CANADIAN UTILITIES LIMITED
An ATCO Company

CANADIAN UTILITIES LIMITED

FINANCIAL INFORMATION

FOR THE THREE MONTHS ENDED MARCH 31, 2019

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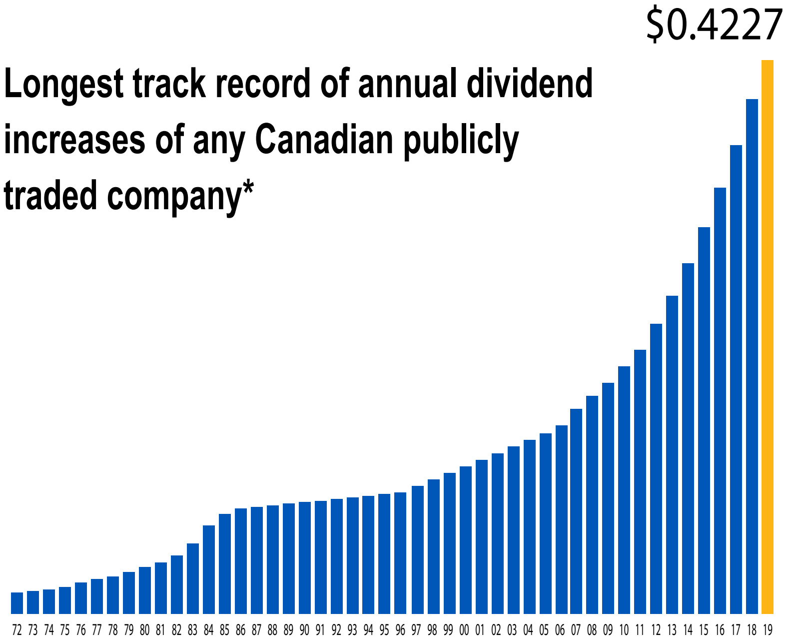
Q1 2019 INVESTOR FACT SHEET

CanadianUtilities.com
ELECTRICITY | PIPELINES & LIQUIDS

CANADIAN UTILITIES LIMITED
An ATCO Company

With approximately 5,000 employees and assets of $22 billion, Canadian Utilities Limited is an ATCO company. Canadian Utilities is a diversified global energy infrastructure corporation delivering service excellence and innovative business solutions in Electricity (electricity generation, transmission, and distribution); Pipelines & Liquids (natural gas transmission, distribution and infrastructure development, energy storage, and industrial water solutions); and Retail Energy (electricity and natural gas retail sales).

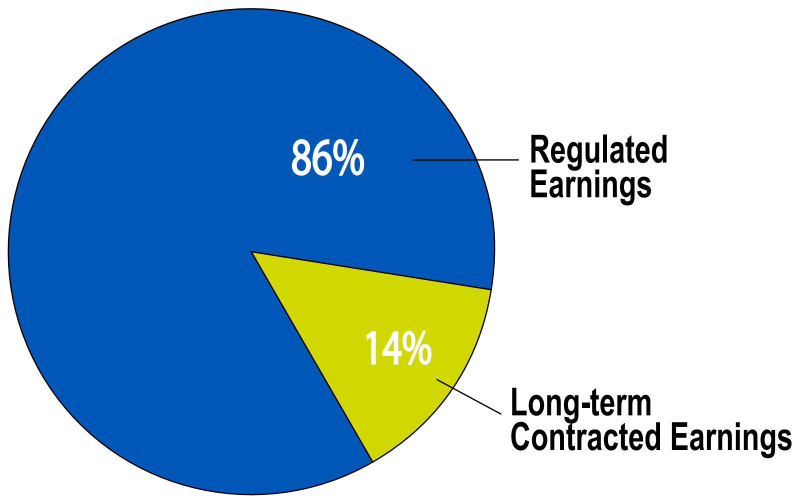
TRACK RECORD OF DIVIDEND GROWTH



* On April 4, 2019, Canadian Utilities declared a second quarter dividend of $0.4227 per share, or $1.69 per share annualized.

HIGH QUALITY EARNINGS BASE

2018 ADJUSTED EARNINGS



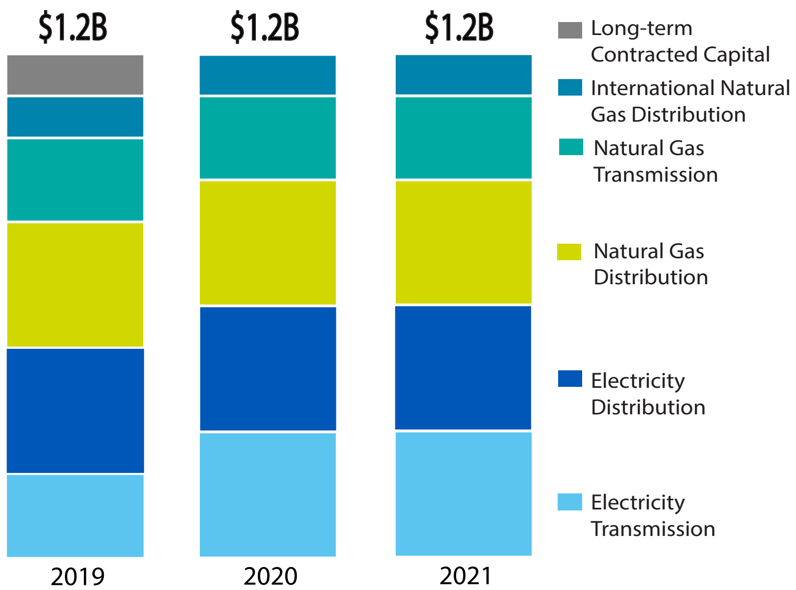
CANADIAN UTILITIES AT A GLANCE

"A-" rating by Standard & Poor's; "A" rating by DBRS Limited

Total Assets	$22 billion
Electric Powerlines	87,000 kms
Pipelines	64,500 kms
Generating Plants	21 Globally
Power Generating Capacity Share	2,517 MW *
Water Infrastructure Capacity	85,200 m³/d **
Natural Gas Storage Capacity	52 PJ ***
Hydrocarbon Storage Capacity	400,000 m³ ****

*megawatts **cubic metres per day ***petajoules ****cubic metres

FUTURE CAPITAL INVESTMENT



$3.6 billion in Regulated Utility and contracted capital growth projects expected in 2019 - 2021

CANADIAN UTILITIES SHARE INFORMATION

Common Shares (TSX): CU, CU.X

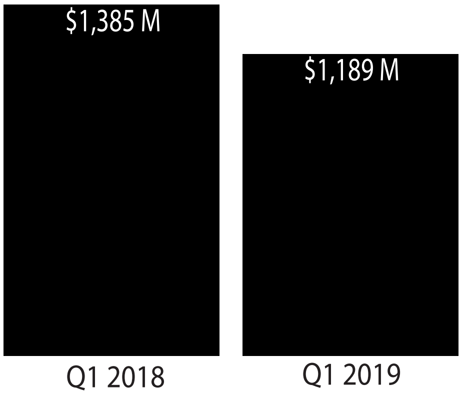
Market Capitalization	$10 billion
Weighted Average Common Shares Outstanding	272.6 million

It is important for prospective owners to understand that Canadian Utilities Limited is a diversified group of companies principally controlled by ATCO Ltd., which in turn is principally controlled by Sentgraf, a Southern family holding company. It is also important for present and prospective share owners to understand that the Canadian Utilities share registry has both Class A non-voting (CU) and Class B common (CU.X) shares.

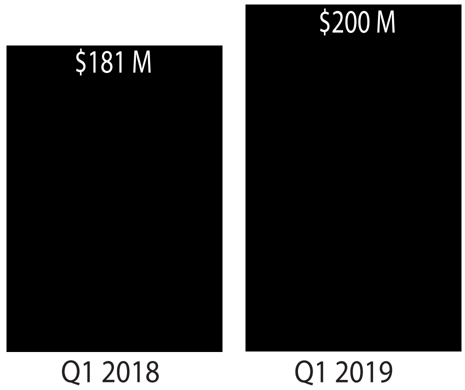
Adjusted earnings are earnings attributable to equity owners of the Company after adjusting for the timing of revenues and expenses associated with rate-regulated activities, dividends on equity preferred shares of the Company, and unrealized gains or losses on mark-to-market forward commodity contracts. Adjusted earnings also exclude one-time gains and losses, significant impairments, and items that are not in the normal course of business or a result of day-to-day operations. Certain statements in this document contain forward-looking information. Please refer to our forward-looking information disclaimer in Canadian Utilities' management's discussion and analysis for more information.

Q1 2019 RESULTS

CONSOLIDATED REVENUES



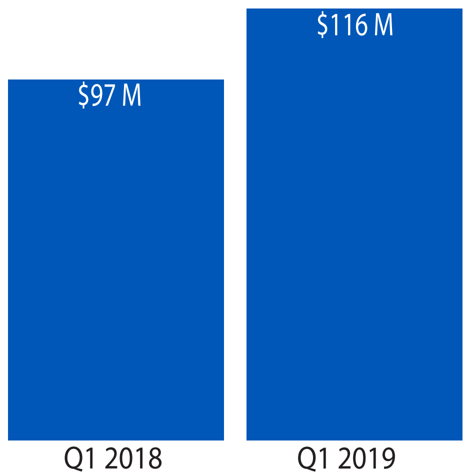
CONSOLIDATED ADJUSTED EARNINGS



ELECTRICITY GLOBAL BUSINESS UNIT

- Higher 2019 first quarter results were mainly due to increased Alberta power market prices, ongoing growth in the regulated rate base, and cost efficiencies in electricity distribution.
- In March, the Fort McMurray West 500-kV Transmission Project was energized three months ahead of schedule, on-budget and with an impeccable safety record. This 508-km transmission line, running from just west of Edmonton to Fort McMurray, will provide essential electricity, greater reliability and enhance the transmission system to meet growing demands in northern Alberta.
- Strategic reviews are under way for Canadian Utilities' ownership position in Alberta PowerLine and Canadian electricity generation assets.

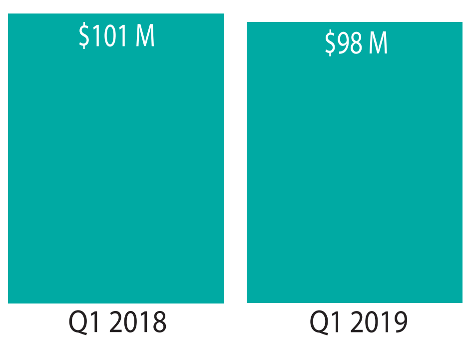
ADJUSTED EARNINGS



PIPELINES & LIQUIDS GLOBAL BUSINESS UNIT

- Lower 2019 first quarter results were mainly due to inflation rate adjustments in international natural gas distribution. Earnings adjustments are made each quarter for the impact of the inflation rate published by the Australian Bureau of Statistics. The published inflation rate for the first quarter of 2019, when applied to the rate of return calculations, produced a reduction to the revenues and earnings for the quarter. Lower results in international natural gas distribution were partially offset by ongoing growth in the natural gas distribution and transmission regulated rate base and cost efficiencies in natural gas distribution.

ADJUSTED EARNINGS



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CANADIAN UTILITIES LIMITED
An ATCO Company

2019 FIRST QUARTER FINANCIAL INFORMATION

INVESTOR FACT SHEET

MANAGEMENT DISCUSSION AND ANALYSIS

UNAUDITED INTERIM CONSOLIDATED FINANCIAL

STATEMENTS FOR THE NINE MONTHS ENDED MARCH 31, 2019

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CANADIAN UTILITIES LIMITED
An ATCO Company

CANADIAN UTILITIES LIMITED

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE THREE MONTHS ENDED MARCH 31, 2019

This Management's Discussion and Analysis (MD&A) is meant to help readers understand key operational and financial events that influenced the results of Canadian Utilities Limited (Canadian Utilities, our, we, us, or the Company) during the three months ended March 31, 2019.

This MD&A was prepared as of April 24, 2019, and should be read with the Company's unaudited interim consolidated financial statements for the three months ended March 31, 2019. Additional information, including the Company's previous MD&A (2018 MD&A), Annual Information Form (2018 AIF), and audited consolidated financial statements for the year ended December 31, 2018, is available on SEDAR at www.sedar.com. Information contained in the 2018 MD&A is not discussed in this MD&A if it remains substantially unchanged.

The Company is controlled by ATCO Ltd. and its controlling share owners, Sentgraf Enterprises Ltd. and the Southern family.

Terms used throughout this MD&A are defined in the Glossary at the end of this document.

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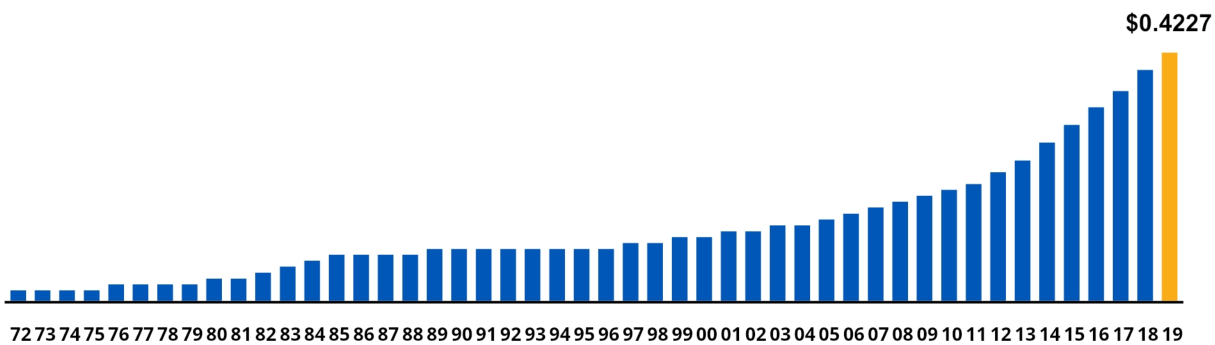
CANADIAN UTILITIES: WHAT SETS US APART

TRACK RECORD OF DIVIDEND GROWTH

We have increased our common share dividend every year for the past 47 years, the longest record of annual dividend increases of any Canadian publicly traded company. On April 4, 2019, we declared a second quarter dividend of 42.27 cents per share or $1.69 per share on an annualized basis. We aim to grow dividends in-line with our sustainable earnings growth, which is linked to growth from our regulated and long-term contracted investments.

Quarterly Dividend Rate 1972 - 2019
(dollars per share)



GROWING A HIGH QUALITY EARNINGS BASE

Over the past ten years, Canadian Utilities has invested approximately $15 billion in regulated and long-term contracted operations. The Regulated Utility portion of total adjusted earnings has grown from 46 per cent in 2009 to 86 per cent in 2018. Our highly contracted and regulated earnings base provides the foundation for continued dividend growth.

