CANADIAN UTILITIES LIMITED
An ATCO Company

CANADIAN UTILITIES LIMITED

FINANCIAL INFORMATION

FOR THE THREE MONTHS ENDED MARCH 31, 2018

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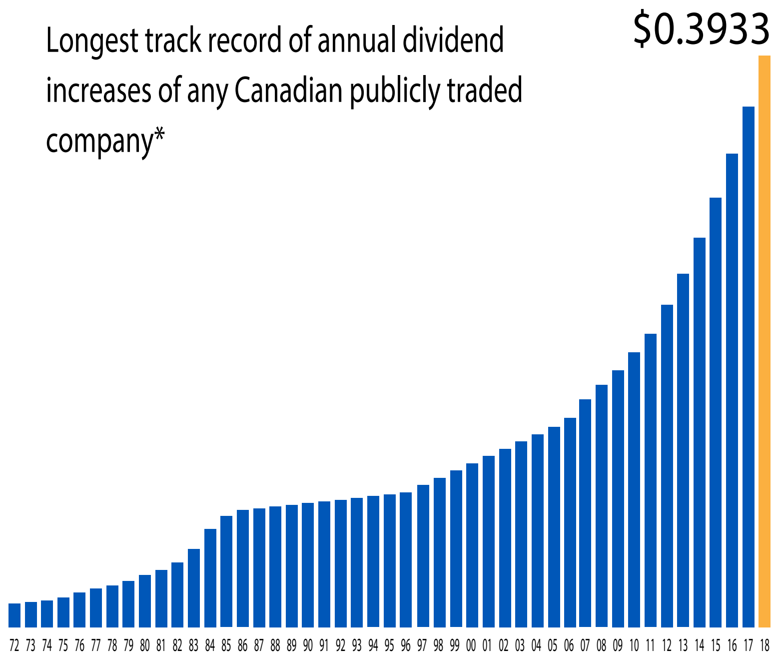
Q1 2018 INVESTOR FACT SHEET

CanadianUtilities.com
ELECTRICITY | PIPELINES & LIQUIDS

CANADIAN UTILITIES LIMITED
An ATCO Company

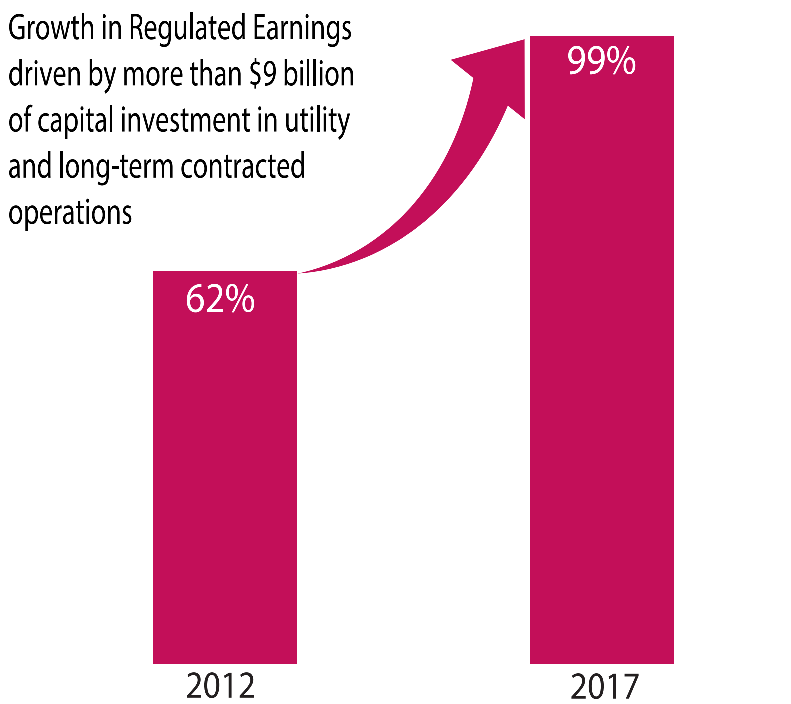
With approximately 5,400 employees and assets of $21 billion, Canadian Utilities Limited is an ATCO company. ATCO is a diversified global corporation delivering service excellence and innovative business solutions in Structures & Logistics (workforce housing, innovative modular facilities, construction, site support services, and logistics and operations management); 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, 2018, Canadian Utilities declared a first quarter dividend of $0.3933 per share, or $1.57 per share annualized.

GROWING A HIGH QUALITY EARNINGS BASE



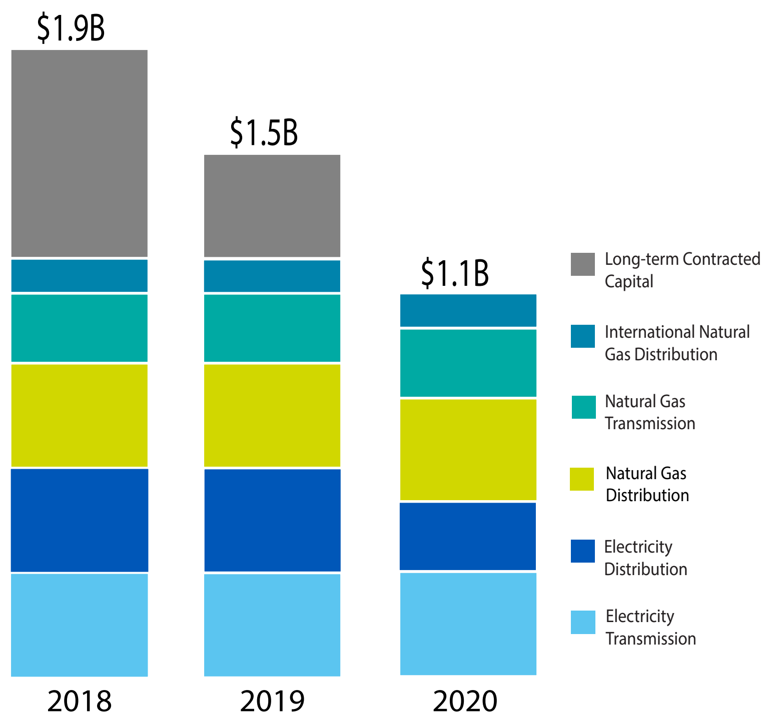
CANADIAN UTILITIES AT A GLANCE

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

Total Assets	$21 billion
Electric Powerlines	87,000 kms
Pipelines	64,500 kms
Power Plants	18 Globally
Power Generating Capacity Share	2,517 MW *
Water Infrastructure Capacity	85,200 m³/d **
Natural Gas Storage Capacity	52 PJ ***
Hydrocarbon Storage Capacity	200,000 m³ ****

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

FUTURE CAPITAL INVESTMENT



$4.5 billion in Regulated Utility and contracted capital growth projects expected in 2018 - 2020

CANADIAN UTILITIES SHARE INFORMATION

Common Shares (TSX): CU, CU.X

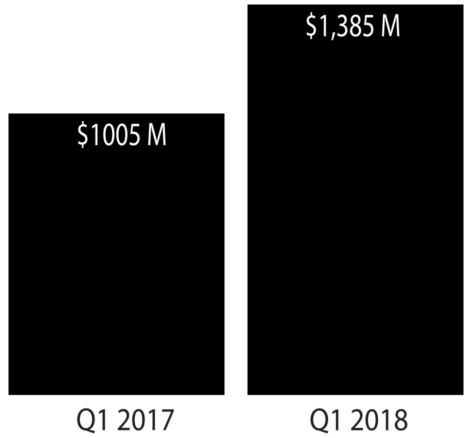
Market Capitalization	$9 billion
Weighted Average Common Shares Outstanding	270.7 million

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.

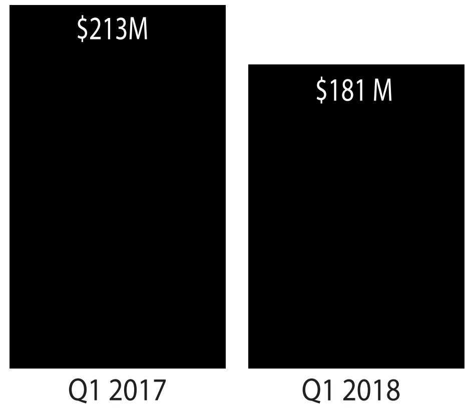
Adjusted earnings are earnings attributable to the Class A and Class B shares after adjusting for the timing of revenues and expenses associated with rate-regulated activities, dividends on equity preferred shares of the Company, and unrealized gains or losses on mark-to-market forward commodity contracts. 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 2018 RESULTS

CANADIAN UTILITIES REVENUES



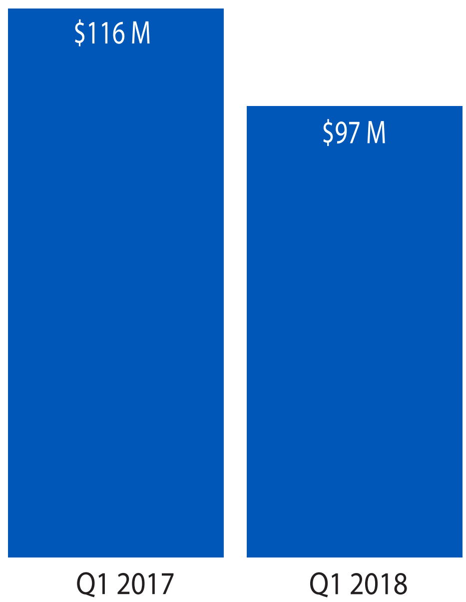
CANADIAN UTILITIES ADJUSTED EARNINGS



ELECTRICITY GLOBAL BUSINESS UNIT

- Adjusted earnings in the first quarter of 2018 were lower than the same period in 2017 mainly due to rate rebasing under Alberta's regulated model in electricity distribution and transmission, and lower contributions from forward sales in generation. Lower earnings were partially offset by higher earnings from Alberta PowerLine and Thermal PPA Plants.
- On February 20, 2018, Canadian Utilities completed the acquisition of Electricidad del Golfo, a long-term contracted, 35 MW hydroelectric power station based in Veracruz, Mexico at an aggregate purchase price of $112 million.
- In March 2018, we announced we will build a long-term contracted 26 MW cogeneration project, known as the La Laguna Cogeneration facility, on the site of the Chemours Company Mexicana S. de R.L. de C.V.'s chemical facility near Gómez Palacio, in the state of Durango, Mexico. Total investment is approximately $70 million, and the facility is expected to be operational in 2019.
- In March 2018, we completed work on Battle River unit 4 to enable the unit to co-fire with natural gas. Natural gas can now be used as fuel to generate approximately half of the unit's 155 MW total electricity generation capacity.
- On March 21, 2018, the Alberta Balancing Pool gave notice of intent to terminate the PPA for Battle River unit 5 and that dispatch control of the unit would be turned back to Canadian Utilities no later than September 30, 2018. As part of the turn back, the Balancing Pool is obligated to pay Canadian Utilities a termination payment, the terms of which have not been finalized.

ADJUSTED EARNINGS



PIPELINES & LIQUIDS GLOBAL BUSINESS UNIT

- Adjusted earnings for the first quarter of 2018 were lower than the same period in 2017 mainly due to rate rebasing under Alberta's regulated model in natural gas distribution. Lower earnings from customer rate rebasing were partially offset by growth in rate base across our Regulated Pipelines & Liquids businesses.
- Construction is substantially complete on two hydrocarbon storage caverns at the ATCO Heartland Energy Centre near Fort Saskatchewan, Alberta, which will double our hydrocarbon storage capacity. These units will begin contributing earnings in the second quarter of 2018.

ADJUSTED EARNINGS

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CANADIAN UTILITIES LIMITED
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2018 FIRST QUARTER FINANCIAL INFORMATION

INVESTOR FACT SHEET

MANAGEMENT DISCUSSION AND ANALYSIS

UNAUDITED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

FOR THE THREE MONTHS ENDED MARCH 31, 2018

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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, 2018

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, 2018.

This MD&A was prepared as of April 25, 2018, and should be read with the Company's unaudited interim consolidated financial statements for the three months ended March 31, 2018. Additional information, including the Company's previous MD&A (2017 MD&A), Annual Information Form (2017 AIF), and audited consolidated financial statements for the year ended December 31, 2017, is available on SEDAR at www.sedar.com. Information contained in the 2017 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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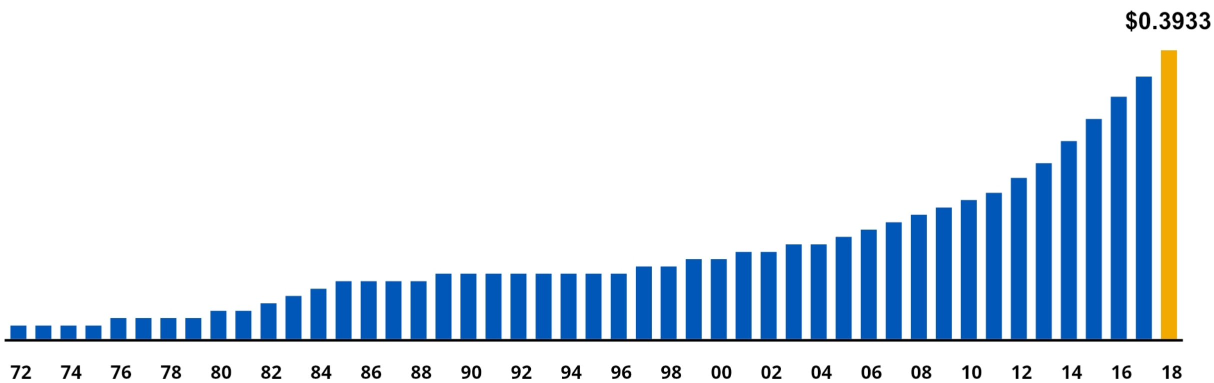
CANADIAN UTILITIES: WHAT SETS US APART

TRACK RECORD OF DIVIDEND GROWTH

We have increased our common share dividend every year for the past 46 years, the longest record of annual dividend increases of any Canadian publicly traded company. On April 4, 2018, we declared a second quarter dividend of 39.33 cents per share or $1.57 per share on an annualized basis.

