regulatory proceedings and/or jurisdiction of the AUC, AESO, Market Surveillance Administrator (MSA) and other authorities. The financial impact of decisions, market rules, regulations and regulatory proceedings is reflected in the consolidated financial statements when the amount can be reasonably estimated.

ENVIRONMENTAL

Provincial regulations aimed at reducing the levels of greenhouse gas (GHG) emissions took effect July 2007 and were subsequently updated in June 2015 for the years 2016 through 2019. The Alberta government proposed new legislation with regards to greenhouse gas emissions in June of 2019, effective January 1, 2020. In 2019 the Canadian Federal Government accepted these proposals as meeting the equivalent standards under the Pan-Canadian Framework.

For the year ended December 31, 2019, the consolidated financial statements include a charge to earnings in the amount of $6.3 million (2018-$6.5 million) included in costs of electricity services provided, relating to estimated compliance costs under the provincial GHG regulations for ENMAX Competitive Energy’s interests in natural gas-fueled generation facilities through its owned assets. Compliance payments are due to the Province of Alberta, directly or via plant owners, by June 30 of the year following the compliance year. ENMAX Competitive Energy has taken steps, including acquiring qualified offset credits from both its wind-generation assets and purchases on the wholesale market, to mitigate impacts of the GHG regulations.

LETTERS OF CREDIT

In the normal course of operations, letters of credit are issued to facilitate the extension of sufficient credit for counterparties having credit exposure to the Corporation or its subsidiaries. The Corporation uses unsecured credit facilities to fund general operating requirements and to provide liquidity support for commercial paper and commodity marketing programs. As at December 31, 2019 the Corporation had issued letters of credit amounting to $358.3 million (December 31, 2018 - $376.4 million).

As at	**December 31, 2019**		**December 31, 2018**	
(millions of Canadian dollars)	**Available**	**Used**	**Available**	**Used**
Unsecured credit facilities				
Bilateral operating facilities	**600.0**	**358.3**	600.0	376.4
Syndicated credit facilities	**250.0**	**53.0**	250.0	-
	850.0	**411.3**	850.0	376.4

28. SUBSEQUENT EVENTS

DIVIDENDS

On March 19, 2020, the Corporation declared a total dividend of $54.0 million payable to the City in quarterly instalments during 2020.

ACQUISITION

On March 25, 2019, the Corporation announced that it had entered into a definitive agreement to acquire Emera Maine, a regulated electric transmission and distribution company in Maine, for a purchase price of $1,286 million. Including assumed debt, the aggregate enterprise value is expected to be approximately $1,800 million. This transaction is aligned with the Corporate strategy to grow regulated cash flows and diversify revenue streams within North America. The acquisition will raise ENMAX's regulated rate base by approximately 50 per cent and increase the portion of future cash flows from regulated and non-commodity sources to approximately 70 per cent. ENMAX intends to finance this transaction using approximately 85 per cent debt and 15 per cent equity. The debt is expected to consist of a two-year bank loan, which is intended to be repaid before maturity, and private notes. The remaining balance will be funded in cash.

On March 17, 2020 the Commissioners of Maine Public Utilities Commission (MPUC) deliberated and approved the acquisition of Emera Maine by ENMAX. Closing will take place following issuance by the MPUC of the written order.

29. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the current period's presentation.

GLOSSARY OF TERMS

AC	Audit Committee
ACFA	Alberta Capital Finance Authority
ACTA	Alberta Corporate Tax Act
AESO	Alberta Electric System Operator
Alberta Finance	Alberta Finance, Tax and Revenue Administration
AOCI	Accumulated Other Comprehensive Income
ARO	Asset Retirement Obligation
AUC	Alberta Utilities Commission
Board	ENMAX's Board of Directors
CAPM	Capital Asset Pricing Model
CCEMA	Change and Emissions Management Amendment
CCIR	Carbon Competitive Incentive Regulation
CES	Calgary Electric System
CGU	Cash Generating Unit
CHP	Combined Heat and Power
CIAC	Contributions in aid of construction
Corporation	ENMAX Corporation and its subsidiaries
CNE	Comparable Net Earnings
CRMC	Commodity Risk Management Committee
CUPE	The Canadian Union of Public Employees
DAS	Distribution Access Services
DB	Defined benefit
DBO	Defined benefit obligation
DC	Defined contribution
Divisions	ENMAX Transmission and ENMAX Distribution
EBIT	Earnings before interest and income taxes
EBITDA	Earnings before interest, income tax and depreciation and amortization
EMCRA	Emissions Management and Climate Resilience Act
EMS	Environmental management system
ENMAX	ENMAX Corporation and its subsidiaries
ERM	Enterprise risk management
FVOCI	Fair value through other comprehensive income
FVTPL	Fair value through profit or loss
FX	Foreign exchange
GHG	Greenhouse gas
GJ	Gigajoule
GWh	Gigawatt hour
IASB	International Accounting Standards Board
IBEW	International Brotherhood of Electrical Workers
ICFR	Internal control over financial reporting
IFRIC	International Financial Reporting Interpretative Committee
IFRS	International Financial Reporting Standard
ITA	Income Tax Act (Canada)
LLR	Line Loss Rule
MD&A	Management's Discussion and Analysis
MPUC	Maine Public Utilities Commission
MSA	Market Surveillance Administrator
MW	Megawatt
MWh	Megawatt hour
NGTL	Nova Gas Transmission Ltd.
NOx	Nitrogen oxide
NSA	Negotiated **s**ettlement agreement
OCI	Other comprehensive income
OM&A	Operations, maintenance and administration
PBR	Performance based regulation
PILOT	Payment in lieu of tax
PPA	Power purchase arrangement
PPE	Property, plant and equipment
RMC	Risk Management Committee
ROE	Return on equity
ROU	Right-of-Use
RRO	Calgary Regulated rate option

GLOSSARY OF TERMS

SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
Shepard	Shepard Energy Centre
SIPP	Statement of Investment Policies and Procedures
SO2	Sulphur dioxide
The City	The City of Calgary
TIER	Technology Innovation and missions Reduction
TSP	Temporary Service Protocol
VIU	Value in Use
WACC	Weighted average cost of capital
WPC	Wind Participation Consortium

ADDITIONAL INFORMATION

ENMAX welcomes questions from stakeholders. Additional information relating to ENMAX can be found at enmax.com.

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