CANADIAN UTILITIES LIMITED
An ATCO Company

CANADIAN UTILITIES LIMITED MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEAR ENDED DECEMBER 31, 2018

This Management's Discussion and Analysis (MD&A) is meant to help readers understand key operational and financial events that influenced the results of Canadian Utilities Limited (Canadian Utilities, our, we, us, or the Company) during the year ended December 31, 2018.

This MD&A was prepared as of February 27, 2019, and should be read with the Company's audited consolidated financial statements (2018 Consolidated Financial Statements) for the year ended December 31, 2018. Additional information, including the Company's Annual Information Form (AIF), is available on SEDAR at www.sedar.com.

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

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

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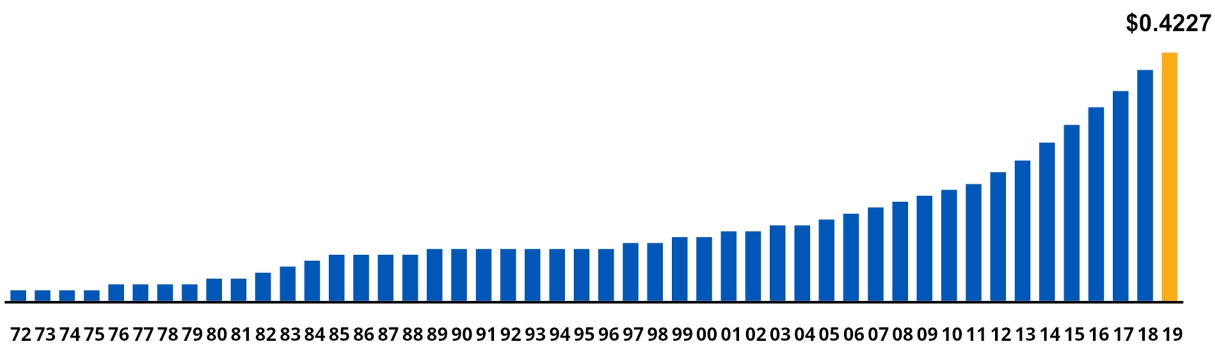
CANADIAN UTILITIES: WHAT SETS US APART

TRACK RECORD OF DIVIDEND GROWTH

We have increased our common share dividend every year for the past 47 years, the longest record of annual dividend increases of any Canadian publicly traded company. On January 10, 2019, we declared a first quarter dividend of 42.27 cents per share or $1.69 per share on an annualized basis. We aim to grow dividends in-line with our sustainable earnings growth, which is linked to growth from our regulated and long-term contracted investments.

Quarterly Dividend Rate 1972 - 2019
(dollars per share)



GROWING A HIGH QUALITY EARNINGS BASE

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

FUTURE CAPITAL INVESTMENT

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

FINANCIAL STRENGTH

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

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

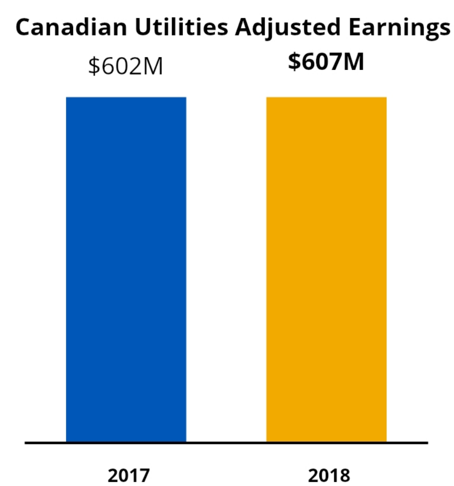
COMPANY OVERVIEW AND OPERATING ENVIRONMENT

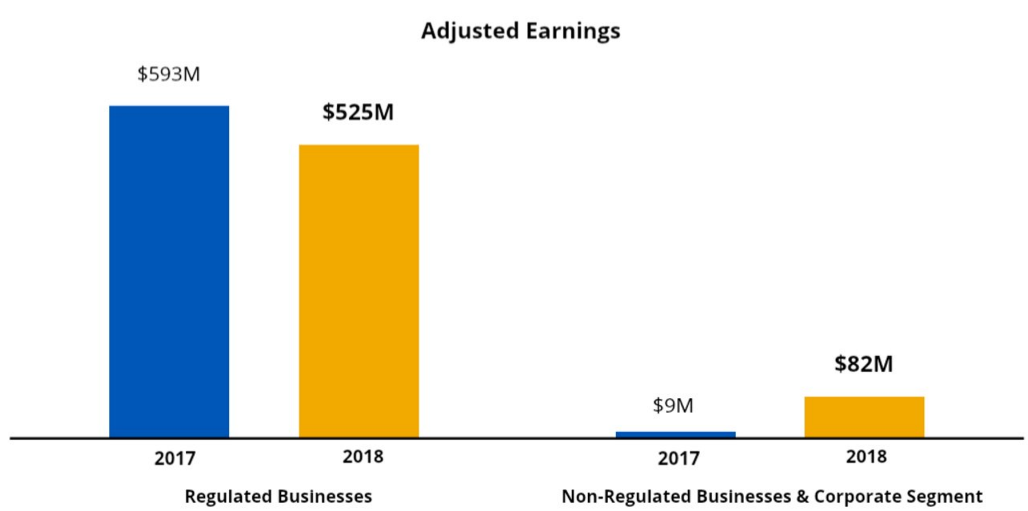
Canadian Utilities is a diversified global enterprise with assets of $22 billion and approximately 5,000 employees engaged in Electricity, Pipelines & Liquids, and Retail Energy. We carefully monitor market opportunities and challenges in each of our Global Business Units to best position the Company for long-term success, while continuing to deliver value to share owners.

The long-term success of Canadian Utilities is dependent upon our ability to grow the business by expanding into new markets and into new business lines. To achieve this, we expanded our sales and customer focus in all of our businesses in 2018. At the same time, we continued to pursue cost-savings and efficiencies in every part of our organization to ensure we deliver the most competitive solutions to our customers.

Canadian Utilities achieved strong adjusted earnings of $607 million in 2018 driven by improved results in our non-regulated businesses mainly due to strong results in electricity generation and Alberta PowerLine.

Continued rate base growth and operational cost improvements in our regulated businesses partially offset the adverse earnings impact of rate re-basing in several of our Alberta Utilities.





ELECTRICITY

The Electricity Global Business Unit's activities are conducted through two regulated businesses: Electricity Distribution and Electricity Transmission, and four non-regulated businesses: Independent Power Plants, Thermal PPA Power Plants, International Electricity Generation and Alberta PowerLine (APL). Together these businesses provide electricity distribution, transmission, and generation, and related infrastructure services.

BUSINESS STRATEGY

Electricity's strategy is to grow its businesses through: investing in regulated electricity distribution and transmission, and capitalizing on opportunities to provide renewable and natural gas-fired electricity generation. Electricity will pursue cost reduction initiatives and efficiencies to transform into an even more customer centric business. Electricity will continue expanding its businesses geographically in select global markets to meet the evolving needs of a global customer base through the development of innovative infrastructure solutions underpinned by long-term contracts.

Oldman River Hydroelectric Plant

MARKET OPPORTUNITIES

The regulated businesses expect to see continued investment opportunities based on customer growth and system replacements. Further electricity distribution and transmission investment opportunities may result from the changing power market in Alberta. A global trend toward renewable electricity generation and energy storage and natural gas-fired electricity generation to backstop the renewable power supply presents opportunities for growth. Expansion will be focused in select global markets, including Canada, Australia, and Latin America. Electricity targets markets with stable regulatory environments and rule of law, excellent long-term growth potential and strategic fit with our existing asset base.

MARKET CHALLENGES

Potential changes in macroeconomic conditions could slow the growth trajectory of these businesses.

PIPELINES & LIQUIDS

The Pipelines & Liquids Global Business Unit activities are conducted through three regulated businesses: Natural Gas Distribution, Natural Gas Transmission, and International Natural Gas Distribution, and one non-regulated business: Storage & Industrial Water. These businesses offer complementary products and services that enable them to deliver comprehensive natural gas distribution and transmission services, energy storage, and industrial water solutions to existing and new customers.

BUSINESS STRATEGY

Pipelines & Liquids' strategy is to grow its businesses through: investing in regulated natural gas distribution and transmission, and becoming a premier hydrocarbon liquids storage and industrial water infrastructure provider. Pipelines & Liquids continues to pursue cost reduction initiatives and efficiencies to transform into an even more customer centric business. Pipelines & Liquids is focused on expanding geographically to meet the evolving needs of a global customer base through the development of innovative infrastructure solutions underpinned by long-term contracts.

Natural Gas Pipeline Valve Assembly

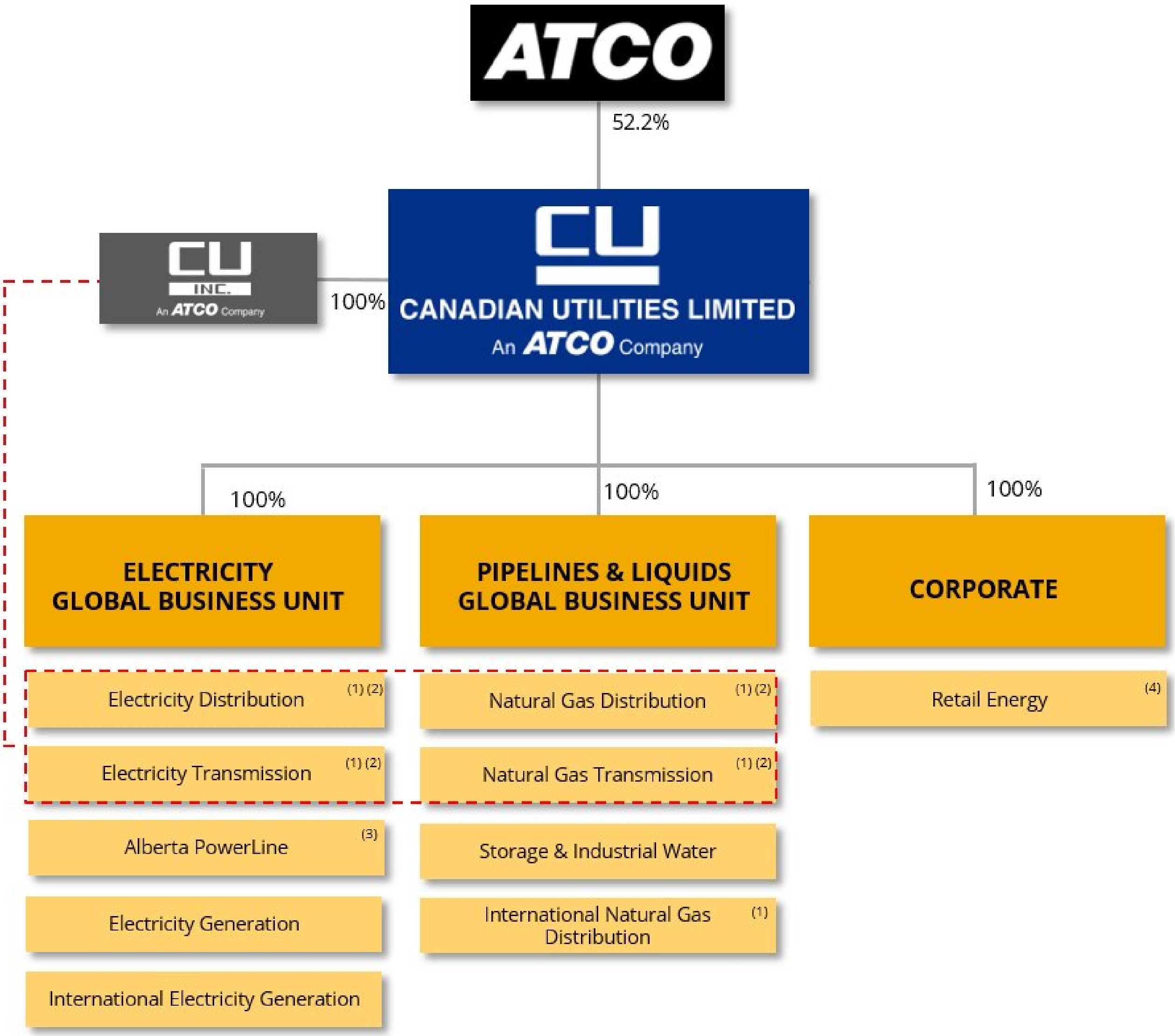
MARKET OPPORTUNITIES

The regulated businesses expect to see continued growth based on forecasted customer growth and system replacements. The continued expansion of pipelines in Alberta is expected to increase the need for energy storage to manage supply and demand, and the industry trend toward sustainability is expected to increase demand for industrial water solutions. Expansion will be focused in select global markets, including Canada, Australia, Latin America, and the U.S. Canadian Utilities targets markets with stable regulatory environments and rule of law, excellent long-term growth potential and strategic fit with our existing asset base.