Quarterly Dividend Rate 1972 - 2018
(dollars per share)



GROWING A HIGH QUALITY EARNINGS BASE

Over the past five years, we have invested more than $9 billion in Regulated Utility and long-term contracted operations. The Regulated Utility portion of our total adjusted earnings has grown from 62 per cent in 2012 to 99 per cent in 2017. 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 2018 to 2020, we expect to invest $4.5 billion in Regulated Utility and long-term contracted assets, which will continue to strengthen our high quality earnings base. Of the $4.5 billion planned spend, $3.5 billion will be on Regulated Utilities, and $1.0 billion will be on long-term contracted assets.

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.

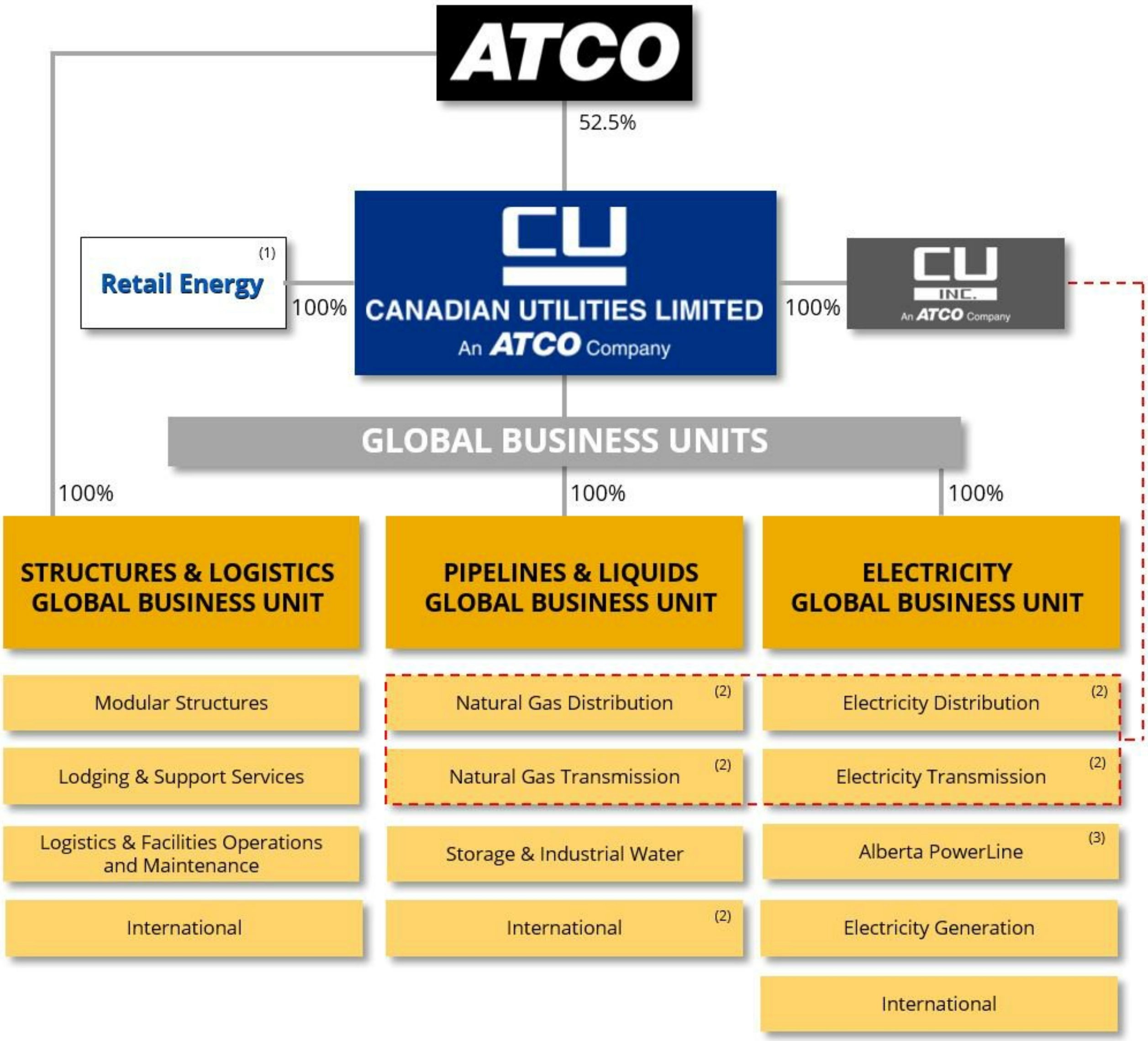
46 year
track record of dividend increases

99%
regulated earnings

$4.5B
3 year capital investment

A
range credit rating

ORGANIZATIONAL STRUCTURE



(1) Retail Energy was launched in early 2016 to provide retail, commercial and industrial electricity and natural gas service in Alberta.

(2) Regulated businesses include ATCO Gas, ATCO Pipelines, ATCO Gas Australia, ATCO Electric Distribution, and ATCO Electric 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).

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.

($ millions, except per share data and outstanding shares)	Three Months Ended March 31 2018	2017 [2] (restated)	Change
Key Financial Metrics			
Revenues	**1,385**	1,005	380
Adjusted earnings [1]	**181**	213	(32)
Electricity	**97**	116	(19)
Pipelines & Liquids	**101**	112	(11)
Corporate & Other	**(17)**	(16)	(1)
Intersegment Eliminations	**–**	1	(1)
Adjusted earnings ($ per share) [1]	**0.67**	0.79	(0.12)
Earnings attributable to Class A and Class B shares	**179**	228	(49)
Earnings attributable to Class A and Class B shares ($ per share)	**0.60**	0.78	(0.18)
Cash dividends declared per Class A and Class B share (cents per share)	**39.33**	35.75	3.58
Funds generated by operations [1]	**525**	506	19
Capital investment [1]	**744**	285	459
Other Financial Metrics			
Weighted average Class A and Class B shares outstanding *(thousands):*			
Basic	**270,715**	268,359	2,356
Diluted	**271,320**	268,970	2,350

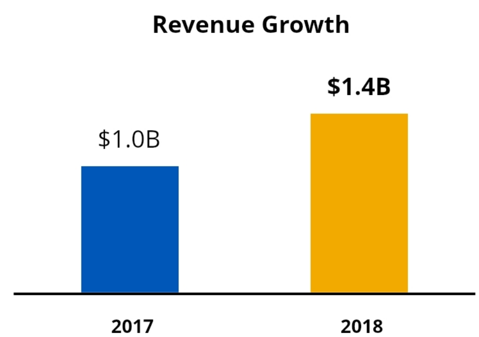
(1) Additional information regarding these measures is provided in the Non-GAAP and Additional GAAP Measures section of this MD&A.

(2) These numbers have been restated to account for the impact of IFRS 15. Additional details on IFRS 15 is discussed in the Other Financial Information section of this MD&A.

REVENUES

Revenues for the first quarter of 2018 were $1,385 million, $380 million higher than the same period in 2017.

These increases were mainly due to revenue recorded for Alberta PowerLine.



ADJUSTED EARNINGS

Our adjusted earnings for the first quarter of 2018 was $181 million, or $0.67 per share, compared to $213 million, or $0.79 per share, for the same period in 2017. The primary drivers of adjusted earnings results were as follows:

- Electricity - Adjusted earnings for the first quarter of 2018 were $19 million lower than the same period of 2017. Lower earnings were mainly due to rate rebasing under Alberta's regulated model in electricity distribution and transmission, and lower contributions from forward sales in electricity generation. Lower earnings were partially offset by higher earnings from Alberta PowerLine.
- Pipelines & Liquids - Adjusted earnings for the first quarter of 2018 were $11 million lower than the same period in 2017 mainly due to rate rebasing under Alberta's regulated model in natural gas distribution. Lower earnings from customer rate rebasing were partially offset by growth in rate base across our Regulated Pipelines & Liquids businesses.
- Corporate & Other - Adjusted earnings in the first quarter in 2018 were lower than the same period in 2017 mainly due to higher business development expenses, partially offset by improved results in Retail Energy from a growing customer portfolio.

EARNINGS ATTRIBUTABLE TO CLASS A AND CLASS B SHARES

Earnings attributable to Class A and Class B shares were $179 million for the first quarter of 2018, compared to $228 million in the same period in 2017. Earnings attributable to Class A and Class B shares includes one-time gains on the sale of operations, significant impairments, timing adjustments related to rate-regulated activities and unrealized losses on mark-to-market forward commodity contracts that are not included in adjusted earnings.

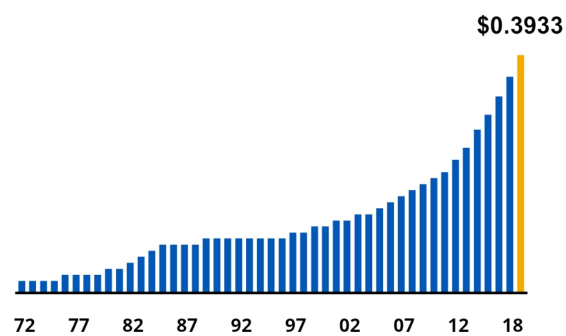
More information on these and other items is included in the Reconciliation of Adjusted Earnings to Earnings Attributable to Class A and Class B shares section of this MD&A.

COMMON SHARE DIVIDENDS

On April 4, 2018, the Board of Directors declared a second quarter dividend of 39.33 cents per share. Dividends paid to Class A and Class B share owners totaled $90 million in the first quarter of 2018.

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

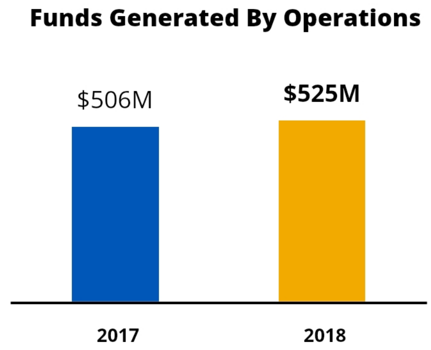
Quarterly Dividend Rate 1972 - 2018 (dollars per share)



FUNDS GENERATED BY OPERATIONS

Funds generated by operations were $525 million in the first quarter of 2018, $19 million higher than the same period in 2017.

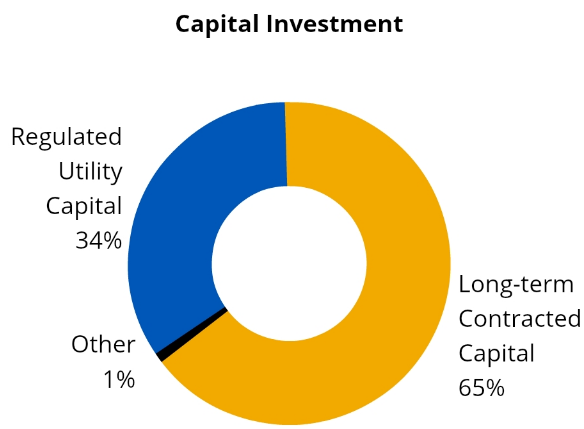
The increase was mainly due to lower cash income taxes paid and higher contributions from customers.



CAPITAL INVESTMENT

Capital investment is defined as cash used for capital expenditures, business combinations and service concession arrangements. Capital expenditures include additions to property, plant and equipment, intangibles and the Company's proportional share of capital expenditures in joint ventures, as well as interest capitalized during construction. Total capital investment in the first quarter of 2018 was $744 million

Capital spending in our Regulated Utilities and on long-term contracted capital assets accounted for $738 million of capital spending in the first quarter of 2018. Of this capital invested, $368 million was invested in Alberta PowerLine. These investments either earn a return under a regulated business model or are under commercially secured long-term contracts.



RECENT DEVELOPMENTS IN THE FIRST QUARTER OF 2018

Mexico Hydro Facility

On February 20, 2018, Canadian Utilities completed the acquisition of Electricidad del Golfo, which owns a long-term contracted, 35 MW hydroelectric power station based in the state of Veracruz, Mexico. The transaction was recorded for an aggregate purchase price of $112 million.

La Laguna Cogeneration Facility

In March 2018, Canadian Utilities announced we will build a 26 MW cogeneration project, known as the La Laguna Cogeneration facility, on the site of the Chemours Company Mexicana S. de R.L. de C.V.'s chemical facility near Gómez Palacio, in the state of Durango, Mexico. Developed in partnership with RANMAN Energy, the La Laguna Cogeneration facility will provide low-carbon and cost-effective electricity and heat under a long-term agreement. The total investment associated with the project is approximately $70 million, and the facility is expected to be operational in 2019.

Battle River Unit 5 PPA

On March 21, 2018, the Alberta Balancing Pool provided notice of its intent to terminate the Power Purchase Arrangement (PPA) for Battle River unit 5 and that dispatch control of Battle River unit 5 would be turned back to Canadian Utilities no later than September 30, 2018. As part of the turn back, the Balancing Pool is obligated to pay Canadian Utilities a PPA termination payment, the terms of which have not been finalized.

Co-Firing Conversion of Battle River Unit 4

In March 2018, we completed work on Battle River unit 4 to enable the unit to co-fire with natural gas. Natural gas can now be used for approximately half of the unit's 155 MW total electricity generation capacity.

GLOBAL BUSINESS UNIT PERFORMANCE

REVENUES

Electricity revenues of $899 million in the first quarter of 2018 were $390 million higher than the same period in 2017, mainly due to revenue recorded for construction activities at Alberta PowerLine and higher flow-through revenue for carbon taxes.

ADJUSTED EARNINGS

	Three Months Ended March 31		
($ millions)	**2018**	**2017 (1) (restated)**	**Change**
Regulated Electricity			
Electricity Distribution	**33**	41	(8)
Electricity Transmission	**40**	54	(14)
Total Regulated Electricity Adjusted Earnings	**73**	95	(22)
Non-regulated Electricity			
Independent Power Plants	**(5)**	3	(8)
Thermal PPA Plants	**14**	10	4
International Power Generation	**5**	6	(1)
Alberta PowerLine	**10**	2	8
Total Non-regulated Electricity Adjusted Earnings	**24**	21	3
Total Electricity Adjusted Earnings	**97**	116	(19)

(1) These numbers have been restated to account for the impact of IFRS 15. Additional details on IFRS 15 is discussed in the Other Financial Information section of this MD&A.

In the first quarter of 2018, our Electricity business earned $97 million, $19 million lower than the same period of 2017. Lower earnings were mainly due to rate rebasing under Alberta's regulated model in electricity distribution and transmission, and lower contributions from forward sales in electricity generation. Lower earnings were partially offset by higher earnings from Alberta PowerLine and Thermal PPA Plants.

