CANADIAN UTILITIES LIMITED
An ATCO Company

CANADIAN UTILITIES LIMITED

FINANCIAL INFORMATION

FOR THE SIX MONTHS ENDED JUNE 30, 2018

CORPORATE OFFICE: 5302 FORAND ST SW, CALGARY, ALBERTA, CANADA T3E 8B4
TEL: 403-292-7500 WWW.CANADIANUTILITIESLIMITED.COM

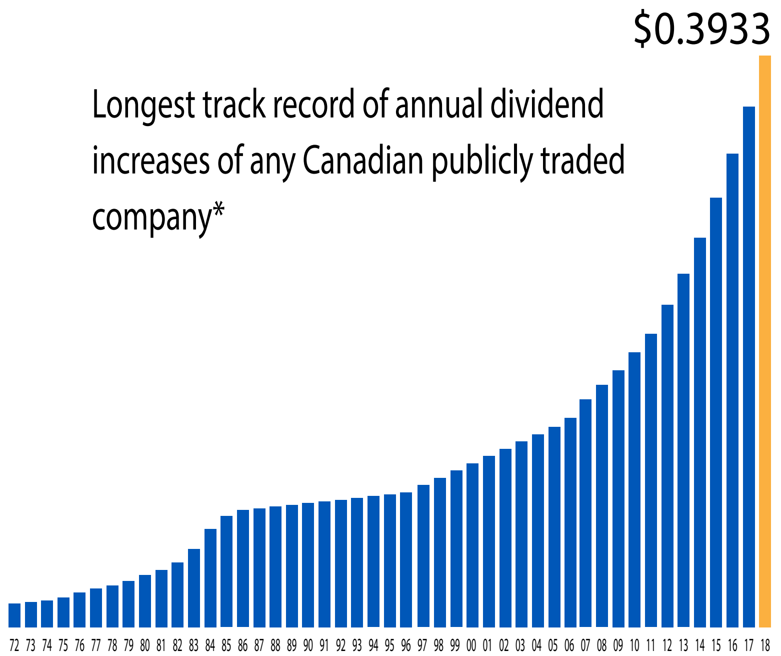
Q2 2018 INVESTOR FACT SHEET

CanadianUtilities.com
ELECTRICITY | PIPELINES & LIQUIDS

CANADIAN UTILITIES LIMITED
An ATCO Company

With approximately 5,200 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).

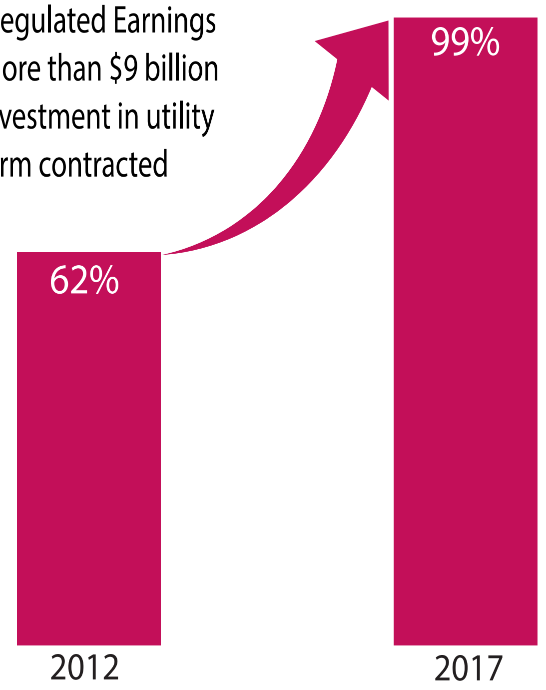
TRACK RECORD OF DIVIDEND GROWTH



* On July 11, 2018, Canadian Utilities delcared a third quarter dividend of $0.3933 per share, or $1.57 per share annualized.

GROWING A HIGH QUALITY EARNINGS BASE

Growth in Regulated Earnings driven by more than $9 billion of capital investment in utility and long-term contracted operations



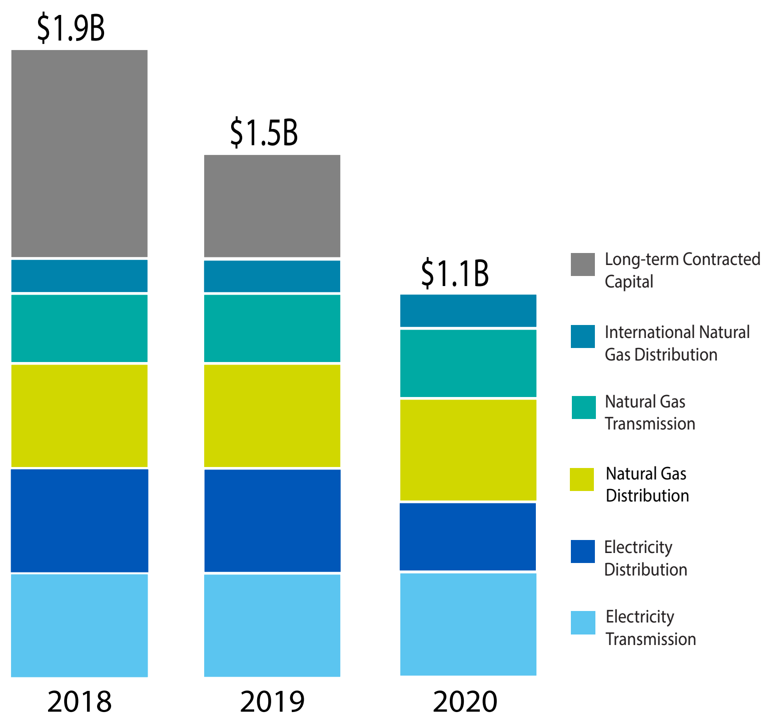
CANADIAN UTILITIES AT A GLANCE

"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	19 Globally
Power Generating Capacity Share	2,517 MW *
Water Infrastructure Capacity	85,200 m^3/d **
Natural Gas Storage Capacity	52 PJ ***
Hydrocarbon Storage Capacity	400,000 m^3 ****

*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

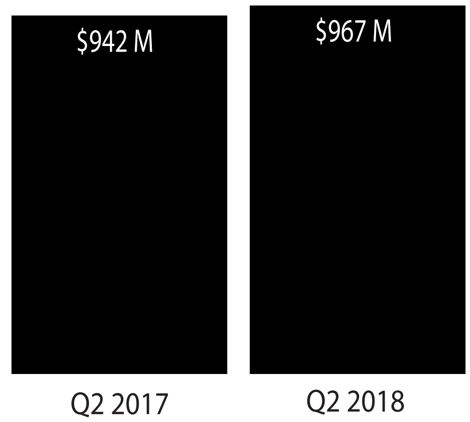
Market Capitalization	$9 billion
Weighted Average Common Shares Outstanding	271.2 million

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.

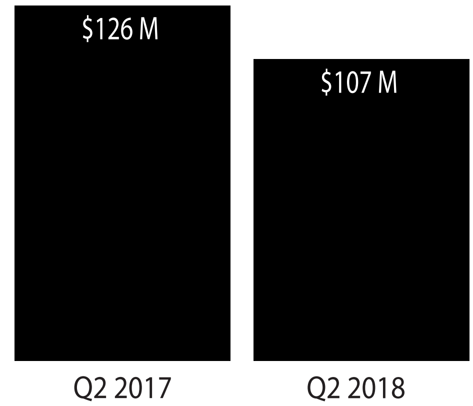
Adjusted earnings are earnings attributable to the Class A and Class B shares after adjusting for the timing of revenues and expenses associated with rate-regulated activities, dividends on equity preferred shares of the Company, and unrealized gains or losses on mark-to-market forward commodity contracts.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

Q2 2018 RESULTS

CANADIAN UTILITIES REVENUES



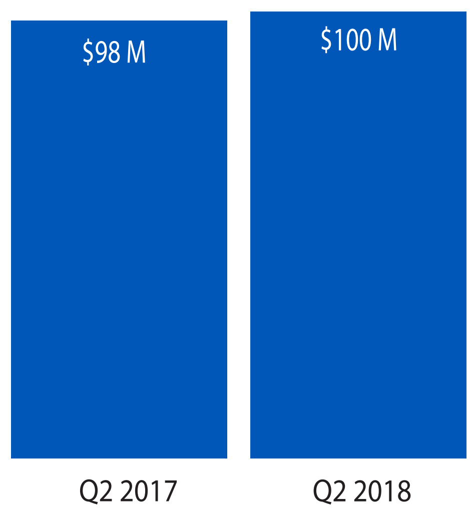
CANADIAN UTILITIES ADJUSTED EARNINGS



ELECTRICITY GLOBAL BUSINESS UNIT

- Higher adjusted earnings for the second quarter of 2018 were mainly due to improved market conditions for Independent Power Plants and higher recognition of availability incentives in the Thermal PPA Plants.
- We continued construction on the approximately 500 km Fort McMurray West 500-kV Project. Second quarter 2018 capital investment of $148 million was mainly due to tower foundation installation and tower assembly, which are proceeding ahead of schedule. The target energization date of June 2019 remains on track.

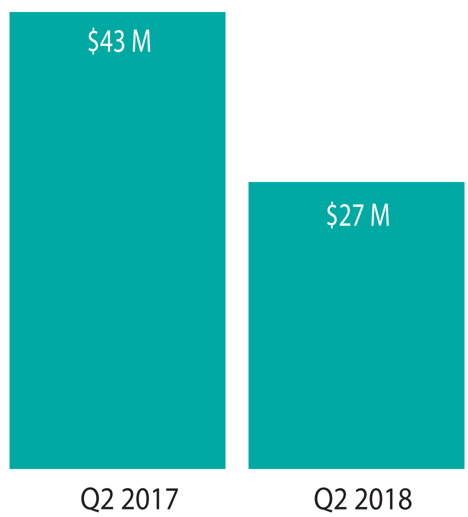
ADJUSTED EARNINGS



PIPELINES & LIQUIDS GLOBAL BUSINESS UNIT

- Lower earnings were mainly due to the impact of ATCO's operating cost reduction initiatives over the first generation PBR period flowing into customer rates under the 2018 to 2022 second generation PBR framework. Lower earnings were partially offset by growth in rate base across our Regulated Pipelines & Liquids businesses.
- We completed construction on two more salt caverns, doubling the capacity at the ATCO Heartland Energy Centre near Fort Saskatchewan, Alberta. Long-term contracts have been secured for all four caverns, which have a combined hydrocarbon storage capacity of 400,000 cubic metres. The first two caverns have been in service since the fourth quarter of 2016, and the two new caverns began contributing earnings in the second quarter of 2018.

ADJUSTED EARNINGS



Investor Relations, c/o Canadian Utilities Limited.
3rd Floor, West Tower
5302 Forand Street SW, Calgary, Alberta, Canada T3E 8B4

InvestorRelations@ATCO.com
T: (403) 292-7500 | F: (403) 292-7532

CANADIAN UTILITIES LIMITED
An ATCO Company

2018 SECOND QUARTER FINANCIAL INFORMATION

INVESTOR FACT SHEET

MANAGEMENT DISCUSSION AND ANALYSIS

UNAUDITED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

FOR THE SIX MONTHS ENDED JUNE 30, 2018

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CANADIAN UTILITIES LIMITED
An ATCO Company

CANADIAN UTILITIES LIMITED

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE SIX MONTHS ENDED JUNE 30, 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 six months ended June 30, 2018.