FUTURE CAPITAL INVESTMENT

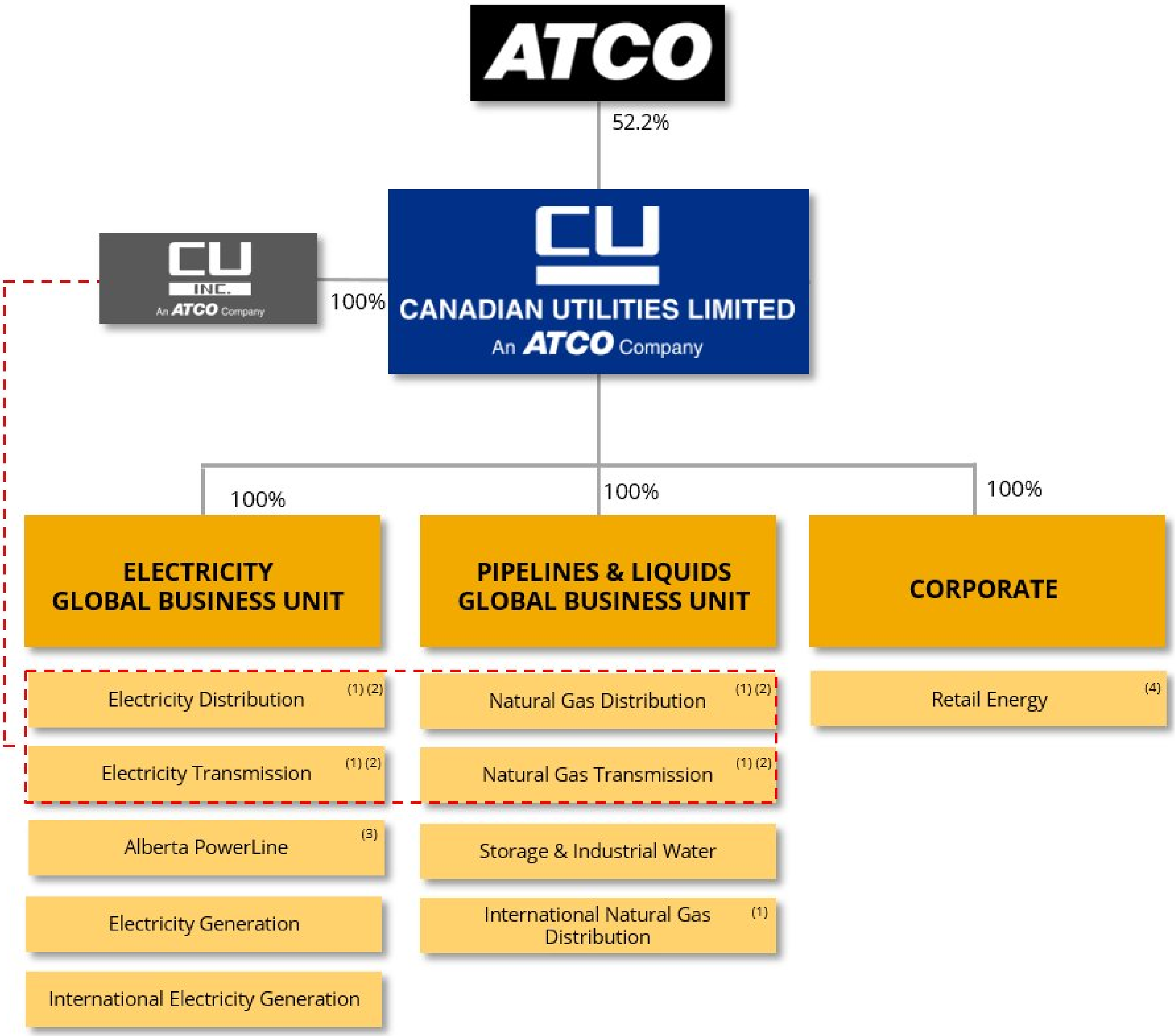
We will continue to grow our business in the years ahead. In the period 2019 to 2021, Canadian Utilities expects to invest $3.6 billion in Regulated Utility and long-term contracted assets in Canada, Australia, and Mexico, which will continue to strengthen our high quality earnings base. Of the $3.6 billion planned spend, $3.5 billion will be on Regulated Utilities.

FINANCIAL STRENGTH

Financial strength is fundamental to our current and future success. It ensures we have the financial capacity to fund our existing and future capital investment. We are committed to maintaining our strong, investment grade credit ratings, which allow us to access capital at attractive rates.

47 year	86%	$3.6B	A
track record of dividend growth	regulated earnings	3 year capital investment plans	range credit rating

ORGANIZATIONAL STRUCTURE



(1) Regulated businesses include Natural Gas Distribution, Natural Gas Transmission, International Natural Gas Distribution, Electricity Distribution, and Electricity Transmission.

(2) CU Inc. includes Natural Gas Distribution, Natural Gas Transmission, Electricity Distribution, and Electricity Transmission.

(3) Alberta PowerLine General Partner Ltd. is the general partner of Alberta PowerLine Limited Partnership (Alberta PowerLine or APL), a partnership between Canadian Utilities Limited (80 per cent) and Quanta Services, Inc. (20 per cent).

(4) Retail Energy, through ATCO Energy Ltd. (ATCOenergy), provides retail, commercial and industrial electricity and natural gas service in Alberta.

The unaudited interim consolidated financial statements include the accounts of Canadian Utilities Limited, and its subsidiaries, including the equity investment in joint ventures and a proportionate share of joint operations.

The unaudited interim consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) and the reporting currency is the Canadian dollar. Certain comparative figures throughout this MD&A have been reclassified to conform to the current presentation.

Canadian Utilities' website, www.canadianutilities.com, is a valuable source for the latest news of the Company's activities. Prior years' reports are also available on this website.

PERFORMANCE OVERVIEW

FINANCIAL METRICS

The following chart summarizes key financial metrics associated with our financial performance.

	Three Months Ended March 31		
($ millions, except per share data and outstanding shares)	**2019**	**2018**	**Change**
Key Financial Metrics			
Revenues	**1,189**	1,385	(196)
Adjusted earnings [1]	**200**	181	19
Electricity	**116**	97	19
Pipelines & Liquids	**98**	101	(3)
Corporate & Other	**(14)**	(17)	3
Adjusted earnings ($ per share) [1]	**0.73**	0.67	0.06
Earnings attributable to equity owners of the Company	**217**	179	38
Earnings attributable to Class A and Class B shares	**200**	162	38
Earnings attributable to Class A and Class B shares ($ per share)	**0.73**	0.60	0.13
Total assets	**22,018**	21,350	668
Cash dividends declared per Class A and Class B share (cents per share)	**42.27**	39.33	2.94
Funds generated by operations [1]	**551**	525	26
Capital investment [1]	**315**	744	(429)
Other Financial Metrics			
Weighted average Class A and Class B shares outstanding *(thousands):*			
Basic	**272,594**	270,715	1,879
Diluted	**273,180**	271,320	1,860

(1) Additional information regarding these measures is provided in the Non-GAAP and Additional GAAP Measures section of this MD&A.

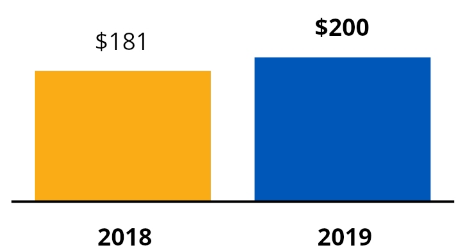
REVENUES

Revenues for the first quarter of 2019 were $1,189 million, $196 million lower than the same period in 2018. Lower revenues were mainly due to reduced Alberta PowerLine construction activity which was completed three months ahead of schedule and on budget.

ADJUSTED EARNINGS

Our adjusted earnings for the first quarter of 2019 were $200 million, or $0.73 per share, compared to $181 million or $0.67 per share for the same period in 2018. Higher earnings were recorded in Regulated Electricity, Independent Power Plants, and Natural Gas Distribution.

Adjusted Earnings ($ Millions)



The primary drivers of higher adjusted earnings results were as follows:

- Electricity adjusted earnings for the first quarter of 2019 were $19 million higher than the same period in 2018. Higher first quarter earnings were mainly due to increased Alberta power market prices, ongoing growth in the rate base and cost efficiencies in electricity distribution.
- Pipelines & Liquids adjusted earnings for the first quarter of 2019 were $3 million lower than the same period in 2018. Lower first quarter earnings were mainly due to inflation adjustments applied to the rate of return calculations in international natural gas distribution, partially offset by ongoing growth in the rate base and customers, and cost efficiencies in natural gas distribution.
- Corporate & Other adjusted earnings for the first quarter of 2019 were $3 million higher than the same period in 2018, mainly due to the timing of certain operating costs.

Additional detail on the financial performance of our Global Business Units is discussed in the Global Business Unit Performance section of this MD&A.

EARNINGS ATTRIBUTABLE TO EQUITY OWNERS OF THE COMPANY

Earnings attributable to equity owners of the Company were $217 million for the first quarter of 2019, or a $38 million increase compared to $179 million in the same period 2018. Earnings attributable to equity owners of the Company include significant impairments, dividends on equity preferred shares of the Company, timing adjustments related to rate-regulated activities, unrealized losses on mark-to-market forward commodity contracts, one-time gains and losses, and items that are not in the normal course of business or a result of day-to-day operations. These items are not included in adjusted earnings. The main drivers of the increase were improved results in all business units as well as unrealized gains on mark-to-market forward commodity contracts in the electricity generation business.

Earnings attributable to equity owners of the Company are earnings attributable to Class A and B shares plus dividends on equity preferred shares of the Company. Additional information regarding earnings attributable to Class A and B shares is presented in Note 6 of the unaudited interim consolidated financial statements.

More information on these and other items is included in the Reconciliation of Adjusted Earnings to Earnings Attributable to Equity Owners of the Company section of this MD&A.

ASSETS

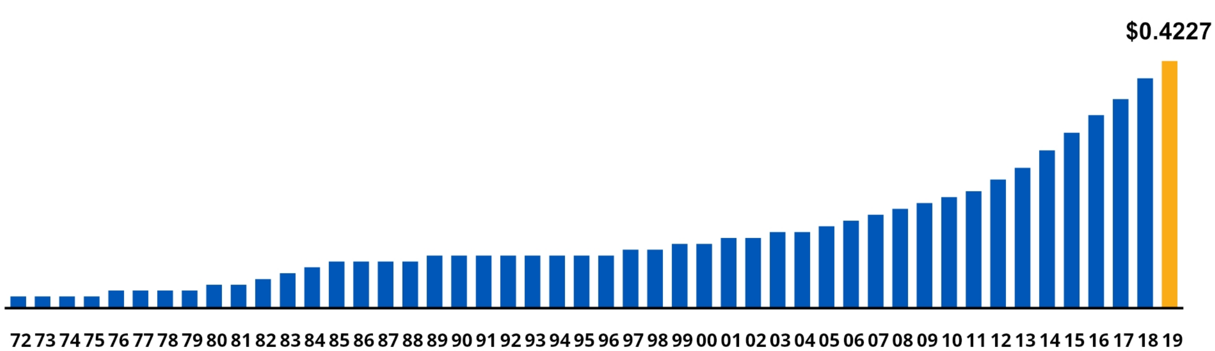
Total assets grew from $21 billion in the first quarter of 2018 to $22 billion in the first quarter of 2019. That growth occurred mainly as a result of continued capital investment in both APL and in the Regulated Utilities.

COMMON SHARE DIVIDENDS

On April 4, 2019, the Board of Directors declared a second quarter dividend of $42.27 cents per share. Dividends paid to Class A and Class B share owners totaled $115 million in the first quarter of 2019.

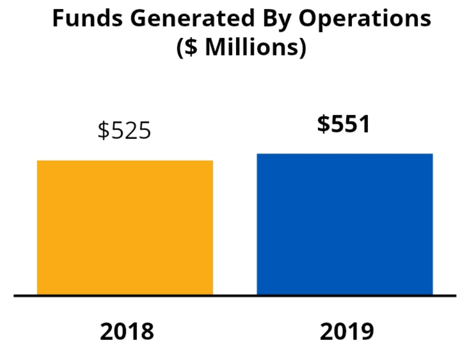
We have increased our common share dividend each year since 1972.

Quarterly Dividend Rate 1972 - 2019
(dollars per share)



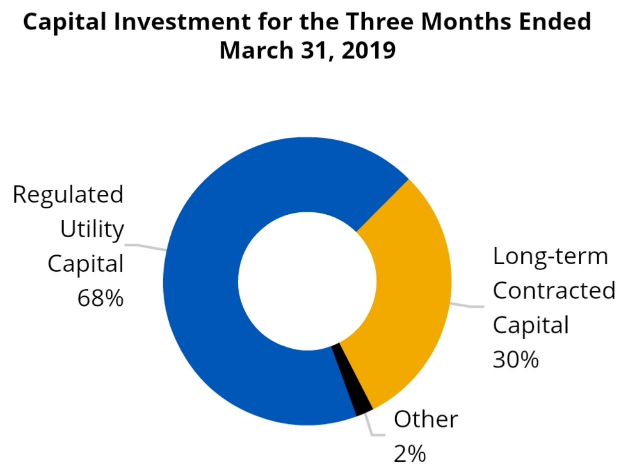
FUNDS GENERATED BY OPERATIONS

Funds generated by operations were $551 million for the first quarter of 2019, $26 million higher than the same period in 2018. The increase was mainly due to higher cash earnings and dividends received from joint ventures, partially offset by higher income taxes paid.



CAPITAL INVESTMENT

Total capital investment in the first quarter of 2019 was $315 million. Of this capital invested, $213 million was invested in Regulated Utilities, and $96 million was invested in long-term contracted assets including Alberta PowerLine. These investments either earn a return under a regulated business model or are under commercially secured long-term contracts.



GLOBAL BUSINESS UNIT PERFORMANCE

REVENUES

Electricity revenues of $690 million in the first quarter of 2019 were $209 million lower than the same period in 2018, mainly due to reduced construction activity for APL, partially offset by improved market conditions for Independent Power Plants.

ADJUSTED EARNINGS

	Three Months Ended March 31		
($ millions)	**2019**	**2018**	**Change**
Regulated Electricity			
Electricity Distribution	**38**	33	5
Electricity Transmission	**45**	40	5
Total Regulated Electricity Adjusted Earnings	**83**	73	10
Non-regulated Electricity			
Independent Power Plants	**14**	(5)	19
Thermal PPA Plants	**7**	14	(7)
International Electricity Generation	**5**	5	–
Alberta PowerLine	**7**	10	(3)
Total Non-regulated Electricity Adjusted Earnings	**33**	24	9
Total Electricity Adjusted Earnings	**116**	97	19

Electricity earnings were $116 million in the first quarter of 2019, $19 million higher than the same period in 2018. Higher first quarter earnings were mainly due to increased Alberta power market prices, ongoing growth in the regulated rate base and cost efficiencies.

Detailed information about the activities and financial results of Electricity's businesses is provided in the following sections.

REGULATED ELECTRICITY

Regulated Electricity provides regulated electricity distribution, transmission and distributed generation mainly in northern and central east Alberta, the Yukon and the Northwest Territories.

Electricity Distribution

Electricity distribution recorded adjusted earnings of $38 million in the first quarter of 2019, $5 million higher than the same period in 2018. Higher earnings were mainly due to ongoing growth in the rate base and cost efficiencies.