MARKET CHALLENGES

Potential changes in macroeconomic conditions could slow the growth trajectory of these businesses.

ORGANIZATIONAL STRUCTURE



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

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

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

(4) Retail Energy, through ATCO Energy Ltd. (ATCOenergy) was launched in early 2016 to provide retail, commercial and industrial electricity and natural gas service in Alberta.

The 2018 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 2018 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.

CANADIAN UTILITIES CORE VALUES AND VISION

EXCELLENCE: THE HEART & MIND OF ATCO

"Going far beyond the call of duty. Doing more than others expect. This is what excellence is all about. It comes from striving, maintaining the highest standards, looking after the smallest detail and going the extra mile. Excellence means caring. It means making a special effort to do more."

R.D. Southern, Founder, ATCO

CORE VALUES

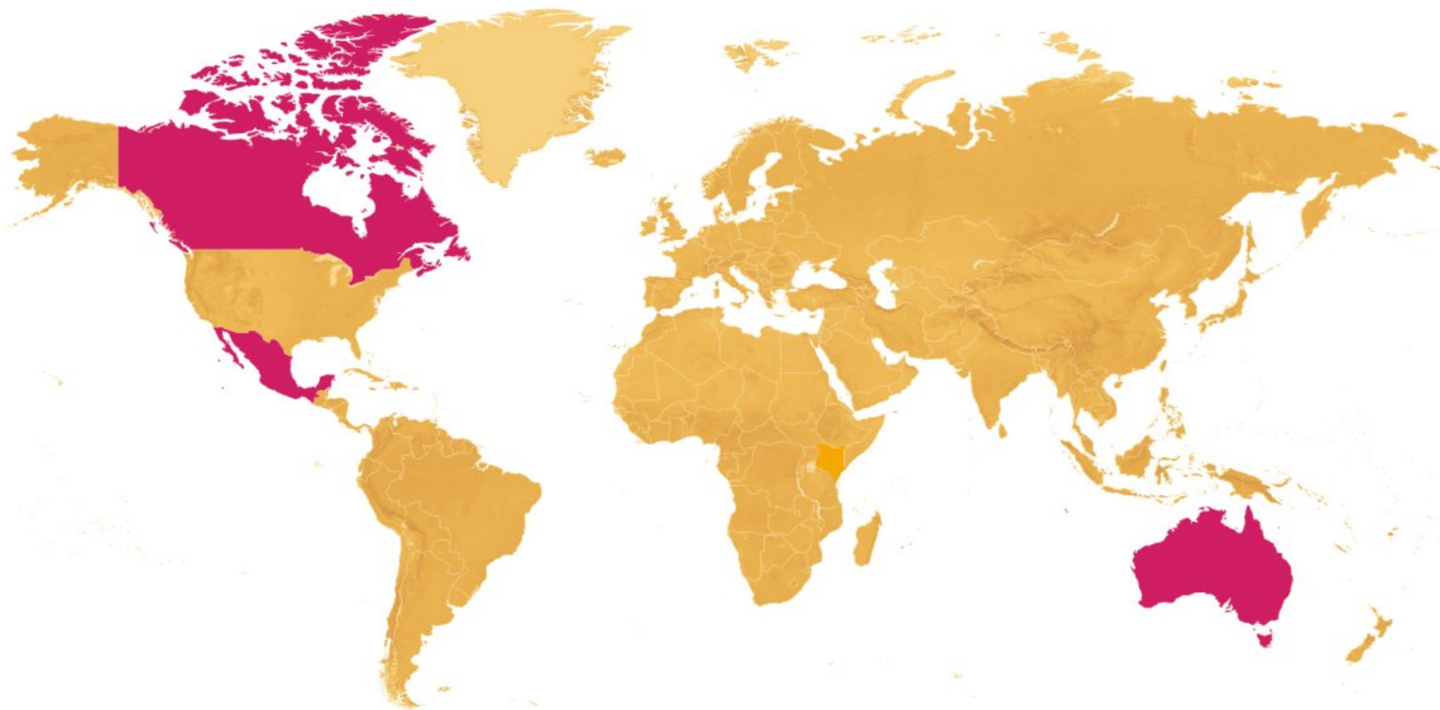
It is ATCO's Heart and Mind that drives the Company's approach to service reliability and product quality; employee, contractor and public safety; and environmental stewardship. Our pursuit of excellence governs the way we act and make decisions. At Canadian Utilities we strive to live by the following values:

CORE VISION

Our core vision is to improve the lives of our customers by providing sustainable, innovative and comprehensive solutions globally. We believe in well-managed risk and a disciplined approach to growth. We fuel the imagination of our people to drive growth over the long-term, ultimately delivering value to our customers and our share owners.

Our strong financial and operating performance reflects our approach to sales and our customers, the strength and determination of our people, a deeply embedded focus on operational excellence with its inherent cost controls, and careful consideration of the environmental and social impact of our actions - now and for the future.

GLOBAL OPERATIONS

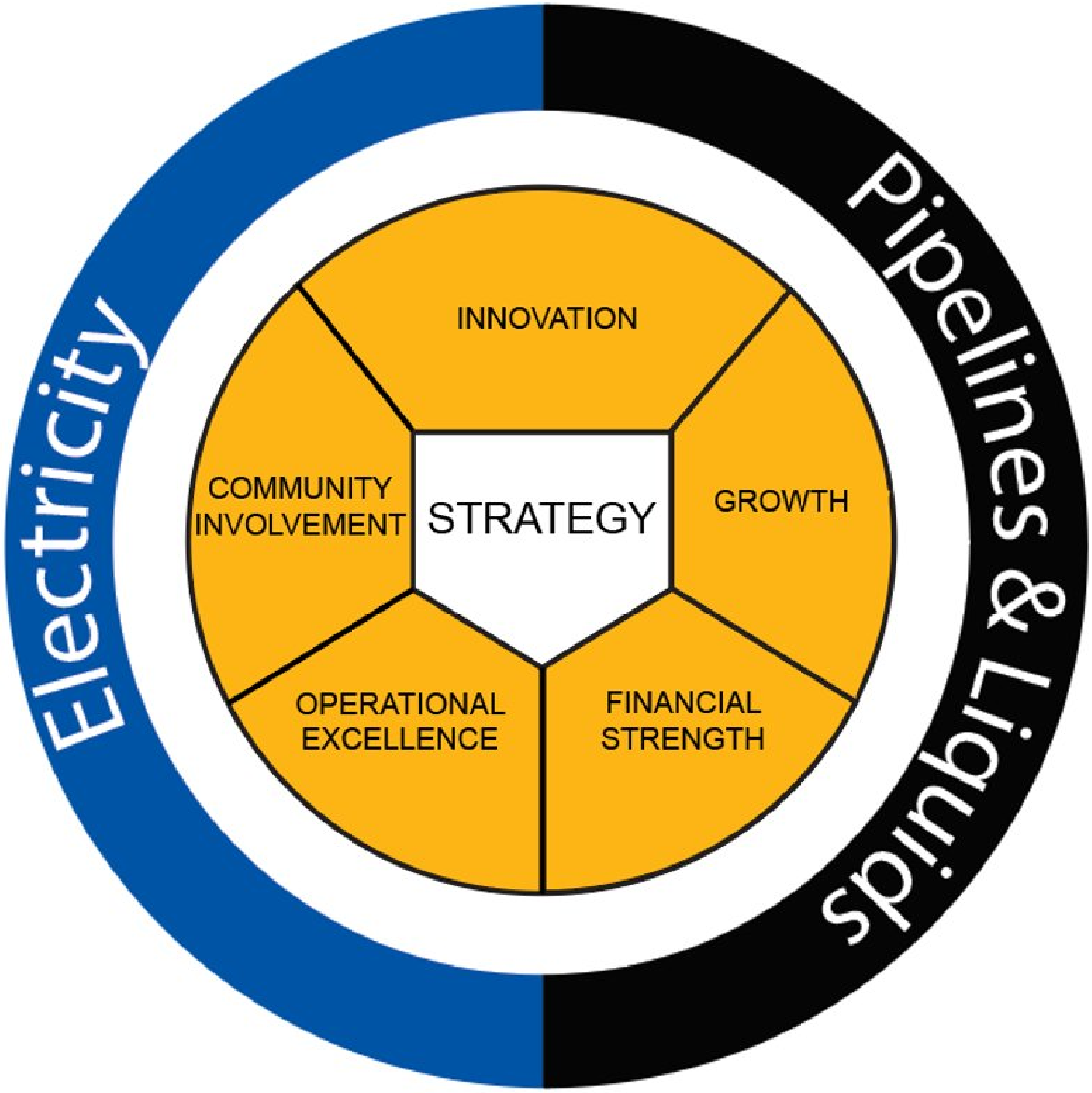


ELECTRICITY AND PIPELINES & LIQUIDS

CANADIAN UTILITIES STRATEGIES

Innovation, growth and financial strength provide the foundation from which we have built our company. Our long-term success depends on our ability to expand into new markets and lines of business, while offering our customers premier, comprehensive and integrated solutions to meet their needs.

These strategic imperatives are supported by our unwavering commitment to operational excellence, our people and the customers and communities we are privileged to serve around the world.



"Making life easier for our customers by offering vertically integrated energy infrastructure solutions around the world."

INNOVATION

We seek to create a work environment where employees are encouraged to take a creative and innovative approach to meeting our customers' needs. By committing to applied research and development, we are able to offer our customers unique and imaginative solutions that differentiate us from our competitors.

GROWTH

Long-term sustainable growth is paramount. We approach this strategy by: expanding geographically to meet the global needs of customers; developing significant, value-creating greenfield projects; and fostering continuous improvement.

Acquisition opportunities provide Canadian Utilities with additional growth potential. We will pursue the acquisition and development of complementary assets that have future growth potential and provide long-term value for share owners.

FINANCIAL STRENGTH

Financial strength is fundamental to our current and future success. It ensures Canadian Utilities has the financial capacity to fund existing and future capital investments through a combination of predictable cash flow from operations, cash balances on hand, committed credit facilities and access to capital markets. It enables Canadian Utilities to sustain our operations and to grow through economic cycles, thereby providing long-term financial benefits.

We continuously review Canadian Utilities' holdings to evaluate opportunities to sell mature assets and recycle the proceeds into growing areas of the Company. The viability of such opportunities depends on the outlook of each business as well as general market conditions. This ongoing focus supports the optimal allocation of capital across Canadian Utilities.

OPERATIONAL EXCELLENCE

We achieve operational excellence through high service, reliability, and product quality for our customers and the communities we serve. We are uncompromising about maintaining a safe work environment for employees and contractors, promoting public safety and striving to minimize environmental impact. We ensure the timely supply of goods and services that are critical to a company's ability to meet its core business objectives.

COMMUNITY INVOLVEMENT

Canadian Utilities maintains a respectful and collaborative community approach, where meaningful partnerships and positive relationships are built with community leaders and groups that will enhance economic and social development. Community involvement creates the opportunity to develop partnerships with Indigenous and community groups that may be affected by projects and operations worldwide, and build ongoing, positive Indigenous relationships that contribute to economic and social development in their communities. We also engage with governing authorities, regulatory bodies, and landowners. We encourage partnerships throughout the organization. We encourage our employees to participate in community initiatives that will serve to benefit non-profit organizations through volunteer efforts, and the provision of products and services in-kind.

FURTHER COMMENTARY REGARDING STRATEGIES AND COMMITMENTS

Canadian Utilities’ financial and operational achievements in 2018 relative to the strategies outlined above are included in this MD&A, the 2018 Consolidated Financial Statements and 2018 AIF. Further commentary regarding strategies and commitments to growth, financial strength, innovation, operational excellence, and community involvement will be provided in the forthcoming 2018 Management Proxy Circular and Sustainability Report. The 2018 Management Proxy Circular also contains discussion of the Company's corporate governance practices.

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.