This MD&A was prepared as of July 25, 2018, and should be read with the Company's unaudited interim consolidated financial statements for the six months ended June 30, 2018. Additional information, including the Company's previous MD&As, 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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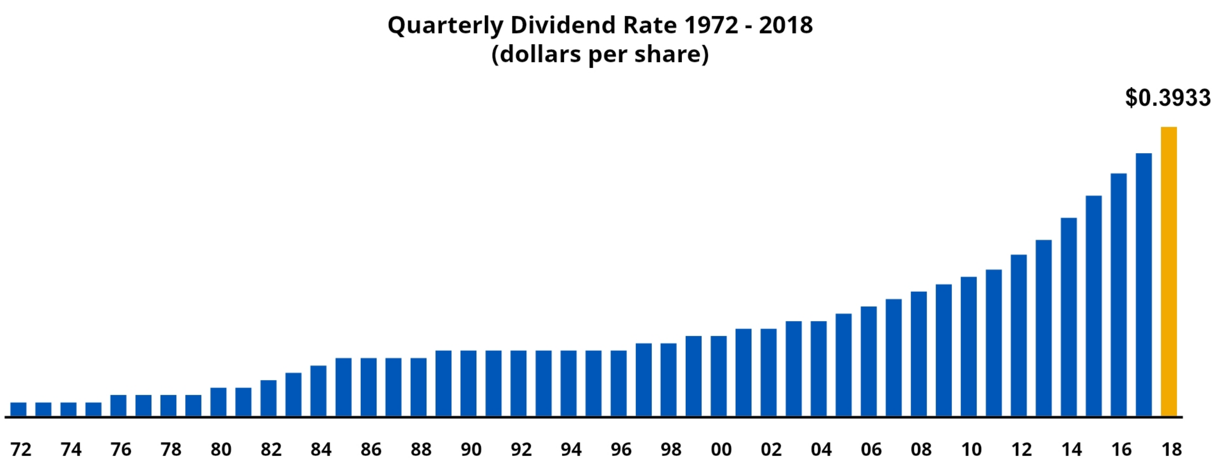
CANADIAN UTILITIES: WHAT SETS US APART

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 July 11, 2018 we declared a third quarter dividend of 39.33 cents per share or $1.57 per share on an annualized basis. We aim to grow dividends in-line with our sustainable earnings growth, which is linked to growth from our regulated and long-term contracted investments.



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

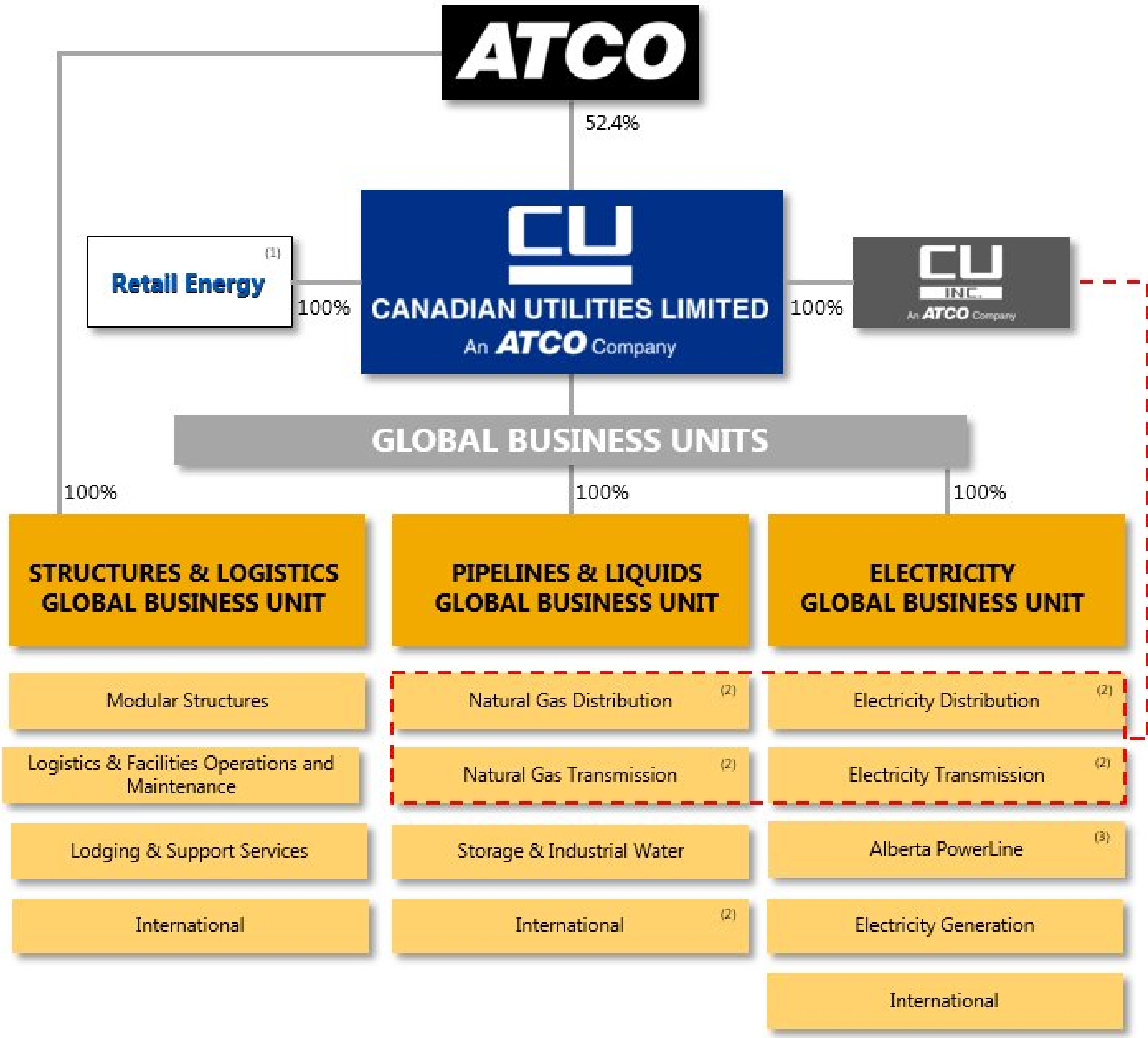
We will continue to grow our business in the years ahead. In the period 2018 to 2020, we expect to invest $4.5 billion in Regulated Utility and long-term contracted assets, which will continue to strengthen our high quality earnings base. Of the $4.5 billion planned spend, $3.5 billion will be on Regulated 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	99%	$4.5B	A
track record of dividend increases	regulated earnings	3 year capital investment	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 June 30 2018	2017 [2] (restated)	Change	Six Months Ended June 30 2018	2017 [2] (restated)	Change
Key Financial Metrics						
Revenues	**967**	942	25	**2,352**	1,947	405
Adjusted earnings [1]	**107**	126	(19)	**288**	339	(51)
Electricity	**100**	98	2	**197**	214	(17)
Pipelines & Liquids	**27**	43	(16)	**128**	155	(27)
Corporate & Other	**(20)**	(14)	(6)	**(37)**	(30)	(7)
Intersegment Eliminations	**–**	(1)	1	**–**	–	–
Adjusted earnings ($ per share) [1]	**0.39**	0.47	(0.08)	**1.06**	1.26	(0.20)
Earnings (loss) attributable to equity owners of the company	**(3)**	90	(93)	**176**	318	(142)
Earnings (loss) attributable to Class A and Class B shares	**(19)**	73	(92)	**143**	284	(141)
Earnings (loss) attributable to Class A and Class B shares ($ per share)	**(0.07)**	0.27	(0.34)	**0.53**	1.05	(0.52)
Cash dividends declared per Class A and Class B share (cents per share)	**39.33**	35.75	3.58	**78.66**	71.50	7.16
Funds generated by operations [1]	**296**	406	(110)	**821**	912	(91)
Capital investment [1]	**442**	398	44	**1,186**	683	503
Other Financial Metrics						
Weighted average Class A and Class B shares outstanding *(thousands):*						
Basic	**271,175**	269,150	2,025	**270,946**	268,757	2,189
Diluted	**271,818**	269,799	2,019	**271,568**	269,358	2,210

(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 detail on IFRS 15 is discussed in the Other Financial Information section of this MD&A.

REVENUES

Revenues for the second quarter and first half of 2018 were $967 million and $2,352 million, $25 million and $405 million higher than the same periods in 2017. These increases were mainly due to improved market conditions for the Independent Power Plants and revenue recorded for Alberta PowerLine.

ADJUSTED EARNINGS

Our adjusted earnings for the second quarter and first half of 2018 were $107 million, or $0.39 per share and $288 million or $1.06 per share compared to $126 million or $0.47 per share and $339 million or $1.26 per share, for the same periods in 2017. The primary drivers of adjusted earnings results were as follows:

- Electricity - Adjusted earnings for the second quarter of 2018 were $2 million higher than the same period in 2017. Higher earnings were mainly due to improved market conditions for Independent Power Plants and higher recognition of availability incentives in the Thermal PPA Plants.
- Pipelines & Liquids - Adjusted earnings for the second quarter of 2018 were $16 million lower than the same period in 2017. Lower earnings were mainly due to rate rebasing under Alberta's regulated model in natural gas distribution, partially offset by growth in rate base across our Regulated Pipelines & Liquids businesses.
- Corporate & Other - Adjusted earnings in the second quarter of 2018 were $6 million lower than the same period in 2017 mainly due to higher salaries and wages expenses and the timing of certain other expenses.

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

EARNINGS ATTRIBUTABLE TO EQUITY OWNERS OF THE COMPANY

Earnings attributable to equity owners of the company were $93 million lower in the second quarter of 2018, compared to the same period in 2017. Earnings attributable to equity owners of the company include significant impairments, timing adjustments related to rate-regulated activities, unrealized losses on mark-to-market forward commodity contracts, one-time gains and losses, and items that are not in the normal course of business or a result of day-to-day operations. These items are not included in adjusted earnings.

In the second quarter of 2018, restructuring and other costs not in the normal course of business of $60 million after tax were recorded. These costs mainly relate to staff reductions and associated severance costs, as well as costs related to decisions to discontinue certain projects that no longer represent long-term strategic value to the Company.

More information on these and other items is included in the Reconciliation of Adjusted Earnings to Earnings attributable to equity owners of the company section of this MD&A.

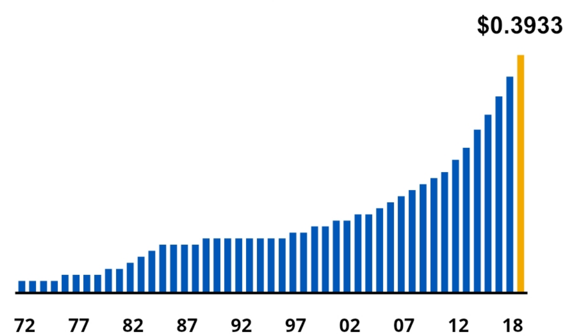
Earnings attributable to Class A and B shares are earnings attributable to equity owners of the company less dividends on equity preferred shares of the Company. Additional information regarding earnings attributable to Class A and B shares is presented in note 8 of the unaudited consolidated interim financial statements.

COMMON SHARE DIVIDENDS

On July 11, 2018, the Board of Directors declared a third quarter dividend of 39.33 cents per share. Dividends paid to Class A and Class B share owners totaled $93 million in the second quarter and $183 million in the first half 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

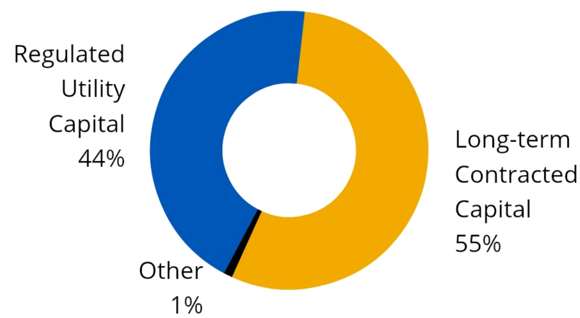
Funds generated by operations were $296 million in the second quarter of 2018, $110 million lower than the same period in 2017. The decrease was mainly due to lower cash earnings as a result of the settlement of regulatory decisions, and the impact of rate re-basing under Alberta's regulated model for natural gas distribution and electric distribution.

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 second quarter and first half of 2018 was $442 million and $1,186 million.

Capital spending in our Regulated Utilities and on long-term contracted capital assets accounted for $430 million of capital spending in the second quarter, and $1,168 million in the first half of 2018. Of this capital invested, $516 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.

Capital Investment for the Six Months Ended June 30, 2018



GLOBAL BUSINESS UNIT PERFORMANCE

REVENUES

Electricity revenues of $634 million in the second quarter of 2018 were $48 million higher than the same period in 2017, mainly due to improved market conditions for the Independent Power Plants.

Electricity revenues of $1,533 million in the first half of 2018 were $438 million higher than the same period in 2017, mainly due to revenue recorded for construction activities at Alberta PowerLine.