Electricity Transmission

Electricity transmission recorded adjusted earnings of $45 million in the first quarter of 2019, $5 million higher than the same period in 2018. Higher earnings were mainly due to the timing of various operating costs. Electric transmission first quarter 2019 adjusted earnings were recorded using interim rates approved by the Alberta Utilities Commission (AUC) for the 2018 to 2019 General Tariff Application (GTA). If the AUC approves all the aspects of the GTA, the potential increase to first quarter 2019 adjusted earnings would be approximately $4 million and would be recognized in adjusted earnings upon receipt of the decision which is expected in mid-2019.

NON-REGULATED ELECTRICITY

Non-regulated electricity activities supply electricity from natural gas, coal-fired and hydroelectric generating plants in Western Canada, Ontario, Australia and Mexico and non-regulated electricity transmission in Alberta.

Generating Plant Availability

Electricity generating availability for the first quarter of 2019 and 2018 is shown in the table below. Generating plant capacity fluctuates with the timing and duration of outages.

	Three Months Ended March 31		
	2019	**2018**	**Change**
Independent Power Plants	**97%**	90%	7%
Thermal PPA Plants	**95%**	92%	3%
International Electricity Generation	**100%**	100%	_

Higher availability in our Independent Power Plants in the first quarter of 2019 was primarily due to fewer planned outages. In the first quarter of 2018, work was completed on Battle River unit 4 to enable the unit to co-fire with natural gas and a planned minor outage was completed at Joffre.

Higher availability in our Thermal PPA Plants in the first quarter of 2019 was primarily due to fewer planned outages. In the first quarter of 2018, a planned minor outage was completed at the Battle River unit 5 plant. Effective January 1, 2019, Battle River unit 5 is being categorized under Independent Power Plants.

Availability in our International Electricity Generation Plants in the first quarter of 2019 was comparable to the same period in 2018.

Alberta Power Market Summary

Average Alberta Power Pool and natural gas prices and the resulting spark spreads for the first quarter of 2019 and 2018 are shown in the table below.

	Three Months Ended March 31		
	2019	**2018**	**Change**
Average Alberta Power Pool electricity price *($/MWh)*	**69.46**	34.93	34.53
Average natural gas price *($/GJ)*	**2.47**	1.96	0.51
Average market spark spread ($/*MWh*)	**48.47**	20.26	28.21

The average Alberta Power Pool electricity price for first quarter of 2019 was $34.53 per MWh higher compared to the same period in 2018. The increase was mainly due to two factors: near record low temperatures in February which increased electricity demand; less available capacity as a result of coal-fired generation outages and low wind generation.

Realized Forwards Sales Program

	Three Months Ended March 31		
	2019	**2018**	**Change**
Average volumes settled *(MW)*	**423**	229	194
Average realized spark spread *($/MWh)*	**28.79**	16.33	12.46

In the first quarter of 2019, Independent Power Plants sold forward 423 MW of power that settled at an average realized spark spread of $28.79 per MWh compared to 229 MW sold forward that settled at an average of $16.33 per MWh in the same period of 2018. Forward sales in the first quarter of 2019 resulted in lower realized earnings for this program compared to the same period in 2018. This was due to the increase in the spot market in the first quarter of 2019 which resulted in the realized spark spread being lower than the market spark spread of $48.47 per MWh, which is shown above in the Alberta Power Market Summary.

Independent Power Plants

Independent Power Plants recorded adjusted earnings of $14 million in the first quarter of 2019, $19 million higher compared to the same period in 2018. Higher earnings were mainly due to increased Alberta power market prices and lower general and administrative costs primarily due to the sale of the Barking power assets in the fourth quarter of 2018. Independent Power Plants' adjusted earnings includes contributions from Battle River unit 5 effective January 1, 2019.

Thermal PPA Plants

The electricity generated by the Sheerness units, and by Battle River unit 5 until September 30, 2018, is sold through PPAs. Under the PPAs, generating capacity for each generating unit must be made available to the PPA purchaser of that unit. These arrangements entitle us to recover forecast fixed and variable costs from the PPA purchaser. An operations and maintenance margin is included on these fixed and variable costs and is recognized over the term of the PPAs. Under the terms of the PPAs, counterparties are also subject to an incentive related to the generating unit availability. Incentives are payable by the PPA counterparties for availability in excess of predetermined targets. These performance obligation amounts are recognized based on the estimates of planned outages that impact future generating unit availability and future electricity prices over the term of the PPAs.

Thermal Power Plants recorded adjusted earnings of $7 million in the first quarter of 2019, $7 million lower than the same period in 2018. Lower earnings were mainly due to Battle River unit 5 earnings being categorized under Independent Power Plants effective January 1, 2019.

International Electricity Generation

International electricity generation activities supplies electricity from two natural gas-fired electricity generation plants in Australia: the Osborne plant in South Australia and the Karratha plant in Western Australia and from distributed electricity generation near San Luis Potosí, Mexico and hydroelectric generation near Veracruz, Mexico.

International electricity generation adjusted earnings in the first quarter of 2019 were comparable to the same period in 2018. Higher earnings from hydroelectricity generation in Veracruz, Mexico were offset by the impact of the new Osborne Power Purchase Agreement which came into effect in December 2018. Canadian Utilities negotiated a five year extension to the Power Purchase Agreement with Origin Energy Electricity Limited for the 180 MW Osborne Power facility. While the extension agreement includes lower pricing terms than the previous agreement, the five year extension represents an outperformance of the project returns contemplated in the original investment decision.

Alberta PowerLine

Alberta PowerLine is a partnership between Canadian Utilities (80 per cent) and Quanta Services, Inc. (20 per cent), with a 35-year contract from the Alberta Electric System Operator (AESO) to design, build, own, and operate the 500 km, Fort McMurray West 500-kV Transmission project, running from Wabamun, near Edmonton to Fort McMurray, Alberta.

APL's adjusted earnings were $7 million in the first quarter of 2019, $3 million lower when compared to the same period in 2018. Lower earnings were mainly due to lower construction activities, partially offset by recognition of the early energization incentive applicable to 2019.

ELECTRICITY RECENT DEVELOPMENTS

Alberta PowerLine

In March 2019, construction was completed the 500 km Fort McMurray West 500-kV Project. First quarter 2019 capital investment of $95 million was mainly due to the completion of electricity transmission line stringing and commissioning. The original target energization date was June 2019. The project was energized on March 28, 2019, three months ahead of schedule and on budget.

A strategic review is ongoing for Canadian Utilities' 80 per cent ownership position in Alberta PowerLine. This process is consistent with the Company's practice of continually evaluating and optimizing its portfolio of businesses. As part of this strategic review process, Canadian Utilities is providing an opportunity for Indigenous communities to obtain an equity interest in Alberta PowerLine. Canadian Utilities intends to remain as the operator of Alberta PowerLine over the 35-year concession arrangement.

Strategic Review of Canadian Electricity Generation Assets

Canadian Utilities announced on September 13, 2018, that it is exploring strategic alternatives for its Canadian electricity generation business. This process is consistent with the Company's practice of continually evaluating and optimizing its portfolio of businesses. There can be no assurance that this process will lead to any transaction.

REVENUES

Pipelines & Liquids revenues of $477 million in the first quarter of 2019 were $8 million lower than the same period in 2018. Lower revenues were mainly due to lower flow-through revenues in natural gas distribution for third party franchise and transmission fees.

ADJUSTED EARNINGS

	Three Months Ended March 31		
($ millions)	**2019**	**2018**	**Change**
Regulated Pipelines & Liquids			
Natural Gas Distribution	**72**	67	5
Natural Gas Transmission	**16**	18	(2)
International Natural Gas Distribution	**8**	14	(6)
Total Regulated Pipelines & Liquids Adjusted Earnings	**96**	99	(3)
Non-regulated Pipelines & Liquids			
Storage & Industrial Water	**2**	2	–
Total Pipelines & Liquids Adjusted Earnings	**98**	101	(3)

Pipelines & Liquids recorded adjusted earnings of $98 million in the first quarter of 2019, $3 million lower than the same period in 2018. Lower earnings were mainly due to inflation rate adjustments applied to the rate of return calculations in international natural gas distribution, partially offset by ongoing growth in the regulated rate base and cost efficiencies.

Detailed information about the activities and financial results of Pipelines & Liquid's businesses is provided in the following sections.

REGULATED PIPELINES & LIQUIDS

Natural Gas Distribution

Natural gas distribution services municipal, residential, business and industrial customers throughout Alberta and in the Lloydminster area of Saskatchewan.

Natural gas distribution recorded adjusted earnings of $72 million in the first quarter of 2019, $5 million higher than the same period in 2018 mainly due to ongoing growth in rate base and customers, and cost efficiencies.

Natural Gas Transmission

Natural gas transmission receives natural gas on its pipeline system from various gas processing plants as well as from other natural gas transmission systems and transports it to end users within the province of Alberta or to other pipeline systems, primarily for export out of the province.

Natural gas transmission recorded adjusted earnings of $16 million in the first quarter of 2019, $2 million lower than the same period in 2018. Lower earnings were mainly due to the timing of an AUC decision on applied-for rates in the 2019-2020 General Rates Application (GRA). If the AUC approves all the aspects of the GRA, the potential increase to first quarter 2019 adjusted earnings would be approximately $4 million and would be recognized in adjusted earnings upon receipt of the decision which is expected in mid-2019.

International Natural Gas Distribution

International natural gas distribution is a regulated provider of natural gas distribution services in Western Australia, serving metropolitan Perth and surrounding regions.

International natural gas distribution business recorded adjusted earnings of $8 million in the first quarter of 2019, $6 million lower than the same period in 2018, mainly due to a significant difference between inflation rates in the first quarter of 2018 and 2019. Earnings adjustments are made each quarter for the impact of the inflation rate published by the Australian Bureau of Statistics. The published inflation rate for the first quarter of 2019, when applied to the rate of return calculations, produced a reduction to the revenues and earnings for the quarter.

NON-REGULATED PIPELINES & LIQUIDS

Storage & Industrial Water

Storage & Industrial Water provides industrial water services and non-regulated natural gas and hydrocarbon storage, and transmission activities in Alberta.

The Storage & Industrial Water business recorded adjusted earnings of $2 million in the first quarter of 2019, comparable to the same period in 2018. Incremental earnings from two additional hydrocarbon storage caverns that became operational in the second quarter of 2018 were offset by lower natural gas storage earnings.

CORPORATE & OTHER

Canadian Utilities' Corporate & Other segment includes Retail Energy through ATCOenergy, launched in 2016 to provide retail electricity and natural gas services in Alberta. Corporate & Other also includes the global corporate head office in Calgary, Canada, the Australia corporate head office in Perth, Australia and the Mexico corporate head office in Mexico City, Mexico. Canadian Utilities Corporate and Other also includes CU Inc. and Canadian Utilities preferred share dividend expenses.

Including intersegment eliminations, Canadian Utilities Corporate & Other adjusted earnings in the first quarter of 2019 were $3 million higher compared to the same period in 2018, mainly due to the timing of certain operating costs.

REGULATORY DEVELOPMENTS

GENERIC COST OF CAPITAL (POST-2020)

In December 2018, the AUC initiated the 2021 Generic Cost of Capital (GCOC) proceeding. The main focus of the proceeding will be to evaluate if a formula-based approach should be used for the ROE. In April 2019, the AUC issued a letter which stated the scope of the proceeding will include a non-formulaic GCOC inquiry for the years 2021 and 2022, as well as consideration of returning to a formula-based approach. Initial evidence is due to be filed in January 2020. The AUC expects to issue a decision in 2020.

INFORMATION TECHNOLOGY COMMON MATTERS

This proceeding impacts the recovery of information technology costs by the Alberta Utilities from January 1, 2015. The Information Technology Common Matters proceeding was initiated in 2015 and was closed in December 2018. A decision is expected in the second quarter of 2019.

1ST GENERATION PERFORMANCE BASED REGULATION (PBR) RE-OPENER

In June 2018, the AUC initiated a process for electricity distribution and natural gas distribution as the re-opener clause was triggered by both utilities in 2017, the final year of the 1st Generation PBR plan. The PBR re-opener thresholds are triggered if a utility's earnings are +/- 500 bps from the approved ROE in one year or +/- 300 bps from approved ROE in two consecutive years.

In February 2019, the Commission issued its decision that the re-opening of the plan is not warranted, agreeing with Canadian Utilities' submission that the achievements of the utilities were not due to a flaw in the PBR plan, but rather were the result of management decisions responding to the incentives the plan created. This process is now closed.

2ND GENERATION PBR REBASING REVIEW AND VARIANCE

In February 2019, the AUC initiated a proceeding to re-consider the parameters of an anomaly adjustment to the going-in rates of the 2nd Generation PBR Plan, and to consider the types of anomaly adjustments to be permitted for Alberta distribution utilities under PBR. Going-in rates for the natural gas and electric distribution utilities for the 2018-2022 PBR Plan remain in place on an interim basis pending the outcome of this review.

ATCO PIPELINES 2019-2020 GENERAL RATE APPLICATION (GRA)

In July 2018, natural gas transmission filed a GRA for 2019 and 2020. The application requests, among other things, additional revenues due to rate base growth driven by capital expenditures, such as the Pembina-Keephills Pipeline project, and operations and maintenance expenditures. A decision from the AUC is expected in mid-2019.

ATCO ELECTRIC HANNA REGION TRANSMISSION DEVELOPMENT DEFERRAL APPLICATION

In February 2017, electricity transmission filed an application seeking approval of approximately $688 million of capital additions related to the Hanna Regional Transmission Development program with in-service dates between 2012 and 2015. A decision is expected in mid-2019.

ATCO ELECTRIC 2015-2017 DIRECT ASSIGNED PROJECTS DEFERRAL APPLICATION

In March 2019, electricity transmission filed an application seeking the approval of approximately $2.2 billion of capital additions from transmission projects with in-service dates between 2015-2017. The application includes $1.8 billion in capital additions from the Eastern Alberta Transmission Line (EATL).

ATCO GAS AUSTRALIA ACCESS ARRANGEMENT

International natural gas distribution submitted Access Arrangement 5 (AA5) to the Economic Regulation Authority (ERA) on August 31, 2018. The ERA released a draft AA5 decision in April 2019 with a final decision due in late third quarter 2019. International natural gas distribution is reviewing the draft decision and has six weeks to submit responses to the ERA.

SUSTAINABILITY, CLIMATE CHANGE AND ENERGY TRANSITION

We believe that reducing our environmental impact is integral to the pursuit of operational excellence and long-term sustainable growth. Our success depends on our ability to operate in a responsible and sustainable manner, today and in the future.

SUSTAINABILITY REPORTING

ATCO's annual Sustainability Report, expected to be released in June 2019, will focus on key material topics including:

- Energy Stewardship: access and affordability, security and reliability, and customer satisfaction,
- Environmental Stewardship: climate change and energy use, and environmental compliance,
- Safety: employee health and safety, public safety, and emergency preparedness, and
- Community and Indigenous Relations.

The Sustainability Report is based upon the internationally recognized Global Reporting Initiative (GRI) Standards. Our reporting is also guided by frameworks such as the Sustainability Accounting Standards Board and the Financial Stability Board’s Task Force on Climate-related Financial Disclosures recommendations.

The 2018 Sustainability Report, GRI Content Index, and other disclosures will be available on our website, at www.canadianutilities.com.

CLIMATE CHANGE AND ENERGY TRANSITION

To contribute to a lower carbon future, we continue to pursue initiatives looking at integrating lower intensity fuels, such as natural gas, hydrogen, renewables, and other clean energy solutions.