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

REGULATED ELECTRICITY

Our Regulated Electricity activities are conducted by ATCO Electric Distribution and ATCO Electric Transmission and their subsidiaries, ATCO Electric Yukon, Northland Utilities (NWT) and Northland Utilities (Yellowknife). These businesses provide regulated electricity distribution, transmission and distributed generation mainly in northern and central east Alberta, the Yukon and the Northwest Territories.

Electricity Distribution

Our electricity distribution business earned $33 million in the first quarter of 2018, $8 million lower than the same period in 2017. Lower earnings were mainly due to the benefit of Canadian Utilities' operating cost reduction initiatives over the first generation Performance Based Regulation (PBR) period flowing into customer rates under the 2018 to 2022 second generation PBR framework. The lower earnings from PBR rebasing were partially offset by earnings from continued growth in rate base and additional return on equity (ROE) due to the efficiency carry-over mechanism incentive granted to distribution utilities in the first two years of the second generation PBR for demonstrating superior cost savings in the prior PBR period.

Electricity Transmission

Our electricity transmission business earned $40 million in the first quarter of 2018, $14 million lower than the same period in 2017. Lower earnings were mainly due to the benefit of Canadian Utilities' operating cost reduction initiatives flowing into customer rates in the 2018 to 2019 General Tariff Application (GTA) and lower interim rates approved by the Alberta Utilities Commission (AUC). Upon receipt of the AUC's decision on the 2018 to 2019 GTA, which is expected in the fourth quarter of 2018, existing interim rates will be updated to include the impact of the decision, including Canadian Utilities' request for an additional increase to 2018 and 2019 rate base of approximately $130 million per year.

Earnings in the first quarter of 2017 were positively impacted by the 2015 to 2017 GTA Review and Variance decision received on March 16, 2017. The impact of this decision was an increase to first quarter 2017 adjusted earnings of $3 million, most of which related to prior years.

NON-REGULATED ELECTRICITY

Our non-regulated electricity activities are conducted by ATCO Power, ATCO Power Australia, ATCO Mexico and Alberta PowerLine. These businesses 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

Our generating availability for the first quarter of 2018 and 2017 is shown in the table below. Generating plant capacity fluctuates with the timing and duration of outages.

	Three Months Ended March 31		
	2018	**2017**	**Change**
Independent Power Plants	**90%**	95%	(5%)
Thermal PPA Plants	**92%**	95%	(3%)
International Power Generation	**100%**	100%	-

Lower availability in our Independent Power Plants in the first quarter of 2018 was primarily due to planned minor outages at the Joffre and Battle River unit 4 plants. In March 2018, we completed work on Battle River unit 4 to enable the unit to co-fire with natural gas. Natural gas can now be used for approximately half of the unit's 155 MW total electricity generation capacity.

Lower availability in our Thermal PPA Plants in the first quarter of 2018 was primarily due to a planned minor outage at the Battle River unit 5 plant.

Availability in our International Power Generation Plants in the first quarter of 2018 was comparable to the same period in 2017.

Alberta Power Market Summary

Average Alberta Power Pool and natural gas prices and the resulting spark spreads for the first quarter of 2018 and 2017 are shown in the table below.

	Three Months Ended March 31		
	2018	**2017**	**Change**
Average Alberta Power Pool electricity price *($/MWh)*	**34.93**	22.39	12.54
Average natural gas price *($/GJ)*	**1.96**	2.55	(0.59)
Average market spark spread *($/MWh)*	**20.26**	3.27	16.99

The average Alberta Power Pool prices for the first quarter of 2018 were higher compared to the same period in 2017. This was mainly due to an increase in carbon prices affecting overall variable price offers in the market, lower electricity supply as a result of the retirement of 280 MW and mothballing of 280 MW of other coal-fired generation in Alberta, and natural gas transmission supply curtailment restrictions.

Independent Power Plants

In the first quarter of 2018, earnings from our Independent Power Plants were $8 million lower compared to the same period in 2017. Earnings generated from increases in market prices were more than offset by lower realized forward sales and increased costs due to planned minor plant outages.

Realized Forwards Sales Program

	Three Months Ended March 31		
	2018	**2017**	**Change**
Average volumes settled *(MW)*	**229**	103	126
Average realized spark spread ($/MWh)	**16.33**	20.87	(4.54)

In the first quarter of 2018, 229 MW of power that was sold forward settled at an average realized spark spread of $16.33 per MWh compared to 103 MW settled at an average of $20.87 in the same period of 2017. Due to the decrease in the realized spark spread, earnings from forward sales in the first quarter of 2018 were lower than the same period in 2017.

Thermal PPA Plants

The electricity generated by the Battle River unit 5 and Sheerness plants is sold through PPAs. Under the PPAs, we must make the generating capacity for each generating unit available to the PPA purchaser of that unit. These arrangements entitle us to recover our forecast fixed and variable costs from the PPA purchaser. Under the terms of the PPAs, we are 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 amounts are recognized based on the estimates of planned outages that impact future generating unit availability and future electricity prices of the term of the PPAs.

In the first quarter of 2018, earnings from our Thermal Power Plants were $4 million higher than the same period in 2017. Higher earnings were due to higher recognition of availability incentives, partially offset by higher maintenance expenses due to a planned minor outage at Battle River unit 5.

The implementation of IFRS 15 accounting resulted in the re-creation of an availability incentive pool (AIP) for Battle River unit 5. In the first quarter of 2018, a portion of the AIP was recognized into earnings due to the completion of a planned outage. At March 31, 2018, the total amount of the AIP remaining is approximately $10 million after tax.

International Power Generation

Our international power generation activities are conducted by ATCO Power Australia and ATCO Mexico. Our ATCO Power Australia business supplies electricity from two natural gas-fired electricity generation plants: the Osborne plant in South Australia and the Karratha plant in Western Australia. Our ATCO Mexico business supplies electricity from distributed generation near San Luis Potosí and hydroelectric generation near Veracruz, Mexico.

Our international power generation business earned $5 million in the first quarter, $1 million lower than the same period in 2017. Lower earnings were mainly due to increased costs associated with the Mexico hydro acquisition.

Alberta PowerLine

Alberta PowerLine (APL) 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.

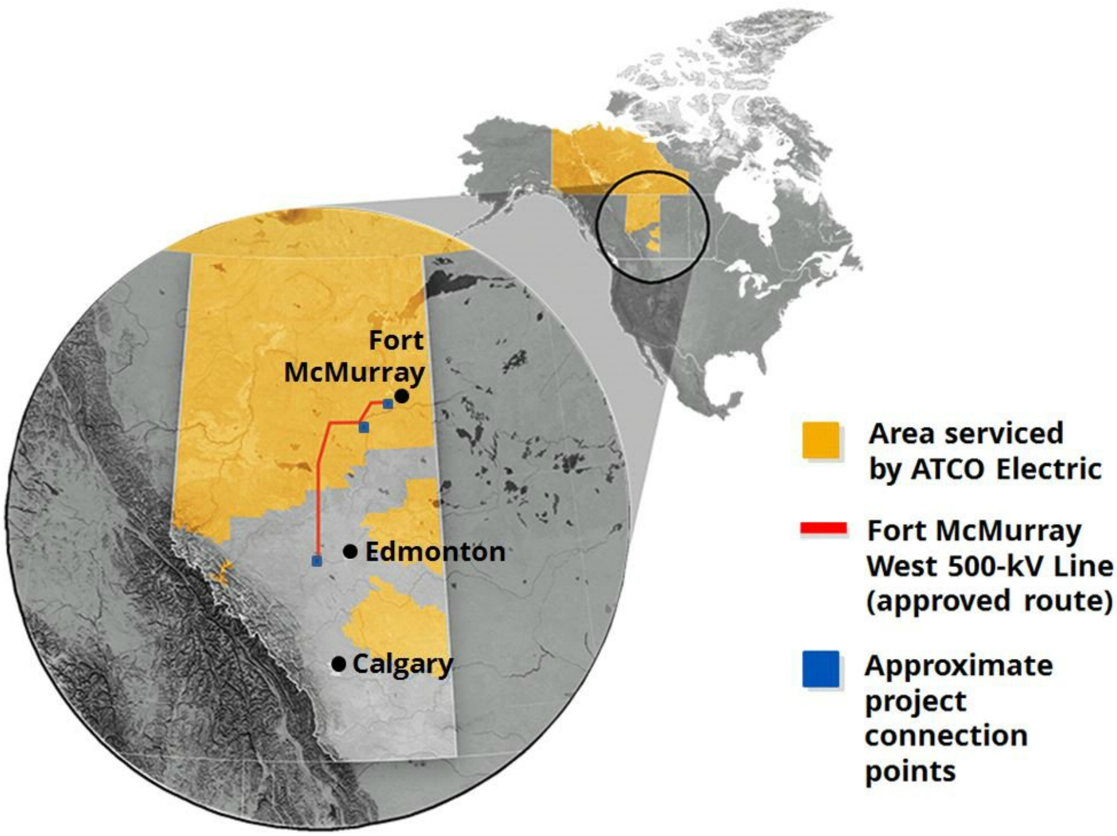
APL's adjusted earnings were $10 million in the first quarter of 2018, $8 million higher when compared to the same period in 2017. Higher earnings were mainly due to the commencement of construction activities in August 2017, partially offset by interest expense on $1.385 billion of senior secured amortizing bonds issued in October 2017 to finance construction activities.

ELECTRICITY MAJOR PROJECT UPDATES

Alberta PowerLine

On November 30, 2017, APL submitted a tariff application as owner of the project. On January 23, 2018, the AUC approved the application.

The design and planning phases of the approximately 500 km, Fort McMurray West 500-kV Project have been completed and construction commenced in August 2017. Robust first quarter 2018 capital investment activity of $368 million was mainly due to land preparation and tower foundation installation and tower assembly proceeding ahead of schedule. The target energization date of June 2019 remains on track.



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Alberta Electricity Market Reform

On November 23, 2016, the Government of Alberta announced its intention to change the existing energy-only electricity market to a capacity market in 2021. A capacity market includes a market component for the provision of capacity, or the ability to produce electricity, in addition to the market for the production of electricity. The Government of Alberta indicated that it will work closely with industry, consumer groups and other stakeholders to establish the framework and implement the capacity market in 2021.

The first version of the Comprehensive Market Design for the capacity market was released on January 26, 2018. The proposed first capacity auction will start in November 2019, for an obligation from November 2021, for a one year term. Multiple aspects of the capacity market design remain under discussion and consultation. The AESO plans to release its second version of the Comprehensive Market Design in April 2018, with a final version expected mid-year 2018.

Thermal PPAs

The electricity generated by the Battle River unit 5 and Sheerness plants is sold through PPAs. Under the PPAs, we must make the generating capacity for each generating unit available to the PPA purchaser of that unit. These arrangements entitle us to recover its forecast fixed and variable costs from the PPA purchaser.

On March 21, 2018, the Alberta Balancing Pool provided notice of their intent to terminate the PPA for Battle River unit 5 and that dispatch control of Battle River unit 5 would be turned back to Canadian Utilities no later than September 30, 2018. As part of the turn back, the Balancing Pool is obligated to pay Canadian Utilities a PPA termination payment, the terms of which have not been finalized.

The PPA for Sheerness units 1 and 2 remains under PPA contract and Canadian Utilities will continue to operate Sheerness under the terms of that PPA which expires at the end of 2020.

REVENUES

Pipelines & Liquids revenues of $485 million in the first quarter of 2018 were $13 million lower than the same period in 2017. Lower revenues in the first quarter were mainly due to lower flow-through revenues in natural gas distribution for third party transmission rate recovery from customers.

ADJUSTED EARNINGS

	Three Months Ended March 31		
($ millions)	**2018**	**2017**	**Change**
Regulated Pipelines & Liquids			
Natural Gas Distribution	**67**	81	(14)
Natural Gas Transmission	**18**	17	1
International Natural Gas Distribution	**14**	12	2
Total Regulated Pipelines & Liquids Adjusted Earnings	**99**	110	(11)
Non-regulated Pipelines & Liquids			
Storage & Industrial Water	**2**	2	–
Total Pipelines & Liquids Adjusted Earnings	**101**	112	(11)

Pipelines & Liquids earnings of $101 million in the first quarter of 2018 were $11 million lower than the same period in 2017 mainly due to rate rebasing under Alberta's regulated model in natural gas distribution. Lower earnings from customer rate rebasing were partially offset by growth in rate base across our Regulated Pipelines & Liquids businesses.

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

Our natural gas distribution activities throughout Alberta and in the Lloydminster area of Saskatchewan are conducted by ATCO Gas. It services municipal, residential, business and industrial customers.

Our natural gas distribution business earned $67 million in the first quarter of 2018, $14 million lower than the same period of 2017. Lower earnings were mainly due to the benefit of Canadian Utilities' operating cost reduction initiatives over the first generation PBR period flowing into customer rates under the 2018 to 2022 second generation PBR framework. The lower earnings from PBR rate rebasing were partially offset by earnings from growth in rate base and additional ROE due to the efficiency carry-over mechanism incentive granted to distribution utilities in the first two years of the second generation PBR for demonstrating superior cost savings in the prior PBR period.

Natural Gas Transmission

Our natural gas transmission activities in Alberta are conducted by ATCO Pipelines. This business 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 or to other pipeline systems, primarily for export out of the province.

Our natural gas transmission business earned $18 million in the first quarter of 2018, $1 million higher than the same period of 2017. Higher earnings in the quarter were mainly due to continued growth in rate base.

International Natural Gas Distribution

Our international natural gas distribution activities are conducted by ATCO Gas Australia. It is a regulated provider of natural gas distribution services in Western Australia, serving metropolitan Perth and surrounding regions.

Our natural gas transmission business earned $14 million in the first quarter of 2018, $2 million higher than the same period in 2017. Higher earnings in the quarter were mainly due to continued growth in rate base.

NON-REGULATED PIPELINES & LIQUIDS

Storage & Industrial Water

Our industrial water services and non-regulated natural gas and hydrocarbon storage, and transmission activities are conducted by ATCO Energy Solutions.

Our storage & industrial water business earned $2 million in the first quarter of 2018, comparable to the same period in 2017.

PIPELINES & LIQUIDS MAJOR PROJECT UPDATES

Hydrocarbon Storage

Construction on the last two of four salt caverns at the ATCO Heartland Energy Centre near Fort Saskatchewan, Alberta is substantially complete. With a combined hydrocarbon storage capacity of approximately 400,000 cubic metres, long-term contracts have been secured for all four caverns. The first two caverns have been in service since the fourth quarter of 2016, and the final two caverns are expected to begin contributing earnings in the second quarter of 2018.