ADJUSTED EARNINGS

	Three Months Ended June 30			Six Months Ended June 30		
($ millions)	2018	2017 (1) (restated)	Change	2018	2017 (1) (restated)	Change
Regulated Electricity						
Electricity Distribution	**27**	31	(4)	**60**	72	(12)
Electricity Transmission	**50**	50	–	**90**	104	(14)
Total Regulated Electricity Adjusted Earnings	**77**	81	(4)	**150**	176	(26)
Non-regulated Electricity						
Independent Power Plants	**3**	(3)	6	**(2)**	–	(2)
Thermal PPA Plants	**13**	10	3	**27**	20	7
International Power Generation	**2**	5	(3)	**7**	11	(4)
Alberta PowerLine	**5**	5	–	**15**	7	8
Total Non-regulated Electricity Adjusted Earnings	**23**	17	6	**47**	38	9
Total Electricity Adjusted Earnings	**100**	98	2	**197**	214	(17)

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

In the second quarter of 2018, our Electricity business earned $100 million, $2 million higher than the same period of 2017. Higher earnings were mainly due to improved market conditions for Independent Power Plants and higher recognition of availability incentives in the Thermal PPA Plants.

In the first half of 2018, Electricity earnings of $197 million were $17 million lower than the same period in 2017. Lower earnings were mainly due to rate rebasing under Alberta's regulated model in electricity distribution and transmission and lower electricity transmission interim rates approved by the AUC, partially offset by higher earnings from Alberta PowerLine, and higher recognition of availability incentives in the 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 $27 million and $60 million in the second quarter and first half of 2018, $4 million and $12 million lower than the same periods in 2017. Lower earnings were mainly due to the impact of 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 $50 million in the second quarter of 2018, comparable to the same period in 2017.

Earnings of $90 million in the first half of 2018 were $14 million lower than the same period in 2017. Lower earnings were mainly due to the impact of operating cost reduction initiatives flowing into customer rates in the 2018 to 2019 General Tariff Application (GTA) and lower interim rates approved by the AUC. Upon receipt of the AUC's decision on the 2018 to 2019 GTA, which is expected in the first quarter of 2019, existing interim rates will be updated to include the impact of the decision.

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 second quarter and first half of 2018 and 2017 is shown in the table below. Generating plant capacity fluctuates with the timing and duration of outages.

		Three Months Ended June 30			Six Months Ended June 30	
	2018	**2017**	**Change**	**2018**	**2017**	**Change**
Independent Power Plants	**91%**	93%	(2%)	**92%**	94%	(2%)
Thermal PPA Plants	**95%**	93%	2%	**94%**	94%	–
International Power Generation	**97%**	97%	–	**98%**	99%	(1%)

Lower availability in our Independent Power Plants in the second quarter of 2018 was due to planned minor outages at the Cory, McMahon, and Joffre plants. Lower availability for the first half of 2018 was due to planned minor outages at the Cory, McMahon, Joffre and Battle River unit 4 plants.

Higher availability in our Thermal PPA Plants in the second quarter of 2018 was due to increased availability at both the Sheerness and Battle River unit 5 plants. Availability for the first half of 2018 was comparable to the same period in 2017.

Availability in our International Power Generation Plants in the second quarter and first half of 2018 was comparable to the same periods in 2017.

Alberta Power Market Summary

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

	Three Months Ended June 30			Six Months Ended June 30		
	2018	**2017**	**Change**	**2018**	**2017**	**Change**
Average Alberta Power Pool electricity price *($/MWh)*	**56.01**	19.29	36.72	**45.52**	20.83	24.69
Average natural gas price *($/GJ)*	**1.14**	2.64	(1.50)	**1.55**	2.60	(1.05)
Average market spark spread *($/MWh)*	**47.45**	(0.51)	47.96	**33.90**	1.36	32.54

The average Alberta Power Pool electricity price for the second quarter and first half of 2018 was higher compared to the same periods 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 1,054 MW of coal-fired generation in Alberta, and natural gas transmission supply curtailment restrictions.

Realized Forwards Sales Program

	Three Months Ended June 30			Six Months Ended June 30		
	2018	**2017**	**Change**	**2018**	**2017**	**Change**
Average volumes settled *(MW)*	**281**	81	200	**255**	92	163
Average realized spark spread *($/MWh)*	**17.31**	11.30	6.01	**16.96**	16.72	0.24

In the second quarter of 2018, 281 MW of power that was sold forward settled at an average realized spark spread of $17.31 per MWh compared to 81 MW settled at an average of $11.30 per MWh in the same period of 2017. Forward sales in 2018 resulted in a loss position compared to earnings in the same period in 2017 due to the realized spark spread being lower than the market spark spread of $47.45 per MWh shown above in the Alberta Power Market Summary.

In the first half of 2018, 255 MW of power that was sold forward settled at an average realized spark spread of $16.96 per MWh compared to 92 MW settled at an average of $16.72 per MWh in the same period of 2017. Forward sales in 2018 resulted in a loss position compared to earnings in the same period in 2017 due to the realized spark spread being lower than the market spark spread of $33.90 per MWh shown above in the Alberta Power Market Summary.

Independent Power Plants

In the second quarter of 2018, earnings from our Independent Power Plants were $6 million higher compared to the same period in 2017 due to an increase in market prices, partially offset by lower realized forward sales and increased costs, which include planned minor outage costs.

In the first half of 2018, earnings were $2 million lower compared to the same period in 2017. Higher earnings generated by our Independent Power Plants due to an increase in market prices were more than offset by lower realized forward sales and increased costs, which include planned minor outage costs.

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.

Adjusted earnings from our Thermal PPA Plants of $13 million in the second quarter of 2018 were $3 million higher than the same period in 2017. Higher earnings were due to higher recognition of availability incentives.

Adjusted earnings from our Thermal PPA Plants of $27 million in the first half of 2018 were $7 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.

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 $2 million in the second quarter and $7 million in the first half of 2018, $3 million and $4 million lower than the same periods in 2017. Lower earnings were a result of increased costs due to Mexican business development activities.

Alberta PowerLine

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

APL's adjusted earnings were $5 million in the second quarter of 2018, comparable to the same period in 2017.

In the first half of 2018, earnings were $15 million, $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 RECENT DEVELOPMENTS

Alberta PowerLine

We continued construction on the approximately 500 km Fort McMurray West 500-kV Project. Second quarter 2018 capital investment of $148 million was mainly due to tower foundation installation and tower assembly, which are proceeding ahead of schedule. The target energization date of June 2019 remains on track.

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 final version of the Comprehensive Market Design for the capacity market was released on June 29, 2018. The proposed first capacity auction will start in November 2019, for an obligation from November 2021 for a one year term. The AESO will develop rules for the implementation of the capacity market design for submission to the AUC in early 2019 with approval expected by October 2019.

REVENUES

Pipelines & Liquids revenues of $315 million in the second quarter and $800 million in the first half of 2018 were $40 million and $53 million lower than the same periods in 2017. Lower revenues were mainly due to lower flow-through revenues in natural gas distribution for third party transmission rate recovery from customers as well as the impact of PBR rate rebasing in natural gas distribution.

ADJUSTED EARNINGS

	Three Months Ended June 30			Six Months Ended June 30		
($ millions)	**2018**	**2017**	**Change**	**2018**	**2017**	**Change**
Regulated Pipelines & Liquids						
Natural Gas Distribution	**(4)**	10	(14)	**63**	91	(28)
Natural Gas Transmission	**18**	16	2	**36**	33	3
International Natural Gas Distribution	**14**	17	(3)	**28**	29	(1)
Total Regulated Pipelines & Liquids Adjusted Earnings	**28**	43	(15)	**127**	153	(26)
Non-regulated Pipelines & Liquids						
Storage & Industrial Water	**(1)**	–	(1)	**1**	2	(1)
Total Pipelines & Liquids Adjusted Earnings	**27**	43	(16)	**128**	155	(27)

Pipelines & Liquids earnings of $27 million in the second quarter and $128 million in the first half of 2018 were $16 million and $27 million lower than the same periods in 2017. Lower earnings were mainly due to rate rebasing under Alberta's regulated model in natural gas distribution, 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 earnings in the second quarter and first half of 2018 were $14 million and $28 million lower than the same periods in 2017. Lower earnings were mainly due to the impact of 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 second quarter and $36 million in the first half of 2018, $2 million and $3 million higher compared to the same periods in 2017. Higher earnings 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 international natural gas distribution business earned $14 million in the second quarter and $28 million in the first half of 2018, $3 million and $1 million lower than the same periods in 2017. Lower earnings in the second quarter and first half of 2018 were mainly due to the difference between inflation rates in the second quarter of 2017 and 2018 as well as the timing of various expenses.

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 earnings in the second quarter and first half of 2018 were $1 million lower compared to the same periods in 2017. Earnings were lower largely due to timing and demand of natural gas storage services and lower contributions from ancillary services, partly offset by higher earnings for hydrocarbon storage services compared to the same period in the prior year.

PIPELINES & LIQUIDS RECENT DEVELOPMENTS

Hydrocarbon Storage

We completed construction on two more salt caverns, doubling the capacity at the ATCO Heartland Energy Centre near Fort Saskatchewan, Alberta. Long-term contracts have been secured for all four caverns, which have a combined hydrocarbon storage capacity of 400,000 cubic metres. The first two caverns have been in service since the fourth quarter of 2016, and the two new caverns began contributing earnings in the second quarter of 2018.

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 second quarter and first half of 2018, were $5 million and $7 million lower than the same periods in 2017, mainly due to higher salaries and wages expenses and the timing of certain other expenses.

REGULATORY DEVELOPMENTS

PBR RE-OPENER

In June 2018, the AUC initiated a process for electricity distribution and natural gas distribution as the re-opener clause was triggered by both utilities in 2017, the final year of the first generation PBR plan. The PBR re-opener thresholds are triggered if a utility's earnings are +/- 500 bps from the approved ROE in one year or +/- 300 bps from approved ROE in two consecutive years. The AUC has determined that it will proceed with a two-phase process. Within the first phase of the proceeding, the Commission will determine whether a re-opener of the utilities' 2013 to 2017 plans is warranted, and if warranted, it will outline the scope of the second phase.

UTILITY ASSET DISPOSITION

In April 2018, the Government of Alberta introduced Bill 13, An Act to Secure Alberta's Electricity Future, for first reading. Components of the bill, as originally proposed, would have significantly impacted key regulatory principles and current law with respect to the recovery of prudently incurred costs, retroactive ratemaking, and utility asset dispositions.

In May 2018, the Government of Alberta amended Bill 13 by removing section 1(2), which was the section of the Bill discussing the disposition of utility assets. The motion to amend Bill 13 was passed by the Alberta Legislature on May 30, 2018.

Z FACTOR DECISION (REGIONAL MUNICIPALITY OF WOOD BUFFALO WILDFIRE)

In June 2018, the AUC issued a decision on natural gas distribution's Z factor application for the recovery of costs and lost revenues associated with the 2016 Wood Buffalo wildfire near Fort McMurray, Alberta. Substantially all requested costs and lost revenues were approved as filed.

ATCO ELECTRIC 2018-2019 GENERAL TARIFF APPLICATION (GTA)

In June 2017, Electric Transmission filed a GTA for its operations for 2018 and 2019. The application requests, among other things, additional revenues to recover higher depreciation, operating costs and financing associated with increased rate base in Alberta. In December 2017, the AUC issued its decision on the interim tariff for 2018 which set an interim tariff based on a continuation of the 2017 revenue requirement. The AUC final decision on this application is expected in the first quarter of 2019.

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, published in June 2018, focused 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 is available on our website, at www.canadianutilities.com.

CLIMATE CHANGE AND THE ENVIRONMENT

Phasing in of Renewable Electricity

On June 20, 2018, the Government of Alberta announced that a new solar energy procurement process will be unveiled in August 2018 to replace the Negotiated Request for Proposal (NRFP) program that was cancelled in February 2018. We have 75 MWs of potential solar projects in Alberta, including the Kneehill Solar Generation Facility Project where ATCO and Samsung are proposing to build and operate a 25 MW solar power generation facility located near Three Hills, Alberta. We will continue to look for opportunities to advance our solar projects either through this Government of Alberta procurement process 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 is scheduled to rise to $40 per tonne in 2021 and $50 per tonne in 2022 based on alignment with the Government of Canada carbon tax. These higher carbon taxes have been a factor in the increase in Alberta Power Pool prices for the second quarter of 2018 when compared to the same period in 2017. Longer term, we anticipate the carbon taxes that electricity generation plants incur will be largely recovered through the Alberta capacity and energy market.