In 2018, we installed three electric vehicle (EV) charging stations between Calgary and Edmonton, Alberta providing end-users an opportunity to replace liquid fuel with a low-carbon emitting energy. In 2019, Canadian Utilities plans to significantly expand its number of EV direct current, fast charging stations in Alberta. The fourth EV station is targeted to be in-service in May with 19 more EV charging stations planned for installation throughout 2019 and 2020.

OTHER EXPENSES AND INCOME

A financial summary of other consolidated expenses and income items for the first quarter of 2019 and 2018 is given below. These amounts are presented in accordance with IFRS accounting standards. They have not been adjusted for the timing of revenues and expenses associated with rate-regulated activities and other items that are not in the normal course of business.

	Three Months Ended March 31		
($ millions)	**2019**	**2018**	**Change**
Operating costs	**529**	516	13
Service concession arrangement costs	**95**	368	(273)
Earnings from investment in joint ventures	**8**	8	–
Depreciation and amortization	**157**	151	6
Net finance costs	**117**	114	3
Income taxes	**80**	63	17

OPERATING COSTS

Operating costs, which are total costs and expenses less service concession arrangement costs and depreciation and amortization, increased by $13 million in the first quarter of 2019 when compared to the same period in 2018. Higher operating costs were mainly due to higher flow-through power and natural gas fuel costs from increased activity in Independent Power Plants and ATCOenergy, partially offset by unrealized gains on mark-to-market forward commodity contracts for the Independent Power Plants.

SERVICE CONCESSION ARRANGEMENT COSTS

Service concession arrangement costs in the first quarter of 2019 are costs Alberta PowerLine has recorded on third party construction activities for the Fort McMurray West 500-kV Project.

EARNINGS FROM INVESTMENT IN JOINT VENTURES

Earnings from investment in joint ventures is mainly comprised of our ownership position in several electricity generation plants and the Strathcona Storage Limited Partnership which operates hydrocarbon storage facilities near Fort Saskatchewan, Alberta.

Earnings in the first quarter of 2019 were comparable to the same period in 2018.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization expense increased by $6 million in the first quarter of 2019 compared to the same period in 2018 mainly due to continued growth in the regulated rate base.

NET FINANCE COSTS

Net finance costs increased by $3 million in the first quarter of 2019 when compared to the same period in 2018, mainly due to lower interest income on APL cash balances and interest expense associated with the incremental debt issued to fund the ongoing capital investment program in the Regulated Utilities.

INCOME TAXES

Income taxes increased by $17 million in the first quarter of 2019 when compared to the same period in 2018 mainly due to higher earnings before income taxes.

LIQUIDITY AND CAPITAL RESOURCES

Our financial position is supported by Regulated Utility and long-term contracted operations. Our business strategies, funding of operations, and planned future growth are supported by maintaining strong investment grade credit ratings and access to capital markets at competitive rates. Primary sources of capital are cash flow from operations and the debt and preferred share capital markets.

We consider it prudent to maintain enough liquidity to fund approximately one full year of cash requirements to preserve strong financial flexibility. Liquidity is generated by cash flow from operations and is supported by appropriate levels of cash and available committed credit facilities.

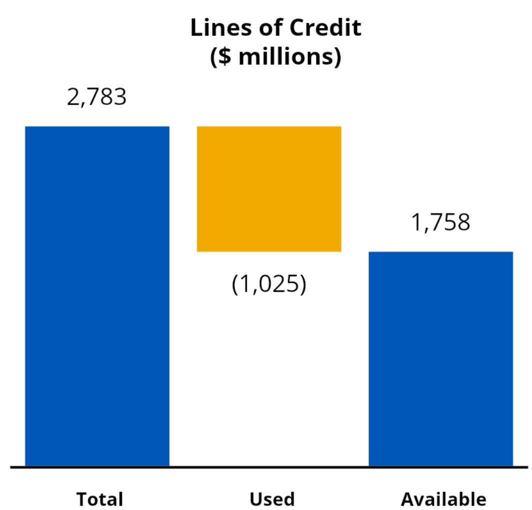
LINES OF CREDIT

At March 31, 2019, Canadian Utilities and its subsidiaries had the following lines of credit.

($ millions)	**Total**	**Used**	**Available**
Long-term committed	**2,230**	790	1,440
Uncommitted	**553**	235	318
Total	**2,783**	1,025	1,758

Of the $2,783 million in total credit lines, $553 million was in the form of uncommitted credit facilities with no set maturity date. The other $2,230 million in credit lines were committed, with maturities between 2020 and 2023, and may be extended at the option of the lenders.

Of the $1,025 million credit line usage, $382 million was related to ATCO Gas Australia Pty Ltd. and $400 million was related to issuances of commercial paper that are back-stopped by the corporate credit facilities. The majority of the remaining usage was associated with the issuance of letters of credit. Long-term committed credit lines are used to satisfy all of ATCO Gas Australia Pty Ltd.'s term debt financing needs.



CONSOLIDATED CASH FLOW

At March 31, 2019, the Company's cash position was $603 million, an increase of $4 million compared to December 31, 2018. The increase was mainly due to earnings achieved during the quarter, partially offset by cash used to fund the capital investment program.

Funds Generated by Operations

Funds generated by operations were $551 million in the first quarter of 2019, $26 million higher than the same period in 2018. The increase was mainly due to higher cash earnings and dividends received from joint ventures, partially offset by higher income taxes paid.

Cash Used for Capital Investment

Cash used for capital investment was $315 million in the first quarter of 2019, $429 million lower than the same period in 2018. Lower capital spending was mainly due to lower planned capital investment in Alberta PowerLine and natural gas distribution and transmission. First quarter 2018 capital investment in electricity generation included the $112 million acquisition of the Mexico hydroelectric facility.

Capital investment for the first quarter of 2019 and 2018 is shown in the table below.

	Three Months Ended March 31		
($ millions)	**2019**	**2018**	**Change**
Electricity			
Electricity Distribution	**45**	46	(1)
Electricity Transmission	**63**	69	(6)
Electricity Generation	**4**	116	(112)
Alberta PowerLine	**95**	368	(273)
Total Electricity	**207**	599	(392)
Pipelines & Liquids			
Natural Gas Distribution	**44**	55	(11)
Natural Gas Transmission	**45**	64	(19)
International Natural Gas Distribution	**16**	16	–
International Natural Gas Transmission and Storage & Industrial Water	**2**	6	(4)
Total Pipelines & Liquids	**107**	141	(34)
Corporate & Other	**1**	4	(3)
Canadian Utilities Total (1) (2)	**315**	744	(429)

(1) Includes capital expenditures in joint ventures of nil (2018 - $5 million) for the first quarter of 2019.

(2) Includes additions to property, plant and equipment, intangibles and $5 million (2018 - $5 million) of interest capitalized during construction for the first quarter of 2019.

Base Shelf Prospectuses

CU Inc. Debentures

On June 11, 2018, CU Inc. filed a base shelf prospectus that permits it to issue up to an aggregate of $1.5 billion of debentures over the 25-month life of the prospectus. As of April 24, 2019, aggregate issuances of debentures were $385 million.

Canadian Utilities Debt Securities and Preferred Shares

On June 11, 2018, Canadian Utilities filed a base shelf prospectus that permits it to issue up to an aggregate of $2 billion of debt securities and preferred shares over the 25-month life of the prospectus. No debt securities or preferred shares have been issued to date under this base shelf prospectus.

Dividends and Common Shares

We have increased our common share dividend each year since 1972, a 47-year track record. Dividends paid to Class A and Class B share owners totaled $115 million in the first quarter of 2019.

On April 4, 2019, the Board of Directors declared a second quarter dividend of 42.27 cents per share. The payment of any dividend is at the discretion of the Board of Directors and depends on our financial condition and other factors.

47 year
track record of increasing common share dividends

Canadian Utilities Dividend Reinvestment Plan (DRIP)

In 2018, Canadian Utilities issued 2,000,420 Class A non-voting shares under its DRIP in lieu of cash dividend payments of $63 million.

Effective January 10, 2019, Canadian Utilities' DRIP was suspended and no Class A non-voting shares were issued under its DRIP.

SHARE CAPITAL

Canadian Utilities' equity securities consist of Class A shares and Class B shares.

At April 23, 2019, we had outstanding 199,404,195 Class A shares, 73,744,280 Class B shares, and options to purchase 789,000 Class A shares.

CLASS A NON-VOTING SHARES AND CLASS B COMMON SHARES

Class A and Class B share owners are entitled to share equally, on a share for share basis, in all dividends the Company declares on either of such classes of shares as well as in the Company's remaining property on dissolution. Class B share owners are entitled to vote and to exchange at any time each share held for one Class A share.

If a take-over bid is made for the Class B shares and if it would result in the offeror owning more than 50 per cent of the outstanding Class B shares (excluding any Class B shares acquired upon conversion of Class A shares), the Class A share owners are entitled, for the duration of the take-over bid, to exchange their Class A shares for Class B shares and to tender the newly exchanged Class B shares to the take-over bid. Such right of exchange and tender is conditional on completion of the applicable take-over bid.

In addition, Class A share owners are entitled to exchange their shares for Class B shares if ATCO Ltd., the Company's controlling share owner, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B shares. In either case, each Class A share is exchangeable for one Class B share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering.

Of the 12,800,000 Class A shares authorized for grant of options under our stock option plan, 5,148,100 Class A shares were available for issuance at March 31, 2019. Options may be granted to officers and key employees of the Company and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the grant date. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant.

QUARTERLY INFORMATION

The following table shows financial information for the eight quarters ended June 30, 2017 through March 31, 2019.

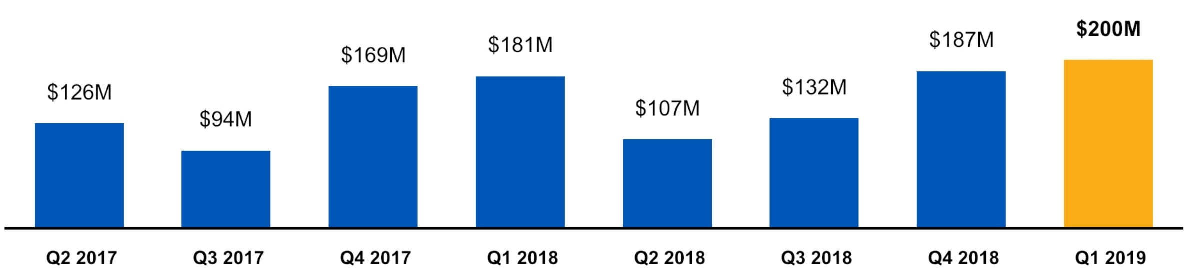
($ millions, except for per share data)	Q2 2018	Q3 2018	Q4 2018	Q1 2019
Revenues	967	990	1,035	**1,189**
Earnings (loss) attributable to equity owners of the Company	(3)	202	256	**217**
Earnings (loss) attributable to Class A and B shares	(19)	185	239	**200**
Earnings (loss) per Class A and Class B share *($)*	(0.07)	0.68	0.87	**0.73**
Diluted earnings (loss) per Class A and Class B share *($)*	(0.07)	0.68	0.87	**0.73**
Adjusted earnings per share per Class A and Class B share *($)*	0.39	0.49	0.69	**0.73**
Adjusted earnings				
Electricity	100	134	103	**116**
Pipelines & Liquids	27	17	102	**98**
Corporate & Other and Intersegment Eliminations	(20)	(19)	(18)	**(14)**
Total adjusted earnings	107	132	187	**200**

($ millions, except for per share data)	Q2 2017 (1)	Q3 2017 (1)	Q4 2017 (1)	Q1 2018
Revenues	942	930	1,208	1,385
Earnings attributable to equity owners of the Company	90	94	102	179
Earnings attributable to Class A and Class B shares	73	78	85	162
Earnings per Class A and Class B share *($)*	0.27	0.29	0.32	0.60
Diluted earnings per Class A and Class B share *($)*	0.27	0.29	0.32	0.60
Adjusted earnings per share per Class A and Class B share *($)*	0.47	0.35	0.63	0.67
Adjusted earnings				
Electricity	98	88	95	97
Pipelines & Liquids	43	24	94	101
Corporate & Other and Intersegment Eliminations	(15)	(18)	(20)	(17)
Total adjusted earnings	126	94	169	181

(1) These numbers have been restated to account for the impact of IFRS 15 adopted on January 1, 2018.

Adjusted Earnings

Our financial results for the previous eight quarters reflect continued growth and regulatory decisions in Regulated Utility operations as well as fluctuating commodity prices in electricity generation and sales, and natural gas storage operations. Interim results will vary due to the seasonal nature of demand for electricity and natural gas, and the timing of utility regulatory decisions.



Electricity

Electricity adjusted earnings are impacted by the timing of certain major regulatory decisions, and Alberta Power Pool pricing and spark spreads.

In 2017, second quarter earnings were impacted by the timing of operating and other costs in electricity distribution, and the 2015 to 2017 GTA Compliance decision in electricity transmission. Third quarter 2017 earnings included the adverse impact of the 2013 to 2014 Deferral Accounts decision in electricity transmission. Fourth quarter 2017 earnings were impacted by lower contributions in the electricity generation business from forward sales and increased business development expenses.

In 2018, earnings were impacted by rate rebasing under Alberta's regulated model in electricity distribution and lower electricity transmission interim rates approved by the AUC.

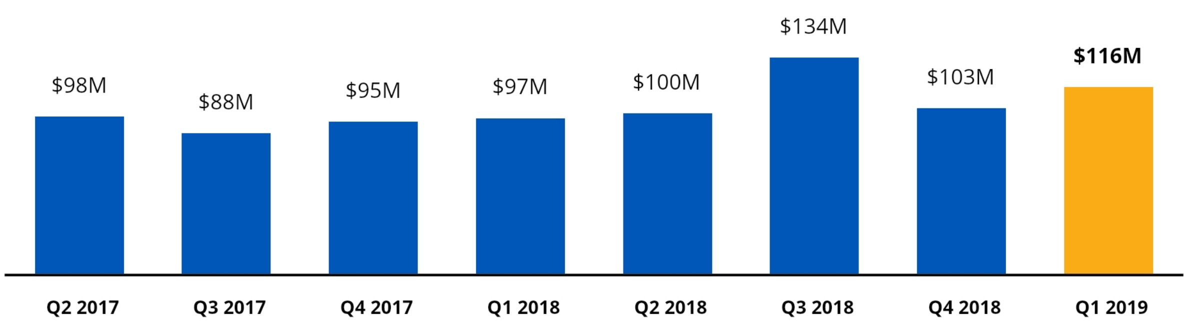
In the first quarter of 2018, Electricity earnings were adversely impacted by realized forward sales and minor plant outage costs in the Independent Power Plants, partially offset by earnings from Alberta PowerLine due to construction activity and earnings in Thermal PPAs due to the recognition of availability incentives.

In the second quarter of 2018, earnings increased compared to the second quarter of 2017 mainly due to improved market conditions for Independent Power Plants and higher recognition of availability incentives in the Thermal PPA Plants.

In the third quarter of 2018, earnings increased compared to the third quarter of 2017 mainly due to the completion of performance obligations and additional availability incentive earnings which resulted from the Battle River unit 5 PPA termination, and improved market conditions for Independent Power Plants. These improved earnings were partially offset by lower earnings due to lower scheduled construction activity at Alberta PowerLine.