CANADIAN UTILITIES SCORECARD

The following scorecard outlines our performance in 2018.

STRATEGIC PRIORITIES	2018 TARGET	2018 PERFORMANCE
INNOVATION		
New and existing products and services	Exploring and testing new products and methods of energy delivery to meet customers' future needs. Continuous improvement of existing products and services.	Achieved 10 per cent market share and became the 3rd largest energy retailer in Alberta. Converted Battle River unit 4 from coal-fired electricity generation to co-fire with natural gas, lowering overall emissions and improving efficiency. Installed three electric vehicle charging stations in Calgary, Red Deer and Edmonton, Alberta. Implemented aerial meter reading for the Alberta natural gas distribution system further creating operating and maintenance cost savings, and lowering driving time and emissions from vehicles. Installed a combined heat and power (CHP) system at Mount Royal University providing 26 per cent of the campus' electricity generation needs. This system is 30 per cent more efficient at generating electricity compared to traditional power generation, lowers total operating costs by $400,000 annually, and lowers GHG emissions by roughly 2,000 tonnes annually or about equal to removing 425 vehicles from the road. Advanced research at the Clean Energy Innovation Hub in Western Australia including using excess renewable energy to produce hydrogen. The data gathered through this project will provide technical insights into how hydrogen could act as a future balancing fuel supporting the electricity grid. Began installing shared energy infrastructure for apartment buildings in Australia through a mix of solar technology and energy from the grid, alleviating some of the high capital costs of investing in renewable energy.
GROWTH		
Regulated and long-term contracted capital investment	Invest $1.8 billion across our Regulated Utilities and in long-term contracted assets.	Invested $1.9 billion in regulated and long-term contracted assets.
Geographic expansion	Asset expansion into select global markets including Canada, Australia, South America, Mexico and the U.S.	Completed the $112 million acquisition of a long-term contracted 35 MW hydroelectric generation asset in Veracruz, Mexico.

STRATEGIC PRIORITIES	2018 TARGET	2018 PERFORMANCE
FINANCIAL STRENGTH		
Credit rating	Maintain investment grade credit rating.	Maintained 'A' credit rating with stable outlook with DBRS. Maintained 'A-' with a stable outlook with Standard & Poor's. Strengthened the balance sheet through the sale of the Barking Power assets in U.K. Sold assets for proceeds of $219 million.
Access to capital markets	Access to capital at attractive rates.	CU Inc. raised $385 million in 30 year debentures at 3.95 per cent, one of the lowest long-term coupons achieved in the Company's history.
OPERATIONAL EXCELLENCE		
Lost-time injury rate: employees	Reduce ATCO lost-time injury rate from 2017 amount of 0.25 cases/ 200,000 hours worked.	ATCO achieved a 36 per cent reduction in the lost time injury rate in 2018 to 0.16 cases/200,000 hours worked.
Total recordable injury frequency: employees	Continue improvement in our safety performance, in addition to comparing favourably to benchmark rates such as Alberta Occupational Health and Safety, US Private Industry, and industry best practice rates for each of our global operating units.	Achieved a 35 per cent reduction in total recordable injury frequency in 2018 to 1.59 cases/200,000 hours worked. This was achieved through awareness and incident prevention campaigns. These incident rate reductions were achieved across Canadian Utilities and we continue to compare favourably to industry benchmarks.
Customer satisfaction	Achieving high service for the customers and communities we serve. Establish company-wide customer satisfaction measurement.	Within our Alberta electricity and natural gas distribution businesses, more than 95 per cent of our customers agreed we provide good service. Within our energy retail operations, 76 per cent of customers who interact with our call centres are "very satisfied" compared with an industry average of 72 per cent. With the increasing breadth of our investments, we continue to define how we measure customer satisfaction.
Organizational transformation	Streamline and gain operational efficiencies.	Integrated natural gas distribution & transmission management teams. Implemented program for improved customer connections across the electricity distribution business to materially reduce the time and cost of projects. Implemented Enterprise Resource Planning (ERP) in the cloud systems thereby streamlining enterprise business processes to increase productivity, lower costs, and enhance financial controls.

STRATEGIC PRIORITIES	2018 TARGET	2018 PERFORMANCE
COMMUNITY INVOLVEMENT		
Indigenous relations	Continue to work together with Indigenous communities to contribute to economic and social development in their communities.	Continued with the Canada-wide expansion of the Indigenous Education Awards program, providing 50 awards totaling $65,500 in 2018. Hosted a Blue Flame Kitchen Skills program, visiting 7 communities and engaging with 539 students. 8 communities and 119 youth engaged in the inaugural Governor General Indigenous Youth Leadership Program (now called ATCO Explore for 2019). 34 communities visited with 4,570 students involved and 38 schools engaged in the Spirit North program. Expansion of the ATCO Indigenous Relations Committee to include representatives of ATCO Mexico & ATCO Australia.
ATCO EPIC (Employees Participating in Communities)	Continue to administer the employee-led campaign to give employees the opportunity to contribute to charitable organizations in the communities in which they work.	In 2018, ATCO and its employees donated $2.72 million and more than 7,700 hours to more than 800 charities to make our communities better places to live and work.

STRATEGIC PRIORITIES FOR 2019

The following table outlines our strategic priorities and targets for 2019.

STRATEGIC PRIORITIES	2019 TARGET
INNOVATION	
New and existing products and services	Explore and test new products and methods of energy delivery to meet customers' future needs. • Expand number of electric vehicle charging stations in Alberta. • Reduce or replace diesel consumption with more energy efficient solutions for customers in remote communities. Demonstrate continuous improvement of existing products and services. • Complete coal-to-natural gas conversion of Battle River unit 5. Launch eCommerce platform and digital strategy for ATCOenergy.
GROWTH	
Regulated and long-term contracted capital investment	Invest $1.2 billion across our Regulated Utilities and in long-term contracted assets. • Complete construction of Alberta PowerLine by March 2019. • Commence construction of natural gas cogeneration power plant in Mexico. Expand hydrocarbon storage services.
Global expansion	Continue asset expansion into select global markets including: Canada, Australia, Latin America, and the U.S.
FINANCIAL STRENGTH	
Credit rating	Maintain investment grade credit rating.
Access to capital markets	Access capital at attractive rates.
OPERATIONAL EXCELLENCE	
Lost-time incident frequency: employees **Total recordable incident frequency: employees**	Continue improvement in our safety performance, in addition to comparing favourably to benchmark rates such as Alberta Occupational Health and Safety, US Private Industry, and industry best practice rates for each of our global operating units.
Customer satisfaction	Achieve high service for the customers and communities we serve. Results from customer satisfaction surveys should be consistent or better than in prior years.
Organizational transformation	Streamline and gain operational efficiencies. • Continue to optimize ERP implementation. • Complete strategic review of Canadian electricity generation assets. • Complete strategic review of Alberta PowerLine ownership interest.
COMMUNITY INVOLVEMENT	
Indigenous relations	Continue to work together with Indigenous communities to contribute to economic and social development in their communities.
ATCO EPIC (Employees Participating in Communities)	Continue to administer the employee-led campaign to give employees the opportunity to contribute to charitable organizations in the communities in which they work.

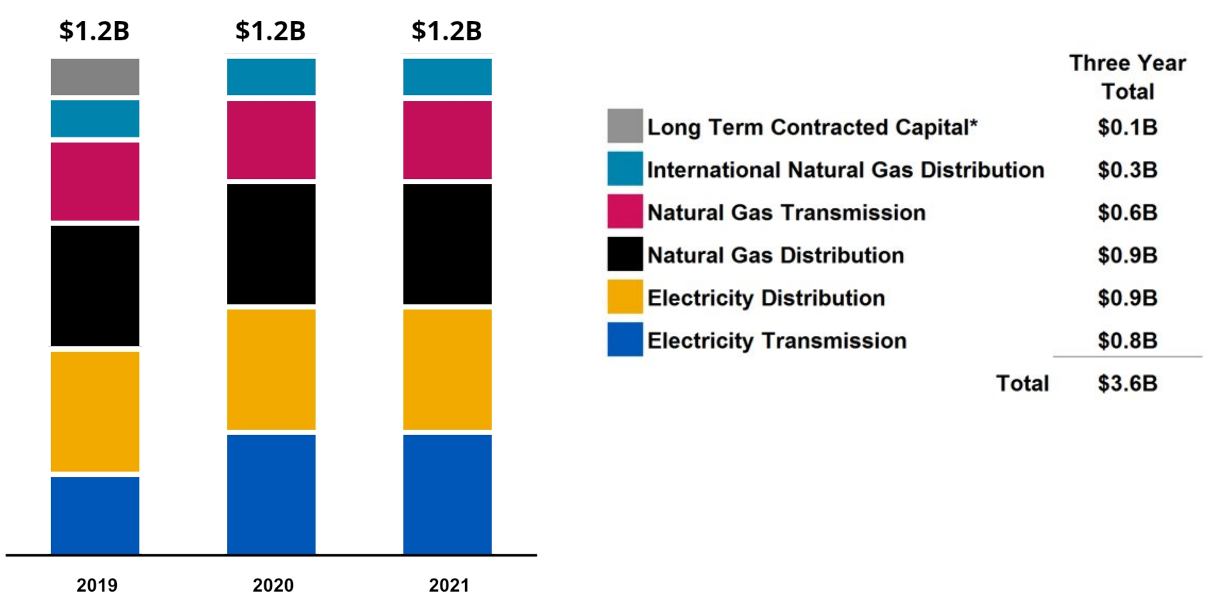
CAPITAL INVESTMENT PLANS

In the 2019 to 2021 period, Canadian Utilities expects to invest $3.6 billion in Regulated Utility and commercially secured energy infrastructure capital growth projects. This capital investment is expected to contribute significant earnings and cash flow and create long-term value for share owners.

This three year plan includes $3.5 billion of planned capital investment in the Regulated Utilities. Electricity Distribution and Electricity Transmission are planning to invest $1.7 billion, and Natural Gas Distribution, Natural Gas Transmission and International Natural Gas Distribution are planning to invest $1.8 billion from 2019 to 2021.

In addition to capital investments in the Regulated Utilities, Canadian Utilities intends to invest $0.1 billion in long-term contracted capital in the APL Fort McMurray West 500-kV Project, contracted industrial water storage in northern Alberta, and in a long-term contracted cogeneration facility in Mexico. Canadian Utilities also continues to pursue various business development opportunities with long-term potential which are not included in these capital growth investment estimates.

Future Regulated Utility and Contracted Capital Investment



** Includes the Company's proportionate share of investment in partnership interests and cash used for service concession arrangements.*

PERFORMANCE OVERVIEW

FINANCIAL METRICS

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

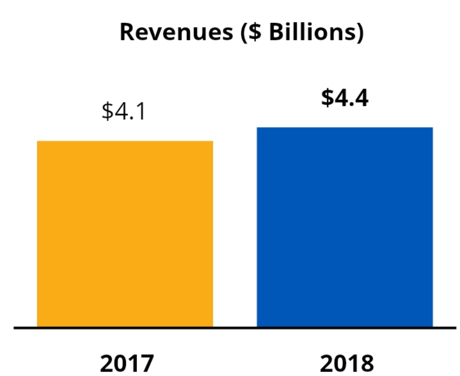
($ millions, except per share data and outstanding shares)	Year Ended December 31 2018	2017 [2]	2016
Key Financial Metrics			
Revenues	**4,377**	4,085	3,399
Adjusted earnings [1]	**607**	602	590
Electricity	**434**	397	402
Pipelines & Liquids	**247**	273	255
Corporate & Other	**(74)**	(69)	(69)
Intersegment Eliminations	**–**	1	2
Adjusted earnings ($ per share) [1]	**2.24**	2.23	2.21
Earnings attributable to equity owners of the Company	**634**	514	620
Earnings attributable to Class A and Class B shares	**567**	447	552
Earnings attributable to Class A and Class B shares ($ per share)	**2.08**	1.66	2.07
Total assets	**21,819**	20,839	18,781
Long-term debt and non-recourse long-term debt	**10,305**	9,915	8,318
Equity attributable to equity owners of the Company	**6,375**	6,153	6,218
Cash dividends declared per Class A and Class B share ($ per share)	**1.57**	1.43	1.30
Funds generated by operations [1]	**1,782**	1,761	1,803
Capital investment [1]	**1,951**	1,703	1,442
Other Financial Metrics			
Weighted average Class A and Class B shares outstanding *(thousands):*			
Basic	**271,464**	269,438	267,173
Diluted	**272,066**	270,055	267,777

(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 Note 3 of the 2018 Consolidated Financial Statements.