Methane Emissions

Further to the previously announced Government of Canada commitment to reduce methane emissions from the oil and gas sector by 40 to 45 percent from 2012 levels by 2025, the Government of Canada published methane regulations in April 2018 with some requirements starting in January 2020. The acceptance of provincial equivalency agreements is yet to be confirmed and Canadian Utilities continues to monitor these developments.

These methane regulations could affect a portion of the Company's fugitive or venting emissions from Canadian natural gas pipeline-related operations. Canadian Utilities has already implemented a number of programs to improve efficiency and reduce fugitive and venting emissions, which typically represents less than four per cent of Canadian Utilities greenhouse gas emissions. In addition, the Company's exposure is limited for the Alberta Utilities because the requirements to upgrade equipment to further reduce methane emissions are expected to be included in rate base on a go-forward basis.

OTHER EXPENSES AND INCOME

A financial summary of other consolidated expenses and income items for the second 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 June 30			Six Months Ended June 30		
($ millions)	**2018**	**2017 (1) (restated)**	**Change**	**2018**	**2017 (1) (restated)**	**Change**
Operating costs	**524**	450	74	**1,040**	896	144
Service concession arrangement costs	**148**	129	19	**516**	178	338
Gain on sale of operation	**–**	–	–	**–**	30	(30)
Earnings from investment in joint ventures	**4**	3	1	**12**	10	2
Depreciation and amortization	**182**	148	34	**333**	296	37
Net finance costs	**115**	98	17	**229**	199	30
Income taxes	**4**	29	(25)	**67**	97	(30)

(1) These numbers have been restated to account for the impact of IFRS 15. Additional detail 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 $74 million in the second quarter and $144 million in the first half of 2018 when compared to the same periods in 2017. Increased costs were mainly due to higher salaries and wages resulting from severance payments, and planned maintenance expenses.

SERVICE CONCESSION ARRANGEMENT COSTS

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

GAIN ON SALE OF OPERATION

Gain on sale of operation decreased by $30 million in the first half 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 electricity generation plants and the Strathcona Storage Limited Partnership which operates hydrocarbon storage facilities near Fort Saskatchewan, Alberta. Earnings increased by $1 million in the second quarter and $2 million in the first half of 2018 when compared to the same periods in 2017, mainly due to higher earnings contributions from the hydrocarbon storage facilities.

DEPRECIATION AND AMORTIZATION

In the second quarter and first half of 2018, depreciation and amortization expense was $34 million and $37 million higher compared to the same periods in 2017. This increase is mainly due to the ongoing capital investment program in our Regulated Utilities as well as costs related to decisions to discontinue certain projects that no longer represent long-term strategic value to the Company.

NET FINANCE COSTS

Net finance costs increased by $17 million and $30 million in the second quarter and first half of 2018 when compared to the same periods 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 October 2017.

INCOME TAXES

Income taxes decreased by $25 million in the second quarter and $30 million in the first half of 2018 mainly due to lower earnings before income taxes when compared to the same periods in 2017.

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 non-voting 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.

CREDIT RATINGS

Credit ratings are important to the Company's financing costs and ability to raise funds. The Company intends to maintain strong investment grade credit ratings in order to provide efficient and cost-effective access to funds required for operations and growth.

On July 13, 2018, Dominion Bond Rating Service affirmed its 'A (high)' long-term corporate credit rating and stable outlook on Canadian Utilities' subsidiary CU Inc.

LINES OF CREDIT

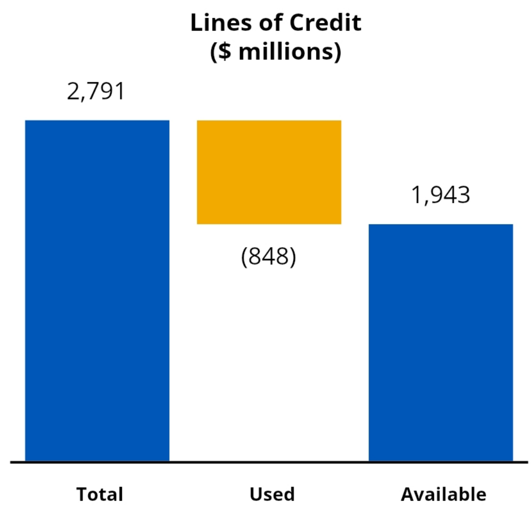
At June 30, 2018, Canadian Utilities and its subsidiaries had the following lines of credit.

($ millions)	**Total**	**Used**	**Available**
Long-term committed	**2,238**	516	1,722
Uncommitted	**553**	332	221
Total	**2,791**	848	1,943

Of the $2,791 million in total credit lines, $553 million was in the form of uncommitted credit facilities with no set maturity date. The other $2,238 million in credit lines were committed, with maturities between 2019 and 2021, and may be extended at the option of the lenders.

Of the $848 million credit line usage, approximately half related to ATCO Gas Australia Limited Partnership, with the majority of the remaining usage pertaining to the issuance of letters of credit.

On July 11, 2018, ATCO Gas Australia Limited Partnership completed the refinancing of $275 million and $450 million in committed credit lines, extending the maturities to 2021 and 2023, respectively. Long-term committed credit lines are used to satisfy all of ATCO Gas Australia Limited Partnership's term debt financing needs.



CONSOLIDATED CASH FLOW

At June 30, 2018, the Company's cash position was $144 million, a decrease of $274 million compared to December 31, 2017. The decrease was mainly due to cash funding of capital investment during the quarter, partially offset by earnings for the period.

Funds Generated by Operations

Funds generated by operations were $296 million in the second quarter and $821 million in the first half of 2018, $110 million and $91 million lower than the same periods in 2017. The decrease was mainly due to lower cash earnings as a result of the settlement of regulatory decisions, and the impact of rate re-basing under Alberta's regulated model for natural gas distribution and electric distribution.

Cash Used for Capital Investment

Cash used for capital investment was $442 million in the second quarter and $1,186 million in the first half of 2018, $44 million and $503 million higher than the same periods in 2017. Higher capital spending was mainly due to increased spending in Alberta PowerLine, and in electric distribution and transmission as well as for the electricity generation business' acquisition of the Mexico hydroelectric facility completed in the first quarter of 2018.

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

	Three Months Ended June 30			Six Months Ended June 30		
($ millions)	2018	2017	Change	2018	2017	Change
Electricity						
Electricity Distribution	**60**	50	10	**106**	106	–
Electricity Transmission	**51**	42	9	**120**	82	38
Electricity Generation	**16**	5	11	**132**	9	123
Alberta PowerLine	**148**	129	19	**516**	178	338
Total Electricity	**275**	226	49	**874**	375	499
Pipelines & Liquids						
Natural Gas Distribution	**80**	100	(20)	**135**	153	(18)
Natural Gas Transmission	**47**	43	4	**111**	100	11
International Natural Gas Distribution	**29**	23	6	**45**	43	2
International Natural Gas Transmission and Storage & Industrial Water	**8**	5	3	**14**	10	4
Total Pipelines & Liquids	**164**	171	(7)	**305**	306	(1)
Corporate & Other	**3**	1	2	**7**	2	5
Total (1) (2)	**442**	398	44	**1,186**	683	503

(1) Includes capital expenditures in joint ventures of $6 million and $8 million (2017 - $1 million and $2 million) for the second quarter and first half of 2018.

(2) Includes additions to property, plant and equipment, intangibles and $5 million and $10 million (2017 - $5 million and $9 million) of interest capitalized during construction for the second quarter and first half of 2018.

Base Shelf Prospectuses

CU Inc. Debentures

On June 11, 2018, CU Inc. filed a base shelf prospectus that permits it to issue up to an aggregate of $1.5 billion of debentures over the 25-month life of the prospectus. No debentures have been issued to date under this base shelf prospectus.

Canadian Utilities Debt Securities and Preferred Shares

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

Dividends and Common Shares

We have increased our common share dividend each year since 1972, a 46 year track record. Dividends paid to Class A and Class B share owners totaled $93 million in the second quarter and $183 million in the first half of 2018.

On July 11, 2018, the Board of Directors declared a third 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

Canadian Utilities Dividend Reinvestment Plan

In the second quarter of 2018, Canadian Utilities issued 490,295 (2017 - 788,627) Class A non-voting shares under its DRIP in lieu of cash dividend payments of $15 million (2017 - $31 million).

In the first half of 2018, Canadian Utilities issued 980,509 (2017 - 1,654,646) Class A non-voting shares under its DRIP in lieu of cash dividend payments of $31 million (2017 - $62 million).

SHARE CAPITAL

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

At July 24, 2018, we had outstanding 198,176,090 Class A shares, 73,944,474 Class B shares, and options to purchase 812,800 Class A shares.

CLASS A NON-VOTING SHARES AND CLASS B COMMON SHARES

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

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

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

Of the 12,800,000 Class A shares authorized for grant of options under our stock option plan, 5,133,300 Class A shares were available for issuance at June 30, 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 September 30, 2016 through June 30, 2018.

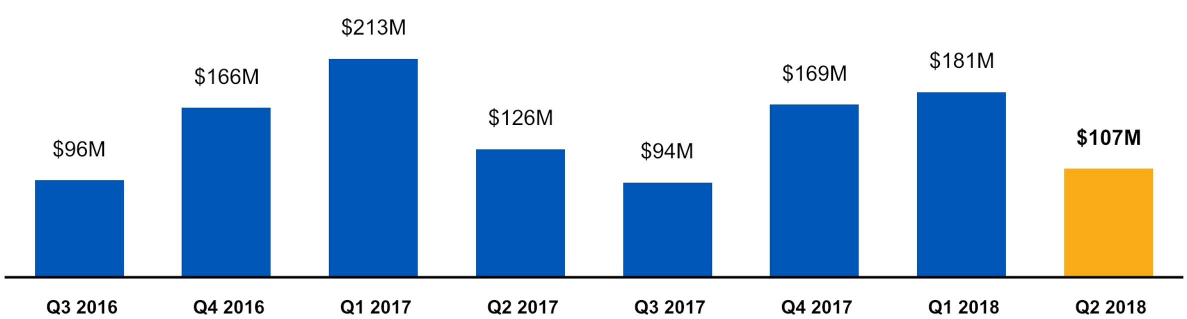
($ millions, except for per share data)	Q3 2017[1] (restated)	Q4 2017[1] (restated)	Q1 2018	Q2 2018
Revenues	930	1,208	1,385	**967**
Earnings (loss) attributable to equity owners of the company	94	102	179	**(3)**
Earnings (loss) attributable to Class A and B shares	78	85	162	**(19)**
Earnings per Class A and Class B share *($ per share)*	0.29	0.32	0.60	**(0.07)**
Diluted earnings per Class A and Class B share *($ per share)*	0.29	0.32	0.60	**(0.07)**
Adjusted earnings per share per Class A and Class B share *($)*	0.35	0.63	0.67	**0.39**
Adjusted earnings				
Electricity	88	95	97	**100**
Pipelines & Liquids	24	94	101	**27**
Corporate & Other and Intersegment Eliminations	(18)	(20)	(17)	**(20)**
Total adjusted earnings	94	169	181	**107**

($ millions, except for per share data)	Q3 2016	Q4 2016	Q1 2017[1] (restated)	Q2 2017[1] (restated)
Revenues	778	1,014	1,005	942
Earnings attributable to equity owners of the company	124	196	228	90
Earnings attributable to Class A and Class B shares	109	182	211	73
Earnings per Class A and Class B share *($ per share)*	0.40	0.67	0.78	0.27
Diluted earnings per Class A and Class B share *($ per share)*	0.40	0.67	0.78	0.27
Adjusted earnings per share per Class A and Class B share *($)*	0.36	0.62	0.79	0.47
Adjusted earnings				
Electricity	87	111	116	98
Pipelines & Liquids	26	81	112	43
Corporate & Other and Intersegment Eliminations	(17)	(26)	(15)	(15)
Total adjusted earnings	96	166	213	126

(1) These numbers have been restated to account for the impact of IFRS 15. Additional detail 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 and regulatory decisions in our Regulated Utility operations as well as fluctuating commodity prices in electricity generation and sales, and natural gas storage operations. Interim results will vary due to the seasonal nature of demand for electricity and natural gas, the timing of utility regulatory decisions and the cyclical demand for workforce housing and space rental products and services.