Industrial Water

In the fourth quarter of 2017, we entered into a long-term commercial agreement with Inter Pipeline Ltd. to provide water services to Inter Pipeline's newly authorized integrated propane dehydrogenation and polypropylene plant to be known as the Heartland Petrochemical Complex. In the first quarter of 2018, we confirmed with Inter Pipeline that the water services contract will commence in 2020.

With the addition of these services, we continue to grow the Company’s suite of water and wastewater services for industrial customers throughout Alberta’s Industrial Heartland.

CORPORATE & OTHER

Our Corporate & Other segment includes Retail Energy through ATCOenergy, launched in 2016 to provide retail electricity and natural gas services in Alberta, our global corporate head office in Calgary, Canada, and our Australia corporate head office in Perth, Western Australia.

Including eliminations, Corporate & Other adjusted earnings in the first quarter of 2018, were $2 million lower than the same period in 2017, mainly due to higher business development expenses, partially offset by improved results in Retail Energy from a growing customer portfolio.

REGULATORY DEVELOPMENTS

NEXT GENERATION OF PERFORMANCE BASED REGULATION

On February 5, 2018, the AUC released a regulatory decision that provides determinations for the going-in rates and incremental capital funding for the second generation of PBR. The following table compares the key aspects of the PBR First Generation with the PBR Second Generation based on the AUC's February 5, 2018 decision.

	PBR First Generation	PBR Second Generation
Timeframe	2013 to 2017	2018 to 2022
Inflation Adjuster (I Factor)	Inflation indexes (AWE and CPI) adjusted annually	Inflation indexes (AWE and CPI) adjusted annually
Productivity Adjuster (X Factor)	1.16%	0.30%
O&M	Based on approved 2012 forecast O&M levels; inflated by I-X thereafter over the PBR term	Based on the lowest annual actual O&M level during 2013-2016, adjusted for inflation, growth and productivity to 2017 dollars; inflated by I-X thereafter over the PBR term
Treatment of Capital Costs	• Recovered through going-in rates inflated by I-X • Significant capital costs not fully recovered by the I-X formula and meeting certain criteria recovered through a K Factor	• Recovered through going-in rates inflated by I-X and a K Bar that is based on inflation adjusted average historical capital costs for the period 2013-2016. The K Bar is calculated annually and adjusted for the actual WACC • Significant capital costs that are extraordinary, not previously incurred and required by a third party recovered through a "Type I" K Factor
ROE Used for Going-in Rates	• 8.75%	• 8.5% • + 0.5% ROE ECM achieved from PBR First Generation added to 2018 and 2019
Efficiency Carry-over Mechanism (ECM)	ECM up to 0.5% additional ROE for the years 2018 and 2019 based on certain criteria	ECM up to 0.5% additional ROE for the years 2023 and 2024 based on certain criteria
Reopener	+/- 300 bps of the approved ROE for two consecutive years or +/- 500 bps of the approved ROE for any single year	+/- 300 bps of the approved ROE for two consecutive years or +/- 500 bps of the approved ROE for any single year
ROE Used for Reopener Calculation	2013 to 2016: 8.3% 2017: 8.5%	• 8.5% Placeholder • At approved ROE pending future GCOC proceeding decisions

UTILITY ASSET DISPOSITION

On April 19, 2018, the Government of Alberta introduced Bill 13, *An Act to Secure Alberta's Electricity Future,* for first reading. The bill, as currently written, would significantly impact key regulatory principles and current law with respect to the recovery of prudently incurred costs, retroactive ratemaking, and utility asset dispositions that would give the AUC the authority to make decisions on a case-by-case basis.

If enacted in its present form, Bill 13 would introduce significant changes to the regulatory framework in which the Company operates, and would introduce increased uncertainty for utility investments. We are in discussions with the Government of Alberta regarding recommended changes to the current draft legislation.

SUSTAINABILITY, CLIMATE CHANGE AND THE ENVIRONMENT

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 has been publishing external sustainability reports since 2008. These reports include Canadian Utilities' operations sustainability performance data. Our 2017 Sustainability Report, expected to be released in June 2018, 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 2017 Sustainability Report will be available on our website, at www.canadianutilities.com.

CLIMATE CHANGE AND THE ENVIRONMENT

Phasing in of Renewable Electricity

As part of its Climate Leadership Plan, the Government of Alberta has published a firm target that 30 per cent of electricity used in Alberta will come from renewable sources such as wind, hydro and solar by 2030. The Government will support 5,000 MW of additional renewable energy capacity. Support will be provided to projects that are based in Alberta, are new or expanded, are greater than five MW in size, and meet the definition of renewable sources as defined by Natural Resources Canada. In December 2017, the Government of Alberta announced the contracts awarded for the first phase auction of the renewable electricity program, totaling 600 MW. On February 5, 2018, the Government of Alberta announced the next two auctions totaling 700 MW.

On May 10, 2017, the Government of Alberta issued a Negotiated Request for Proposal (NRFP). The NRFP was canceled on February 22, 2018. We will look for future opportunities to advance our solar projects either through potential Government procurement processes or through other long-term contracts.

Tax on Carbon Emissions

The Government of Alberta is phasing in a carbon tax across all sectors. An economy-wide carbon tax of $20 per tonne in 2017 was increased to $30 per tonne carbon tax in 2018, and may move to the Government of Canada requirement of $40 per tonne in 2021 and $50 per tonne in 2022. These higher carbon taxes have been a factor in the increase in Alberta Power Pool prices for the first quarter of 2018 when compared to the same period in 2017.

OTHER EXPENSES AND INCOME

A financial summary of other consolidated expenses and income items for the first quarter 2018 and 2017 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)	**2018**	**2017 (1) (restated)**	**Change**
Operating costs	**516**	446	70
Service concession arrangement costs	**368**	49	319
Gain on sale of operation	–	30	(30)
Earnings from investment in joint ventures	**8**	7	1
Depreciation and amortization	**151**	148	3
Net finance costs	**114**	101	13
Income taxes	**63**	68	(5)

(1) These numbers have been restated to account for the impact of IFRS 15. Additional details on IFRS 15 is discussed in the Other Financial Information section of this MD&A.

OPERATING COSTS

Operating costs, which are total costs and expenses less service concession arrangement costs and depreciation and amortization, increased by $70 million in the first quarter of 2018 when compared to the same period in 2017. Increased costs were mainly due to higher unrealized losses on mark-to-market forward commodity contracts, higher salaries and wages, and higher flow-through carbon taxes.

SERVICE CONCESSION ARRANGEMENT COSTS

Service concession arrangement costs in the first quarter of 2018 are costs Alberta PowerLine has recorded on third party construction activities for the Fort McMurray West 500-kV Project.

GAIN ON SALES OF OPERATIONS

Gain on sales of operations decreased by $30 million in the first quarter of 2018 when compared to the same period in 2017. In 2017, we sold our 100 per cent investment in ATCO Real Estate Holdings Ltd, resulting in a gain of $30 million.

EARNINGS FROM INVESTMENT IN JOINT VENTURES

Earnings from investment in joint ventures is mainly comprised of our ownership position in several power generation plants and the Strathcona Storage Limited Partnership. Earnings in the first quarter of 2018 were $1 million higher than the same period in 2017, primarily due to higher earnings contributions from Strathcona Storage Limited Partnership's hydrocarbon storage facility.

DEPRECIATION AND AMORTIZATION

In the first quarter of 2018, depreciation and amortization expense was $151 million in the first quarter of 2018, comparable to the same period in 2017.

NET FINANCE COSTS

Net finance costs increased by $13 million in the first quarter of 2018 when compared to the same period in 2017, mainly as a result of incremental debt issued to fund the ongoing capital investment program in our Regulated Utilities and Alberta PowerLine's project financing in 2017.

INCOME TAXES

Income taxes decreased in the first quarter of 2018 when compared to the same period in 2017, mainly due to lower earnings before income taxes in the first quarter 2018.

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. An additional source of capital is the Class A shares the Company issues under its Dividend Reinvestment Plan (DRIP).

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.

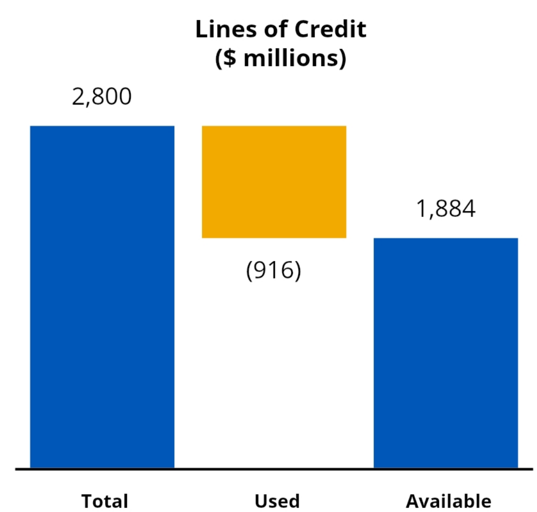
LINES OF CREDIT

At March 31, 2018, Canadian Utilities and its subsidiaries had the following lines of credit.

($ millions)	**Total**	**Used**	**Available**
Long-term committed	**2,247**	575	1,672
Uncommitted	**553**	341	212
Total	**2,800**	916	1,884

Of the $2,800 million in total credit lines, $553 million was in the form of uncommitted credit facilities with no set maturity date. The other $2,247 million in credit lines were committed, with maturities between 2019 and 2021, and may be extended at the option of the lenders.

Of the $916 million credit line usage, approximately half related to ATCO Gas Australia Limited Partnership, with the majority of the remaining usage pertaining to letter of credit issuances. Long-term committed credit lines are used to satisfy all of ATCO Gas Australia Limited Partnership's term debt financing needs. Credit lines for ATCO Gas Australia Limited Partnership are provided by Australian banks, with the majority of all other credit lines provided by Canadian banks.



CONSOLIDATED CASH FLOW

At March 31, 2018, the Company's cash position was $490 million, an increase of $72 million compared to December 31, 2017. The increase is mainly due to earnings achieved during the quarter, partially offset by cash used to fund our capital investment program.

Funds Generated by Operations

Funds generated by operations were $525 million in the first quarter of 2018, $19 million higher than the same period in 2017. The increase was mainly due to lower cash income taxes paid and higher contributions from customers.

Cash Used for Capital Investment

Cash used for capital investment was $744 million in the first quarter of 2018, $459 million higher than the same period in 2017, mainly due to increased spending in Alberta PowerLine and the acquisition of the Mexico hydro facility.

Capital investment for the first quarter of 2018 and 2017 is shown in the table below.

	Three Months Ended March 31		
($ millions)	**2018**	**2017**	**Change**
Electricity			
Electricity Distribution	**46**	56	(10)
Electricity Transmission	**69**	40	29
Electricity Generation	**116**	4	112
Alberta PowerLine	**368**	49	319
Total Electricity	**599**	149	450
Pipelines & Liquids			
Natural Gas Distribution	**55**	53	2
Natural Gas Transmission	**64**	57	7
International Natural Gas Distribution	**16**	20	(4)
International Natural Gas Transmission and Storage & Industrial Water	**6**	5	1
Total Pipelines & Liquids	**141**	135	6
Corporate & Other	**4**	1	3
Total (1) (2)	**744**	285	459

(1) Includes capital expenditures in joint ventures of $5 million (2017 - $1 million) for the first quarter of 2018.

(2) Includes additions to property, plant and equipment, intangibles and $5 million (2017 - $4 million) of interest capitalized during construction for the first quarter of 2018.

Base Shelf Prospectuses

CU Inc. Debentures

On May 16, 2016, 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, 2018, aggregate issuances of debentures were $805 million.

Canadian Utilities Debt Securities and Preferred Shares

On April 12, 2016, 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 46 year track record. Dividends paid to Class A and Class B share owners totaled $90 million in the first quarter of 2018.

On April 4, 2018, the Board of Directors declared a second quarter dividend of 39.33 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.

46 year
track record of increasing common share dividends

Dividend Reinvestment Plan

In the first quarter of 2018, we issued 490,214 (2017 - 866,019) Class A shares under our DRIP in lieu of cash dividend payments of $16 million (2017- $31 million).

SHARE CAPITAL

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

At April 24, 2018, the Company had outstanding 197,635,895 Class A shares, 73,992,374 Class B shares, and options to purchase 819,000 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 the Company's stock option plan, 5,128,100 Class A shares were available for issuance at March 31, 2018. 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, 2016 through March 31, 2018.

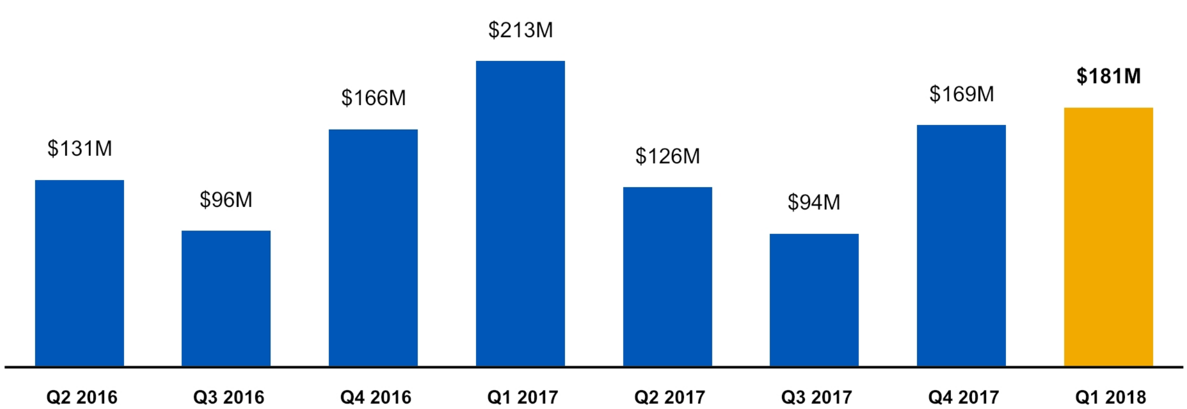
($ millions, except for per share data)	Q2 2017(1) (restated)	Q3 2017(1) (restated)	Q4 2017(1) (restated)	Q1 2018
Revenues	942	930	1,208	**1,385**
Earnings attributable to Class A and Class B shares	90	94	102	**179**
Earnings per Class A and Class B share *($)*	0.27	0.29	0.32	**0.60**
Diluted earnings per Class A and Class B share *($)*	0.27	0.29	0.32	**0.60**
Adjusted earnings per share per Class I and Class II 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**

($ millions, except for per share data)	Q2 2016	Q3 2016	Q4 2016	Q1 2017(1) (restated)
Revenues	756	778	1,014	1,005
Earnings attributable to Class A and Class B shares	108	124	196	228
Earnings per Class A and Class B share *($)*	0.34	0.40	0.67	0.78
Diluted earnings per Class A and Class B share *($)*	0.34	0.40	0.67	0.78
Adjusted earnings per share per Class I and Class II Share *($)*	0.49	0.36	0.62	0.79
Adjusted earnings				
Electricity	102	87	111	116
Pipelines & Liquids	43	26	81	112
Corporate & Other and Intersegment Eliminations	(14)	(17)	(26)	(15)
Total adjusted earnings	131	96	166	213

(1) These numbers have been restated to account for the impact of IFRS 15. Additional details on IFRS 15 is discussed in the Other Financial Information section of this MD&A.