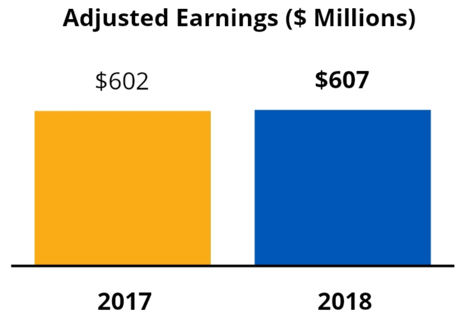
REVENUES

Revenues in 2018 were $4,377 million, $292 million higher than in 2017. Higher revenues in 2018 were mainly due to revenue relating to increased construction activities at Alberta PowerLine, improved power market conditions for the Independent Power Plants, and Thermal PPA revenue recorded for the termination of the Battle River unit 5 PPA.



ADJUSTED EARNINGS

Our adjusted earnings in 2018 were $607 million, or $2.24 per share, compared to $602 million or $2.23 per share in 2017. Higher earnings came from improved results in our non-regulated businesses mainly due to higher electricity prices and effective capital recycling activity in the Electricity business.



The primary drivers of adjusted earnings results were as follows:

- Electricity adjusted earnings in 2018 were $37 million higher than in 2017. Higher 2018 earnings were driven by improved results in our non-regulated businesses in electricity generation and Alberta PowerLine. These higher earnings were partially offset by the impact of rate rebasing under Alberta's regulated model in electricity distribution and transmission and lower interim rates approved by the Alberta Utilities Commission (AUC) for electricity transmission.
- Pipelines & Liquids adjusted earnings in 2018 were $26 million lower than 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 the Regulated Pipelines & Liquids businesses.
- Corporate & Other adjusted earnings in 2018 were $5 million lower than in 2017 mainly due to the timing of certain expenses, as well as forgone earnings from the sale of the 24.5 per cent ownership interest in Structures & Logistics to ATCO which was completed on December 31, 2017.

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 $634 million in 2018, or a $120 million increase compared to $514 million 2017. Earnings attributable to equity owners of the Company include significant impairments, dividends on equity preferred shares of the Company, timing adjustments related to rate-regulated activities, unrealized losses on mark-to-market forward commodity contracts, one-time gains and losses, and items that are not in the normal course of business or a result of day-to-day operations. These items are not included in adjusted earnings. The main drivers of this increase were a 2018 gain on sale of ATCO subsidiary Canadian Utilities' 100 per cent ownership interest in the Barking Power assets, and unrealized gains on mark-to-market forward commodity contracts, partially offset by 2018 restructuring and other costs.

Earnings attributable to equity owners of the Company are earnings attributable to Class A and B shares plus dividends on equity preferred shares of the Company. Additional information regarding earnings attributable to Class A and B shares is presented in Note 9 of the 2018 Consolidated Financial Statements.

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

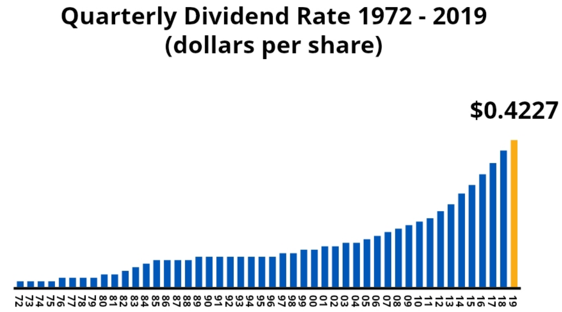
ASSETS, DEBT & EQUITY

Our total assets, long-term debt and Class A and Class B share owners' equity reflect the significant growth achieved during 2018 and how that growth was financed. Total assets grew from $20.8 billion at the beginning of 2018 to $21.8 billion at year end. That growth occurred mainly as a result of continued capital investment in APL and the Regulated Utilities. Class A and Class B share owners' equity increased over the prior year mainly as a result of 2018 earnings, partially offset by higher dividends paid to share owners.

COMMON SHARE DIVIDENDS

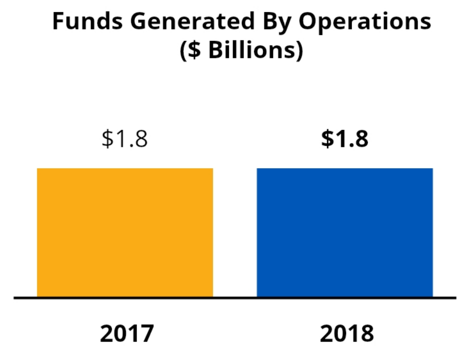
On January 10, 2019, the Board of Directors declared a first quarter dividend of 42.27 cents per share. Dividends paid to Class A and Class B share owners totaled $365 million in 2018.

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



FUNDS GENERATED BY OPERATIONS

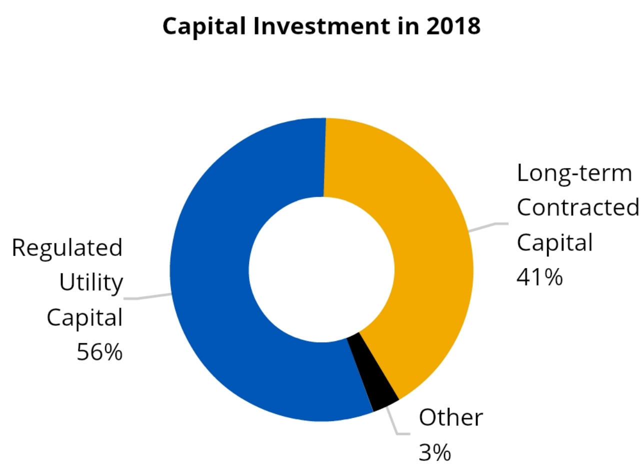
Funds generated by operations were $1,782 million in 2018, $21 million higher than in 2017. The increase was mainly due to higher customer contributions for utility capital expenditures and lower cash income taxes paid.



CAPITAL INVESTMENT

Total capital investment in 2018 was $1,951 million.

Capital spending in the Regulated Utilities and on long-term contracted capital assets accounted for $1,894 million in 2018. Of this capital invested, $1,089 million was invested in Regulated Utilities, and $805 million was invested in long-term contracted assets including Alberta PowerLine and the Mexico hydroelectric power station acquisition. These investments either earn a return under a regulated business model or are under commercially secured long-term contracts.



GLOBAL BUSINESS UNIT PERFORMANCE

REVENUES

Electricity revenues of $637 million in the fourth quarter of 2018 were $130 million lower than the same period in 2017, mainly due to the prior year revenue recognition associated with the Muskeg lease conversion in fourth quarter 2017 and lower revenues recorded due to reduced construction activity for Alberta PowerLine (APL). These lower revenues were partially offset by revenues from improved market conditions for Independent Power Plants and recognition of early energization incentives for APL recognized in the fourth quarter of 2018.

Electricity revenues of $2,858 million in 2018 were $398 million higher than in 2017, mainly due to revenue recorded for construction activities at APL, improved market conditions for the Independent Power Plants, and Thermal PPA revenue recorded for the termination of the Battle River unit 5 PPA, partially offset by the prior year revenue recognition associated with the Muskeg lease conversion.

ADJUSTED EARNINGS

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2018**	**2017 (1)**	**Change**	**2018**	**2017 (1)**	**Change**
Regulated Electricity						
Electricity Distribution	**26**	30	(4)	**112**	134	(22)
Electricity Transmission	**42**	50	(8)	**176**	196	(20)
Total Regulated Electricity Adjusted Earnings	**68**	80	(12)	**288**	330	(42)
Non-regulated Electricity						
Independent Power Plants	**11**	2	9	**17**	4	13
Thermal PPA Plants	**5**	7	(2)	**82**	34	48
International Electricity Generation	**3**	5	(2)	**12**	14	(2)
Alberta PowerLine	**16**	1	15	**35**	15	20
Total Non-regulated Electricity Adjusted Earnings	**35**	15	20	**146**	67	79
Total Electricity Adjusted Earnings	**103**	95	8	**434**	397	37

(1) These numbers have been restated to account for the impact of IFRS 15. Additional detail on IFRS 15 is discussed in Note 3 of the 2018 Consolidated Financial Statements.

Electricity earnings were $103 million and $434 million in the fourth quarter and full year of 2018, $8 million and $37 million higher than the same periods in 2017. Higher fourth quarter earnings were mainly due to higher earnings from APL and improved conditions in the Alberta power market. Higher earnings in 2018 were mainly due to earnings associated with the Balancing Pool's termination of the Battle River unit 5 PPA, earnings associated with the sale of the Barking Power assets, higher earnings from APL, and improved conditions in the Alberta power market. These improved earnings contributions were partially offset by rate rebasing under Alberta's regulated model in electricity distribution and transmission and lower interim rates approved by the Alberta Utilities Commission (AUC) for electricity transmission.

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

REGULATED ELECTRICITY

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

Electricity Distribution

Electricity distribution earned $26 million and $112 million in the fourth quarter and full year of 2018, $4 million and $22 million lower than the same periods in 2017. Lower earnings were mainly due to the earnings 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 impact of the PBR efficiency carry-over mechanism (ECM), higher industrial demand, and new operational efficiencies realized in 2018. The ECM is 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

Electricity transmission earned $42 million and $176 million in the fourth quarter and full year of 2018, $8 million and $20 million lower than the same periods in 2017. Lower earnings were mainly due operating cost reduction initiatives flowing into customer rates in the 2018 to 2019 General Tariff Application (GTA) and due to the earnings impact of lower interim rates approved by the AUC. Upon receipt of the AUC's decision on the GTA, which is expected in mid-2019, existing interim rates will be updated to include the impact of the decision. If the AUC decision approves all of the aspects of the GTA, the total potential increase to 2018 earnings would be an additional $13 million and would be recognized in 2019 adjusted earnings upon receipt of the decision in 2019.

NON-REGULATED ELECTRICITY

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

Generating Plant Availability

Electricity generating availability for the fourth quarter and full year of 2018 and 2017 is shown in the table below. Generating plant capacity fluctuates with the timing and duration of outages.

	Three Months Ended December 31			Year Ended December 31		
	2018	**2017**	**Change**	**2018**	**2017**	**Change**
Independent Power Plants	**96%**	95%	1%	**94%**	94%	–
Thermal PPA Plants	**94%**	88%	6%	**95%**	93%	2%
International Power Generation	**79%**	96%	(17%)	**94%**	98%	(4%)

Availability in Independent Power Plants in the fourth quarter of 2018 and for the full year of 2018 was comparable to the same periods in 2017.

Higher availability in Thermal PPA Plants in the fourth quarter and full year of 2018 is primarily due to a planned major outage at the Sheerness plant in 2017.

Lower availability in International Electricity Generation Plants in the fourth quarter and full year of 2018 was due to an unplanned outage at the Osborne plant in Adelaide, Australia. This was the first significant unplanned outage in its 20-year history. The Osborne plant returned to service in November 2018.

Alberta Power Market Summary

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

	Three Months Ended December 31			Year Ended December 31		
	2018	**2017**	**Change**	**2018**	**2017**	**Change**
Average Alberta Power Pool electricity price *($/MWh)*	**55.52**	22.46	33.06	**50.35**	22.19	28.16
Average natural gas price *($/GJ)*	**1.48**	1.64	(0.16)	**1.42**	2.05	(0.63)
Average market spark spread ($/*MWh*)	**44.45**	10.16	34.29	**39.69**	6.84	32.85

The average Alberta Power Pool electricity price for the fourth quarter and full year of 2018 was higher compared to the same periods in 2017. The quarter and full year increases were 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 560 MW and mothballing of 776 MW of coal-fired generation in Alberta, commercial offer behavior, and an increase in demand.

Realized Forwards Sales Program

	Three Months Ended December 31			Year Ended December 31		
	2018	**2017**	**Change**	**2018**	**2017**	**Change**
Average volumes settled *(MW)*	**430**	305	125	**325**	216	109
Average realized spark spread *($/MWh)*	**22.88**	12.56	10.32	**19.47**	11.67	7.80

In the fourth quarter of 2018, 430 MW of power that was sold forward settled at an average realized spark spread of $22.88 per MWh compared to 305 MW settled at an average of $12.56 per MWh in the same period of 2017. Forward sales in 2018 resulted in a loss position compared to earnings in 2017 due to the realized spark spread being lower than the market spark spread of $44.45 per MWh shown above in the Alberta Power Market Summary.