In the fourth quarter of 2018, higher earnings compared to the fourth quarter of 2017 were mainly due to earnings from the sale of the Barking Power assets and improved conditions in the Alberta power market, as well as higher APL earnings recorded as result of an early energization incentive.

In the first quarter of 2019, higher earnings were mainly due to increased Alberta power market prices, ongoing growth in the regulated rate base and cost efficiencies in electricity distribution.



Pipelines & Liquids

Pipelines & Liquids' adjusted earnings are impacted by the timing of certain major regulatory decisions, seasonality, and demand for hydrocarbon and natural gas storage and water services.

Earnings in the second quarter of 2017 were impacted by lower seasonal demand in our natural gas distribution business. In the third quarter of 2017, earnings were impacted by inflation adjustments to rates in our international natural gas distribution business. Higher earnings in the fourth quarter of 2017 were mainly a result of rate base growth across Pipelines & Liquids' regulated utilities.

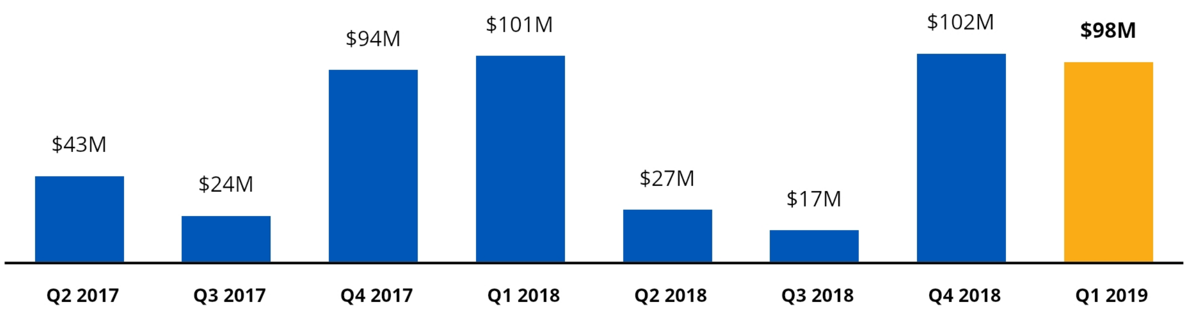
In 2018, earnings were adversely impacted by rate rebasing under Alberta's regulated model in natural gas distribution.

In the first quarter of 2018, earnings were positively impacted by higher seasonal demand and growth in rate base across the Pipelines & Liquids' Regulated businesses.

In the second and third quarters of 2018, lower earnings compared to the same periods in 2017 were mainly due to lower seasonal demand and the impact of rate rebasing under Alberta's regulated model in natural gas distribution, partially offset by growth in rate base across our Regulated Pipelines & Liquids businesses.

In the fourth quarter of 2018, higher earnings compared to the fourth quarter of 2017 were mainly due to growth in rate base, the timing of regulatory decisions and higher seasonal demand.

In the first quarter of 2019, lower earnings compared to the first quarter of 2018 were mainly due to inflation rate adjustments applied to the rate of return calculations in international natural gas distribution, partially offset by ongoing growth in the regulated rate base and cost efficiencies in natural gas distribution.



Earnings attributable to equity owners of the Company

Earnings attributable to equity owners of the Company includes timing adjustments related to rate-regulated activities and unrealized gains or losses on mark-to-market forward commodity contracts. They also include one-time gains and losses, significant impairments, restructuring charges and other items that are not in the normal course of business or a result of day-to-day operations recorded at various times over the past eight quarters. These items are excluded from adjusted earnings and are highlighted below:

- In the fourth quarter of 2017, Structures & Logistics recognized an impairment relating to workforce housing assets in Canada and space rental assets in the U.S. Structures & Logistics determined these assets were impaired due to a reduction in utilization, sustained decreases in key commodity prices as well as a significant reduction in the capital expenditure programs of key customers. The Company's 24.5 per cent share of the impairment decreased equity earnings by $7 million in the Corporate & Other segment.
- In the fourth quarter of 2017, the Company recorded an increase to earnings of $31 million on derecognition of customer contributions related to a sale of electricity generation assets on transitioning to finance lease accounting which resulted from the implementation of IFRS 15.
- In the second quarter of 2018, restructuring and other costs not in the normal course of business of $60 million after-tax were recorded. These costs mainly relate to staff reductions and associated severance costs, as well as costs related to decisions to discontinue certain projects that no longer represent long-term strategic value to the Company.
- In the third quarter of 2018, the Battle River unit 5 PPA was terminated by the Balancing Pool and dispatch control was returned to Canadian Utilities. Canadian Utilities received a payment from the Balancing Pool and also recorded additional coal-related costs and Asset Retirement Obligations associated with the Battle River generating facility. This one-time receipt and costs in the net amount of $36 million after-tax was excluded from adjusted earnings.
- In the fourth quarter of 2018, Canadian Utilities sold its 100 per cent ownership interest in Barking Power assets. An after-tax gain in the amount of $87 million was excluded from adjusted earnings.

NON-GAAP AND ADDITIONAL GAAP MEASURES

Adjusted earnings are defined as earnings attributable to equity owners of the Company after adjusting for the timing of revenues and expenses associated with rate-regulated activities, dividends on equity preferred shares of the Company, and unrealized gains or losses on mark-to-market forward commodity contracts. Adjusted earnings also exclude one-time gains and losses, significant impairments, and items that are not in the normal course of business or a result of day-to-day operations.

Adjusted earnings present earnings from rate-regulated activities on the same basis as was used prior to adopting IFRS - that basis being the U.S. accounting principles for rate-regulated activities. Management's view is that adjusted earnings allow for a more effective analysis of operating performance and trends. A reconciliation of adjusted earnings to earnings attributable to equity owners of the Company is presented in this MD&A. Adjusted earnings is an additional GAAP measure presented in Note 4 of the unaudited interim consolidated financial statements.

Adjusted earnings per Class A and Class B share is calculated by dividing adjusted earnings by the weighted average number of shares outstanding for the period.

Funds generated by operations is defined as cash flow from operations before changes in non-cash working capital and change in receivable under service concession arrangement. In management's opinion, funds generated by operations is a significant performance indicator of the Company's ability to generate cash during a period to fund capital expenditures. Funds generated by operations does not have any standardized meaning under IFRS and might not be comparable to similar measures presented by other companies. A reconciliation of funds generated by operations to cash flows from operating activities is presented in this MD&A.

Capital investment is defined as cash used for capital expenditures, business combinations, service concession arrangements, and cash used in the Company's proportional share of capital expenditures in joint ventures. In management's opinion, capital investment reflects the Company's total cash investment in assets. Capital expenditures includes additions to property, plant and equipment and intangibles as well as interest capitalized during construction. A reconciliation of capital investments to capital expenditures is presented in this MD&A.

RECONCILIATION OF ADJUSTED EARNINGS TO EARNINGS ATTRIBUTABLE TO EQUITY OWNERS OF THE COMPANY

Adjusted earnings are earnings attributable to equity owners of the Company after adjusting for the timing of revenues and expenses associated with rate-regulated activities, dividends on equity preferred shares of the Company, and unrealized gains or losses on mark-to-market forward commodity contracts. Adjusted earnings also exclude one-time gains and losses, significant impairments, and items that are not in the normal course of business or a result of day-to-day operations.

Adjusted earnings are a key measure of segment earnings that management uses to assess segment performance and allocate resources. It is management's view that adjusted earnings allow a better assessment of the economics of rate regulation in Canada and Australia than IFRS earnings.

($ millions)					**Three Months Ended March 31**
2019 **2018**	**Electricity**	**Pipelines & Liquids**	**Corporate & Other**	**Intersegment Eliminations**	**Consolidated**
Revenues	**690**	**477**	**69**	**(47)**	**1,189**
	899	485	39	(38)	1,385
Adjusted earnings	**116**	**98**	**(14)**	**–**	**200**
	97	101	(17)	–	181
Unrealized gains (losses) on mark-to-market forward commodity contracts	**6**	**–**	**–**	**–**	**6**
	(18)	–	–	–	(18)
Rate-regulated activities	**(3)**	**(5)**	**–**	**1**	**(7)**
	(13)	9	–	1	(3)
Dividends on equity preferred shares of Canadian Utilities Limited	**1**	**1**	**15**	**–**	**17**
	1	–	16	–	17
Other	**–**	**1**	**–**	**–**	**1**
	–	2	–	–	2
Earnings (loss) attributable to equity owners of the Company	**120**	**95**	**1**	**1**	**217**
	67	112	(1)	1	179

UNREALIZED GAINS (LOSSES) ON MARK-TO-MARKET FORWARD COMMODITY CONTRACTS

The Company enters into forward contracts in order to optimize available merchant capacity and manage exposure to electricity market price movements for its Independent Power and Thermal Plants not governed by a Power Purchase Arrangement. The forward contracts are measured at fair value. Unrealized gains and losses due to changes in the fair value of the forward contracts are recognized in earnings where hedge accounting is not applied. The CODM believes that removal of the unrealized gains or losses on mark-to-market forward commodity contracts provides a better representation of operating results for the Company's Independent Power and Thermal Plants not governed by a Power Purchase Arrangement. Realized gains or losses are recognized in adjusted earnings when the commodity contracts are settled.

RATE-REGULATED ACTIVITIES

ATCO Electric and its subsidiaries, ATCO Electric Yukon, Northland Utilities (NWT) and Northland Utilities (Yellowknife), as well as ATCO Gas, ATCO Pipelines and ATCO Gas Australia are collectively referred to as Regulated Utilities.

There is currently no specific guidance under IFRS for rate-regulated entities that the Company is eligible to adopt. In the absence of this guidance, the utilities do not recognize assets and liabilities from rate-regulated activities as may be directed by regulatory decisions. Instead, the Regulated Utilities recognize revenues in earnings when amounts are billed to customers, consistent with the regulator-approved rate design. Operating costs and expenses are recorded when incurred. Costs incurred in constructing an asset that meet the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

The Company uses standards issued by the Financial Accounting Standards Board (FASB) in the United States as another source of generally accepted accounting principles to account for rate-regulated activities in its internal reporting provided to the CODM. The CODM believes that earnings presented in accordance with the FASB standards are a better representation of the operating results of the Company's rate-regulated activities. Therefore, the Company presents adjusted earnings as part of its segmented disclosures on this basis. Rate-regulated accounting (RRA) standards impact the timing of how certain revenues and expenses are recognized when compared to non-rate regulated activities, to appropriately reflect the economic impact of a regulator's decisions on revenues.

At March 31, the significant timing adjustments as a result of the differences between rate-regulated accounting and IFRS are as follows:

	Three Months Ended March 31		
($ millions)	**2019**	**2018**	**Change**
Additional revenues billed in current period			
Future removal and site restoration costs (1)	**20**	19	1
Impact of colder temperatures (2)	**12**	12	–
Revenues to be billed in future periods			
Deferred income taxes (3)	**(28)**	(33)	5
Settlement of regulatory decisions and other items	**(11)**	(1)	(10)
	(7)	(3)	(4)

(1) Removal and site restoration costs are billed to customers over the estimated useful life of the related assets based on forecast costs to be incurred in future periods.

(2) ATCO Gas' customer rates are based on a forecast of normal temperatures. Fluctuations in temperatures may result in more or less revenue being recovered from customers than forecast. Revenues above or below the normal in the current period are refunded to or recovered from customers in future periods.

(3) Income taxes are billed to customers when paid by the Company.

Rate-regulated accounting differs from IFRS in the following ways:

Timing Adjustment	Items	RRA Treatment	IFRS Treatment
Additional revenues billed in current period	Future removal and site restoration costs, and impact of colder temperatures.	The Company defers the recognition of cash received in advance of future expenditures.	The Company recognizes revenues when amounts are billed to customers and costs when they are incurred.
Revenues to be billed in future periods	Deferred income taxes, impact of warmer temperatures, and impact of inflation on rate base.	The Company recognizes revenues associated with recoverable costs in advance of future billings to customers.	The Company recognizes costs when they are incurred, but does not recognize their recovery until customer rates are changed and amounts are collected through future billings.
Regulatory decisions received	For further details on regulatory decisions that caused a timing adjustment financial impact, refer to the Regulatory Developments section in this MD&A.	The Company recognizes the earnings from a regulatory decision pertaining to current and prior periods when the decision is received.	The Company does not recognize earnings from a regulatory decision when it is received as regulatory assets and liabilities are not recorded under IFRS.
Settlement of regulatory decisions and other items	Settlement of amounts receivable or payable to customers and other items.	The Company recognizes the amount receivable or payable to customers as a reduction in its regulatory assets and liabilities when collected or refunded through future billings.	The Company recognizes earnings when customer rates are changed and amounts are recovered or refunded to customers through future billings.

OTHER

Each quarter, the Company adjusts the deferred tax asset which was recognized as a result of the 2015 Tula Pipeline Project impairment. During the three months ended March 31, the Company recorded a foreign exchange gain of $1 million (2018 - foreign exchange gain of $2 million) due to a difference between the tax base currency, which is Mexican pesos, and the U.S. dollar functional currency.

RECONCILIATION OF FUNDS GENERATED BY OPERATIONS TO CASH FLOWS FROM OPERATING ACTIVITIES

Funds generated by operations is defined as cash flow from operations before changes in non-cash working capital and change in receivable under service concession arrangement. In management's opinion, funds generated by operations is a significant performance indicator of the Company's ability to generate cash during a period to fund capital expenditures. Funds generated by operations does not have any standardized meaning under IFRS and might not be comparable to similar measures presented by other companies.

($ millions)

2019 2018	Three Months Ended March 31
Funds generated by operations	**551** 525
Changes in non-cash working capital	**(110)** 163
Change in receivable under service concession arrangement	**(126)** (399)
Cash flows from operating activities	**315** 289

RECONCILIATION OF CAPITAL INVESTMENT TO CAPITAL EXPENDITURES

Capital investment is defined as cash used for capital expenditures, business combinations, service concession arrangements, and cash used in the Company's proportional share of capital expenditures in joint ventures. In management's opinion, capital investment reflects the Company's total cash investment in assets. Capital expenditures includes additions to property, plant and equipment and intangibles as well as interest capitalized during construction. A reconciliation of capital investments to capital expenditures is presented in this MD&A.

($ millions)				**Three Months Ended March 31**
2019 **2018**	**Electricity**	**Pipelines & Liquids**	**CUL Corporate & Other**	**Consolidated**
Capital Investment	**207**	**107**	**1**	**315**
	599	141	4	744
Capital Expenditure in joint ventures	–	–	–	–
	(3)	(2)	–	(5)
Business Combination [1]	–	–	–	–
	(112)	–	–	(112)
Service concession arrangement	**(95)**	–	–	**(95)**
	(368)	–	–	(368)
Capital Expenditures	**112**	**107**	**1**	**220**
	116	139	4	259

(1) Business combination includes ATCO subsidiary Canadian Utilities' acquisition of Electricidad de Golfo, a long-term contracted, 35 MW hydroelectric power station in the state of Veracruz, Mexico.