Adjusted Earnings

Our financial results for the previous eight quarters reflect continued growth in our Regulated Utility operations as well as fluctuating commodity prices in electricity generation and sales, and natural gas storage operations. In addition, interim results will vary due to the seasonal nature of demand for electricity and natural gas, the timing of utility regulatory decisions and the cyclical demand for workforce housing and space rental products and services.



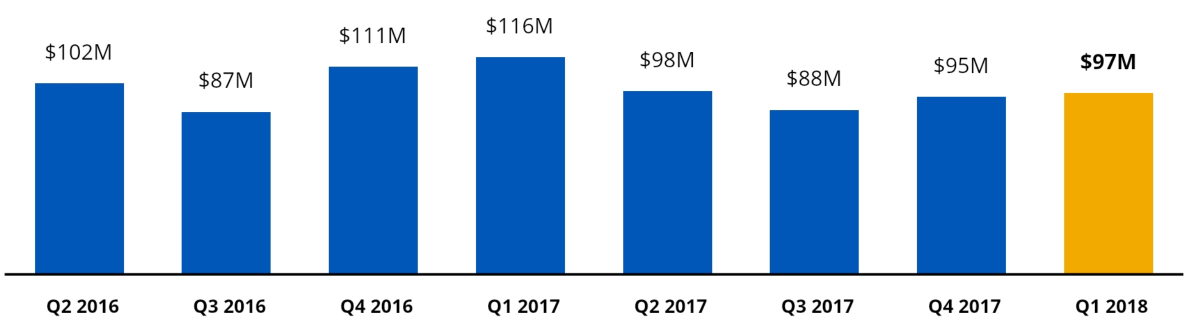
Electricity

Electricity's adjusted earnings reflect the large capital investment made by Regulated Electricity in the previous eight quarters. These investments, which earn a return under a regulated business model, drive growth in adjusted earnings. Adjusted earnings have also been affected by the timing of certain major regulatory decisions, and Alberta Power Pool pricing and spark spreads.

In 2016, earnings reflected continued capital investment and rate base growth and business-wide cost reduction initiatives. Lower earnings in the third quarter were due to the financial impact of electricity transmission's 2015 to 2017 General Tariff Application regulatory decision.

In 2017, higher first quarter earnings were mainly due to continued capital investment and rate base growth within Regulated Electricity and lower operating costs. Lower second quarter earnings were mainly due to the timing of operating and other costs in electric distribution, and the impact of the 2015 to 2017 GTA Compliance decision in electric transmission. Third quarter earnings were lower mainly due to the impact of the 2013 to 2014 Deferral Accounts decision in electric transmission. Fourth quarter earnings were impacted by lower contributions in our electricity generation business from forward sales and increased business development expenses.

In the first quarter of 2018, lower earnings in our regulated utilities and Independent Power Plants were partially offset by higher earnings from Alberta PowerLine and Thermal PPAs.



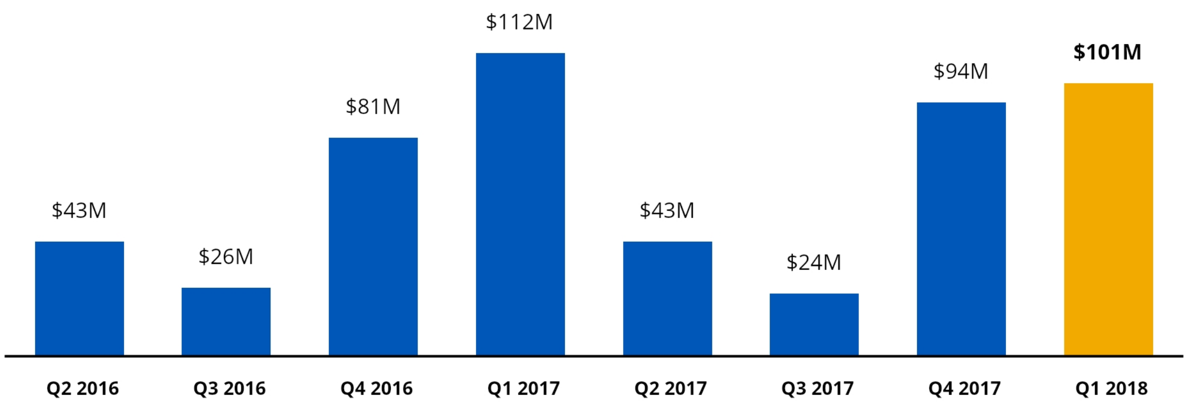
Pipelines & Liquids

Pipelines & Liquids' adjusted earnings reflect the large capital investment made by Regulated Pipelines & Liquids in the previous eight quarters. These investments, which earn a return under a regulated business model, drive growth in adjusted earnings. Adjusted earnings have also been affected by the timing of certain major regulatory decisions, seasonality, and commodity prices.

In the second and third quarters of 2016, lower earnings were due to lower seasonal demand in our natural gas distribution business.

In the first quarter of 2017, increased earnings were mainly due to continued capital investment and rate base growth. 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, lower earnings were impacted by inflation adjustments to rates in our international natural gas distribution business. Higher earnings in the fourth quarter of 2017 were primarily a result of higher rate base and customers.

In the first quarter of 2018, higher seasonal demand and growth in rate base across the Pipelines & Liquids regulated utilities was partially offset by lower earnings in natural gas distribution.



Earnings attributable to Class A and Class B shares

Earnings attributable to Class A and Class B shares 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:

- Each quarter, the Company adjusts the deferred tax asset which was recognized as a result of the 2015 Tula Pipeline Project impairment. The adjustments of $2 million to date in 2018, less than $1 million in 2017, and $5 million in 2016 is due to a difference between the tax base currency, which is the Mexican peso, and the U.S. dollar functional currency.
- In the fourth quarter of 2017, Structures & Logistics recognized a pre-tax impairment of $34 million relating to certain 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 first quarter of 2017, we recorded a gain of $30 million on the sale of our 100 per cent investment in ATCO Real Estate Holdings Ltd.

NON-GAAP AND ADDITIONAL GAAP MEASURES

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.

Adjusted earnings are defined as earnings attributable to Class A and Class B shares 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 Class A and Class B shares is presented in this MD&A. Adjusted earnings is an additional GAAP measure presented in Note 5 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.

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

RECONCILIATION OF ADJUSTED EARNINGS TO EARNINGS ATTRIBUTABLE TO CLASS A AND CLASS B SHARES

Adjusted earnings are earnings attributable to the Class A and Class B shares 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
2018 **2017 (restated)** [(1)]	**Electricity**	**Pipelines & Liquids**	**Corporate & Other**	**Intersegment Eliminations**	**Consolidated**
Revenues	**899**	**485**	**39**	**(38)**	**1,385**
	509	498	24	(26)	1,005
Adjusted earnings	**97**	**101**	**(17)**	**–**	**181**
	116	112	(16)	1	213
Gain on sale of operation	**–**	**–**	**–**	**–**	**–**
	–	–	30	–	30
Unrealized losses on mark-to-market forward commodity contracts	**(18)**	**–**	**–**	**–**	**(18)**
	(5)	–	–	–	(5)
Rate-regulated activities	**(13)**	**9**	**–**	**1**	**(3)**
	(39)	11	–	1	(27)
Dividends on equity preferred shares of Canadian Utilities Limited	**1**	**–**	**16**	**–**	**17**
	1	–	16	–	17
Other	**–**	**2**	**–**	**–**	**2**
	–	–	–	–	–
Earnings attributable to Class A and Class B shares	**67**	**112**	**(1)**	**1**	**179**
	73	123	30	2	228

(1) These numbers have been restated to account for the impact of IFRS 15. Additional details on IFRS 15 is discussed in the Other Financial Information section of this MD&A.

GAIN ON SALE OF OPERATION

In January 2017, we sold our 100 per cent investment in ATCO Real Estate Holdings Ltd. to ATCO Ltd. for cash proceeds of $47 million, which resulted in a gain of $30 million. The proceeds will be deployed for continued capital investment, to repay indebtedness, and for other general corporate purposes.

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

In order to optimize the available merchant capacity and manage exposure to electricity market price movements for our Independent Power Plants, we enter into forward contracts. The MW capacity limits on forward commodity contracts were increased in 2016 which heightens the potential for higher unrealized gains or losses in advance of the settlement of the contract.

Effective the first quarter of 2017, adjusted earnings do not include unrealized gains or losses on mark-to-market forward commodity contracts. Removal of the unrealized gains or losses on mark-to-market forward commodity contracts provides a better representation of the operating results of the Independent Power Plants and more closely aligns us with our electricity generation and utility company peer disclosure. Realized gains or losses are recognized in adjusted earnings when the commodity contracts are settled.

RATE-REGULATED ACTIVITIES

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.

As a result, the Company uses standards issued by the Financial Accounting Standards Board (FASB) in the United States as another source of GAAP to account for rate-regulated activities in its internal reporting provided to the Chief Operating Decision Maker (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 regulators' decisions on revenues.

Earnings adjustments to reflect rate-regulated accounting are shown in the following table.

		Three Months Ended March 31	
($ millions)	**2018**	**2017**	**Change**
Additional revenues billed in current period			
Future removal and site restoration costs [1]	**19**	19	–
Impact of colder temperatures [2]	**12**	–	12
Revenues to be billed in future periods			
Deferred income taxes [3]	**(33)**	(30)	(3)
Settlement of regulatory decisions and other items [4]	**(1)**	(16)	15
	(3)	(27)	24

(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.

(4) Includes PBR interim rate accrual of $9 million. Starting January 2018, natural gas distribution and electric distribution commenced a new PBR period. New rates came into effect April 1st, 2018, which will reverse the PBR interim rate accrual during 2018.

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, 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.	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 as well as the Segmented Information presented in unaudited interim consolidated financial statements.	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.

For further details on additional revenues billed in the current period, revenues to be billed in future periods, and settlement of regulatory decisions and other items, refer to the Segmented Information presented in Note 5 of the 2018 unaudited interim consolidated financial statements.

OTHER

Each quarter, the Company adjusts the deferred tax asset which was recognized as a result of the 2015 Tula Pipeline Project impairment. The adjustment of $2 million is due to a difference between the tax base currency, which is the Mexican peso, 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)

2018 **2017 (restated)** [(1)]	**Three Months Ended March 31**
Funds generated by operations	**525**
	506
Changes in non-cash working capital	**163**
	98
Change in receivable under service concession arrangement	**(399)**
	(54)
Cash flows from operating activities	**289**
	550

(1) These numbers have been restated to account for the impact of IFRS 15. Additional details on IFRS 15 is discussed in the Other Financial Information section of this MD&A.

OTHER FINANCIAL INFORMATION

ACCOUNTING CHANGES

Certain new or amended standards or interpretations issued by the International Accounting Standards Board (IASB) or IFRS Interpretations Committee (IFRIC) have been adopted in the current period. These standards or interpretations are substantially unchanged from those reported in the 2017 MD&A.

- IFRS 9 (2014) Financial Instruments - this standard replaces IAS 39 Financial Instruments: Recognition and Measurement and previous versions of IFRS 9. It incorporates IFRS 9 (2013), with a further classification category for financial assets, and includes a new impairment model for financial instruments. The Company early adopted two out of three components of this standard (Classification and Measurement and Hedge Accounting) on January 1, 2015. This standard was effective on January 1, 2018, at which time the Company adopted the final component, Impairments. This component includes a new expected credit loss model for calculating impairment on financial assets and replaces the current incurred loss impairment model. The new standard will increase bad debt provisioning for all trade receivables, however the impact is not material due to current provisioning procedures, the low credit risk with current counterparties, and collateral and parental guarantee arrangements in place for the Company's significant receivables. Additional information regarding the impact of the adoption of IFRS 9 is presented in Note 3 of the unaudited interim consolidated financial statements.
- IFRS 15 Revenue from Contracts with Customers - this standard replaces IAS 18 Revenue and related interpretations and is effective on or after January 1, 2018. It provides a framework to determine when to recognize revenue and at what amount. It applies to new contracts created on or after the effective date and to existing contracts not completed as of the effective date. The Company has applied the full retrospective transition method. The Company is party to numerous contracts with customers that will be impacted by the new standard. Under IFRS 15, the timing of revenue recognition for certain contracts are impacted by the new revenue recognition model. Additional information regarding the impact of the adoption of IFRS 15 is presented in Note 3 of the unaudited interim consolidated financial statements.

Certain new or amended standards or interpretations issued by the International Accounting Standards Board (IASB) or IFRS Interpretations Committee (IFRIC) do not need to be adopted in the current period. The Company anticipates that these standards issued, but not yet effective, may have a material effect on the consolidated financial statements are described below.

- IFRS 16 Leases - this standard replaces IAS 17 Leases and related interpretations and is effective on or after January 1, 2019. It requires a lessee to recognize assets and liabilities on the balance sheet for the rights and obligations created by leases. Lessor accounting remains substantially unchanged. The Company is currently assessing the impact and will not early adopt the standard.

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

INTERNAL CONTROLS 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, 2018, and ended on March 31, 2018, 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 consolidated financial statements and its MD&A for the three months ended March 31, 2018. 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 Electric Distribution (ATCO Electric Distribution), Electric 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, President 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 electric utility business in Alberta. PPAs are legislatively mandated and approved by the AUC.