In 2018, 325 MW of power that was sold forward settled at an average realized spark spread of $19.47 per MWh compared to 216 MW settled at an average of $11.67 per MWh in 2017. Forward sales in 2018 resulted in a loss position compared to earnings in 2017 due to the realized spark spread being lower than the market spark spread of $39.69 per MWh shown above in the Alberta Power Market Summary.

Independent Power Plants

In the fourth quarter and full year of 2018, earnings from Independent Power Plants were $9 million and $13 million higher compared to the same periods in 2017. Higher earnings generated by Independent Power Plants were mainly due to earnings associated with the sale of the Barking Power assets, and an increase in Alberta market prices, partially offset by lower earnings from realized forward sales.

Thermal PPA Plants

The electricity generated by the Sheerness plants, and by Battle River unit 5 until September 30, 2018, is sold through PPAs. Under the PPAs, generating capacity must be made for each generating unit available to the PPA purchaser of that unit. These arrangements entitle us to recover forecast fixed and variable costs from the PPA purchaser. Under the IFRS 15 accounting standard, an operations and maintenance margin is included on these fixed and variable costs and is recognized over the term of the PPAs. Under the terms of the PPAs, counterparties are also subject to an incentive related to the generating unit availability. Incentives are payable by the PPA counterparties for availability in excess of predetermined targets. These performance obligation amounts are recognized based on the estimates of planned outages that impact future generating unit availability and future electricity prices over the term of the PPAs. Merchant earnings from Battle River unit 5 are recorded in Thermal PPA Plants in the fourth quarter of 2018.

In the fourth quarter of 2018, earnings from Thermal Power Plants were $2 million lower than the same period in 2017. Earnings from increased Alberta market prices and lower operating costs were offset by earnings foregone due to the turn back of Battle River unit 5 PPA.

In 2018, earnings from Thermal Power Plants were $48 million higher than 2017 mainly due to higher earnings from the Balancing Pool's termination of the Battle River unit 5 PPA in the third quarter of 2018. With the termination of the Battle River unit 5 PPA, $25 million of operations and maintenance margin was recognized as earnings in the third quarter of 2018. The termination of the Battle River unit 5 PPA also triggered the recognition of $10 million of earnings from the availability incentive pool as part of the completion of performance obligations. Higher earnings in 2018 were also due to higher availability incentives under the Sheerness PPA.

International Electricity Generation

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

International electricity generation adjusted earnings were $2 million lower in the fourth quarter and full year of 2018 compared to the same periods in 2017. Higher earnings from the electricity generation in Mexico were offset due to an unplanned outage at the Osborne plant. The Osborne plant returned to service in November 2018.

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.

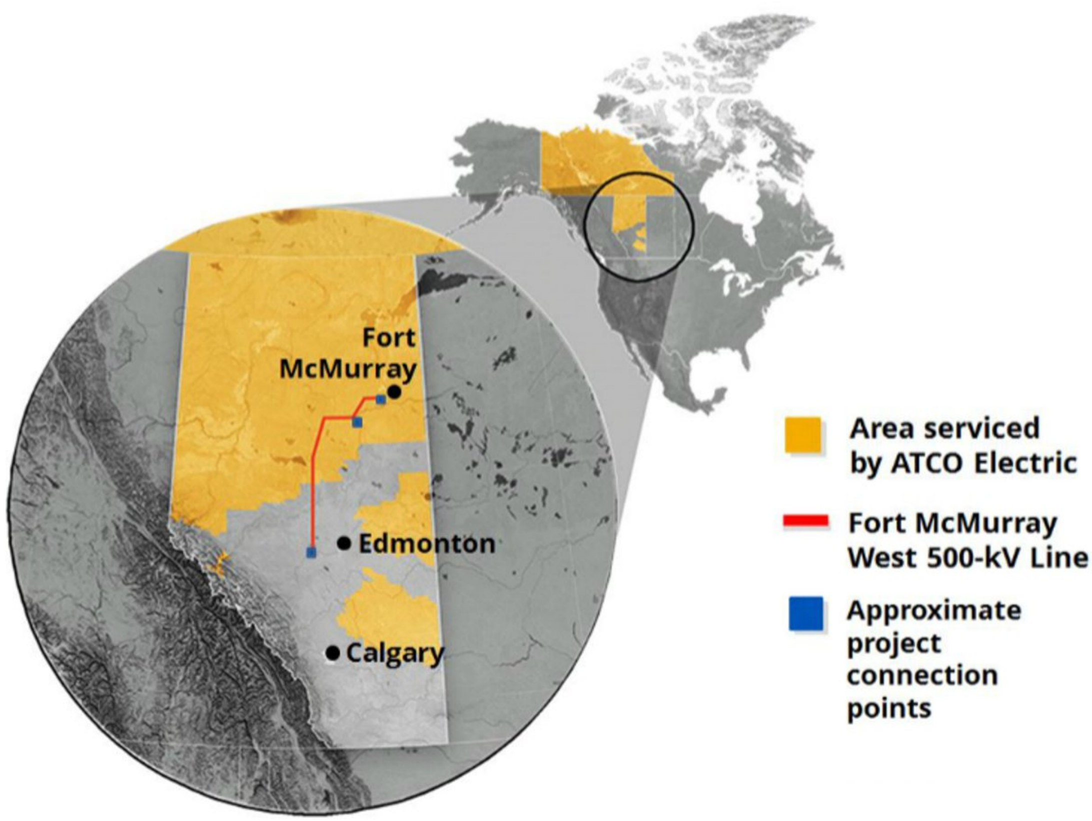
APL's adjusted earnings were $16 million and $35 million in the fourth quarter and full year of 2018, $15 million and $20 million higher when compared to the same periods in 2017. Higher earnings were mainly due to an early energization incentive recognized in the fourth quarter and increased construction activity in 2018.

ELECTRICITY RECENT DEVELOPMENTS

Alberta PowerLine

In August 2017, construction commenced on the approximately 500 km Fort McMurray West 500-kV Project. In 2018, construction continued on the project. Fourth quarter and full year 2018 capital investment of $44 million and $664 million was mainly due to tower assembly and line stringing. The target energization date was June 2019. Due to the project being ahead of schedule, the expected energization date has been advanced to March 2019 resulting in the recognition of an early energization incentive.

Construction of Alberta PowerLine



Sale of Barking Power Assets in the U.K.

In the fourth quarter of 2018, Canadian Utilities sold its 100 per cent ownership interest in the Barking Power assets. The total proceeds received on sale of the Barking Power assets were $219 million. The sale resulted in a net increase to adjusted earnings of $13 million related to the reversal of the reclamation costs. This transaction is consistent with Canadian Utilities' strategy of selling mature assets and recycling the proceeds into growing areas of the Company.

Thermal PPAs

The electricity generated by the Sheerness plants is sold through PPAs. Until September 30, 2018, the electricity generated by the Battle River unit 5 plant was sold through a PPA. Under the PPAs, Canadian Utilities must make the generating capacity for each generating unit available to the PPA purchaser of that unit. These arrangements entitle Canadian Utilities to recover its forecast fixed and variable costs from the PPA purchaser.

On March 21, 2018, the Alberta Balancing Pool provided notice of their intent to terminate the PPA for Battle River unit 5. Effective September 30, 2018, the Battle River unit 5 PPA was terminated by the Balancing Pool and dispatch control was returned to Canadian Utilities. Associated with this change, Canadian Utilities recorded $42 million in earnings for the completion of performance obligations and availability incentives were recognized in earnings in the third quarter of 2018. These earnings would have been recognized in the normal course of business over the life of the PPA and are included in adjusted earnings.

In line with coal to natural gas conversion plans for the Battle River generating facility, the non-coal related asset life was extended to 2037 effective October 1, 2018, which is consistent with the treatment for the Sheerness generating facility.

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

Coal to Natural Gas Conversion Strategy

Canadian Utilities is planning to be the first coal-fired generator in Alberta to end coal-fired power generation in its fleet. In the first quarter of 2018, Canadian Utilities successfully completed a project to co-fire natural gas at Battle River unit 4, enabling the use of natural gas for 50 per cent of the unit's 155 MW generating capacity. In the next phase of this initiative, a conversion project will allow co-firing of natural gas on Battle River unit 5 for 100 per cent of its 385 MW capacity, with an expected completion in late 2019. A full conversion of Battle River unit 4 and Battle River unit 3 is under analysis.

Canadian Utilities is committed to the conversion of Sheerness unit 1 and unit 2 to run on natural gas. Full conversion of Sheerness is planned to be completed in advance of firm natural gas supply, which has been secured for the second quarter of 2022.

Primrose and Rainbow Lake Contracts

During the fourth quarter of 2018, contract renegotiations for both Primrose and Rainbow Lake were completed. The Primrose contract, which will be a finance lease, will be in effect for a 10-year period commencing on January 1, 2019. The Rainbow Lake contract amendment takes effect in the second quarter of 2019 until 2030.

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 has developed rules for the implementation of the capacity market design and submitted them to the AUC in January 2019 with approval expected by July 2019. The Government of Alberta released the Capacity Market Regulation and amendments to the Fair, Efficient and Open Competition Regulation in December 2018 to facilitate the implementation of the capacity market.

Osborne PPA Extension

Canadian Utilities has negotiated a five year extension to the Power Purchase Agreement with Origin Energy Electricity Limited for the 180 MW Osborne Power facility, located near Adelaide, Australia. The original agreement, for 180 MW of contracted capacity, was scheduled to expire in 2018 and has now been extended to December 31, 2023. While the extension agreement includes lower pricing terms than the current agreement, the five year extension represents an outperformance of the project returns contemplated in the original investment decision.

Mexico Hydro Facility

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

Electricdad del Golfo Hydroelectric Power Station

Mexico Cogeneration Facility

In March 2018, we announced that we will build a 26 MW cogeneration project, known as the La Laguna Cogeneration facility, on the site of the Chemours Company Mexicana S. de R.L. de C.V.'s chemical facility near Gómez Palacio, in the state of Durango, Mexico. Developed in partnership with RANMAN Energy, the La Laguna Cogeneration facility will provide low-carbon and cost-effective electricity and heat under a long-term agreement. Engineering and procurement activities are underway. The total investment associated with the project is approximately $70 million, and the facility is expected to be operational in 2020.

Rendition of La Laguna Cogeneration

Strategic Review of Canadian Electricity Generation Assets

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

REVENUES

Pipelines & Liquids revenues of $383 million in the fourth quarter and $1,470 million in the full year of 2018 were $64 million and $160 million lower than the same periods in 2017. Lower revenues were mainly due to lower flow-through revenues primarily in natural gas distribution for third party transmission rate recovery from customers as well as the revenue impact of PBR rate rebasing in natural gas distribution.

ADJUSTED EARNINGS

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2018**	**2017**	**Change**	**2018**	**2017**	**Change**
Regulated Pipelines & Liquids						
Natural Gas Distribution	**64**	60	4	**110**	144	(34)
Natural Gas Transmission	**19**	17	2	**72**	66	6
International Natural Gas Distribution	**12**	11	1	**55**	53	2
Total Regulated Pipelines & Liquids Adjusted Earnings	**95**	88	7	**237**	263	(26)
Non-regulated Pipelines & Liquids						
Storage & Industrial Water	**7**	6	1	**10**	10	–
Total Pipelines & Liquids Adjusted Earnings	**102**	94	8	**247**	273	(26)

Pipelines & Liquids earnings of $102 million in the fourth quarter in 2018 were $8 million higher than the same period in 2017. Higher earnings were mainly due to growth in rate base.

In 2018, earnings were $247 million, $26 million lower than 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 the 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

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

Natural gas distribution earnings in the fourth quarter were $4 million higher than the same period in 2017 mainly due to the timing of regulatory decisions recorded in 2017.

Earnings in 2018 were $34 million lower than in 2017. Lower earnings were mainly due to the earnings 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 rebasing were partially offset by earnings from continued growth in rate base and customers, additional return on equity (ROE) due to the PBR efficiency carry-over mechanism (ECM), and continued operational efficiencies realized in 2018. The ECM is 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

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

Natural gas transmission earned $19 million in the fourth quarter and $72 million in the full year of 2018, $2 million and $6 million higher than the same periods in 2017. Higher earnings were mainly due to continued growth in rate base.

