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'Connor 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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