Regulated Utilities means Electric Distribution (ATCO Electric Distribution), Electric 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, 2018

TABLE OF CONTENTS

CONSOLIDATED STATEMENT OF EARNINGS

(millions of Canadian Dollars except per share data)	Note	Three Months Ended March 31 2018	2017 (Note 3)
Revenues	6	**1,385**	1,005
Costs and expenses			
Salaries, wages and benefits		**(102)**	(80)
Energy transmission and transportation		**(44)**	(54)
Plant and equipment maintenance		**(53)**	(46)
Fuel costs		**(62)**	(55)
Purchased power		**(38)**	(27)
Service concession arrangement costs		**(368)**	(49)
Depreciation and amortization	10	**(151)**	(148)
Franchise fees		**(79)**	(83)
Property and other taxes		**(44)**	(32)
Unrealized losses on mark-to-market forward commodity contracts		**(24)**	(7)
Other		**(70)**	(62)
		(1,035)	(643)
Gain on sale of operation	7	**–**	30
Earnings from investment in joint ventures		**8**	7
Operating profit		**358**	399
Interest income		**9**	5
Interest expense		**(123)**	(106)
Net finance costs		**(114)**	(101)
Earnings before income taxes		**244**	298
Income taxes		**(63)**	(68)
Earnings for the period		**181**	230
Earnings attributable to:			
Class A and Class B shares		**179**	228
Non-controlling interests		**2**	2
		181	230
Earnings per Class A and Class B share	8	**$0.60**	$0.78
Diluted earnings per Class A and Class B share	8	**$0.60**	$0.78

See accompanying Notes to Unaudited Interim Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	Three Months Ended March 31	
(millions of Canadian Dollars)	**2018**	**2017 (Note 3)**
Earnings for the period	**181**	230
Other comprehensive loss, net of income taxes		
Items that will not be reclassified to earnings:		
Re-measurement of retirement benefits (1)	**(21)**	(40)
Share of re-measurement of retirement benefits of ATCO Structures & Logistics (2)	**–**	(1)
	(21)	(41)
Items that are or may be reclassified subsequently to earnings:		
Cash flow hedges (3)	**(5)**	(4)
Cash flow hedges reclassified to earnings (2)	**–**	(1)
Foreign currency translation adjustment (2)	**18**	26
Share of other comprehensive income of joint ventures (2)	**–**	1
	13	22
Other comprehensive loss	**(8)**	(19)
Comprehensive income for the period	**173**	211
Comprehensive income attributable to:		
Class A and Class B shares	**171**	209
Non-controlling interests	**2**	2
	173	211

(1) Net of income taxes of $8 million for the three months ended March 31, 2018 (2017 - $15 million).

(2) Net of income taxes of nil.

(3) Net of income taxes of $2 million for the three months ended March 31, 2018 (2017 - $2 million).

See accompanying Notes to Unaudited Interim Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET

(millions of Canadian Dollars)	Note	March 31 2018	December 31 2017 (Note 3)	January 1 2017 (Note 3)
ASSETS				
Current assets				
Cash and cash equivalents	15	**494**	425	345
Accounts receivable and contract assets		**573**	616	518
Finance lease receivables		**16**	15	12
Inventories		**48**	40	38
Income taxes receivable		**29**	35	35
Restricted project funds	9	**692**	861	–
Prepaid expenses and other current assets		**55**	45	37
		1,907	2,037	985
Non-current assets				
Property, plant and equipment	10	**17,013**	16,786	16,363
Intangibles		**608**	563	526
Investment in ATCO Structures & Logistics		**–**	–	199
Investment in joint ventures		**203**	196	189
Finance lease receivables		**394**	395	302
Deferred income tax assets		**89**	84	80
Receivable under service concession arrangement		**992**	593	77
Restricted project funds	9	**57**	104	–
Other assets		**87**	86	85
Total assets		**21,350**	20,844	18,806
LIABILITIES				
Current liabilities				
Bank indebtedness	15	**4**	7	5
Accounts payable and accrued liabilities		**933**	827	609
Asset retirement obligations and other provisions		**37**	33	40
Other current liabilities		**70**	64	18
Short-term debt	11	**100**	–	55
Long-term debt	12	**229**	5	155
Non-recourse long-term debt		**15**	15	14
		1,388	951	896
Non-current liabilities				
Deferred income tax liabilities		**1,280**	1,229	1,135
Asset retirement obligations and other provisions		**128**	128	132
Retirement benefit obligations		**371**	340	302
Deferred revenues		**1,818**	1,808	1,870
Other liabilities		**190**	147	46
Long-term debt	12	**8,367**	8,494	8,065
Non-recourse long-term debt		**1,397**	1,401	84
Total liabilities		**14,939**	14,498	12,530
EQUITY				
Equity preferred shares		**1,483**	1,483	1,483
Class A and Class B share owners' equity				
Class A and Class B shares	14	**1,177**	1,162	1,070
Contributed surplus		**14**	12	15
Retained earnings		**3,582**	3,547	3,511
Accumulated other comprehensive loss		**(32)**	(45)	(5)
		4,741	4,676	4,591
Non-controlling interests		**187**	187	202
Total equity		**6,411**	6,346	6,276
Total liabilities and equity		**21,350**	20,844	18,806

See accompanying Notes to Unaudited Interim Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

		Attributable to Equity Owners of the Company							
(millions of Canadian Dollars)	**Note**	**Class A and Class B Shares**	**Equity Preferred Shares**	**Contributed Surplus**	**Retained Earnings**	**Accumulated Other Comprehensive Income**	**Total**	**Non-Controlling Interests**	**Total Equity**
December 31, 2016, as previously reported	3	1,070	1,483	15	3,655	(5)	6,218	202	6,420
IFRS 15 re-measurement adjustments	3	–	–	–	(144)	–	(144)	–	(144)
January 1, 2017, restated	3	1,070	1,483	15	3,511	(5)	6,074	202	6,276
Earnings for the period, as previously reported		–	–	–	230	–	230	2	232
Re-measurement adjustments	3	–	–	–	(2)	–	(2)	–	(2)
Other comprehensive loss		–	–	–	–	(19)	(19)	–	(19)
Losses on retirement benefits transferred to retained earnings		–	–	–	(41)	41	–	–	–
Shares issued		31	–	–	–	–	31	–	31
Dividends	13,14	–	–	–	(113)	–	(113)	(2)	(115)
Share-based compensation		(1)	–	(2)	–	–	(3)	–	(3)
Other		–	–	–	–	–	–	(15)	(15)
March 31, 2017	3	1,100	1,483	13	3,585	17	6,198	187	6,385
December 31, 2017, as previously reported	3	1,162	1,483	12	3,663	(45)	6,275	187	6,462
IFRS 15 and IFRS 9 re-measurement adjustments	3	–	–	–	**(116)**	–	**(116)**	–	**(116)**
January 1, 2018, restated	3	**1,162**	**1,483**	**12**	**3,547**	**(45)**	**6,159**	**187**	**6,346**
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**	**3,582**	**(32)**	**6,224**	**187**	**6,411**

See accompanying Notes to Unaudited Interim Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOW

(millions of Canadian Dollars)	Note	Three Months Ended March 31 2018	 2017 (Note 3)
Operating activities			
Earnings for the period		**181**	230
Adjustments to reconcile earnings to cash flows from operating activities	15	**344**	276
Changes in non-cash working capital		**163**	98
Change in receivable under service concession arrangement		**(399)**	(54)
Cash flows from operating activities		**289**	550
Investing activities			
Additions to property, plant and equipment		**(240)**	(215)
Additions to intangibles		**(14)**	(16)
Acquisition, net of cash acquired	4	**(70)**	–
Proceeds on sale of operation	7	**–**	47
Investment in joint ventures		**(6)**	(5)
Changes in non-cash working capital		**(26)**	(21)
Other		**(3)**	12
Cash flows used in investing activities		**(359)**	(198)
Financing activities			
Net issue (repayment) of short-term debt	11	**100**	(20)
Issue of long-term debt	12	**40**	–
Release of restricted project funds	9	**216**	–
Repayment of non-recourse long-term debt		**(4)**	(4)
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		**(90)**	(65)
Interest paid		**(102)**	(91)
Other		**2**	8
Cash flows from (used in) financing activities		**144**	(191)
Increase in cash position (1)		**74**	161
Foreign currency translation		**(2)**	3
Beginning of period		**418**	340
End of period	15	**490**	504

(1) Cash position includes $93 million which is not available for general use by the Company (2017 - $41 million).

See accompanying Notes to Unaudited Interim Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

MARCH 31, 2018

(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); and
- Pipelines & Liquids (natural gas transmission, distribution and infrastructure development, energy storage, and industrial water solutions).

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, 2017, 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 policies 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 25, 2018.

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 POLICIES

FINANCIAL INSTRUMENTS CREDIT LOSSES

The Company adopted the final component of IFRS 9 Financial Instruments, Impairments, on January 1, 2018. This component includes a new expected credit loss model. The new model takes into account an expectation of future events by estimating credit losses based on assessment of the counterparty credit risk. The change results in earlier recognition of bad debt expense. For accounts receivable and contract assets and finance lease receivables, the Company estimates credit loss allowances at initial recognition and throughout the life of the receivable. For receivable under service concession arrangement, which is assessed as a low risk of default, the Company estimates credit loss allowances from possible default events within the twelve months after the balance sheet date. The Company applies a provision matrix based on historical collection experience, third party default probabilities, and customer acceptance scores.

REVENUE RECOGNITION

The Company adopted IFRS 15 *Revenue from Contracts with Customers* on January 1, 2018, using the full retrospective transition method. Under the full retrospective transition method, the comparative figures for 2017 in the Company's unaudited interim consolidated financial statements have been restated. Certain practical expedients have been applied.

The Company enters into contracts that include various goods and services promised to the customer. Determining whether the goods and services are considered distinct performance obligations may require significant judgment. Revenue is allocated to the respective performance obligations based on relative transaction prices, and is recognized as goods and services are delivered to the customer. Revenue is measured as the amount of consideration expected to be received in exchange for the goods transferred or services delivered. The amount of revenue recognized reflects the time value of money where a significant financing component has been identified.

Contract modifications are accounted for prospectively or as a cumulative catch-up adjustment depending on the nature of the change.

Where the amount of goods and services delivered to the customer corresponds directly to the amount invoiced, the Company recognizes revenue equal to what it has the right to invoice.

Where the Company arranges for another party to provide a specified good or service (that is, it does not control the specified good or service provided by another party before that good or service is transferred to the customer), only revenues net of payments to the other party for the goods or services provided are recognized.

Non-cash considerations received from the Company's customers are included in the amount of revenue recognized and measured at fair value.

Costs incurred directly to obtain or fulfill a contract are capitalized and amortized to expense over the life of the contract.

The Company makes judgments with respect to: determining whether the promised goods and services are considered distinct performance obligations by considering the relationship of such promised goods and services; allocating the transaction price for each distinct performance obligation identified through stand-alone selling price; evaluating when a customer obtains controls of the goods or service promised; and evaluating whether the Company acts as principal or agent on certain flow-through charges to customers.

Electricity generation and delivery

Revenue from independent power plant (IPP) contracts providing generation capacity to customers is recognized over the contract term and is measured based on fixed or variable capacity payments. Revenue from operating and maintaining the plant is recognized as the Company incurs costs to service the plant.

Electricity and natural gas transmission

Revenue from electricity and natural gas transmission services is recognized when service is provided to customers and is measured in proportion to the amount it has the right to invoice under the contract.

Customer contributions for extensions to plant are included in deferred revenues and recognized as revenue over the life of the related asset.

Electricity and natural gas distribution

Revenue from distribution of electricity and natural gas is recognized when the services are provided to the customer based on metered consumption, which is adjusted periodically to reflect differences between estimated and actual consumption. Distribution of regulated and non-regulated electricity and natural gas is based on tariff-approved rates established by Alberta Electric Systems Operator and Natural Gas Exchange and rates stipulated in the contracts, respectively. The Company recognizes revenue in an amount that corresponds directly with the services delivered and the amount invoiced.

Gas storage and transportation

Revenue from hydrocarbon storage and transportation is recognized as the service is rendered to customers based on the length of the required service and contracted schedule of injections and withdrawals from the storage facilities.

Lease revenue

Power purchase agreements (PPA) for the generation of electricity are accounted for as operating leases, finance leases or executory contracts, depending on the terms of the PPAs.

Operating lease PPAs are subject to incentives and penalties relating to the generating unit's availability. Incentives are paid to the Company by the PPA counterparties for availability in excess of predetermined targets, whereas penalties are paid by the Company to the PPA counterparties when the availability targets are not achieved. The Company recognizes operating lease income on a declining rate base method, in accordance with the lease contract. Accumulated incentives in excess of accumulated penalties are deferred and operating lease income is recognized over the remaining term of the PPA. Conversely, any shortfall is expensed in the year the shortfall occurs.

Certain PPAs are classified as finance leases. Finance lease income is included in revenues. Non-lease components of the PPAs are accounted for based on the applicable performance obligations.

Service concession arrangement

Revenue on design and construction of the Fort McMurray 500 kV Transmission project (Project) is recognized based on the stage of completion of the related services. Revenue on operating and maintenance of the Project are recognized as related costs are incurred using the applicable markup.

Franchise fees

Municipal governments charge franchise fees to the utilities in Canada for the exclusive right to provide service in their community. These costs are charged to customers through rates approved by the regulator. Franchise fees do not represent a separate performance obligation to a customer and are recovered through utilities transmission and distribution prices. The recovery is part of the provision of continuous electricity and natural gas transmission and distribution service performance obligation. Franchise fees invoiced to customers are recognized as revenues.

Practical expedients

Effective January 1, 2017, the IFRS 15 transition date, the Company elected to use the following practical expedients:

(i). Information on the remaining performance obligations that have original expected duration of one year or less is not disclosed;

(ii). For periods presented before January 1, 2018, the IFRS 15 adoption date, the information regarding the amount of the transaction price allocated to the remaining performance obligations and an explanation of when the Company expects to recognize this amount as revenue, are not disclosed;

(iii). Costs to obtain or fulfill a contract with an amortization period of less than a year have been expensed as incurred;

(iv). Where the Company has a right to consideration from a customer in an amount that corresponds directly with the value to the customer of the Company's performance to date, revenue is recognized in the amount to which the Company has a right to invoice. Such performance obligations include:

- Provision of continuous distribution of electricity service;
- Provision of continuous distribution of natural gas service;
- Provision of transmission of electricity service;
- Provision of transmission of natural gas service;
- Certain operating and maintenance services;
- Supply of electricity and natural gas to businesses and households.