OTHER FINANCIAL INFORMATION

ACCOUNTING CHANGES

On January 1, 2019, the Company adopted the new accounting standard, IFRS 16 *Leases*, which replaces IAS 17 *Leases* and related interpretations. This standard introduces a new approach to lease accounting that requires a lessee to recognize right-of-use assets and lease liabilities for the rights and obligations created by leases. It brings most leases on-balance sheet for lessees, eliminating the distinction between operating and finance leases. Lessor accounting under the new standard retains similar classifications to the previous guidance.

The Company adopted the standard using the modified retrospective approach which does not require restatement of prior period financial information, as it recognizes the cumulative impact on the opening balance sheet and applies the standard prospectively. Accordingly, the comparative information in the unaudited interim consolidated financial statements is not restated.

On adoption of the new standard on January 1, 2019, the Company recognized $67 million of right-of-use assets and $67 million of lease liabilities. The right-of-use assets and lease liabilities relate to leases for land and buildings. From January 1, 2019, the Company recognizes depreciation expense on right-of-use assets and interest expense on lease liabilities with lease payments recorded as a reduction of the lease liability. Prior to the adoption of IFRS 16, lease payments were recorded as expenses in the statement of earnings. The adoption of IFRS 16 has not had a significant impact on earnings. Further information on the adoption of IFRS 16, right-of-use assets and lease liabilities are provided in Notes 3, 9 and 12 of the unaudited interim consolidated financial statements.

There are no other new or amended standards issued, but not yet effective, that the Company anticipates will have a material effect on the unaudited interim consolidated financial statements.

INTERNAL CONTROL OVER FINANCIAL REPORTING

There was no change in the Company's internal control over financial reporting that occurred during the period beginning on January 1, 2019, and ended on March 31, 2019, that materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

FORWARD-LOOKING INFORMATION

Certain statements contained in this MD&A constitute forward-looking information. Forward-looking information is often, but not always, identified by the use of words such as "anticipate", "plan", "estimate", "expect", "may", "will", "intend", "should", and similar expressions. Forward-looking information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. The Company believes that the expectations reflected in the forward-looking information are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking information should not be unduly relied upon.

The Company's actual results could differ materially from those anticipated in any forward-looking information contained in this MD&A as a result of regulatory decisions, competitive factors in the industries in which the Company operates, prevailing economic conditions, and other factors, many of which are beyond the control of the Company.

Any forward-looking information contained in this MD&A represents the Company's expectations as of the date hereof, and is subject to change after such date. The Company disclaims any intention or obligation to update or revise any forward-looking information whether as a result of new information, future events or otherwise, except as required by applicable securities legislation.

ADDITIONAL INFORMATION

Canadian Utilities has published its unaudited interim consolidated financial statements and its MD&A for the three months ended March 31, 2019. Copies of these documents may be obtained upon request from Investor Relations at 3rd Floor, West Building, 5302 Forand Street S.W., Calgary, Alberta, T3E 8B4, telephone 403-292-7500, fax 403-292-7532 or email investorrelations@atco.com.

GLOSSARY

AESO means the Alberta Electric System Operator.

Alberta Power Pool means the market for electricity in Alberta operated by AESO.

Alberta Utilities means Electricity Distribution (ATCO Electric Distribution), Electricity Transmission (ATCO Electric Transmission), Natural Gas Distribution (ATCO Gas) and Natural Gas Transmission (ATCO Pipelines).

AUC means the Alberta Utilities Commission.

Availability is a measure of time, expressed as a percentage of continuous operation, that a generating unit is capable of producing electricity, regardless of whether the unit is actually generating electricity.

Class A shares means Class A non-voting shares of the Company.

Class B shares means Class B common shares of the Company.

CODM means Chief Operating Decision Maker, and is comprised of the Chair and Chief Executive Officer, and the other members of the Executive Committee.

Company means Canadian Utilities Limited and, unless the context otherwise requires, includes its subsidiaries and joint arrangements.

DRIP means the dividend reinvestment plan (refer to the "Dividend Reinvestment Plan" section of this MD&A).

Earnings means Adjusted Earnings as defined in the Non-GAAP and Additional GAAP Measures section of this MD&A.

GAAP means Canadian generally accepted accounting principles.

Gigajoule (GJ) is a unit of energy equal to approximately 948.2 thousand British thermal units.

IFRS means International Financial Reporting Standards.

LNG means liquefied natural gas.

Megawatt (MW) is a measure of electric power equal to 1,000,000 watts.

Megawatt hour (MWh) is a measure of electricity consumption equal to the use of 1,000,000 watts of electricity over a one-hour period.

PPA means Power Purchase Arrangements that became effective on January 1, 2001, as part of the process of restructuring the electricity utility business in Alberta. PPAs are legislatively mandated and approved by the AUC.

Regulated Utilities means Electricity Distribution (ATCO Electric Distribution), Electricity Transmission (ATCO Electric Transmission), Natural Gas Distribution (ATCO Gas), Natural Gas Transmission (ATCO Pipelines) and International Natural Gas Distribution (ATCO Gas Australia).

Spark spread is the difference between the selling price of electricity and the marginal cost of producing electricity from natural gas. In this MD&A, spark spreads are based on an approximate industry heat rate of 7.5 GJ per MWh.

CANADIAN UTILITIES LIMITED
An ATCO Company

CANADIAN UTILITIES LIMITED

INTERIM CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

FOR THE THREE MONTHS ENDED MARCH 31, 2019

TABLE OF CONTENTS

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian Dollars except per share data)	Note	Three Months Ended March 31 2019	2018
Revenues	5	**1,189**	1,385
Costs and expenses			
Salaries, wages and benefits		**(88)**	(102)
Energy transmission and transportation		**(52)**	(44)
Plant and equipment maintenance		**(60)**	(53)
Fuel costs		**(78)**	(62)
Purchased power		**(64)**	(38)
Service concession arrangement costs		**(95)**	(368)
Depreciation and amortization	8, 9	**(157)**	(151)
Franchise fees		**(74)**	(79)
Property and other taxes		**(48)**	(44)
Unrealized gains (losses) on mark-to-market forward commodity contracts		**8**	(24)
Other		**(73)**	(70)
		(781)	(1,035)
Earnings from investment in joint ventures		**8**	8
Operating profit		**416**	358
Interest income		**6**	9
Interest expense		**(123)**	(123)
Net finance costs		**(117)**	(114)
Earnings before income taxes		**299**	244
Income taxes		**(80)**	(63)
Earnings for the period		**219**	181
Earnings attributable to:			
Equity owners of the Company		**217**	179
Non-controlling interests		**2**	2
		219	181
Earnings per Class A and Class B share	6	**$0.73**	$0.60
Diluted earnings per Class A and Class B share	6	**$0.73**	$0.60

See accompanying Notes to Unaudited Interim Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian Dollars)	Three Months Ended March 31 **2019**	**2018**
Earnings for the period	**219**	181
Other comprehensive loss, net of income taxes		
Items that will not be reclassified to earnings:		
Re-measurement of retirement benefits (1)	**(77)**	(21)
Items that are or may be reclassified subsequently to earnings:		
Cash flow hedges (2)	**(3)**	(5)
Cash flow hedges reclassified to earnings (3)	**2**	–
Foreign currency translation adjustment (3)	**(4)**	18
	(5)	13
Other comprehensive loss	**(82)**	(8)
Comprehensive income for the period	**137**	173
Comprehensive income attributable to:		
Equity owners of the Company	**135**	171
Non-controlling interests	**2**	2
	137	173

(1) Net of income taxes of $28 million for the three months ended March 31, 2019 (2018 - $8 million).

(2) Net of income taxes of $1 million for the three months ended March 31, 2019 (2018 - $2 million).

(3) Net of income taxes of nil.

See accompanying Notes to Unaudited Interim Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

(millions of Canadian Dollars)	Note	March 31 2019	December 31 2018
ASSETS			
Current assets			
Cash and cash equivalents	15	**603**	599
Accounts receivable and contract assets		**681**	676
Finance lease receivables		**19**	15
Inventories		**33**	31
Income taxes receivable		**18**	45
Restricted project funds	7	**307**	339
Receivable under service concession arrangement		**92**	67
Prepaid expenses and other current assets		**74**	84
		1,827	1,856
Non-current assets			
Property, plant and equipment	8	**17,309**	17,259
Intangibles		**631**	630
Right-of-use assets	3, 9	**64**	–
Investment in joint ventures		**196**	195
Finance lease receivables		**388**	380
Deferred income tax assets		**76**	69
Receivable under service concession arrangement		**1,430**	1,329
Other assets		**97**	101
Total assets		**22,018**	21,819
LIABILITIES			
Current liabilities			
Accounts payable and accrued liabilities		**833**	845
Asset retirement obligations and other provisions		**15**	32
Lease liabilities	3, 12	**11**	–
Other current liabilities		**50**	88
Short-term debt	10	**400**	175
Long-term debt	11	**366**	485
Non-recourse long-term debt		**20**	20
		1,695	1,645
Non-current liabilities			
Deferred income tax liabilities		**1,410**	1,380
Asset retirement obligations and other provisions		**146**	142
Retirement benefit obligations		**465**	356
Customer contributions		**1,808**	1,798
Lease liabilities	3, 12	**53**	–
Other liabilities		**143**	136
Long-term debt	11	**8,355**	8,419
Non-recourse long-term debt		**1,378**	1,381
Total liabilities		**15,453**	15,257
EQUITY			
Equity preferred shares		**1,483**	1,483
Class A and Class B share owners' equity			
Class A and Class B shares	14	**1,226**	1,226
Contributed surplus		**15**	15
Retained earnings		**3,683**	3,675
Accumulated other comprehensive loss		**(29)**	(24)
Total equity attributable to equity owners of the Company		**6,378**	6,375
Non-controlling interests		**187**	187
Total equity		**6,565**	6,562
Total liabilities and equity		**22,018**	21,819

See accompanying Notes to Unaudited Interim Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian Dollars)	Note	Class A and Class B Shares	Equity Preferred Shares	Contributed Surplus	Retained Earnings	Accumulated Other Comprehensive Loss	Total	Non-Controlling Interests	Total Equity
		Attributable to Equity Owners of the Company							
December 31, 2017		1,162	1,483	12	3,541	(45)	6,153	187	6,340
Earnings for the period		–	–	–	179	–	179	2	181
Other comprehensive loss		–	–	–	–	(8)	(8)	–	(8)
Losses on retirement benefits transferred to retained earnings		–	–	–	(21)	21	–	–	–
Shares issued		16	–	–	–	–	16	–	16
Dividends	13, 14	–	–	–	(123)	–	(123)	(2)	(125)
Share-based compensation		(1)	–	2	–	–	1	–	1
March 31, 2018		1,177	1,483	14	3,576	(32)	6,218	187	6,405
December 31, 2018		1,226	1,483	15	3,675	(24)	6,375	187	6,562
Earnings for the period		–	–	–	**217**	–	**217**	**2**	**219**
Other comprehensive loss		–	–	–	–	**(82)**	**(82)**	–	**(82)**
Losses on retirement benefits transferred to retained earnings		–	–	–	**(77)**	**77**	–	–	–
Dividends	13, 14	–	–	–	**(132)**	–	**(132)**	**(2)**	**(134)**
March 31, 2019		**1,226**	**1,483**	**15**	**3,683**	**(29)**	**6,378**	**187**	**6,565**

See accompanying Notes to Unaudited Interim Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian Dollars)	Note	Three Months Ended March 31 2019	2018
Operating activities			
Earnings for the period		**219**	181
Adjustments to reconcile earnings to cash flows from operating activities	15	**332**	344
Changes in non-cash working capital		**(110)**	163
Change in receivable under service concession arrangement		**(126)**	(399)
Cash flows from operating activities		**315**	289
Investing activities			
Additions to property, plant and equipment		**(201)**	(240)
Additions to intangibles		**(14)**	(14)
Acquisition, net of cash acquired		**–**	(70)
Investment in joint ventures		**–**	(6)
Changes in non-cash working capital		**(14)**	(26)
Other		**–**	(3)
Cash flows used in investing activities		**(229)**	(359)
Financing activities			
Net issue of short-term debt	10	**225**	100
Issue of long-term debt		**–**	40
Release of restricted project funds	7	**105**	216
Repayment of long-term debt		**(180)**	–
Repayment of non-recourse long-term debt		**(3)**	(4)
Repayment of lease liabilities	12	**(3)**	–
Issue of Class A shares		**–**	1
Dividends paid on equity preferred shares		**(17)**	(17)
Dividends paid to non-controlling interests		**(2)**	(2)
Dividends paid to Class A and Class B share owners		**(115)**	(90)
Interest paid		**(104)**	(102)
Other		**14**	2
Cash flows (used in) from financing activities		**(80)**	144
Increase in cash position (1)		**6**	74
Foreign currency translation		**(2)**	(2)
Beginning of period		**599**	418
End of period	15	**603**	490

(1) Cash position includes $74 million which is not available for general use by the Company (2018 - $93 million).

See accompanying Notes to Unaudited Interim Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

MARCH 31, 2019

(Tabular amounts in millions of Canadian Dollars, except as otherwise noted)

1. THE COMPANY AND ITS OPERATIONS

Canadian Utilities Limited was incorporated under the laws of Canada and is listed on the Toronto Stock Exchange. Its head office is at 4th Floor, West Building, 5302 Forand Street SW, Calgary, Alberta T3E 8B4 and its registered office is 20th Floor, 10035 - 105 Street, Edmonton, Alberta T5J 2V6. The Company is controlled by ATCO Ltd. and its controlling share owner, the Southern family.

Canadian Utilities Limited is engaged in the following global business activities:

- Electricity (electricity generation, distributed generation, and electricity distribution, transmission and infrastructure development);
- Pipelines & Liquids (natural gas transmission, distribution and infrastructure development, energy storage, and industrial water solutions); and
- Retail Energy (included in the Corporate & Other segment).

The unaudited interim consolidated financial statements include the accounts of Canadian Utilities Limited and its subsidiaries (the Company). The statements also include the accounts of a proportionate share of the Company's investments in joint operations and its equity-accounted investments in joint ventures.

2. BASIS OF PRESENTATION

STATEMENT OF COMPLIANCE

The unaudited interim consolidated financial statements are prepared according to International Accounting Standard (IAS) 34 Interim Financial Reporting using accounting policies consistent with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board and IFRS Interpretations Committee (IFRIC). They do not include all the disclosures required in annual consolidated financial statements and should be read in conjunction with the Company's consolidated financial statements for the year ended December 31, 2018, prepared according to IFRS.

The unaudited interim consolidated financial statements are prepared following the same accounting policies used in the Company's most recent annual consolidated financial statements, except for the change in accounting policy described in Note 3 and income taxes. In interim periods, income taxes are accrued using an estimate of the annualized effective tax rate applied to year-to-date earnings.

The unaudited interim consolidated financial statements were authorized for issue by the Audit & Risk Committee, on behalf of the Board of Directors, on April 24, 2019.

BASIS OF MEASUREMENT

The unaudited interim consolidated financial statements are prepared on a historic cost basis, except for derivative financial instruments, retirement benefit obligations and cash-settled share-based compensation liabilities which are carried at remeasured amounts or fair value.