International Natural Gas Distribution

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

International natural gas distribution business earned $12 million in the fourth quarter and $55 million in the full year of 2018, $1 million and $2 million higher than the same periods in 2017. Higher earnings, mainly due to continued rate base growth, were partially offset by the foreign exchange impact of a weaker Australian currency compared to the Canadian dollar.

NON-REGULATED PIPELINES & LIQUIDS

Storage & Industrial Water

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

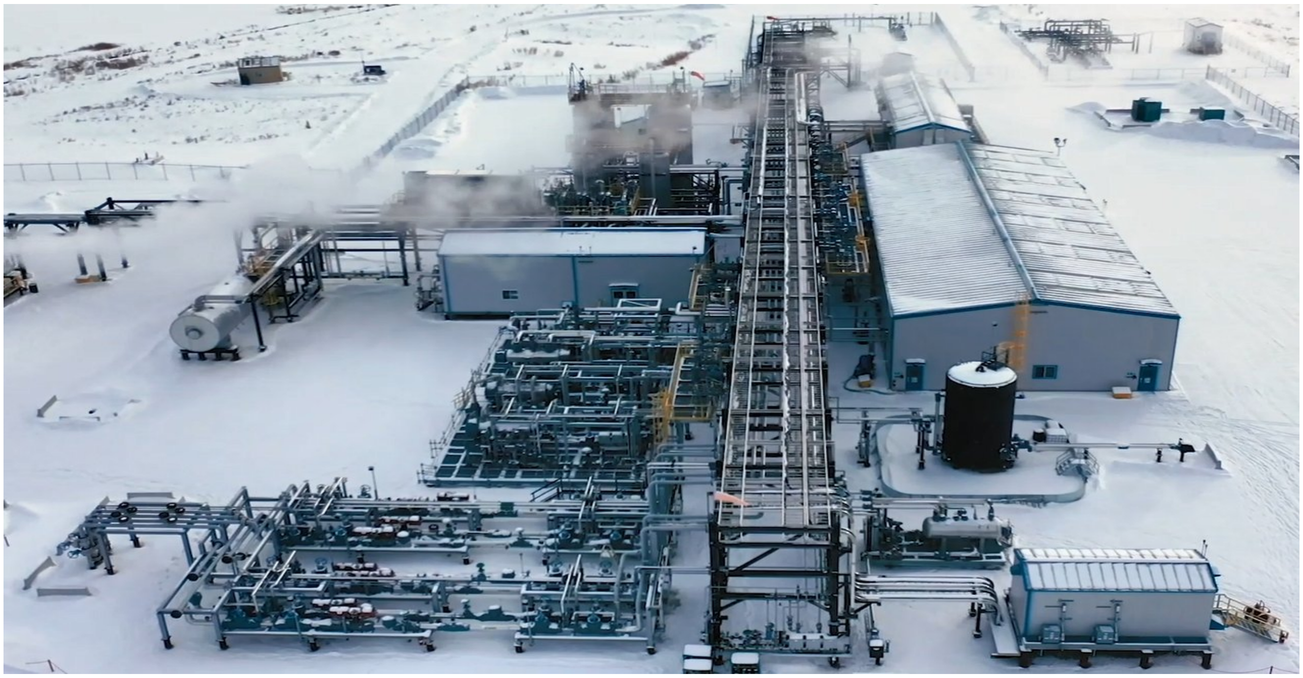
Storage & industrial water business earned $7 million in the fourth quarter of 2018, $1 million higher than the same period in 2017 mainly due to higher earnings from hydrocarbon storage services, partially offset by lower contributions from ancillary services.

Earnings in 2018 were $10 million, comparable to 2017.

PIPELINES & LIQUIDS RECENT DEVELOPMENTS

Hydrocarbon Storage

In 2018, construction was completed 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.



ATCO Heartland hydrocarbon storage facility

Industrial Water

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

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

Urban Pipelines Replacement Program

The Urban Pipelines Replacement (UPR) project is replacing and relocating aging, high-pressure natural gas pipelines in densely populated areas of Calgary and Edmonton to address safety, reliability and future growth. Construction is expected to be complete in 2020 and the total cost of the UPR project is estimated to be approximately $900 million. Natural gas distribution and natural gas transmission invested $750 million in the UPR program since the program's inception.

Mains Replacement Program

Natural gas distribution has 8,000 km of plastic pipe and 9,000 km of steel pipe that have been identified for potential replacement. The Plastic Mains Replacement program commenced in 2011 and is a 20-year program aimed at replacing polyvinyl chloride (PVC) and early generation polyethylene (PE) pipe. Natural gas distribution replaced 1,841 km of plastic pipe since the program's inception.

The Steel Mains Replacement program replaces steel pipe that is generally more than 60 years old. Natural gas distribution replaced 305 km of steel pipe since the program's inception.

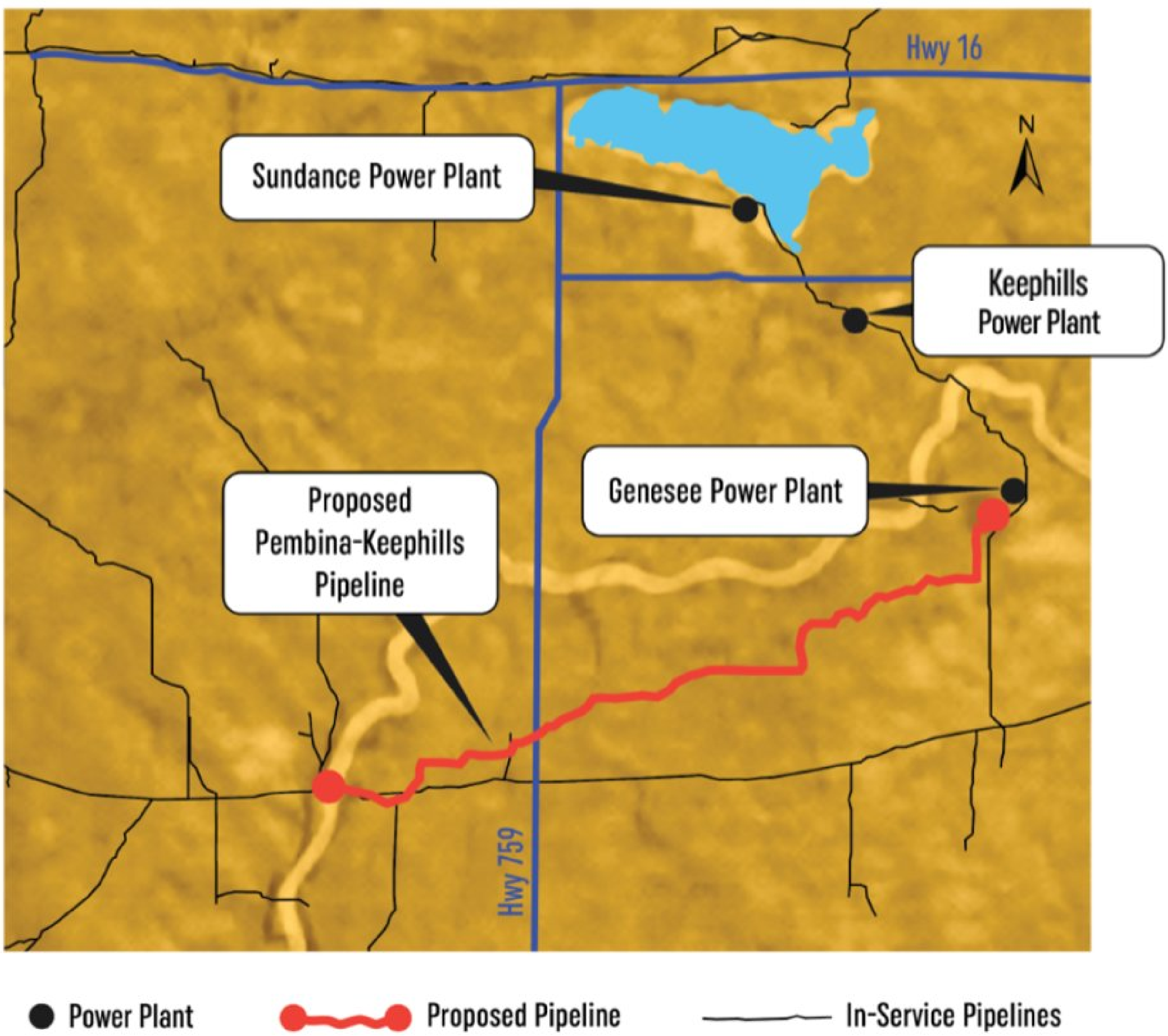
International Natural Gas Transmission - Mexico Tula Pipeline

In 2014, Canadian Utilities was awarded a 25-year Transportation Services Agreement with the Comisión Federal De Electricidad (CFE) to design, build, own and operate a 16 km natural gas pipeline near the town of Tula in the state of Hidalgo, Mexico. Canadian Utilities has completed applications for all required permits and continues to work with the Government of Mexico regarding land access and the completion of construction.

Pembina-Keephills Project

The Pembina-Keephills project is a 59 km high-pressure natural gas pipeline located approximately 80 km south-west of Edmonton, Alberta. The project directly supports coal-to-gas conversion of power producers in the Genesee and surrounding areas of Alberta with the capacity to deliver up to 550 TJ per day. The pipeline will supply natural gas to the Genesee generating station and has capacity to support the forecast demands of other power producers in the area. Construction is expected to start in mid-2019 and be completed by early-2020. The estimate to construct this project is approximately $200 million and is included in our three year capital investment plan.

Pembina-Keephills Natural Gas Pipeline Project



CORPORATE & OTHER

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

Including intersegment eliminations, Canadian Utilities Corporate & Other adjusted earnings in the fourth quarter of 2018 were $2 million higher compared to the same period in 2017, mainly due to the timing of certain expenses.

Canadian Utilities Corporate and Other adjusted earnings for 2018 were $6 million lower than in 2017 mainly due to the timing of certain expenses, as well as forgone earnings from the sale of Canadian Utilities' 24.5 per cent ownership interest in Structures & Logistics to ATCO which was completed on December 31, 2017.

In 2018, ATCOenergy achieved 10 per cent market share and became the third largest energy retailer in Alberta.

REGULATORY DEVELOPMENTS

REGULATED BUSINESS MODELS

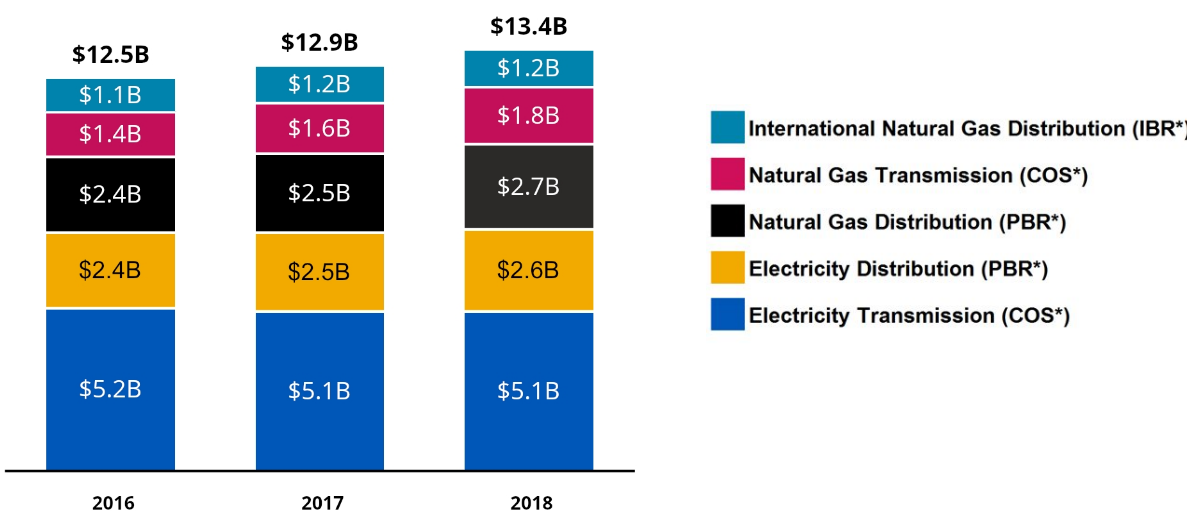
The business operations of electricity distribution, electricity transmission, natural gas distribution and natural gas transmission are regulated mainly by the Alberta Utilities Commission (AUC). The AUC administers acts and regulations covering such matters as rates, financing and service area.