Remaining performance obligations

The Company is party to certain remaining performance obligations, which have a duration of more than one year. The most significant remaining performance obligations at January 1, 2018, relate to the Company's 35-year service concession arrangement and amounts to $1.8 billion. Out of this $1.8 billion, the Company recognized $0.4 billion as revenue during the three months ended March 31, 2018, and expects to recognize approximately $0.4 billion as revenue during the remaining nine months of 2018, subject to satisfaction of related performance obligations.

IMPACT OF CHANGES IN ACCOUNTING POLICIES

The impact on amounts recognized in the Company's consolidated statement of earnings for the three months ended March 31, 2017, is shown below.

		Three Months Ended March 31, 2017		
(millions of Canadian Dollars except per share data)	**Note**	**As previously reported**	**IFRS 15 re-measurement adjustments**	**Restated**
Revenues	(ii.), (iii.), (iv.), (v.)	997	8	1,005
Costs and expenses				
Salaries, wages and benefits		(80)	–	(80)
Energy transmission and transportation	(iv.)	(68)	14	(54)
Plant and equipment maintenance		(46)	–	(46)
Fuel costs	(iii.)	(33)	(22)	(55)
Purchased power		(27)	–	(27)
Service concession arrangement costs		(49)	–	(49)
Depreciation and amortization		(148)	–	(148)
Franchise fees		(83)	–	(83)
Property and other taxes		(32)	–	(32)
Unrealized losses on mark-to-market forward commodity contracts		(7)	–	(7)
Other		(62)	–	(62)
		(635)	(8)	(643)
Gain on sale of operation		30	–	30
Earnings from investment in joint ventures		7	–	7
Operating profit		399	–	399
Interest income		5	–	5
Interest expense	(v.)	(103)	(3)	(106)
Net finance costs		(98)	(3)	(101)
Earnings before income taxes		301	(3)	298
Income taxes		(69)	1	(68)
Earnings for the period		232	(2)	230
Earnings attributable to:				
Class A and Class B shares		230	(2)	228
Non-controlling interests		2	–	2
		232	(2)	230
Earnings per Class A and Class B share	8	$0.79	$(0.01)	$0.78
Diluted earnings per Class A and Class B share	8	$0.79	$(0.01)	$0.78

The cumulative effect of the adjustments made to the amounts recognized in the Company's consolidated balance sheets as at January 1, 2017, and at December 31, 2017, is shown below.

				January 1, 2017
(millions of Canadian Dollars)	**Note**	**As previously reported**	**IFRS 15 re-measurement adjustments**	**Restated**
ASSETS				
Current assets				
Cash and cash equivalents		345	–	345
Accounts receivable and contract assets		518	–	518
Finance lease receivables		12	–	12
Inventories		38	–	38
Income taxes receivable		35	–	35
Prepaid expenses and other current assets		37	–	37
		985	–	985
Non-current assets				
Property, plant and equipment		16,363	–	16,363
Intangibles		526	–	526
Investment in ATCO Structures & Logistics		199	–	199
Investment in joint ventures		189	–	189
Finance lease receivables		302	–	302
Deferred income tax assets	(ii.)	55	25	80
Receivable under service concession arrangement		77	–	77
Other assets		85	–	85
Total assets		18,781	25	18,806
LIABILITIES				
Current liabilities				
Bank indebtedness		5	–	5
Accounts payable and accrued liabilities	(ii.)	605	4	609
Asset retirement obligations and other provisions		40	–	40
Other current liabilities		18	–	18
Short-term debt		55	–	55
Long-term debt		155	–	155
Non-recourse long-term debt		14	–	14
		892	4	896
Non-current liabilities				
Deferred income tax liabilities	(ii.)	1,163	(28)	1,135
Asset retirement obligations and other provisions		132	–	132
Retirement benefit obligations		302	–	302
Deferred revenues	(ii.)	1,689	181	1,870
Other liabilities	(ii.)	34	12	46
Long-term debt		8,065	–	8,065
Non-recourse long-term debt		84	–	84
Total liabilities		12,361	169	12,530
EQUITY				
Equity preferred shares		1,483	–	1,483
Class A and Class B share owners' equity				
Class A and Class B shares		1,070	–	1,070
Contributed surplus		15	–	15
Retained earnings		3,655	(144)	3,511
Accumulated other comprehensive loss		(5)	–	(5)
		4,735	(144)	4,591
Non-controlling interests		202		202
Total equity		6,420	(144)	6,276
Total liabilities and equity		18,781	25	18,806

					December 31, 2017
(millions of Canadian Dollars)	Note	As previously reported	IFRS 15 re-measurement adjustments	IFRS 9 re-measurement adjustments	Restated
ASSETS					
Current assets					
Cash and cash equivalents		425	–	–	425
Accounts receivable and contract assets	(i.)	619	–	(3)	616
Finance lease receivables		15	–	–	15
Inventories		40	–	–	40
Income taxes receivable		35	–	–	35
Restricted project funds		861	–	–	861
Prepaid expenses and other current assets		45	–	–	45
		2,040	–	(3)	2,037
Non-current assets					
Property, plant and equipment		16,786	–	–	16,786
Intangibles		563	–	–	563
Investment in ATCO Structures & Logistics		–	–	–	–
Investment in joint ventures		196	–	–	196
Finance lease receivables		395	–	–	395
Deferred income tax assets	(ii.)	62	22	–	84
Receivable under service concession arrangement		593	–	–	593
Restricted project funds		104	–	–	104
Other assets		86	–	–	86
Total assets		20,825	22	(3)	20,844
LIABILITIES					
Current liabilities					
Bank indebtedness		7	–	–	7
Accounts payable and accrued liabilities	(ii.)	824	3	–	827
Asset retirement obligations and other provisions		33	–	–	33
Other current liabilities		64	–	–	64
Short-term debt		–	–	–	–
Long-term debt		5	–	–	5
Non-recourse long-term debt		15	–	–	15
		948	3	–	951
Non-current liabilities					
Deferred income tax liabilities	(ii.)	1,248	(19)	–	1,229
Asset retirement obligations and other provisions		128	–	–	128
Retirement benefit obligations		340	–	–	340
Deferred revenues	(ii.)	1,676	132	–	1,808
Other liabilities	(ii.)	128	19	–	147
Long-term debt		8,494	–	–	8,494
Non-recourse long-term debt		1,401	–	–	1,401
Total liabilities		14,363	135	–	14,498
EQUITY					
Equity preferred shares		1,483	–	–	1,483
Class A and Class B share owners' equity					
Class A and Class B shares		1,162	–	–	1,162
Contributed surplus		12	–	–	12
Retained earnings		3,663	(113)	(3)	3,547
Accumulated other comprehensive loss		(45)	–	–	(45)
		4,792	(113)	(3)	4,676
Non-controlling interests		187	–	–	187
Total equity		6,462	(113)	(3)	6,346
Total liabilities and equity		20,825	22	(3)	20,844

Impact of adoption of IFRS 9 on consolidated financial statements

(i) To determine the amount of expected credit losses, the Company used default and recoverability probabilities for the majority of its operations and a provision matrix for certain operations in the Corporate & Other operating segments.

At January 1, 2018, the total credit loss provision was $4 million, which includes $3 million determined based on third party average default and recoverability probabilities and $1 million based on the provision matrix method. This resulted in an increase of $3 million in the credit loss provision recorded on adoption of IFRS 9.

The expected credit losses determined based on third party average default and recoverability probabilities, for respective credit ratings are as follows:

	Credit Quality			
January 1, 2018 *(millions of Canadian Dollars)*	**High (AA to AAA)**	**Medium (BBB to A)**	**Low [3] (BB and below)**	**Total**
Expected loss rate	0.00% - 0.03%	0.05% - 0.26%	0.36% - 1.05%	
Net Exposure [1]	763	413	116	1,292
Loss allowance [2]	–	2	1	3

(1) Net exposure is gross receivables less collateral consideration received from the customer.

(2) Loss allowance includes additional credit allowances for specific accounts receivable where the Company believes there is a high probability of customer default.

(3) For receivables from counterparties that do not have third party credit ratings, the Company used its best estimates to approximate their credit quality.

Impact of adoption of IFRS 15 on consolidated financial statements

(ii) The timing differences between consideration received and satisfaction of the provision of availability or existence of the contracted electricity generation capacity performance obligation in the Electricity operating segment resulted in recognition of deferred revenue balances on January 1, 2017 and over the remaining terms of the IPP contracts. The deferred revenue represents a significant financing component, as there is a benefit that has been or will be realized due to the timing of the consideration received in advance of satisfaction of the performance obligation.

At January 1, 2017, the Company recorded a decrease to retained earnings of $144 million, deferred income tax liabilities of $28 million, with a corresponding increase of $181 million to deferred revenues, $12 million to other liabilities, $25 million to deferred income tax assets and $4 million to current portion of deferred revenues included in accounts payable and accrued liabilities.

At December 31, 2017, the Company recorded a decrease to retained earnings of $113 million, deferred income tax liabilities of $19 million, with a corresponding increase of $132 million to deferred revenues, $19 million to other liabilities, $22 million to deferred income tax assets and $3 million to current portion of deferred revenues included in accounts payable and accrued liabilities.

The deferred revenues recorded at transition to IFRS 15 will be recognized in earnings in future years, up to and including 2043. During the three months ended March 31, 2017, the Company recorded a decrease to revenues from electricity generation and delivery of $3 million due to recognition of deferred revenues. As a result of this adjustment, in the consolidated statement of cash flow for the three months ended March 31, 2017, the Company recorded a decrease to earnings for the period of $2 million, with a corresponding increase of $2 million to adjustments to reconcile earnings to cash flows from operating activities.

(iii) As a result of recognition of non-cash considerations received from customers during the three months ended March 31, 2017, at fair value, the Company recorded an increase to revenue from electricity generation and delivery of $22 million, with a corresponding increase of $22 million to fuel costs.

(iv) As a result of the agent classification of certain charges collected from customers on behalf of distribution and transmission services providers, during the three months ended March 31, 2017, the Company recorded a decrease to revenue from commodity sales of $14 million, with a corresponding decrease of $14 million to energy transmission and transportation costs.

(v) As a result of recognition of financing component on upfront considerations received from customers, during the three months ended March 31, 2017, the Company recorded an increase to revenue from electricity generation and delivery of $3 million, with a corresponding increase of $3 million to interest expense.

4. BUSINESS COMBINATION

On February 20, 2018, the Company acquired a 100 per cent ownership interest in Electricidad del Golfo (EGO). EGO owns a long-term contracted, 35 megawatt hydroelectric power station based in Veracruz, Mexico. The acquisition, which increases the Company's presence in Mexico, is reported in the Electricity operating segment.

The aggregate consideration paid for EGO was $112 million, which is comprised of $70 million cash paid, net of cash acquired, and the assumption of EGO's long-term debt of $42 million. There is no contingent consideration with this acquisition.

The acquisition was accounted for using the acquisition method; the estimated fair values of the identifiable assets acquired and liabilities assumed were as follows:

Cash and cash equivalents	**9**
Accounts receivable	**2**
Prepaid expenses and other current assets	**2**
Property, plant & equipment	**88**
Intangible assets	**34**
Goodwill	**8**
Accounts payable and accrued liabilities	**(2)**
Deferred income tax liabilities	**(19)**
Deferred revenues	**(1)**
Long-term debt	**(42)**
Total identifiable net assets	**79**

The fair value of the acquired identifiable intangible assets, including power purchase agreements, licenses and environmental permits, is provisional pending receipt of the final valuations for these assets.

The fair value of the acquired accounts receivable approximated the carrying value due to their short-term nature. None of the accounts receivable acquired were impaired and the full contractual amount is expected to be collected.

From the date of acquisition, revenues of $1 million, and earnings of less than a million were included in the consolidated statement of earnings for the three months ended March 31, 2018, as a result of the acquisition. Transaction costs of $2 million for incremental legal and advisory services fees were expensed during the three months ended March 31, 2018 and included in other costs and expenses in the consolidated statement of earnings.

The Company's pro-forma consolidated revenues and earnings attributable to Class A and Class B shares for the three months ended March 31, 2018, would have been $1,387 million and $179 million, respectively, if the acquisition had occurred on January 1, 2018. These pro-forma adjustments reflect adjustments for depreciation and amortization assuming the fair values attributed in the purchase price allocation occurred on January 1, 2018. These pro-forma results may not necessarily be indicative of actual results had the acquisition occurred on January 1, 2018.

5. SEGMENTED INFORMATION

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

2018 **2017 (restated)**	**Electricity**	**Pipelines & Liquids**	**Corporate & Other**	**Intersegment Eliminations**	**Consolidated**
Revenues - external	**888**	**468**	**29**	**–**	**1,385**
	499	489	17	–	1,005
Revenues - intersegment	**11**	**17**	**10**	**(38)**	**–**
	10	9	7	(26)	–
Revenues	**899**	**485**	**39**	**(38)**	**1,385**
	509	498	24	(26)	1,005
Operating expenses (1)	**(642)**	**(236)**	**(45)**	**39**	**(884)**
	(255)	(236)	(30)	26	(495)
Depreciation and amortization	**(92)**	**(59)**	**(2)**	**2**	**(151)**
	(92)	(57)	(2)	3	(148)
Gain on sale of operation	**–**	**–**	**–**	**–**	**–**
	–	–	30	–	30
Earnings from investment in joint ventures	**7**	**1**	**–**	**–**	**8**
	6	1	–	–	7
Net finance costs	**(79)**	**(38)**	**4**	**(1)**	**(114)**
	(67)	(35)	2	(1)	(101)
Earnings before income taxes	**93**	**153**	**(4)**	**2**	**244**
	101	171	24	2	298
Income taxes	**(25)**	**(40)**	**3**	**(1)**	**(63)**
	(27)	(47)	6	–	(68)
Earnings for the period	**68**	**113**	**(1)**	**1**	**181**
	74	124	30	2	230
Adjusted earnings	**97**	**101**	**(17)**	**–**	**181**
	116	112	(16)	1	213
Total assets (2)	**13,324**	**7,653**	**386**	**(13)**	**21,350**
	13,013	7,489	448	(106)	20,844
Capital expenditures (3)	**116**	**139**	**4**	**–**	**259**
	100	134	1	–	235

(1) *Includes total costs and expenses, excluding depreciation and amortization expense.*

(2) *2017 comparatives are at December 31, 2017*

(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, 2018 (2017 - $4 million).*

ADJUSTED EARNINGS

Adjusted earnings are earnings attributable to Class A and B shares after adjusting for:

- the timing of revenues and expenses for rate-regulated activities,
- dividends on equity preferred shares of Canadian Utilities Limited,
- 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 Chief Operating Decision Maker (CODM) to assess segment performance and allocate resources. Other accounts in the 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.