Electricity

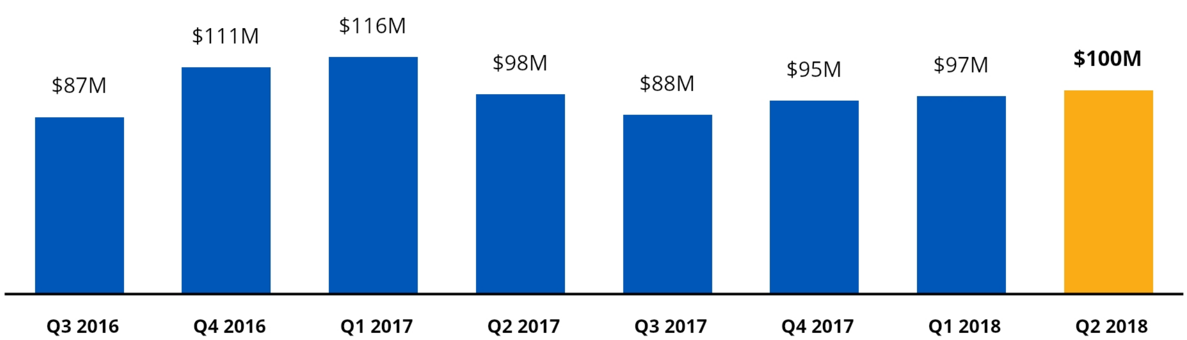
Electricity's adjusted earnings reflect the large capital investment made by Regulated Electricity in the previous eight quarters. These investments, which earn a return under a regulated business model, drive growth in adjusted earnings. Adjusted earnings have also been affected by the timing of certain 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, our regulated utility earnings were impacted by rate rebasing under Alberta's regulated model in electricity distribution and lower electricity transmission interim rates approved by the AUC. Lower earnings in our Independent Power Plants due to lower realized forward sales and minor plants outage costs were partially offset by higher earnings from Alberta PowerLine and Thermal PPAs.

In the second quarter of 2018, higher earnings were mainly due to improved market conditions for Independent Power Plants and higher recognition of availability incentives in the Thermal PPA Plants, partially offset by rate rebasing under Alberta's regulated model in electricity distribution and lower electricity transmission interim rates approved by the AUC.



Pipelines & Liquids

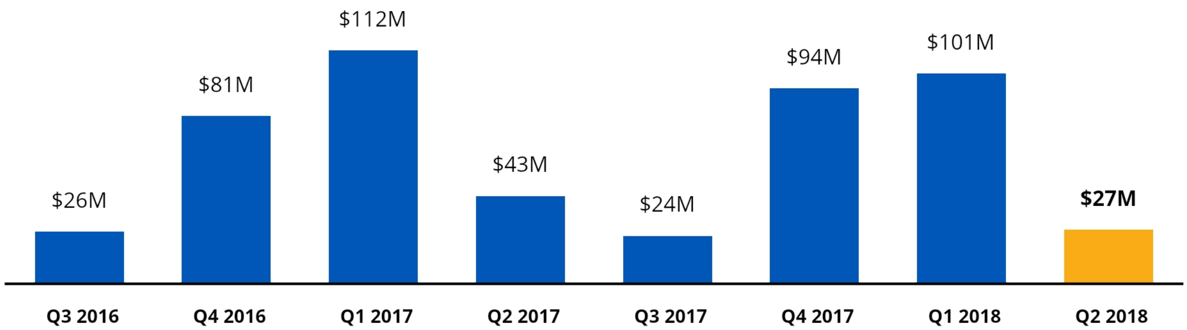
Pipelines & Liquids' adjusted earnings reflect the large capital investment made by Regulated Pipelines & Liquids in the previous eight quarters. These investments, which earn a return under a regulated business model, drive growth in adjusted earnings. Adjusted earnings have also been affected by the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

In the third quarter 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 were partially offset by lower earnings in natural gas distribution mainly due to rate rebasing under Alberta's regulated model.

In the second quarter of 2018, lower earnings were mainly due to rate rebasing under Alberta's regulated model in natural gas distribution, partially offset by growth in rate base across our Regulated Pipelines & Liquids businesses.



Earnings attributable to equity owners of the company

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

- 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 $9 million in 2016 are 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 an impairment relating to workforce housing assets in Canada and space rental assets in the U.S. Structures & Logistics' determined these assets were impaired due to a reduction in utilization, sustained decreases in key commodity prices as well as a significant reduction in the capital expenditure programs of key customers. The Company's 24.5 per cent share of the impairment decreased equity earnings by $7 million in the Corporate & Other segment.
- In the second quarter of 2018, restructuring and other costs not in the normal course of business of $60 million were recorded. These costs mainly relate to staff reductions and associated severance costs, as well as costs related to decisions to discontinue certain projects that no longer represent long-term strategic value to the Company.

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

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

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

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

($ millions) — **Three Months Ended June 30**

2018 **2017 (restated)** [(1)]	**Electricity**	**Pipelines & Liquids**	**Corporate & Other**	**Intersegment Eliminations**	**Consolidated**
Revenues	**634**	**315**	**37**	**(19)**	**967**
	586	355	20	(19)	942
Adjusted earnings	**100**	**27**	**(20)**	**–**	**107**
	98	43	(14)	(1)	126
Restructuring and other costs	**(36)**	**(19)**	**(5)**	**–**	**(60)**
	–	–	–	–	–
Unrealized gains (losses) on mark-to-market forward commodity contracts	**12**	**–**	**–**	**–**	**12**
	(26)	–	–	–	(26)
Rate-regulated activities	**(53)**	**(22)**	**–**	**1**	**(74)**
	(22)	(9)	–	1	(30)
Dividends on equity preferred shares of Canadian Utilities Limited	**1**	**–**	**15**	**–**	**16**
	–	1	16	–	17
Other	**–**	**(4)**	**–**	**–**	**(4)**
	–	3	–	–	3
Earnings (loss) attributable to equity owners of the Company	**24**	**(18)**	**(10)**	**1**	**(3)**
	50	38	2	–	90

($ millions)					Six Months Ended June 30
2018 **2017 (restated)** [(1)]	**Electricity**	**Pipelines & Liquids**	**Corporate & Other**	**Intersegment Eliminations**	**Consolidated**
Revenues	**1,533**	**800**	**76**	**(57)**	**2,352**
	1,095	853	44	(45)	1,947
Adjusted earnings	**197**	**128**	**(37)**	**–**	**288**
	214	155	(30)	–	339
Restructuring and other costs	**(36)**	**(19)**	**(5)**	**–**	**(60)**
	–	–	–	–	–
Gain on sale of operation	**–**	**–**	**–**	**–**	**–**
	–	–	30	–	30
Unrealized losses on mark-to-market forward commodity contracts	**(6)**	**–**	**–**	**–**	**(6)**
	(31)	–	–	–	(31)
Rate-regulated activities	**(66)**	**(13)**	**–**	**2**	**(77)**
	(61)	2	–	2	(57)
Dividends on equity preferred shares of Canadian Utilities Limited	**2**	**–**	**31**	**–**	**33**
	1	1	32	–	34
Other	**–**	**(2)**	**–**	**–**	**(2)**
	–	3	–	–	3
Earnings attributable to equity owners of the Company	**91**	**94**	**(11)**	**2**	**176**
	123	161	32	2	318

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

RESTRUCTURING AND OTHER COSTS

In the second quarter of 2018, restructuring and other costs not in the normal course of business of $60 million after tax were recorded. These costs mainly relate to staff reductions and associated severance costs, as well as costs related to decisions to discontinue certain projects that no longer represent long-term strategic value to the Company.

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.

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 June 30			Six Months Ended June 30		
($ millions)	**2018**	**2017**	**Change**	**2018**	**2017**	**Change**
Additional revenues billed in current period						
Future removal and site restoration costs [1]	**20**	19	1	**39**	38	1
Impact of colder temperatures [2]	**–**	–	–	**12**	–	12
Revenues to be billed in future periods						
Deferred income taxes [3]	**(26)**	(25)	(1)	**(59)**	(55)	(4)
Impact of warmer temperatures [2]	**–**	(3)	3	**–**	(3)	3
Regulatory decisions received	**–**	7	(7)	**–**	7	(7)
Settlement of regulatory decisions and other items [4]	**(68)**	(28)	(40)	**(69)**	(44)	(25)
	(74)	(30)	(44)	**(77)**	(57)	(20)

(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) In the second quarter of 2018, ATCO Electric recorded a decrease in earnings for the period of $38 million mainly related to the refund of deferral account balances for 2013 and 2014. ATCO Gas also recorded a reduction in earnings for the period of $23 million related to the refund of previously over collected transmission costs.

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, impact of warmer temperatures.	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. For the three and six months ended June 30, 2018, the Company recorded a foreign exchange loss of $4 million and $2 million, respectively, (2017 - a foreign exchange gain of $3 million for the three and six months) due to a difference between the tax base currency, which is Mexican pesos, and the U.S. dollar functional currency.

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

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

($ millions)

2018 **2017 (restated)** [(1)]	**Three Months Ended June 30**	**Six Months Ended June 30**
Funds generated by operations	**296**	**821**
	406	912
Changes in non-cash working capital	**(52)**	**111**
	9	107
Change in receivable under service concession arrangement	**(181)**	**(580)**
	(144)	(198)
Cash flows from operating activities	**63**	**352**
	271	821

(1) These numbers have been restated to account for the impact of IFRS 15. Additional detail 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 is 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 IASB or the IFRIC do not need to be adopted in the current period. The Company anticipates that this standard issued, but not yet effective, may have a material effect on the consolidated financial statements as 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. It brings most leases on-balance sheet for lessees, eliminating the distinction between operating and finance leases. Lessor accounting under the new standard retains similar classifications to the previous guidance, however the new standard may change the accounting treatment of certain components of lessor contracts and sub-leasing arrangements. The Company is currently in the process of gathering detailed information on its leases, and analyzing the related contract terms and conditions under this standard in accordance with its adoption project plan. Current evaluations of adoption impacts are ongoing and it is expected that the adoption may result in a material increase in assets and liabilities within the consolidated financial statements. The Company is also assessing the practical expedients available in the standard which could be utilized on transition, including allowing entities to not have to reassess whether an arrangement contains a lease under the provisions of IFRS 16. As the review is still in process, at this time, it is not practicable to quantify the precise impact of adopting the standard. Once further phases of the adoption plan are completed, a quantitative estimate of the impact on the consolidated financial statements will be made.