Natural gas transmission and electricity transmission operate under a cost of service (COS) regulation. Under this model, the regulator establishes the revenues to provide for a fair return on utility investment using mid-year calculations of the total investment less depreciation, otherwise known as Mid-Year Rate Base. Growth in Mid-Year Rate Base is a leading indicator of the business' earnings trend, depending on the equity ratio of the Mid-Year Rate Base and the Rate of Return on Common Equity.

Natural gas distribution and electricity distribution operate under performance based regulation (PBR). Under PBR, revenue is determined by a formula that adjusts customer rates for inflation less an estimated amount for productivity improvements. The AUC reviews the utilities' results annually to ensure the rate of return on common equity is within certain upper and lower boundaries. To do these calculations, the AUC reviews Mid-Year Rate Base. For this reason, growth in Mid-Year Rate Base can be a leading indicator of the business' earnings trend, depending on the ability of the business to maintain costs based mainly on the formula that adjusts rates for inflation and productivity improvements.

International natural gas distribution is regulated mainly by the Economic Regulation Authority (ERA) of Western Australia. International natural gas distribution operates under incentive based regulation (IBR) under which the ERA establishes the prices for each five year period to recover a return on projected rate base, including income taxes, depreciation on the projected rate base, and forecasted operating costs based on projected throughput. For this reason, growth in rate base can be a leading indicator of the business' earnings trend, depending on the ability of the business to maintain costs within approved forecasts.

Regulated Utilities Mid-Year Rate Base



** IBR means Incentive Based Regulation; COS means Cost of Service Regulation; PBR means Performance Based Regulation*

GENERIC COST OF CAPITAL (GCOC)

In August 2018, the AUC issued a decision approving a Return on Equity (ROE) of 8.5 per cent and capital structure of 37 per cent equity for the 2018, 2019 and 2020 periods for all Alberta utilities. This decision presented no change to the 2018 interim approved ROE and capital structure. In December 2018, the AUC initiated the 2021 GCOC proceeding. The main focus of the proceeding will be to evaluate if a formula-based approach should be used for the ROE.

The following table contains the ROE and deemed common equity ratios resulting from the most recent GCOC decisions. The information reflects the most recent amending or varying orders issued after the original decision date. The table also contains the mid-year rate base for each Alberta Utility.

	Year	AUC Decision	Rate of Return on Common Equity (%) (1)	Common Equity Ratio (%) (2)	Mid-Year Rate Base ($ millions)
Electricity Distribution	**2018**	**2018 GCOC (4)**	**8.50**	**37.0**	**2,585 (5)**
	2017	2016 GCOC (3)	8.50	37.0	2,471 (6)
	2016	2016 GCOC (3)	8.30	37.0	2,361 (6)
Electricity Transmission	**2018**	**2018 GCOC (4)**	**8.50**	**37.0**	**5,095 (8)**
	2017	2016 GCOC (3)	8.50 (7)	37.0	5,097 (6)
	2016	2016 GCOC (3)	8.30 (7)	37.0	5,236 (6)
Natural Gas Distribution	**2018**	**2018 GCOC (4)**	**8.50**	**37.0**	**2,717 (5)**
	2017	2016 GCOC (3)	8.50	37.0	2,549 (6)
	2016	2016 GCOC (3)	8.30	37.0	2,369 (6)
Natural Gas Transmission	**2018**	**2018 GCOC (4)**	**8.50**	**37.0**	**1,802 (9)**
	2017	2016 GCOC (3)	8.50	37.0	1,614 (6)
	2016	2016 GCOC (3)	8.30	37.0	1,407 (6)

(1) Rate of return on common equity is the rate of return on the portion of rate base considered to be financed by common equity.

(2) The common equity ratio is the portion of rate base considered to be financed by common equity.

(3) The AUC released its GCOC decision for the periods 2016 to 2017 on October 7, 2016.

(4) The AUC released its GCOC decision for the periods 2018 to 2020 on August 2, 2018.

(5) The mid-year rate base for 2018 is based on the 2019 PBR application filed on September 10, 2018 and includes estimated mid-year work in progress for Electricity Distribution and Natural Gas Distribution.

(6) The mid-year rate base for 2016 and 2017 is based on the Rule 005 Actuals Package and includes mid-year work in progress.

(7) The ROE and common equity ratio for Electricity Transmission were approved on an interim basis on October 7, 2016, and were approved on a final basis on December 16, 2016.

(8) The mid-year rate base for 2018 is based on the 2018 to 2019 GTA application update filed on September 4, 2018 and includes mid-year work in progress.

(9) The mid-year rate base for 2018 is based on the 2019 to 2020 General Rate Application filed on July 30, 2018 and includes mid-year work in progress.

International Natural Gas Distribution Access Arrangement Decision

International natural gas distribution's current Access Arrangement period (AA4) is in place from July 2014 to December 2019. The following table contains the ROE and deemed common equity ratios from the current Access Arrangement. The table also contains the mid-year rate base.

	Year	ERA Decision	Rate of Return on Common Equity (%) (1)	Common Equity Ratio (%) (2)	Mid-Year Rate Base ($ millions)
International Natural Gas Distribution	**2018**	**2016 AA4 (3)**	**7.21**	**40.0**	**1,211 (4)**
	2017	2016 AA4 (3)	7.21	40.0	1,179
	2016	2016 AA4 (3)	7.21	40.0	1,111

(1) Rate of return on common equity is the rate of return on the portion of rate base considered to be financed by common equity.

(2) The common equity ratio is the portion of rate base considered to be financed by common equity.

(3) The ERA released its AA4 Amended Final Decision on September 10, 2015. This was superseded when the ERA released its AA4 Revised Final Decision on October 25, 2016.

(4) 2018 Mid-Year Rate Base was impacted by a strengthening Canadian dollar in 2018. The 2018 Mid-Year Rate Base was calculated using a foreign exchange rate of Australian $1 to Canadian $0.96 compared to Canadian $0.98 in 2017. The Mid-Year Rate Base in Australian dollars was $1,260 in 2018 and $1,205 in 2017, which is a $55 million increase from 2017 to 2018.

NEXT GENERATION OF PERFORMANCE BASED REGULATION

On December 16, 2016, the AUC released its decision on the second generation PBR plan framework for electricity and natural gas distribution utilities in Alberta. Under the 2018 to 2022 second generation PBR framework, utility rates continue to be adjusted by a formula that estimates inflation annually and assumes productivity improvements. The framework also contains modified provisions for supplemental funding of capital expenditures that are not recovered as part of the base inflation less productivity formula.

On February 5, 2018, the AUC released a regulatory decision that provided determinations for the going-in rates and incremental capital funding for the second generation of PBR. In November 2018, the AUC issued a Phase I Review and Variance decision to reassess anomaly adjustments for all Alberta distribution utilities for the purposes of establishing 2018 going-in rates. On February 14, 2019, the AUC commenced a proceeding to undertake that review. The following table compares the key aspects of the PBR First Generation with the PBR Second Generation based on the AUC's February 5, 2018 decision.

	PBR First Generation	**PBR Second Generation**
Timeframe	2013 to 2017	2018 to 2022
Inflation Adjuster (I Factor)	Inflation indices (AWE and CPI) adjusted annually	Inflation indices (AWE and CPI) adjusted annually
Productivity Adjuster (X Factor)	1.16%	0.30%
O&M	Based on approved 2012 forecast O&M levels; inflated by I-X thereafter over the PBR term	Based on the lowest annual actual O&M level during 2013-2016, adjusted for inflation, growth and productivity to 2017 dollars; inflated by I-X thereafter over the PBR term
Treatment of Capital Costs	• Recovered through going-in rates inflated by I-X • Significant capital costs not fully recovered by the I-X formula and meeting certain criteria recovered through a K Factor	• Recovered through going-in rates inflated by I-X and a K Bar that is based on inflation adjusted average historical capital costs for the period 2013-2016. The K Bar is calculated annually and adjusted for the actual WACC • Significant capital costs that are extraordinary, not previously incurred and required by a third party recovered through a “Type I” K Factor
ROE Used for Going-in Rates	• 8.75%	• 8.5% • + 0.5% ROE ECM achieved from PBR First Generation added to 2018 and 2019
Efficiency Carry-over Mechanism (ECM)	ECM up to 0.5% additional ROE for the years 2018 and 2019 based on certain criteria	ECM up to 0.5% additional ROE for the years 2023 and 2024 based on certain criteria
Reopener	+/- 300 bps of the approved ROE for two consecutive years or +/- 500 bps of the approved ROE for any single year	+/- 300 bps of the approved ROE for two consecutive years or +/- 500 bps of the approved ROE for any single year
ROE Used for Reopener Calculation	• 2013 to 2016: 8.3% • 2017: 8.5%	• 2018: 8.5% excluding impact of ECM • 2019: 8.5% excluding impact of ECM • 2020: 8.5% • 2021 and beyond: At approved ROE pending future GCOC proceeding decisions

ATCO GAS 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.

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 then outline the scope of the second phase.

Electricity distribution and natural gas distribution have filed a submission for the first phase stating that the higher earnings were a direct result of management’s response to the incentive to implement efficiency improvements and not due to a flaw in the PBR framework.

ATCO ELECTRIC 2018-2019 GENERAL TARIFF APPLICATION (GTA)

In June 2017, electricity transmission filed a GTA for its operations for 2018 and 2019. In September 2018, electricity transmission filed an update to its application as directed by the AUC. The September 2018 application update incorporated, among other things, achieved operating cost efficiencies and resulted in a reduction to the originally applied-for revenues. Due to additional process steps, as directed by the AUC, a decision is now expected in mid-2019. If the decision approves all the aspects of the GTA as filed, the favorable earnings impact for 2018 would be an additional $13 million and would be recognized in 2019 adjusted earnings upon receipt of the decision.

In January 2019, the AUC issued a decision on the interim rates for the 2019 portion of the GTA. The AUC approved a 2019 rate that represents a continuation of the approved 2018 interim rates. The approved amount represents just over 96 per cent of the applied-for revenue requirement.

ATCO PIPELINES 2019-2020 GENERAL RATE APPLICATION (GRA)

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

ATCO GAS AUSTRALIA ACCESS ARRANGEMENT

International natural gas distribution submitted Access Arrangement 5 (AA5) to the ERA on August 31, 2018. The ERA is expected to deliver a draft AA5 decision by the end of the first quarter of 2019 and ATCO Gas Australia will have an opportunity to respond to the draft decision. A final ERA decision on AA5 is expected in the third quarter of 2019. The tariffs included in the final decision will be applicable as of January 1, 2020 until December 31, 2024.

INFORMATION TECHNOLOGY COMMON MATTERS

In December 2018, the record for the Information Technology Common Matters proceeding, which was initiated in 2015, was closed. This proceeding impacts the recovery of information technology costs by the Alberta Utilities. A decision is expected in the first quarter of 2019.

SUSTAINABILITY, CLIMATE CHANGE AND ENERGY TRANSITION

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

SUSTAINABILITY REPORTING

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

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

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

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

CLIMATE CHANGE AND ENERGY TRANSITION

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

Climate Change Policy

We actively and constructively work with federal and provincial governments with the goal of finding the best long-term solutions. We participate in a wide number of discussions, and the following are examples of where we are focusing our efforts.

Coal-to-Gas Conversion

Canadian Utilities is planning to be the first coal-fired generator in Alberta to convert the coal-fired power generation fleet to burn lower emitting natural gas.

In 2018, Canadian Utilities was the first coal-fired generator in Alberta to receive a permit to allow a full conversion for one of the coal units to run on natural gas. Canadian Utilities successfully completed a project to co-fire natural gas at the coal unit, Battle River unit 4, enabling the use of natural gas for up to 50 per cent of the unit's 150 MW generating capacity. The next phase of the initiative will allow the full conversion of a second 385 MW unit, Battle River unit 5, with an expected completion in late 2019. A full conversion of Battle River unit 4 and Battle River unit 3 is under analysis.

Converting coal-fired electricity generation to natural gas electricity generation allows significant and immediate reductions to greenhouse gases and air emissions and extends the life of existing assets. In addition, reliability and affordability are maintained by utilizing existing resources, such as a skilled labour force and existing electricity transmission infrastructure.