2018 **2017 (restated)**	**Electricity**	**Pipelines & Liquids**	**Corporate & Other**	**Intersegment Eliminations**	**Consolidated**
Adjusted earnings	**97**	**101**	**(17)**	**–**	**181**
	116	112	(16)	1	213
Gain on sale of operation	**–**	**–**	**–**	**–**	**–**
	–	–	30	–	30
Unrealized losses on mark-to-market forward commodity contracts	**(18)**	**–**	**–**	**–**	**(18)**
	(5)	–	–	–	(5)
Rate-regulated activities	**(13)**	**9**	**–**	**1**	**(3)**
	(39)	11	–	1	(27)
Dividends on equity preferred shares of Canadian Utilities Limited	**1**	**–**	**16**	**–**	**17**
	1	–	16	–	17
Other	**–**	**2**	**–**	**–**	**2**
	–	–	–	–	–
Earnings attributable to Class A and Class B shares	**67**	**112**	**(1)**	**1**	**179**
	73	123	30	2	228
Earnings attributable to non-controlling interests					**2**
					2
Earnings for the period					**181**
					230

Gain on sale of operation

The Company adjusted for the following one-time gains, after-tax:

	Note	Segment	2018	2017
Real estate	7	Corporate & Other	–	30

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 Plants. 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 Plants. 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 in the consolidated financial statements 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 regulators' 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, 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.	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.

The significant timing adjustments as a result of the differences between rate-regulated accounting and IFRS for the three months ended March 31 are as follows:

	2018	2017
Additional revenues billed in current period		
Future removal and site restoration costs (1)	**19**	19
Impact of colder temperatures (2)	**12**	–
Revenues to be billed in future periods		
Deferred income taxes (3)	**(33)**	(30)
Settlement of regulatory decisions and other items (4)	**(1)**	(16)
	(3)	(27)

(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.

(4) Includes Performance Based Regulation (PBR) interim rate accrual of $9 million. Starting January 2018, natural gas distribution and electric distribution commenced a new PBR period. New rates came into effect April 1st, 2018, which will reverse the PBR interim rate accrual during 2018.

Other

Each quarter, the Company adjusts the deferred tax asset which was recognized as a result of the 2015 Tula Pipeline Project impairment. The adjustment of $2 million in the first quarter of 2018 (2017 - nil) is due to a difference between the tax base currency, which is Mexican pesos, and the U.S. dollar functional currency.

6. 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 for each operating segment for the three months ended March 31 are shown below:

2018 **2017 (restated)**	**Electricity**	**Pipelines & Liquids**	**Corporate & Other**	**Total**
Revenue Streams				
Sale of Goods				
Electricity generation and delivery	**5**	**–**	**–**	**5**
	5	–	–	5
Commodity sales	**84**	**3**	**–**	**87**
	67	1	–	68
Total sale of goods	**89**	**3**	**–**	**92**
	72	1	–	73
Rendering of Services				
Distribution services	**140**	**311**	**–**	**451**
	136	328	–	464
Transmission services	**169**	**64**	**–**	**233**
	160	64	–	224
Customer contributions	**9**	**4**	**–**	**13**
	10	6	–	16
Franchise fees	**8**	**71**	**–**	**79**
	7	76	–	83
Retail electricity and natural gas services	**–**	**–**	**27**	**27**
	–	–	15	15
Storage and Industrial Water	**–**	**14**	**–**	**14**
	–	14	–	14
Total rendering of services	**326**	**464**	**27**	**817**
	313	488	15	816
Lease income				
Finance lease	**9**	**–**	**–**	**9**
	9	–	–	9
Operating lease	**59**	**–**	**–**	**59**
	48	–	–	48
Total lease income	**68**	**–**	**–**	**68**
	57	–	–	57
Service concession arrangement	**399**	**–**	**–**	**399**
	54	–	–	54
Other	**6**	**1**	**2**	**9**
	3	–	2	5
Total	**888**	**468**	**29**	**1,385**
	499	489	17	1,005

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

	2018	2017 (restated)
Regulated business operations		
Regulated Electricity		
Electricity Distribution	**156**	150
Electricity Transmission	**171**	163
	327	313
Regulated Pipelines & liquids		
Natural gas Distribution	**350**	369
Natural gas Transmission	**66**	66
International Natural Gas Distribution	**38**	40
	454	475
Total Regulated business operations	**781**	788
Non-regulated business operations		
Non-regulated Electricity		
Independent Power Plants	**74**	64
Thermal PPA plants	**83**	62
International Power Generation	**5**	6
Alberta PowerLine	**399**	54
	561	186
Non-regulated Pipelines & liquids		
Storage and Industrial Water	**14**	14
	14	14
Other non-regulated business operations		
Retail electricity and natural gas services	**27**	15
Other	**2**	2
	29	17
Total Non-regulated business operations	**604**	217
Total	**1,385**	1,005

7. SALE OF OPERATION

SALE OF ATCO REAL ESTATE HOLDINGS LTD.

On January 1, 2017, the Company sold its 100 per cent investment in ATCO Real Estate Holdings Ltd. (AREHL) to ATCO Ltd. for cash proceeds of $47 million, resulting in a gain of $30 million. The transaction occurred on a tax-deferred basis. The proceeds represent the fair value of AREHL, which was supported by independent appraisals. Commencing January 1, 2017, the Company no longer recognizes these assets in its financial position, results of operations and cash flows in the consolidated financial statements. These assets were previously reported in the Corporate & Other segment.

8. 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 are as follows:

	Three Months Ended March 31	
	2018	**2017 (restated)**
Average shares		
Weighted average shares outstanding	**270,714,977**	268,359,223
Effect of dilutive stock options	**47,306**	125,818
Effect of dilutive MTIP	**557,390**	485,053
Weighted average dilutive shares outstanding	**271,319,673**	268,970,094
Earnings for earnings per share calculation		
Earnings for the period	**181**	230
Dividends on equity preferred shares of the Company	**(17)**	(17)
Non-controlling interests	**(2)**	(2)
	162	211
Earnings and diluted earnings per Class A and Class B share		
Earnings per Class A and Class B share	**$0.60**	$0.78
Diluted earnings per Class A and Class B share	**$0.60**	$0.78

9. RESTRICTED PROJECT FUNDS

At March 31, 2018, Alberta PowerLine (APL), a partnership between Canadian Utilities Limited and Quanta Services Inc., that 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), had $749 million of funds restricted under the terms of APL's non-recourse long-term debt financing agreement signed in October 2017. The restricted project funds are released as the Project progresses, subject to satisfaction of certain performance conditions under the financing agreement.

Restricted project funds are comprised of:

	March 31, 2018	December 31, 2017
Current assets		
Restricted cash	**300**	351
Restricted funds invested in structured deposit note [1]	**392**	510
	692	861
Non-current assets		
Restricted cash	**–**	69
Restricted funds for construction holdbacks [2]	**57**	35
	57	104
	749	965

(1) At March 31, 2018, the Company had $392 million of funds invested in a structured deposit note, which pays interest at a fixed rate of 1.707 per cent per annum, and will mature by the end of 2018 (December 31, 2017 - $510 million).

(2) At March 31, 2018, the Company had $57 million of restricted funds for construction lien holdbacks (December 31, 2017 - $35 million).

10. 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, 2017	18,465	1,869	786	609	1,004	22,733
Additions	**6**	–	–	**240**	**1**	**247**
Transfers	**98**	–	**2**	**(105)**	**5**	–
Retirements and disposals	**(10)**	–	–	–	**(1)**	**(11)**
Acquisition of EGO *(Note 4)*	–	**87**	–	–	**1**	**88**
Foreign exchange rate adjustment	**21**	**3**	**9**	**4**	**1**	**38**
March 31, 2018	**18,580**	**1,959**	**797**	**748**	**1,011**	**23,095**
Accumulated depreciation and impairment						
December 31, 2017	4,016	1,305	147	77	402	5,947
Depreciation	**107**	**15**	**5**	–	**14**	**141**
Retirements and disposals	**(10)**	–	–	–	**(1)**	**(11)**
Foreign exchange rate adjustment	**3**	–	–	**2**	–	**5**
March 31, 2018	**4,116**	**1,320**	**152**	**79**	**415**	**6,082**
Net book value						
December 31, 2017	14,449	564	639	532	602	16,786
March 31, 2018	**14,464**	**639**	**645**	**669**	**596**	**17,013**

The additions to property, plant and equipment included $5 million of interest capitalized during construction for the three months ended March 31, 2018 (2017 - $4 million).

11. SHORT-TERM DEBT

At March 31, 2018, the Company had $100 million of commercial paper outstanding at an interest rate of 1.64 per cent, maturing in May 2018 (December 31, 2017 - nil). The commercial paper is supported by the Company's long-term committed credit facilities.

12. LONG-TERM DEBT

On February 20, 2018, the Company assumed $42 million of long-term debt on the acquisition of EGO (see Note 4). On March 20, 2018, the Company issued additional long-term debt of $40 million under a fixed-term credit facility, at Mexican interbank rates maturing in March 2023, that will be used to fund the retirement of EGO's long-term debt with its Mexican counterparty. The long-term debt assumed on acquisition of EGO was repaid on April 2, 2018.

To mitigate the variable interest rate risk, the Company entered into an interest rate swap agreement to fix the interest rate at 8.77 per cent (see Note 16).

13. EQUITY PREFERRED SHARES

Cash dividends declared and paid per share are as follows:

	Three Months Ended March 31	
(dollars per share)	**2018**	**2017**
Perpetual Cumulative Second Preferred Shares		
4.60% Series V [(1)]	**0.2875**	0.2500
Cumulative Redeemable Second Preferred Shares		
3.403% Series Y [(2)]	**0.2127**	0.2500
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**	0.3282
4.50% Series FF	**0.2812**	0.2812

(1) Effective October 3, 2017, the annual dividend rate for the Series V Preferred Shares was reset to 4.60 per cent for the next five years. Prior to October 3, 2017, the annual dividend rate was 4.00 per cent.

(2) Effective June 1, 2017, the annual dividend rate for the Series Y Preferred Shares was reset to 3.403 per cent for the next five years. Prior to June 1, 2017, the annual dividend rate was 4.00 per cent.

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

There were 197,580,286 (2017 - 195,182,221) Class A shares and 74,047,983 (2017 - 74,241,383) Class B shares outstanding at March 31, 2018. In addition, there were 819,000 options to purchase Class A shares outstanding at March 31, 2018, under the Company's stock option plan.

DIVIDENDS

The Company declared and paid cash dividends of $0.3933 per Class A and Class B share during the three months ended March 31, 2018 (2017 - $0.3575). 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

During the three months ended March 31, 2018, 490,214 Class A shares were issued under the Company's dividend reinvestment plan (2017 - 866,019), using re-invested dividends of $16 million (2017 - $31 million). The shares were priced at an average of $33.09 per share (2017 - $35.30 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.

	2018	2017 (restated)
Depreciation and amortization	**151**	148
Gain on sale of operation	**–**	(30)
Earnings from investment in ATCO Structures & Logistics, net of dividends received	**–**	2
Earnings from investment in joint ventures, net of dividends and distributions received	**(3)**	(1)
Income taxes	**63**	68
Unearned availability incentives	**(5)**	(2)
Unrealized losses on mark-to-market forward commodity contracts	**24**	7
Contributions by customers for extensions to plant	**23**	16
Amortization of customer contributions	**(13)**	(16)
Net finance costs	**114**	101
Income taxes paid	**(18)**	(27)
Other	**8**	10
	344	276

CASH POSITION

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

	2018	2017
Cash	**395**	473
Short-term investments	**6**	1
Restricted cash [1]	**93**	41
Cash and cash equivalents	**494**	515
Bank indebtedness	**(4)**	(11)
	490	504

(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, bank indebtedness, 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, pre-tax 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, 2018		December 31, 2017	
Recurring Measurements	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial Assets				
Lease receivables	**410**	**564**	410	568
Receivable under service concession arrangement	**992**	**992**	593	593
Financial Liabilities				
Long-term debt	**8,596**	**9,628**	8,499	9,679
Non-recourse long-term debt	**1,412**	**1,562**	1,416	1,562

FINANCIAL INSTRUMENTS MEASURED AT FAIR VALUE

The Company's derivative instruments are measured at fair value. At March 31, 2018, 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 U.S. 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, 2018					
Financial Assets					
Prepaid expenses and other current assets	**–**	**–**	**3**	**1**	**4**
Other assets	**–**	**2**	**–**	**–**	**2**
Financial Liabilities					
Other current liabilities (1)	**4**	**19**	**34**	**1**	**58**
Other liabilities (1)	**1**	**16**	**35**	**–**	**52**
December 31, 2017					
Financial Assets					
Prepaid expenses and other current assets	–	2	3	–	5
Other assets	–	3	1	–	4
Financial Liabilities					
Other current liabilities	4	14	32	–	50
Other liabilities	–	16	35	–	51

(1) *At March 31, 2018, the Company paid a total of $75 million of cash collateral to third parties on commodity forward positions related to future periods (December 31, 2017 - $54 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)**	**Foreign Currency Forward Contracts**	**Natural Gas (1)**	**Power (2)**	**Foreign Currency Forward Contracts**
March 31, 2018							
Purchases (3)	–	**17,617,000**	–	–	**73,533,200**	**6,546,505**	–
Sales (3)	–	–	**1,580,235**	–	**18,720,200**	**12,582,350**	–
Currency							
Canadian dollars	**3**	–	–	–	–	–	–
Australian dollars	**749**	–	–	–	–	–	–
Mexican pesos	**570**	–	–	–	–	–	**155**
U.S. dollars	–	–	–	**30**	–	–	–
Maturity	**2019-2023**	**2018-2021**	**2018-2020**	**2018**	**2018-2021**	**2018-2020**	**2018**
December 31, 2017							
Purchases (3)	–	19,237,000	–	–	85,926,700	7,326,745	–
Sales (3)	–	–	1,731,365	–	27,445,800	14,101,265	–
Currency							
Canadian dollars	3	–	–	–	–	–	–
Australian dollars	749	–	–	–	–	–	–
U.S. dollars	–	–	–	–	–	–	63
Maturity	2020	2018-2021	2018-2020	–	2018-2021	2018-2020	2018

(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.