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 CONTROL OVER FINANCIAL REPORTING

There was no change in the Company’s internal control over financial reporting that occurred during the period beginning on April 1, 2018, and ended on June 30, 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 June 30, 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 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 SIX MONTHS ENDED JUNE 30, 2018

TABLE OF CONTENTS

CONSOLIDATED STATEMENT OF EARNINGS

(millions of Canadian Dollars except per share data)	Note	Three Months Ended June 30 2018	Three Months Ended June 30 2017 (Note 3)	Six Months Ended June 30 2018	Six Months Ended June 30 2017 (Note 3)
Revenues	6	**967**	942	**2,352**	1,947
Costs and expenses					
Salaries, wages and benefits		**(139)**	(88)	**(241)**	(168)
Energy transmission and transportation		**(46)**	(54)	**(90)**	(108)
Plant and equipment maintenance		**(64)**	(44)	**(117)**	(90)
Fuel costs		**(48)**	(51)	**(110)**	(106)
Purchased power		**(43)**	(21)	**(81)**	(48)
Service concession arrangement costs		**(148)**	(129)	**(516)**	(178)
Depreciation and amortization	10	**(182)**	(148)	**(333)**	(296)
Franchise fees		**(44)**	(52)	**(123)**	(135)
Property and other taxes		**(48)**	(31)	**(92)**	(63)
Unrealized gains (losses) on mark-to-market forward commodity contracts		**16**	(35)	**(8)**	(42)
Other		**(108)**	(74)	**(178)**	(136)
		(854)	(727)	**(1,889)**	(1,370)
Gain on sale of operation	7	**–**	–	**–**	30
Earnings from investment in ATCO Structures & Logistics		**–**	1	**–**	1
Earnings from investment in joint ventures		**4**	3	**12**	10
Operating profit		**117**	219	**475**	618
Interest income		**9**	5	**18**	10
Interest expense		**(124)**	(103)	**(247)**	(209)
Net finance costs		**(115)**	(98)	**(229)**	(199)
Earnings before income taxes		**2**	121	**246**	419
Income taxes		**(4)**	(29)	**(67)**	(97)
Earnings (loss) for the period		**(2)**	92	**179**	322
Earnings (loss) attributable to:					
Equity owners of the Company		**(3)**	90	**176**	318
Non-controlling interests		**1**	2	**3**	4
		(2)	92	**179**	322
Earnings (loss) per Class A and Class B share	8	**$(0.07)**	$0.27	**$0.53**	$1.05
Diluted earnings (loss) per Class A and Class B share	8	**$(0.07)**	$0.27	**$0.53**	$1.05

See accompanying Notes to Unaudited Interim Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(millions of Canadian Dollars)	Note	Three Months Ended June 30 2018	Three Months Ended June 30 2017 (Note 3)	Six Months Ended June 30 2018	Six Months Ended June 30 2017 (Note 3)
Earnings (loss) for the period		**(2)**	92	**179**	322
Other comprehensive income (loss), net of income taxes					
Items that will not be reclassified to earnings:					
Re-measurement of retirement benefits (1)		**44**	(23)	**23**	(63)
Share of re-measurement of retirement benefits of ATCO Structures & Logistics (2)		**–**	1	**–**	–
		44	(22)	**23**	(63)
Items that are or may be reclassified subsequently to earnings:					
Cash flow hedges (3)		**1**	(8)	**(4)**	(12)
Cash flow hedges reclassified to earnings (2)		**3**	(1)	**3**	(2)
Foreign currency translation adjustment (2)		**(17)**	(13)	**1**	13
Share of other comprehensive loss of joint ventures (2)		**–**	(2)	**–**	(1)
		(13)	(24)	**–**	(2)
Other comprehensive income (loss)		**31**	(46)	**23**	(65)
Comprehensive income for the period		**29**	46	**202**	257
Comprehensive income attributable to:					
Equity owners of the Company		**28**	44	**199**	253
Non-controlling interests		**1**	2	**3**	4
		29	46	**202**	257

(1) Net of income taxes of $(17) million and $(9) million for the three and six months ended June 30, 2018 (2017 - $8 million and $23 million).

(2) Net of income taxes of nil.

(3) Net of income taxes of $(2) million and nil for the three and six months ended June 30, 2018 (2017 - $3 million and $5 million).

See accompanying Notes to Unaudited Interim Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEET

(millions of Canadian Dollars)	Note	June 30 2018	December 31 2017 (Note 3)	January 1 2017 (Note 3)
ASSETS				
Current assets				
Cash and cash equivalents	15	**148**	425	345
Accounts receivable and contract assets		**489**	616	518
Finance lease receivables		**16**	15	12
Inventories		**39**	40	38
Income taxes receivable		**39**	35	35
Restricted project funds	9	**386**	861	–
Prepaid expenses and other current assets		**64**	45	37
		1,181	2,037	985
Non-current assets				
Property, plant and equipment	10	**17,107**	16,786	16,363
Intangibles		**600**	563	526
Investment in ATCO Structures & Logistics		**–**	–	199
Investment in joint ventures		**198**	196	189
Finance lease receivables		**387**	395	302
Deferred income tax assets		**92**	84	80
Receivable under service concession arrangement		**1,173**	593	77
Restricted project funds	9	**86**	104	–
Other assets		**87**	86	85
Total assets		**20,911**	20,844	18,806
LIABILITIES				
Current liabilities				
Bank indebtedness	15	**4**	7	5
Accounts payable and accrued liabilities		**693**	827	609
Asset retirement obligations and other provisions		**68**	33	40
Other current liabilities		**55**	64	18
Short-term debt	11	**50**	–	55
Long-term debt	12	**185**	5	155
Non-recourse long-term debt		**15**	15	14
		1,070	951	896
Non-current liabilities				
Deferred income tax liabilities		**1,301**	1,229	1,135
Asset retirement obligations and other provisions		**134**	128	132
Retirement benefit obligations		**311**	340	302
Deferred revenues		**1,828**	1,808	1,870
Other liabilities		**196**	147	46
Long-term debt	12	**8,346**	8,494	8,065
Non-recourse long-term debt		**1,394**	1,401	84
Total liabilities		**14,580**	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	**1,194**	1,162	1,070
Contributed surplus		**13**	12	15
Retained earnings		**3,499**	3,547	3,511
Accumulated other comprehensive loss		**(45)**	(45)	(5)
Total equity attributable to equity owners of the Company		**6,144**	6,159	6,074
Non-controlling interests		**187**	187	202
Total equity		**6,331**	6,346	6,276
Total liabilities and equity		**20,911**	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		–	–	–	323	–	323	4	327
Re-measurement adjustments	3	–	–	–	(5)	–	(5)	–	(5)
Other comprehensive loss		–	–	–	–	(65)	(65)	–	(65)
Losses on retirement benefits transferred to retained earnings		–	–	–	(63)	63	–	–	–
Shares issued		62	–	–	–	–	62	–	62
Dividends	13,14	–	–	–	(226)	–	(226)	(4)	(230)
Share-based compensation		2	–	(6)	–	–	(4)	–	(4)
Other		–	–	–	–	–	–	(15)	(15)
June 30, 2017		1,134	1,483	9	3,540	(7)	6,159	187	6,346
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		**–**	**–**	**–**	**176**	**–**	**176**	**3**	**179**
Other comprehensive income		**–**	**–**	**–**	**–**	**23**	**23**	**–**	**23**
Gains on retirement benefits transferred to retained earnings		**–**	**–**	**–**	**23**	**(23)**	**–**	**–**	**–**
Shares issued		**31**	**–**	**–**	**–**	**–**	**31**	**–**	**31**
Dividends	13,14	**–**	**–**	**–**	**(247)**	**–**	**(247)**	**(3)**	**(250)**
Share-based compensation		**1**	**–**	**1**	**–**	**–**	**2**	**–**	**2**
June 30, 2018		**1,194**	**1,483**	**13**	**3,499**	**(45)**	**6,144**	**187**	**6,331**

See accompanying Notes to Unaudited Interim Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOW

(millions of Canadian Dollars)	Note	Three Months Ended June 30 2018	Three Months Ended June 30 2017 (Note 3)	Six Months Ended June 30 2018	Six Months Ended June 30 2017 (Note 3)
Operating activities					
Earnings (loss) for the period		**(2)**	92	**179**	322
Adjustments to reconcile earnings to cash flows from operating activities	15	**298**	314	**642**	590
Changes in non-cash working capital		**(52)**	9	**111**	107
Change in receivable under service concession arrangement		**(181)**	(144)	**(580)**	(198)
Cash flows from operating activities		**63**	271	**352**	821
Investing activities					
Additions to property, plant and equipment		**(266)**	(237)	**(506)**	(452)
Proceeds on disposal of property, plant and equipment		**1**	–	**1**	–
Additions to intangibles		**(20)**	15	**(34)**	15
Acquisition, net of cash acquired	4	**–**	(26)	**(70)**	(42)
Proceeds on sale of operation	7	**–**	–	**–**	47
Investment in joint ventures		**–**	(5)	**(6)**	(10)
Changes in non-cash working capital		**(55)**	(19)	**(81)**	(40)
Other		**(1)**	1	**(4)**	13
Cash flows used in investing activities		**(341)**	(271)	**(700)**	(469)
Financing activities					
Net issue (repayment) of short-term debt	11	**(50)**	140	**50**	120
Issue of long-term debt	12	**–**	–	**40**	–
Release of restricted project funds	9	**277**	–	**493**	–
Repayment of long-term debt		**(46)**	(3)	**(46)**	(3)
Repayment of non-recourse long-term debt		**(3)**	(3)	**(7)**	(7)
Issue of Class A shares		**–**	4	**1**	4
Dividends paid on equity preferred shares		**(16)**	(17)	**(33)**	(34)
Dividends paid to non-controlling interests		**(1)**	(2)	**(3)**	(4)
Dividends paid to Class A and Class B share owners		**(93)**	(65)	**(183)**	(130)
Interest paid		**(136)**	(115)	**(238)**	(206)
Other		**2**	13	**4**	21
Cash flows (used in) from financing activities		**(66)**	(48)	**78**	(239)
(Decrease) increase in cash position (1)		**(344)**	(48)	**(270)**	113
Foreign currency translation		**(2)**	(1)	**(4)**	2
Beginning of period		**490**	504	**418**	340
End of period	15	**144**	455	**144**	455

(1) Cash position includes $48 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)

JUNE 30, 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 July 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 $0.2 billion and $0.6 billion as revenue during the three and six months ended June 30, 2018, and expects to recognize approximately $0.2 billion as revenue during the remaining six 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 June 30, 2017, is shown below.

		Three Months Ended June 30, 2017		
(millions of Canadian Dollars except per share data)	**Note**	**As previously reported**	**IFRS 15 re-measurement adjustments**	**Restated**
Revenues	(ii.), (iii.), (iv.), (v.)	938	4	942
Costs and expenses				
Salaries, wages and benefits		(88)	–	(88)
Energy transmission and transportation	(iv.)	(67)	13	(54)
Plant and equipment maintenance		(44)	–	(44)
Fuel costs	(iii.)	(33)	(18)	(51)
Purchased power		(21)	–	(21)
Service concession arrangement costs		(129)	–	(129)
Depreciation and amortization		(148)	–	(148)
Franchise fees		(52)	–	(52)
Property and other taxes		(31)	–	(31)
Unrealized losses on mark-to-market forward commodity contracts		(35)	–	(35)
Other		(74)	–	(74)
		(722)	(5)	(727)
Earnings from investment in ATCO Structures & Logistics		1	–	1
Earnings from investment in joint ventures		3	–	3
Operating profit		220	(1)	219
Interest income		5	–	5
Interest expense	(v.)	(100)	(3)	(103)
Net finance costs		(95)	(3)	(98)
Earnings before income taxes		125	(4)	121
Income taxes		(30)	1	(29)
Earnings for the period		95	(3)	92
Earnings attributable to:				
Equity owners of the Company		93	(3)	90
Non-controlling interests		2	–	2
		95	(3)	92
Earnings per Class A and Class B share	8	$0.28	$(0.01)	$0.27
Diluted earnings per Class A and Class B share	8	$0.28	$(0.01)	$0.27

The impact on amounts recognized in the Company's consolidated statement of earnings for the six months ended June 30, 2017, is shown below.