Revenues, earnings and adjusted earnings for any quarter are not necessarily indicative of operations on an annual basis. Quarterly financial results may be affected by the seasonal nature of the Company's operations, changes in electricity prices in Alberta, the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees, the timing of maintenance outages at power generating plants, and the timing of utility rate decisions.

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

3. CHANGE IN ACCOUNTING POLICY

LEASES

The Company adopted IFRS 16 *Leases* on January 1, 2019, which introduces a new approach to lease accounting. The Company adopted the standard using the modified retrospective approach, which does not require restatement of prior period financial information, as it recognizes the cumulative impact on the opening balance sheet and applies the standard prospectively. Accordingly, the comparative information in these unaudited interim consolidated financial statements is not restated.

At the inception of a contract, the Company assesses whether the contract is, or contains, a lease based on whether the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. This policy is applied to contracts entered into, or modified, on or after January 1, 2019.

Practical expedients

Effective January 1, 2019, the IFRS 16 transition date, the Company elected to use the following practical expedients under the modified retrospective transition approach:

- Leases with lease terms of less than twelve months (short-term leases) and leases of low-value assets (less than $5,000 U.S. dollars) (low-value leases) that have been identified at transition, were not recognized in the consolidated balance sheet;
- Right-of-use assets on transition were measured at the amount equal to the lease liabilities at transition, adjusted by the amount of any prepaid or accrued lease payments;
- For certain leases having associated initial direct costs, the Company, at initial measurement on transition, excluded these directs costs from the measurement of the right-of-use assets; and
- Any provision for onerous lease contracts previously recognized at the date of adoption of IFRS 16, has been applied to the associated right-of-use asset recognized upon transition.

The Company as a lessee

Where the Company is a lessee, a right-of-use asset representing the right to use the underlying asset with a corresponding lease liability is recognized when the leased asset becomes available for use by the Company.

The right-of-use asset is recognized at cost and is depreciated on a straight-line basis over the shorter of the estimated useful life of the asset and the lease term on a straight-line basis. The cost of the right-of-use asset is based on the following:

- the amount of initial recognition of related lease liability;
- adjusted by any lease payments made on or before inception of the lease;
- increased by any initial direct costs incurred; and
- decreased by lease incentives received and any costs to dismantle the leased asset.

The lease term includes consideration of an option to extend or to terminate if the Company is reasonably certain to exercise that option. In addition, the right-of-use asset is periodically reduced by impairment losses, if any, and adjusted for certain re-measurements of the lease liability.

Lease liabilities are initially recognized at the present value of the lease payments. The lease payments are discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the Company's incremental borrowing rate. Generally, the Company uses its incremental borrowing rate as the discount rate. Subsequent to recognition, lease liabilities are measured at amortized cost using the effective interest rate method. Lease liabilities are remeasured when there is a change in future lease payments arising mainly from a change in an index or rate, if there is a change in the Company's estimate of the amount expected to be payable under a residual value guarantee, or if the Company changes its assessment of whether it will exercise a purchase, renewal or termination option.

The payments related to short-term leases and low-value leases are recognized as other expenses over the lease term in the unaudited interim consolidated statements of earnings.

Significant accounting estimates and assumptions

In the situation where the implicit interest rate in the lease is not readily determined, the Company uses judgment to estimate the incremental borrowing rate for discounting the lease payments. The Company's incremental borrowing rate generally reflects the interest rate that the Company would have to pay to borrow a similar amount at a similar term and with a similar security. The Company estimates the lease term by considering the facts and circumstances that create an economic incentive to exercise an extension or termination option. Certain qualitative and quantitative assumptions are used when evaluating these incentives.

The Company as a lessor

The Company's unaudited interim consolidated financial statements were not impacted by the adoption of IFRS 16 *Leases* in relation to lessor accounting. Lessors will continue with the dual classification model for recognized leases with the resultant accounting remaining unchanged from IAS 17 *Leases*.

IMPACT OF CHANGES IN ACCOUNTING POLICY

Impact of adoption of IFRS 16 on unaudited interim consolidated financial statements

On January 1, 2019, the Company recognized $67 million of right-of-use assets and $67 million of lease liabilities. The Company applied its weighted average incremental borrowing rate at January 1, 2019, 3.00 per cent, to determine the amount of lease liabilities. The effect of the adjustment to the amounts recognized in the Company's unaudited interim consolidated balance sheet at January 1, 2019 is shown below.

(millions of Canadian Dollars)	Note	December 31, 2018, as previously reported	IFRS 16 re-measurement adjustments on January 1, 2019	Restated
ASSETS				
Non-current assets				
Right-of-use assets	9	–	67	67
Total assets		21,819	67	21,886
LIABILITIES				
Current liabilities				
Lease liabilities	12	–	11	11
Non-current liabilities				
Lease liabilities	12	–	56	56
Total liabilities		15,257	67	15,324
EQUITY				
Equity preferred shares		1,483	–	1,483
Class A and Class B share owners' equity				
Class A and Class B shares		1,226	–	1,226
Contributed surplus		15		15
Retained earnings		3,675		3,675
Accumulated other comprehensive loss		(24)	–	(24)
Total equity attributable to equity owners of the Company		6,375	–	6,375
Non-controlling interests		187	–	187
Total equity		6,562	–	6,562
Total liabilities and equity		21,819	67	21,886

The reconciliation of differences between the operating lease commitments disclosed at December 31, 2018 (when applying IAS 17 *Leases*), discounted using the weighted average incremental borrowing rate at January 1, 2019, and the lease liabilities recognized upon adoption of IFRS 16 *Leases*, is shown below.

Operating lease commitments at December 31, 2018, as previously reported	138
Adjustment to reflect discounting of the operating lease commitments at December 31, 2018, using the weighted average incremental borrowing rate	(17)
Lease liabilities at January 1, 2019, before exemptions and other adjustments	121
Exemptions applied upon recognition of lease liabilities:	
Short-term leases	(1)
Contracts not meeting the definition of a lease [(1)]	(55)
Recognition of the lease term extension option [(2)]	2
Lease liabilities recognized at January 1, 2019	67

(1) Contracts not meeting the definition of a lease are comprised of contracts or certain components of contracts that are considered executory service arrangements.

(2) Recognition of the lease term extension option relates to leases where the extension option is reasonably certain to be exercised.

4. SEGMENTED INFORMATION

Results by operating segment for the three months ended March 31 are shown below.

2019 2018	Electricity	Pipelines & Liquids	Corporate & Other	Intersegment Eliminations	Consolidated
Revenues - external	**681**	**448**	**60**	**–**	**1,189**
	888	468	29	–	1,385
Revenues - intersegment	**9**	**29**	**9**	**(47)**	**–**
	11	17	10	(38)	–
Revenues	**690**	**477**	**69**	**(47)**	**1,189**
	899	485	39	(38)	1,385
Operating expenses (1)	**(358)**	**(247)**	**(65)**	**46**	**(624)**
	(642)	(236)	(45)	39	(884)
Depreciation and amortization	**(92)**	**(63)**	**(4)**	**2**	**(157)**
	(92)	(59)	(2)	2	(151)
Earnings from investment in joint ventures	**5**	**3**	**–**	**–**	**8**
	7	1	–	–	8
Net finance costs	**(80)**	**(39)**	**2**	**–**	**(117)**
	(79)	(38)	4	(1)	(114)
Earnings before income taxes	**165**	**131**	**2**	**1**	**299**
	93	153	(4)	2	244
Income taxes	**(44)**	**(35)**	**(1)**	**–**	**(80)**
	(25)	(40)	3	(1)	(63)
Earnings for the period	**121**	**96**	**1**	**1**	**219**
	68	113	(1)	1	181
Adjusted earnings	**116**	**98**	**(14)**	**–**	**200**
	97	101	(17)	–	181
Total assets (2)	**13,430**	**7,881**	**1,222**	**(515)**	**22,018**
	13,494	7,842	574	(91)	21,819
Capital expenditures (3)	**112**	**107**	**1**	**–**	**220**
	116	139	4	–	259

(1) *Includes total costs and expenses, excluding depreciation and amortization expense.*
(2) *2018 comparatives are at December 31, 2018.*
(3) *Includes additions to property, plant and equipment and intangibles and $5 million of interest capitalized during construction for the three months ended March 31, 2019 (2018 - $5 million).*

ADJUSTED EARNINGS

Adjusted earnings are earnings attributable to equity owners of the Company after adjusting for:

- the timing of revenues and expenses for rate-regulated activities,
- dividends on equity preferred shares of the Company,
- one-time gains and losses,
- unrealized gains and losses on mark-to-market forward commodity contracts,
- significant impairments, and
- items that are not in the normal course of business or a result of day-to-day operations.

Adjusted earnings are a key measure of segment earnings used by the CODM to assess segment performance and allocate resources. Other accounts in the unaudited interim consolidated financial statements have not been adjusted as they are not used by the CODM for those purposes.

The reconciliation of adjusted earnings and earnings for the three months ended March 31 is shown below.

2019 2018	Electricity	Pipelines & Liquids	Corporate & Other	Intersegment Eliminations	Consolidated
Adjusted earnings	**116**	**98**	**(14)**	**–**	**200**
	97	101	(17)	–	181
Unrealized gain (losses) on mark-to-market forward commodity forward commodity contracts	**6**	**–**	**–**	**–**	**6**
	(18)	–	–	–	(18)
Rate-regulated activities	**(3)**	**(5)**	**–**	**1**	**(7)**
	(13)	9	–	1	(3)
Dividends on equity preferred shares of Canadian Utilities Limited	**1**	**1**	**15**	**–**	**17**
	1	–	16	–	17
Other	**–**	**1**	**–**	**–**	**1**
	–	2	–	–	2
Earnings attributable to equity owners of the Company	**120**	**95**	**1**	**1**	**217**
	67	112	(1)	1	179
Earnings attributable to non-controlling interests					**2**
					2
Earnings for the period					**219**
					181

Unrealized gains and losses on mark-to-market forward commodity contracts

The Company enters into forward contracts in order to optimize available merchant capacity and manage exposure to electricity market price movements for its Independent Power and Thermal Plants not governed by a Power Purchase Arrangement. The forward contracts are measured at fair value. Unrealized gains and losses due to changes in the fair value of the forward contracts are recognized in earnings where hedge accounting is not applied. The CODM believes that removal of the unrealized gains or losses on mark-to-market forward commodity contracts provides a better representation of operating results for the Company's Independent Power and Thermal Plants not governed by a Power Purchase Arrangement. Realized gains or losses are recognized in adjusted earnings when the commodity contracts are settled.

Rate-regulated activities

ATCO Electric and its subsidiaries, ATCO Electric Yukon, Northland Utilities (NWT) and Northland Utilities (Yellowknife), as well as ATCO Gas, ATCO Pipelines and ATCO Gas Australia are collectively referred to as utilities.

There is currently no specific guidance under IFRS for rate-regulated entities that the Company is eligible to adopt. In the absence of this guidance, the utilities do not recognize assets and liabilities from rate-regulated activities as may be directed by regulatory decisions. Instead, the utilities recognize revenues in earnings when amounts are billed to customers, consistent with the regulator-approved rate design. Operating costs and expenses are recorded when incurred. Costs incurred in constructing an asset that meet the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

The Company uses standards issued by the Financial Accounting Standards Board (FASB) in the United States as another source of generally accepted accounting principles to account for rate-regulated activities in its internal reporting provided to the CODM. The CODM believes that earnings presented in accordance with the FASB standards are a better representation of the operating results of the Company’s rate-regulated activities. Therefore, the Company presents adjusted earnings as part of its segmented disclosures on this basis. Rate-regulated accounting (RRA) standards impact the timing of how certain revenues and expenses are recognized when compared to non-rate regulated activities, to appropriately reflect the economic impact of a regulator's decisions on revenues.

Rate-regulated accounting differs from IFRS in the following ways:

Timing Adjustment	Items	RRA Treatment	IFRS Treatment
1. Additional revenues billed in current period	Future removal and site restoration costs, and impact of colder temperatures.	The Company defers the recognition of cash received in advance of future expenditures.	The Company recognizes revenues when amounts are billed to customers and costs when they are incurred.
2. Revenues to be billed in future periods	Deferred income taxes, impact of warmer temperatures, and impact of inflation on rate base.	The Company recognizes revenues associated with recoverable costs in advance of future billings to customers.	The Company recognizes costs when they are incurred, but does not recognize their recovery until customer rates are changed and amounts are collected through future billings.
3. Regulatory decisions received	Regulatory decisions received which relate to current and prior periods.	The Company recognizes the earnings from a regulatory decision pertaining to current and prior periods when the decision is received.	The Company does not recognize earnings from a regulatory decision when it is received as regulatory assets and liabilities are not recorded under IFRS.
4. Settlement of regulatory decisions and other items	Settlement of amounts receivable or payable to customers and other items.	The Company recognizes the amount receivable or payable to customers as a reduction in its regulatory assets and liabilities when collected or refunded through future billings.	The Company recognizes earnings when customer rates are changed and amounts are recovered or refunded to customers through future billings.

At March 31, the significant timing adjustments as a result of the differences between rate-regulated accounting and IFRS are as follows:

	2019	2018
Additional revenues billed in current period		
Future removal and site restoration costs (1)	**20**	19
Impact of colder temperatures (2)	**12**	12
Revenues to be billed in future periods		
Deferred income taxes (3)	**(28)**	(33)
Settlement of regulatory decisions and other items	**(11)**	(1)
	(7)	(3)

(1) Removal and site restoration costs are billed to customers over the estimated useful life of the related assets based on forecast costs to be incurred in future periods.

(2) ATCO Gas' customer rates are based on a forecast of normal temperatures. Fluctuations in temperatures may result in more or less revenue being recovered from customers than forecast. Revenues above or below the normal in the current period are refunded to or recovered from customers in future periods.

(3) Income taxes are billed to customers when paid by the Company.

Other

Each quarter, the Company adjusts the deferred tax asset which was recognized as a result of the 2015 Tula Pipeline Project impairment. During the three months ended March 31, the Company recorded a foreign exchange gain of $1 million (2018 - foreign exchange gain of $2 million) due to a difference between the tax base currency, which is Mexican pesos, and the U.S. dollar functional currency.