		Six Months Ended June 30, 2017		
(millions of Canadian Dollars except per share data)	**Note**	**As previously reported**	**IFRS 15 re-measurement adjustments**	**Restated**
Revenues	(ii.), (iii.), (iv.), (v.)	1,935	12	1,947
Costs and expenses				
Salaries, wages and benefits		(168)	–	(168)
Energy transmission and transportation	(iv.)	(135)	27	(108)
Plant and equipment maintenance		(90)	–	(90)
Fuel costs	(iii.)	(66)	(40)	(106)
Purchased power		(48)	–	(48)
Service concession arrangement costs		(178)	–	(178)
Depreciation and amortization		(296)	–	(296)
Franchise fees		(135)	–	(135)
Property and other taxes		(63)	–	(63)
Unrealized losses on mark-to-market forward commodity contracts		(42)	–	(42)
Other		(136)	–	(136)
		(1,357)	(13)	(1,370)
Gain on sale of operation		30	–	30
Earnings from investment in ATCO Structures & Logistics		1	–	1
Earnings from investment in joint ventures		10	–	10
Operating profit		619	(1)	618
Interest income		10	–	10
Interest expense	(v.)	(203)	(6)	(209)
Net finance costs		(193)	(6)	(199)
Earnings before income taxes		426	(7)	419
Income taxes		(99)	2	(97)
Earnings for the period		327	(5)	322
Earnings attributable to:				
Equity owners of the Company		323	(5)	318
Non-controlling interests		4	–	4
		327	(5)	322
Earnings per Class A and Class B share	8	$1.07	$(0.02)	$1.05
Diluted earnings per Class A and Class B share	8	$1.07	$(0.02)	$1.05

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)
Total equity attributable to equity owners of the Company		6,218	(144)	6,074
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 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)
Total equity attributable to equity owners of the Company		6,275	(113)	(3)	6,159
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 and six months ended June 30, 2017, the Company recorded a decrease to revenues from electricity generation and delivery of $4 million and $7 million, and an increase to income taxes of $1 million and $2 million, respectively, due to recognition of deferred revenues. As a result of this adjustment, in the consolidated statement of cash flow for the three and six months ended June 30, 2017, the Company recorded a decrease to earnings of $3 million and $5 million, with a corresponding increase of $3 million and $5 million to adjustments to reconcile earnings to cash flows from operating activities, respectively.

(iii) As a result of recognition of non-cash considerations received from customers during the three and six months ended June 30, 2017, at fair value, the Company recorded an increase to revenue from electricity generation and delivery of $18 million and $40 million, with a corresponding increase of $18 million and $40 million to fuel costs, respectively.

(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 and six months ended June 30, 2017, the Company recorded a decrease to revenue from commodity sales of $13 million and $27 million, with a corresponding decrease of $13 million and $27 million to energy transmission and transportation costs, respectively.

(v) As a result of recognition of financing component on upfront considerations received from customers, during the three and six months ended June 30, 2017, the Company recorded an increase to revenue from electricity generation and delivery of $3 million and $6 million, with a corresponding increase of $3 million and $6 million to interest expense, respectively.

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 acquired	**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 $4 million and $5 million, and earnings of less than a million were included in the consolidated statement of earnings for the three and six months ended June 30, 2018, as a result of the acquisition. Transaction costs of $2 million for incremental legal and advisory services fees were expensed during the six months ended June 30, 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 six months ended June 30, 2018, would have been $2,354 million, and $176 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

SEGMENTED RESULTS

Results by operating segment for the three months ended June 30 are shown below.

2018 2017 (restated)	Electricity	Pipelines & Liquids	Corporate & Other	Intersegment Eliminations	Consolidated
Revenues - external	**635**	**304**	**28**	**–**	**967**
	585	344	13	–	942
Revenues - intersegment	**(1)**	**11**	**9**	**(19)**	**–**
	1	11	7	(19)	–
Revenues	**634**	**315**	**37**	**(19)**	**967**
	586	355	20	(19)	942
Operating expenses [(1)]	**(411)**	**(224)**	**(54)**	**17**	**(672)**
	(361)	(214)	(21)	17	(579)
Depreciation and amortization	**(109)**	**(73)**	**(2)**	**2**	**(182)**
	(91)	(57)	(2)	2	(148)
Earnings from investment in ATCO Structures & Logistics	**–**	**–**	**–**	**–**	**–**
	–	–	1	–	1
Earnings from investment in joint ventures	**2**	**2**	**–**	**–**	**4**
	3	–	–	–	3
Net finance costs	**(80)**	**(39)**	**4**	**–**	**(115)**
	(66)	(36)	2	2	(98)
Earnings before income taxes	**36**	**(19)**	**(15)**	**–**	**2**
	71	48	–	2	121
Income taxes	**(11)**	**1**	**5**	**1**	**(4)**
	(20)	(9)	2	(2)	(29)
Earnings (loss) for the period	**25**	**(18)**	**(10)**	**1**	**(2)**
	51	39	2	–	92
Adjusted earnings	**100**	**27**	**(20)**	**–**	**107**
	98	43	(14)	(1)	126
Capital expenditures [(3)]	**126**	**162**	**3**	**–**	**291**
	97	170	1	–	268

Results by operating segment for the six months ended June 30 is shown below.

2018 2017 (restated)	Electricity	Pipelines & Liquids	Corporate & Other	Intersegment Eliminations	Consolidated
Revenues - external	**1,523**	**772**	**57**	**–**	**2,352**
	1,084	833	30	–	1,947
Revenues - intersegment	**10**	**28**	**19**	**(57)**	**–**
	11	20	14	(45)	–
Revenues	**1,533**	**800**	**76**	**(57)**	**2,352**
	1,095	853	44	(45)	1,947
Operating expenses [(1)]	**(1,053)**	**(460)**	**(99)**	**56**	**(1,556)**
	(616)	(450)	(51)	43	(1,074)
Depreciation and amortization	**(201)**	**(132)**	**(4)**	**4**	**(333)**
	(183)	(114)	(4)	5	(296)
Gain on sale of operation (*Note 7*)	**–**	**–**	**–**	**–**	**–**
	–	–	30	–	30
Earnings from investment in ATCO Structures & Logistics	**–**	**–**	**–**	**–**	**–**
	–	–	1	–	1
Earnings from investment in joint ventures	**9**	**3**	**–**	**–**	**12**
	9	1	–	–	10
Net finance costs	**(159)**	**(77)**	**8**	**(1)**	**(229)**
	(133)	(71)	4	1	(199)
Earnings before income taxes	**129**	**134**	**(19)**	**2**	**246**
	172	219	24	4	419
Income taxes	**(36)**	**(39)**	**8**	**–**	**(67)**
	(47)	(56)	8	(2)	(97)
Earnings for the period	**93**	**95**	**(11)**	**2**	**179**
	125	163	32	2	322
Adjusted earnings	**197**	**128**	**(37)**	**–**	**288**
	214	155	(30)	–	339
Total assets [(2)]	**13,215**	**7,562**	**150**	**(16)**	**20,911**
	13,013	7,489	448	(106)	20,844
Capital expenditures [(3)]	**242**	**301**	**7**	**–**	**550**
	197	304	2	–	503

(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 and $10 million of interest capitalized during construction for the three and six months ended June 30, 2018 (2017 - $5 million and $9 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 June 30 is shown below.

2018 **2017 (restated)**	**Electricity**	**Pipelines & Liquids**	**Corporate & Other**	**Intersegment Eliminations**	**Consolidated**
Adjusted earnings	**100**	**27**	**(20)**	**–**	**107**
	98	43	(14)	(1)	126
Restructuring and other costs	**(36)**	**(19)**	**(5)**	**–**	**(60)**
	–	–	–	–	–
Unrealized gains (losses) on mark-to-market forward commodity contracts	**12**	**–**	**–**	**–**	**12**
	(26)	–	–	–	(26)
Rate-regulated activities	**(53)**	**(22)**	**–**	**1**	**(74)**
	(22)	(9)	–	1	(30)
Dividends on equity preferred shares of Canadian Utilities Limited	**1**	**–**	**15**	**–**	**16**
	–	1	16	–	17
Other	**–**	**(4)**	**–**	**–**	**(4)**
	–	3	–	–	3
Earnings (loss) attributable to equity owners of the Company	**24**	**(18)**	**(10)**	**1**	**(3)**
	50	38	2	–	90
Earnings attributable to non-controlling interests					**1**
					2
Earnings (loss) for the period					**(2)**
					92

The reconciliation of adjusted earnings and earnings for the six months ended June 30 is shown below.

2018 **2017 (restated)**	**Electricity**	**Pipelines & Liquids**	**Corporate & Other**	**Intersegment Eliminations**	**Consolidated**
Adjusted earnings	**197**	**128**	**(37)**	**–**	**288**
	214	155	(30)	–	339
Gain on sale of operation (*Note 7*)	**–**	**–**	**–**	**–**	**–**
	–	–	30	–	30
Restructuring and other costs	**(36)**	**(19)**	**(5)**	**–**	**(60)**
	–	–	–	–	–
Unrealized losses on mark-to-market forward commodity forward commodity contracts	**(6)**	**–**	**–**	**–**	**(6)**
	(31)	–	–	–	(31)
Rate-regulated activities	**(66)**	**(13)**	**–**	**2**	**(77)**
	(61)	2	–	2	(57)
Dividends on equity preferred shares of Canadian Utilities Limited	**2**	**–**	**31**	**–**	**33**
	1	1	32	–	34
Other	**–**	**(2)**	**–**	**–**	**(2)**
	–	3	–	–	3
Earnings attributable to equity owners of the Company	**91**	**94**	**(11)**	**2**	**176**
	123	161	32	2	318
Earnings attributable to non-controlling interests					**3**
					4
Earnings for the period					**179**
					322

Gain on sale of operation

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

			Three Months Ended June 30		Six Months Ended June 30	
	Note	**Segment**	**2018**	**2017**	**2018**	**2017**
Real estate	7	Corporate & Other	–	–	–	30

Restructuring and other costs

In the second quarter of 2018, the Company recorded restructuring and other costs of $60 million, after tax, that were not in the normal course of business. These costs mainly relate to staff reductions and associated severance costs, as well as costs related to decisions to discontinue certain projects that no longer represent long-term strategic value to the Company.

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, impact of warmer temperatures.	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 are as follows:

	Three Months Ended June 30		Six Months Ended June 30	
	2018	**2017**	**2018**	**2017**
Additional revenues billed in current period				
Future removal and site restoration costs (1)	**20**	19	**39**	38
Impact of colder temperatures (2)	**–**	–	**12**	–
Revenues to be billed in future periods				
Deferred income taxes (3)	**(26)**	(25)	**(59)**	(55)
Impact of warmer temperatures (2)	**–**	(3)	**–**	(3)
Regulatory decisions received	**–**	7	**–**	7
Settlement of regulatory decisions and other items (4)	**(68)**	(28)	**(69)**	(44)
	(74)	(30)	**(77)**	(57)

(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) In the second quarter of 2018, ATCO Electric recorded a decrease in earnings for the period of $38 million mainly related to the refund of deferral account balances for 2013 and 2014. ATCO Gas also recorded a reduction in earnings for the period of $23 million related to the refund of previously over collected transmission costs.

Other

Each quarter, the Company adjusts the deferred tax asset which was recognized as a result of the 2015 Tula Pipeline Project impairment. For the three and six months ended June 30, 2018, the Company recorded a foreign exchange loss of $4 million and $2 million, respectively, (2017 - a foreign exchange gain of $3 million for the three and six months) 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 June 30 are shown below:

2018 **2017 (restated)**	**Electricity**	**Pipelines & Liquids**	**Corporate & Other**	**Total**
Revenue Streams				
Sale of Goods				
Electricity generation and delivery	**116**	**–**	**–**	**116**
	71	–	–	71
Commodity sales	**3**	**3**	**–**	**6**
	2	4	–	6
Total sale of goods	**119**	**3**	**–**	**122**
	73	4	–	77
Rendering of Services				
Distribution services	**143**	**187**	**–**	**330**
	148	215	–	363
Transmission services	**100**	**65**	**–**	**165**
	135	63	–	198
Customer contributions	**10**	**5**	**–**	**15**
	9	3	–	12
Franchise fees	**7**	**38**	**–**	**45**
	7	47	–	54
Retail electricity and natural gas services	**–**	**–**	**27**	**27**
	–	–	13	13
Storage and industrial water	**–**	**5**	**–**	**5**
	–	10	–	10
Total rendering of services	**260**	**300**	**27**	**587**
	299	338	13	650
Lease income				
Finance lease	**8**	**–**	**–**	**8**
	8	–	–	8
Operating lease	**62**	**–**	**–**	**62**
	57	–	–	57
Total lease income	**70**	**–**	**–**	**70**
	65	–	–	65
Service concession arrangement	**181**	**–**	**–**	**181**
	144	–	–	144
Other	**5**	**1**	**1**	**7**
	4	2	–	6
Total	**635**	**304**	**28**	**967**
	585	344	13	942

The disaggregation of revenues by revenue streams for each operating segment for the six months ended June 30 are shown below:

2018 **2017 (restated)**	**Electricity**	**Pipelines & Liquids**	**Corporate & Other**	**Total**
Revenue Streams				
Sale of Goods				
Electricity generation and delivery	**200**	–	–	**200**
	138	–	–	138
Commodity sales	**8**	**6**	–	**14**
	7	5	–	12
Total sale of goods	**208**	**6**	–	**214**
	145	5	–	150
Rendering of Services				
Distribution services	**283**	**498**	–	**781**
	284	543	–	827
Transmission services	**269**	**129**	–	**398**
	295	127	–	422
Customer contributions	**19**	**9**	–	**28**
	19	9	–	28
Franchise fees	**15**	**110**	–	**125**
	14	124	–	138
Retail electricity and natural gas services	–	–	**54**	**54**
	–	–	28	28
Storage and industrial water	–	**19**	–	**19**
	–	24	–	24
Total rendering of services	**586**	**765**	**54**	**1,405**
	612	827	28	1,467
Lease income				
Finance lease	**17**	–	–	**17**
	17	–	–	17
Operating lease	**121**	–	–	**121**
	105	–	–	105
Total lease income	**138**	–	–	**138**
	122	–	–	122
Service concession arrangement	**580**	–	–	**580**
	198	–	–	198
Other	**11**	**1**	**3**	**15**
	7	1	2	10
Total	**1,523**	**772**	**57**	**2,352**
	1,084	833	30	1,947

Disaggregation of revenues by regulated and non-regulated business operations is shown below:

	Three Months Ended June 30		Six Months Ended June 30	
	2018	2017 (restated)	2018	2017 (restated)
Regulated business operations				
Regulated Electricity				
Electricity Distribution	**158**	161	**314**	311
Electricity Transmission	**103**	138	**274**	301
	261	299	**588**	612
Regulated Pipelines & liquids				
Natural Gas Distribution	**182**	216	**532**	585
Natural Gas Transmission	**66**	65	**132**	131
International Natural Gas Distribution	**44**	47	**82**	87
	292	328	**746**	803
Total Regulated business operations	**553**	627	**1,334**	1,415
Non-regulated business operations				
Non-regulated Electricity				
Independent Power Plants	**104**	73	**178**	137
Thermal PPA Plants	**82**	63	**165**	125
International Power Generation	**5**	5	**10**	11
Alberta PowerLine	**181**	144	**580**	198
	372	285	**933**	471
Non-regulated Pipelines & liquids				
Storage and Industrial Water	**5**	10	**19**	24
	5	10	**19**	24
Other non-regulated business operations				
Retail Electricity and Natural Gas Services	**27**	13	**54**	28
Other	**10**	7	**12**	9
	37	20	**66**	37
Total Non-regulated business operations	**414**	315	**1,018**	532
Total	**967**	942	**2,352**	1,947

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 June 30		Six Months Ended June 30	
	2018	2017 (restated)	2018	2017 (restated)
Average shares				
Weighted average shares outstanding	**271,175,287**	269,150,453	**270,946,405**	268,757,024
Effect of dilutive stock options	**33,797**	107,597	**38,532**	88,163
Effect of dilutive MTIP	**609,230**	540,545	**583,452**	512,953
Weighted average dilutive shares outstanding	**271,818,314**	269,798,595	**271,568,389**	269,358,140
Earnings for earnings per share calculation				
Earnings (loss) for the period	**(2)**	92	**179**	322
Dividends on equity preferred shares of the Company	**(16)**	(17)	**(33)**	(34)
Non-controlling interests	**(1)**	(2)	**(3)**	(4)
Earnings (loss) attributable to Class A and B shares	**(19)**	73	**143**	284
Earnings and diluted earnings per Class A and Class B share				
Earnings (loss) per Class A and Class B share	**$(0.07)**	$0.27	**$0.53**	$1.05
Diluted earnings (loss) per Class A and Class B share	**$(0.07)**	$0.27	**$0.53**	$1.05

9. RESTRICTED PROJECT FUNDS

At June 30, 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 $472 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:

	June 30, 2018	December 31, 2017
Current assets		
Restricted cash	**132**	351
Restricted funds invested in structured deposit note (1)	**254**	510
	386	861
Non-current assets		
Restricted cash	**–**	69
Restricted funds for construction holdbacks (2)	**86**	35
	86	104
	472	965

(1) At June 30, 2018, the Company had $254 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 June 30, 2018, the Company had $86 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	**15**	**4**	**9**	**491**	**8**	**527**
Transfers	**307**	–	**3**	**(322)**	**12**	–
Retirements and disposals	**(31)**	**(28)**	**(1)**	–	**(3)**	**(63)**
Acquisition of EGO *(Note 4)*	–	**87**	–	–	**1**	**88**
Foreign exchange rate adjustment	**(8)**	**5**	**4**	**6**	–	**7**
June 30, 2018	**18,748**	**1,937**	**801**	**784**	**1,022**	**23,292**
Accumulated depreciation						
December 31, 2017	4,016	1,305	147	77	402	5,947
Depreciation	**216**	**36**	**9**	–	**36**	**297**
Retirements and disposals	**(31)**	**(28)**	**(1)**	–	**(2)**	**(62)**
Foreign exchange rate adjustment	**(1)**	–	–	**4**	–	**3**
June 30, 2018	**4,200**	**1,313**	**155**	**81**	**436**	**6,185**
Net book value						
December 31, 2017	14,449	564	639	532	602	16,786
June 30, 2018	**14,548**	**624**	**646**	**703**	**586**	**17,107**

The additions to property, plant and equipment included $10 million of interest capitalized during construction for the six months ended June 30, 2018 (2017 - $9 million).

11. SHORT-TERM DEBT

At June 30, 2018, the Company had $50 million of commercial paper outstanding at an interest rate of 1.67 per cent, maturing in August 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 was 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 June 30		Six Months Ended June 30	
(dollars per share)	2018	2017	2018	2017
Perpetual Cumulative Second Preferred Shares				
4.60% Series V (1)	**0.2875**	0.2500	**0.5750**	0.5000
Cumulative Redeemable Second Preferred Shares				
3.403% Series Y (2)	**0.2127**	0.2500	**0.4254**	0.5000
4.90% Series AA	**0.3063**	0.3063	**0.6125**	0.6125
4.90% Series BB	**0.3063**	0.3063	**0.6125**	0.6125
4.50% Series CC	**0.2813**	0.2813	**0.5625**	0.5625
4.50% Series DD	**0.2813**	0.2813	**0.5625**	0.5625
5.25% Series EE	**0.3281**	0.3281	**0.6563**	0.6563
4.50% Series FF	**0.2813**	0.2813	**0.5625**	0.5625

(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 198,169,290 (2017 - 196,165,348) Class A shares and 73,949,274 (2017 - 74,189,583) Class B shares outstanding at June 30, 2018. In addition, there were 813,800 options to purchase Class A shares outstanding at June 30, 2018, under the Company's stock option plan.

DIVIDENDS

The Company declared and paid cash dividends of $0.3933 and $0.7866 per Class A and Class B share during the three and six months ended June 30, 2018 (2017 - $0.3575 and $0.7150). 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 and six months ended June 30, 2018, 490,295 and 980,509 Class A shares were issued under the Company's dividend reinvestment plan (2017 - 788,627 and 1,654,646), using re-invested dividends of $15 million and $31 million (2017- $31 million and $62 million). The shares were priced at an average of $30.73 and $31.91 per share (2017 - $39.92 and $37.50).

15. CASH FLOW INFORMATION

ADJUSTMENTS TO RECONCILE EARNINGS TO CASH FLOWS FROM OPERATING ACTIVITIES

Adjustments to reconcile earnings to cash flows from operating activities are summarized below.

	Three Months Ended June 30		Six Months Ended June 30	
	2018	**2017 (restated)**	**2018**	**2017 (restated)**
Depreciation and amortization	**182**	148	**333**	296
Gain on sale of operation (*Note 7*)	**–**	–	**–**	(30)
Earnings from investment in ATCO Structures & Logistics, net of dividends received	**–**	21	**–**	23
Earnings from investment in joint ventures, net of dividends and distributions received	**2**	(2)	**(1)**	(3)
Income taxes	**4**	29	**67**	97
Unearned availability incentives	**1**	2	**(4)**	–
Unrealized (gains) losses on mark-to-market forward commodity contracts	**(16)**	35	**8**	42
Contributions by customers for extensions to plant	**25**	21	**48**	37
Amortization of customer contributions	**(15)**	(9)	**(28)**	(25)
Net finance costs	**115**	98	**229**	199
Income taxes paid	**(20)**	(24)	**(38)**	(51)
Other	**20**	(5)	**28**	5
	298	314	**642**	590

CASH POSITION

Cash position in the consolidated statement of cash flow at June 30 is comprised of:

	2018	**2017**
Cash	**99**	417
Short-term investments	**–**	1
Restricted cash [(1)]	**48**	41
Cash and cash equivalents	**148**	459
Bank indebtedness	**(4)**	(4)
	144	455

(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:

	June 30, 2018		December 31, 2017	
Recurring Measurements	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial Assets				
Lease receivables	**403**	**554**	410	568
Receivable under service concession arrangement	**1,173**	**1,173**	593	593
Financial Liabilities				
Long-term debt	**8,531**	**9,563**	8,499	9,679
Non-recourse long-term debt	**1,409**	**1,557**	1,416	1,562

FINANCIAL INSTRUMENTS MEASURED AT FAIR VALUE

The Company's derivative instruments are measured at fair value. At June 30, 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 Euros, Mexican Pesos and U.S. Dollars, 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**
June 30, 2018					
Financial Assets					
Prepaid expenses and other current assets	**1**	**1**	**3**	–	**5**
Other assets	**1**	–	–	–	**1**
Financial Liabilities					
Other current liabilities [(1)]	**2**	**17**	**28**	–	**47**
Other liabilities [(1)]	–	**14**	**28**	–	**42**
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 June 30, 2018, the Company paid a total of $72 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:

Notional value and maturity	Subject to Hedge Accounting: Interest Rate Swaps	Natural Gas (1)	Power (2)	Foreign Currency Forward Contracts	Not Subject to Hedge Accounting: Natural Gas (1)	Power (2)	Foreign Currency Forward Contracts
June 30, 2018							
Purchases (3)	–	**15,888,000**	–	–	**67,161,200**	**5,358,385**	–
Sales (3)	–	–	**1,427,355**	–	**14,643,700**	**10,950,170**	–
Currency							
Canadian dollars	**3**	–	–	–	–	–	–
Australian dollars	**1**	–	–	–	–	–	–
Mexican pesos	**570**	–	–	–	–	–	**140**
U.S. dollars	–	–	–	**16**	–	–	–
Euro	–	–	–	**12**	–	–	–
Maturity	**2019-2023**	**2018-2021**	**2018-2020**	**2018**	**2018-2022**	**2018-2021**	**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.

17. ACCOUNTING STANDARDS AND INTERPRETATIONS NOT YET ADOPTED

Certain new or amended standards or interpretations issued by the IASB or IFRIC do not need to be adopted in the current period. The Company anticipates that the IFRS 16 *Leases*, which was issued, but is not yet effective, may have a material effect on the consolidated financial statements or note disclosures are described below.

Standard	Description	Effective Date
IFRS 16 *Leases*	This standard replaces IAS 17 *Leases* and related interpretations. It introduces a new approach to lease accounting that requires a lessee to recognize assets and liabilities for the rights and obligations created by leases. It brings most leases on-balance sheet for lessees, eliminating the distinction between operating and finance leases. Lessor accounting under the new standard retains similar classifications to the previous guidance, however the new standard may change the accounting treatment of certain components of lessor contracts and sub-leasing arrangements. The Company is currently in the process of gathering detailed information on its leases, and analyzing the related contract terms and conditions under this standard in accordance with its adoption project plan. Current evaluations of adoption impacts are ongoing and it is expected that the adoption may result in a material increase in assets and liabilities within the consolidated financial statements. The Company is also assessing the practical expedients available in the standard which could be utilized on transition, including allowing entities to not have to reassess whether an arrangement contains a lease under the provisions of IFRS 16. As the review is still in process, at this time, it is not practicable to quantify the precise impact of adopting the standard. Once further phases of the adoption plan are completed, a quantitative estimate of the impact on the consolidated financial statements will be made.	Effective for annual periods on or after January 1, 2019.