5. REVENUES

The Company disaggregates revenues based on the revenue streams and by regulated and non-regulated business operations. The disaggregation of revenues by revenue streams by each operating segment for the three months ended March 31 are shown below:

2019 **2018**	**Electricity**	**Pipelines & Liquids**	**Corporate & Other**	**Total**
Revenue Streams				
Sale of Goods				
Electricity generation and delivery	**164**	**–**	**–**	**164**
	84	–	–	84
Commodity sales	**4**	**5**	**–**	**9**
	5	3	–	8
Total sale of goods	**168**	**5**	**–**	**173**
	89	3	–	92
Rendering of Services				
Distribution services	**155**	**294**	**–**	**449**
	140	311	–	451
Transmission services	**169**	**66**	**–**	**235**
	169	64	–	233
Customer contributions	**10**	**5**	**–**	**15**
	9	4	–	13
Franchise fees	**8**	**66**	**–**	**74**
	8	71	–	79
Retail electricity and natural gas services	**–**	**–**	**56**	**56**
	–	–	27	27
Storage and industrial water	**–**	**7**	**–**	**7**
	–	14	–	14
Total rendering of services	**342**	**438**	**56**	**836**
	326	464	27	817
Lease income				
Finance lease	**9**	**–**	**–**	**9**
	9	–	–	9
Operating lease	**21**	**–**	**–**	**21**
	59	–	–	59
Total lease income	**30**	**–**	**–**	**30**
	68	–	–	68
Service concession arrangement	**126**	**–**	**–**	**126**
	399	–	–	399
Other	**15**	**5**	**4**	**24**
	6	1	2	9
Total	**681**	**448**	**60**	**1,189**
	888	468	29	1,385

Disaggregation of revenues by rate-regulated and non-rate-regulated business operations for the three months ended March 31 is shown below:

	2019	2018
Rate-regulated business operations		
Rate-regulated Electricity		
Electricity Distribution	**179**	156
Electricity Transmission	**175**	171
	354	327
Rate-regulated Pipelines & liquids		
Natural Gas Distribution	**338**	350
Natural Gas Transmission	**68**	66
International Natural Gas Distribution	**35**	38
	441	454
Total rate-regulated business operations	**795**	781
Non-rate-regulated business operations		
Non-rate-regulated Electricity		
Independent Power Plants	**154**	74
Thermal PPA Plants	**42**	83
International Power Generation	**5**	5
Service concession arrangement	**126**	399
	327	561
Non-rate-regulated Pipelines & liquids		
Storage and Industrial Water	**7**	14
	7	14
Other non-rate-regulated business operations		
Retail Electricity and Natural Gas Services	**56**	27
Other	**4**	2
	60	29
Total non-rate-regulated business operations	**394**	604
Total	**1,189**	1,385

6. EARNINGS PER SHARE

Earnings per Class A non-voting (Class A) and Class B common (Class B) share are calculated by dividing the earnings attributable to Class A and Class B shares by the weighted average shares outstanding. Diluted earnings per share are calculated using the treasury stock method, which reflects the potential exercise of stock options and vesting of shares under the Company's mid-term incentive plan (MTIP) on the weighted average Class A and Class B shares outstanding.

The earnings and average number of shares used to calculate earnings per share for the three months ended March 31 are as follows:

	2019	2018
Average shares		
Weighted average shares outstanding	**272,593,727**	270,714,977
Effect of dilutive stock options	**37,979**	47,306
Effect of dilutive MTIP	**548,026**	557,390
Weighted average dilutive shares outstanding	**273,179,732**	271,319,673
Earnings for earnings per share calculation		
Earnings for the period	**219**	181
Dividends on equity preferred shares of the Company	**(17)**	(17)
Dividends to non-controlling interests	**(2)**	(2)
Earnings attributable to Class A and B shares	**200**	162
Earnings and diluted earnings per Class A and Class B share		
Earnings per Class A and Class B share	**$0.73**	$0.60
Diluted earnings per Class A and Class B share	**$0.73**	$0.60

7. RESTRICTED PROJECT FUNDS

At March 31, 2019, Alberta PowerLine (APL), a partnership between the Company and Quanta Services Inc., had $307 million of funds restricted under the terms of APL's non-recourse long-term debt financing agreement signed in October 2017. APL was awarded a 35-year contract by the Alberta Electric System Operator (AESO) to design, build, own, and operate the Fort McMurray 500 kV Transmission project (Project). In March 2019, the construction of the Project was completed. The restricted project funds are released subject to the satisfaction of certain terms and conditions under the financing agreement.

Restricted project funds are as follows:

	March 31 2019	December 31 2018
Current assets		
Restricted cash (1)	**185**	230
Restricted funds for construction lien holdbacks	**122**	109
	307	339

(1) At March 31, 2019, restricted cash includes $173 million of funds contributed by APL partners as part of the equity contribution requirements, that are not available for general use by the Company (December 31, 2018 - $100 million).

8. PROPERTY, PLANT AND EQUIPMENT

A reconciliation of the changes in the carrying amount of property, plant and equipment is as follows:

	Utility Transmission & Distribution	Electricity Generation	Land and Buildings	Construction Work-in-Progress	Other	Total
Cost						
December 31, 2018	19,315	1,950	703	661	1,042	23,671
Additions	**6**	**1**	**–**	**201**	**1**	**209**
Transfers	**88**	**4**	**1**	**(101)**	**8**	**–**
Retirements and disposals	**(6)**	**(27)**	**–**	**–**	**(2)**	**(35)**
Foreign exchange rate adjustment	**(7)**	**–**	**–**	**(3)**	**–**	**(10)**
March 31, 2019	**19,396**	**1,928**	**704**	**758**	**1,049**	**23,835**
Accumulated depreciation						
December 31, 2018	4,384	1,338	163	84	443	6,412
Depreciation	**112**	**15**	**5**	**–**	**11**	**143**
Retirements and disposals	**(6)**	**(18)**	**–**	**–**	**(3)**	**(27)**
Foreign exchange rate adjustment	**(1)**	**–**	**–**	**(1)**	**–**	**(2)**
March 31, 2019	**4,489**	**1,335**	**168**	**83**	**451**	**6,526**
Net book value						
December 31, 2018	14,931	612	540	577	599	17,259
March 31, 2019	**14,907**	**593**	**536**	**675**	**598**	**17,309**

The additions to property, plant and equipment included $5 million of interest capitalized during construction for the three months ended March 31, 2019 (2018 - $5 million).

9. RIGHT-OF-USE ASSETS

The Company's right-of-use assets mainly relate to the lease of land and buildings.

	Note	Land and Buildings
Cost		
January 1, 2019, on adoption of IFRS 16	3	67
March 31, 2019		**67**
Accumulated depreciation		
January 1, 2019, on adoption of IFRS 16	3	–
Depreciation		**3**
March 31, 2019		**3**
Net book value		
January 1, 2019, on adoption of IFRS 16	3	67
March 31, 2019		**64**

10. SHORT-TERM DEBT

At March 31, 2019, the Company had $400 million of commercial paper outstanding at a weighted average effective interest rate of 1.97 per cent, maturing in April 2019 (December 31, 2018 - $175 million of commercial paper outstanding at a weighted average effective interest rate of 2.25 per cent, maturing in January 2019).

The commercial paper is supported by the Company's long-term committed credit facilities.

11. LONG-TERM DEBT

On January 23, 2019, CU Inc., a wholly owned subsidiary of the Company, repaid $180 million of 5.432 per cent debentures.

12. LEASE LIABILITIES

The Company has recognized lease liabilities in relation to the arrangements to lease land and buildings. The reconciliation of movements in lease liabilities is as follows:

	Note	
January 1, 2019, on adoption of IFRS 16	3	67
Interest expense [1]		**–**
Lease payments		**(3)**
		64
Less: amounts due within one year		**(11)**
March 31, 2019		**53**

(1) During the three months ended March 31, 2019, interest expense was less than $1 million.

The maturity analysis of the undiscounted contractual balances of the lease liabilities is as follows:

In one year or less	**13**
In more than one year, but not more than five years	**39**
In more than five years	**21**
	73

During the three months ended March 31, 2019, $1 million was expensed in relation to low-value leases, and no expenses were incurred in relation to short-term leases or leases with variable payments.

13. EQUITY PREFERRED SHARES

Cash dividends declared and paid per share for the three months ended March 31 are as follows:

(dollars per share)	2019	2018
Perpetual Cumulative Second Preferred Shares		
4.60% Series V	**0.2875**	0.2875
Cumulative Redeemable Second Preferred Shares		
3.403% Series Y	**0.2127**	0.2127
4.90% Series AA	**0.3062**	0.3062
4.90% Series BB	**0.3062**	0.3062
4.50% Series CC	**0.2812**	0.2812
4.50% Series DD	**0.2812**	0.2812
5.25% Series EE	**0.3281**	0.3281
4.50% Series FF	**0.2812**	0.2812

The payment of any dividend is at the discretion of the Board and depends on the financial condition of the Company and other factors.

14. CLASS A AND CLASS B SHARES

At March 31, 2019, there were 199,399,195 (December 31, 2018 - 199,366,495) Class A shares and 73,747,280 (December 31, 2018 - 73,774,980) Class B shares outstanding . In addition, there were 791,000 options to purchase Class A shares outstanding at March 31, 2019, under the Company's stock option plan.

DIVIDENDS

The Company declared and paid cash dividends of $0.4227 per Class A and Class B share during the three months ended March 31, 2019 (2018 - $0.3933). The Company’s policy is to pay dividends quarterly on its Class A and Class B shares. The payment of any dividend is at the discretion of the Board and depends on the financial condition of the Company and other factors.

DIVIDEND REINVESTMENT PLAN

No Class A shares were issued under the Company's dividend reinvestment program (DRIP) during the three months ended March 31, 2019 as on January 10, 2019, the DRIP was suspended.

During the three months ended March 31, 2018, 490,214 Class A shares were issued under the DRIP, using re-invested dividends of $16 million. The shares were priced at an average of $33.09 per share.

15. CASH FLOW INFORMATION

ADJUSTMENTS TO RECONCILE EARNINGS TO CASH FLOWS FROM OPERATING ACTIVITIES

Adjustments to reconcile earnings to cash flows from operating activities for the three months ended March 31 are summarized below.

	2019	2018
Depreciation and amortization	**157**	151
Earnings from investment in joint ventures, net of dividends received	**–**	(3)
Income taxes	**80**	63
Unearned availability incentives	**–**	(5)
Unrealized (gains) losses on mark-to-market forward commodity contracts	**(8)**	24
Contributions by customers for extensions to plant	**25**	23
Amortization of customer contributions	**(15)**	(13)
Net finance costs	**117**	114
Income taxes paid	**(32)**	(18)
Other	**8**	8
	332	344

CASH POSITION

Cash position in the consolidated statement of cash flow at March 31 is comprised of:

	2019	2018
Cash	**529**	395
Short-term investments	**–**	6
Restricted cash (1)	**74**	93
Cash and cash equivalents	**603**	494
Bank indebtedness	**–**	(4)
	603	490

(1) Cash balances which are restricted under the terms of joint arrangement agreements are considered not available for general use by the Company.

16. FINANCIAL INSTRUMENTS

FAIR VALUE MEASUREMENT

Financial instruments are measured at amortized cost or fair value. Fair value represents the estimated amounts at which financial instruments could be exchanged between knowledgeable and willing parties in an arm's length transaction. Determining fair value requires management judgment. The valuation methods used to determine the fair value of each financial instrument and its associated level in the fair value hierarchy is described below.

Financial Instruments	Fair Value Method
Measured at Amortized Cost	
Cash and cash equivalents, accounts receivable and contract assets, restricted project funds, accounts payable and accrued liabilities and short-term debt.	Assumed to approximate carrying value due to their short-term nature.
Finance lease receivables and receivable under service concession arrangement.	Determined using a risk-adjusted interest rate to discount future cash receipts (Level 2).
Long-term debt and non-recourse long-term debt.	Determined using quoted market prices for the same or similar issues. Where the market prices are not available, fair values are estimated using discounted cash flow analysis based on the Company's current borrowing rate for similar borrowing arrangements (Level 2).
Measured at Fair Value	
Interest rate swaps	Determined using interest rate yield curves at period-end (Level 2).
Foreign currency contracts	Determined using quoted forward exchange rates at period-end (Level 2).
Commodity contracts	Determined using observable period-end forward curves, with inputs validated by publicly available market providers. The fair values were also determined using extrapolation formulas using readily observable inputs and implied volatility (Level 2).

FINANCIAL INSTRUMENTS MEASURED AT AMORTIZED COST

The fair values of the Company's financial instruments measured at amortized cost are as follows:

		March 31, 2019		December 31, 2018	
Recurring Measurements	Note	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial Assets					
Finance lease receivables		**407**	**482**	395	487
Receivable under service concession arrangement		**1,522**	**1,522**	1,396	1,396
Financial Liabilities					
Long-term debt		**8,721**	**9,943**	8,904	9,547
Non-recourse long-term debt		**1,398**	**1,570**	1,401	1,474

FINANCIAL INSTRUMENTS MEASURED AT FAIR VALUE

The Company's derivative instruments are measured at fair value. At March 31, 2019, the following derivative instruments were outstanding:

- interest rate swaps for the purpose of limiting interest rate risk on the variable future cash flows of long-term debt and non-recourse long-term debt held in a joint venture;
- foreign currency forward contracts for the purpose of limiting exposure to exchange rate fluctuations relating to expenditures denominated in Australian dollars and Mexican pesos; and
- natural gas and forward power sale and purchase contracts for the purpose of limiting exposure to electricity and natural gas market price movements.

The balance sheet classification and fair values of the Company's derivative financial instruments are as follows:

	Subject to Hedge Accounting		Not Subject to Hedge Accounting		
Recurring Measurements	**Interest Rate Swaps**	**Commodities**	**Commodities**	**Foreign Currency Forward Contracts**	**Total Fair Value of Derivatives**
March 31, 2019					
Financial Assets					
Prepaid expenses and other current assets	**–**	**1**	**–**	**–**	**1**
Other assets	**–**	**1**	**2**	**–**	**3**
Financial Liabilities					
Other current liabilities (1)	**–**	**14**	**22**	**–**	**36**
Other liabilities (1)	**3**	**7**	**18**	**–**	**28**
December 31, 2018					
Financial Assets					
Prepaid expenses and other current assets	1	2	–	–	3
Other assets	1	2	4	–	7
Financial Liabilities					
Other current liabilities	–	15	34	4	53
Other liabilities	3	8	27	–	38

(1) At March 31, 2019, the Company paid a total of $29 million of cash collateral to third parties on commodity forward positions related to future periods (December 31, 2018 - $18 million). The contracts held with these third parties have an enforceable master netting arrangement, which allows the right to offset.

Notional and maturity summary

The notional value and maturity dates of the Company's derivative instruments outstanding are as follows:

	Subject to Hedge Accounting			Not Subject to Hedge Accounting		
Notional value and maturity	**Interest Rate Swaps**	**Natural Gas (1)**	**Power (2)**	**Natural Gas (1)**	**Power (2)**	**Foreign Currency Forward Contracts**
March 31, 2019						
Purchases (3)	**–**	**10,745,000**		**48,155,200**	**2,747,165**	**–**
Sales (3)	**–**	**–**	**923,360**	**5,355,700**	**6,366,635**	**–**
Currency						
Canadian dollars	**2**	**–**	**–**	**–**	**–**	**–**
Australian dollars	**744**	**–**	**–**	**–**	**–**	**–**
Mexican pesos	**570**	**–**	**–**	**–**	**–**	**140**
Maturity	**2019-2023**	**2019-2021**	**2019-2020**	**2019-2022**	**2019-2021**	**2019**
December 31, 2018						
Purchases (3)	–	12,545,000	–	58,518,200	3,254,650	–
Sales (3)	–	–	1,193,640	7,740,700	7,574,926	–
Currency						
Canadian dollars	2	–	–	–	–	–
Australian dollars	744	–	–	–	–	–
Mexican pesos	570	–	–	–	–	140
British pounds	–	–	–	–	–	74
Maturity	2019-2023	2019-2021	2019-2020	2019-2022	2019-2021	2019

(1) Notional amounts for the natural gas purchase contracts are the maximum volumes that can be purchased over the terms of the contracts.

(2) Notional amounts for the forward power sale and purchase contracts are the commodity volumes committed in the contracts.

(3) Volumes for natural gas and power derivatives are in GJ and MWh, respectively.