Carbon Pricing / Output-Based Pricing Systems

The Government of Alberta is phasing in a carbon tax across all sectors. The economy-wide carbon tax of $20 per tonne in 2017 was increased to $30 per tonne 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.

Sheerness units 1 and 2 PPAs allow for the recovery of the costs of compliance with Government of Alberta regulations through the term of the PPAs. If the costs are for operations after the PPA term, the plant owner, not the PPA counterparty, bears the burden of these costs. The coal-to-gas conversion plans for Battle River and Sheerness will not only lower emissions, but will also make the plants more cost effective.

We continue to explore fuel switching opportunities such as reducing or replacing diesel consumption with more energy efficient solutions for customers in remote communities.

The Alberta Utilities' financial exposure to carbon pricing is not considered significant for electricity transmission and distribution because of their limited direct carbon emissions. Carbon taxes and other costs or requirements to upgrade equipment for the Alberta Utilities are expected to be included in customer rates on a go-forward basis.

Clean Fuel Standards

We have been actively engaging with the Government of Canada on proposed Clean Fuel Standards which will be important to future fuel switching options and innovation. In December 2018, the Government of Canada released a Regulatory Design Paper for the Clean Fuel Standard. One of the key design elements covered in the paper is that credits can be generated when end-users displace liquid transportation fuel with natural gas, propane or a non-carbon energy carrier (such as electricity or hydrogen).

In 2018, we installed three electric vehicle charging stations between Calgary and Edmonton, Alberta providing end-users an opportunity to replace liquid fuel with a non-carbon emitting energy. In 2019, we plan to significantly expand our number of electric vehicle charging stations in Alberta.

Methane Reductions

The Government of Alberta's plan is to reduce methane emissions by 45 per cent from 2012 by 2025 by applying new emissions design standards to new Alberta facilities, and developing a five year voluntary Joint Initiative on Methane Reductions and Verification.

Future provincial regulations or reduction targets for methane emissions predominantly affect the Company's fugitive or venting emissions from natural gas pipeline-related operations. Fugitive and venting emissions typically account for less than four per cent of Canadian Utilities' greenhouse gas emissions. Canadian Utilities has already implemented a number of programs to improve efficiency and reduce fugitive and venting emissions in the natural gas distribution and transmission businesses.

We continue to monitor developments, such as provincial equivalency to the Government of Canada announcement to reduce methane emissions from the oil and gas sector by 40 to 45 percent from 2012 levels by 2025.

These methane regulations could affect a portion of the Company’s fugitive or venting emissions from Canadian natural gas pipeline-related operations. But the Company's exposure is limited for the Alberta Utilities because requirements to upgrade equipment in order to further reduce methane emissions are expected to be included in rate base on a go-forward basis.

Phasing-in of Renewable Electricity

The Government of Alberta has published a firm target that 30 per cent of electricity used in Alberta will come from renewable sources such as wind, hydro and solar by 2030. The Government of Alberta's Renewable Electricity Program (REP) is intended to encourage the development of this large-scale renewable electricity generation to support the target. The AESO is responsible for implementing and administering the program through a series of competitions that incent the development of renewable electricity generation through the purchase of renewable attributes.

On October 2, 2018, the Government of Alberta announced a Request for Proposal (RFP) for a new solar energy procurement process for 135,000 MWh per year for 20 years. Canadian Utilities submitted a proposal for 50 MW of solar generation to this procurement process. The successful proponents were announced on February 15, 2019. Canadian Utilities was not awarded a contract through this solar procurement process.

We have 75 MWs of potential solar projects located near Three Hills and Drumheller, Alberta, where Canadian Utilities and Samsung have obtained permits to build and operate solar power generation facilities. We will continue to look for opportunities to advance these solar projects either through future Government of Alberta REP competitions, solar RFP procurement processes or through other long-term contracts.

We actively look for renewable energy generation investment opportunities in other jurisdictions. In 2018, we acquired a 35 MW hydroelectric generation asset in Veracruz, Mexico.

Climate Change Resiliency

Climate-related risks are included within the Company's established risk management process. We continue to carefully manage physical risks, including preparing for, and responding to, extreme weather events through activities such as proactive route selection, asset hardening, regular maintenance, and insurance. The Company follows regulated engineering codes and continues to evaluate ways to create greater system reliability and resiliency. When planning for capital investment or acquiring assets we consider site specific climate and weather factors, such as flood plain mapping and extreme weather history.

In electricity transmission and distribution operations, grid resiliency initiatives focus on prevention, protection, and reaction. Prevention includes minimizing operational risks and ensuring system adequacy through system planning and coordination. Protection is focused on improving grid resiliency through activities such as retrofitting and vegetation management to reduce incidents that result in outages. For example, in addition to other regular maintenance activities, Wildfire Management Plans include requirements to conduct annual patrols of all power lines in forest protection areas. Finally, we look to restore services in the shortest possible timeframe through grid modernization, adequate contingency planning and dispatch.

In natural gas transmission and distribution activities, the majority of the Company's pipeline network is underground, making it less susceptible to extreme weather events. We work with regulators to increase resiliency where appropriate through asset improvement projects. For example, we are replacing shallow water crossings with deeper, directionally drilled lines and we are hardening water crossings to prevent further erosion and exposure of pipelines. We have also mapped and continue to regularly inspect pipeline water crossings.

We have streamlined our Crisis Response and Emergency Preparedness systems, and we continuously improve our ability to rapidly mobilize and effectively respond to crises globally. We incorporate learnings from responding to extreme weather events, such as the 2013 Calgary Flood and 2016 Fort McMurray wildfire in Alberta, which enables us to continue to strengthen our emergency response capabilities.

OTHER EXPENSES AND INCOME

A financial summary of other consolidated expenses and income items for the fourth quarter and full year of 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 December 31			Year Ended December 31		
($ millions)	**2018**	**2017 (1)**	**Change**	**2018**	**2017 (1)**	**Change**
Operating costs	**507**	661	(154)	**1,951**	1,963	(12)
Service concession arrangement costs	**44**	132	(88)	**664**	456	208
Gain on sale of operation	**–**	–	–	**–**	30	(30)
Gain on sale of Barking Power assets	**125**	–	125	**125**	–	125
Proceeds from termination of Power Purchase Arrangement	**–**	–	–	**62**	–	62
Loss from investment in ATCO Structures & Logistics	**–**	(5)	5	**–**	(4)	4
Earnings from investment in joint ventures	**5**	6	(1)	**24**	20	4
Depreciation and amortization	**147**	155	(8)	**638**	598	40
Net finance costs	**125**	117	8	**469**	420	49
Income taxes	**84**	40	44	**225**	173	52

(1) These numbers have been restated to account for the impact of IFRS 15. Additional detail on IFRS 15 is discussed in Note 3 of the 2018 Consolidated Financial Statements.

OPERATING COSTS

Operating costs, which are total costs and expenses less service concession arrangement costs and depreciation and amortization decreased by $154 million in the fourth quarter of 2018 when compared to the same period in 2017. Lower operating costs were mainly due to lower unrealized losses on mark-to-market forward commodity contracts for the Independent Power Plants and Thermal PPA Plants not governed by a PPA, and costs recognized in the fourth quarter of 2017 relating to the accounting reclassification of a finance lease.

In 2018, operating costs decreased by $12 million when compared to 2017. Decreased costs were mainly due to unrealized gains on mark-to-market forward commodity contracts for the Independent Power Plants and costs recognized on the accounting reclassification of a finance lease in the fourth quarter of 2017, partially offset by higher salaries and wages resulting from severance payments, planned maintenance expenses, higher purchased power costs in ATCOenergy due to a growing customer portfolio, and higher carbon taxes for electricity generation which are offset by higher electricity generation revenues.

SERVICE CONCESSION ARRANGEMENT COSTS

Service concession arrangement costs in the fourth quarter and full year 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 2018 when compared 2017. In 2017, Canadian Utilities sold its 100 per cent investment in ATCO Real Estate Holdings Ltd. to ATCO resulting in a gain of $30 million.

GAIN ON SALE OF BARKING POWER ASSETS

In the fourth quarter of 2018, Canadian Utilities sold its 100 per cent ownership interest in the Barking Power assets. In accordance with IFRS accounting standards, Canadian Utilities recorded a gain on sale of $125 million.

PROCEEDS FROM TERMINATION OF POWER PURCHASE ARRANGEMENT

Effective September 30, 2018, the Battle River unit 5 PPA was terminated by the Balancing Pool and dispatch control was returned to Canadian Utilities. Canadian Utilities received a $62 million payment from the Balancing Pool.

LOSS FROM INVESTMENT IN ATCO STRUCTURES & LOGISTICS

In the fourth quarter of 2017, Structures & Logistics recognized an impairment of $34 million relating to certain workforce housing assets in Canada and space rental assets in the U.S. Canadian Utilities' 24.5 per cent share of the impairment resulted in an equity loss of $5 million in the fourth quarter of 2017.

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 were comparable in the fourth quarter of 2018 and 2017. In the full year of 2018 earnings were $4 million higher when compared to 2017, mainly due to higher earnings contributions from the hydrocarbon storage facilities.

DEPRECIATION AND AMORTIZATION

In the fourth quarter of 2018, depreciation and amortization was $8 million lower compared to the same period in 2017 mainly due to an asset life extension for the non-coal related assets at the Battle River & Sheerness power plants as a result of coal to gas conversion and a conversion to finance lease accounting for the Muskeg River generating plant.

In 2018, depreciation and amortization was $40 million higher compared to 2017 mainly due to the ongoing capital investment program in the 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 $8 million and $49 million in the fourth quarter and full year 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 the Regulated Utilities, and Alberta PowerLine's project financing completed in October 2017.

INCOME TAXES

Income taxes increased by $44 million in the fourth quarter and $52 million in the full year of 2018 when compared to the same periods in 2017 mainly due to higher earnings before income taxes.

LIQUIDITY AND CAPITAL RESOURCES

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

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

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.

The following table shows the current credit ratings assigned to Canadian Utilities Limited, CU Inc., and ATCO Gas Australia Pty Ltd.

	DBRS	S&P
Canadian Utilities Limited		
Issuer	A	A-
Senior unsecured debt	A	BBB+
Commercial paper	R-1 (low)	A-1 (low)
Preferred shares	PFD-2 (high)	P-2
CU Inc.		
Issuer and senior unsecured debt	A (high)	A-
Commercial paper	R-1 (low)	A-1 (low)
Preferred shares	PFD-2 (high)	P-2
ATCO Gas Australia Pty Ltd. (1)		
Issuer and senior unsecured debt	N/A	BBB+

(1) ATCO Gas Australia Pty Ltd. is a regulated provider of natural gas distribution services in Western Australia, serving metropolitan Perth and surrounding regions.

On July 13, 2018, DBRS Limited (DBRS) affirmed its 'A (high)' long-term corporate credit rating and stable trend on Canadian Utilities' subsidiary CU Inc. On August 10, 2018, DBRS affirmed its 'A' long-term corporate credit rating and stable trend on Canadian Utilities Limited.

On September 21, 2018, S&P Global Ratings (S&P) affirmed its 'BBB+' long-term issuer credit rating and stable outlook on Canadian Utilities Limited subsidiary ATCO Gas Australia Pty Ltd.

On September 27, 2018, S&P affirmed its 'A-' long-term issuer credit rating and stable outlook on Canadian Utilities Limited and its subsidiary CU Inc.

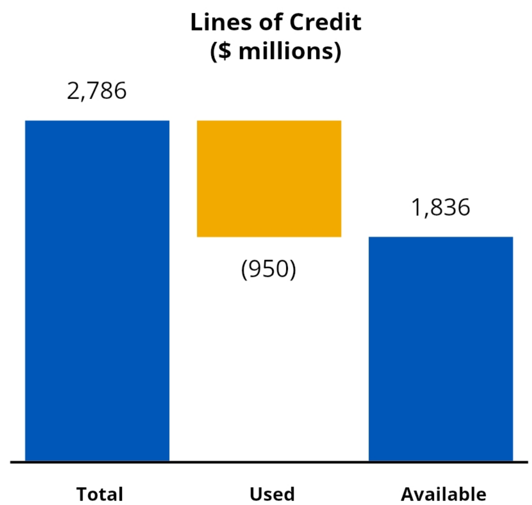
LINES OF CREDIT

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

($ millions)	**Total**	**Used**	**Available**
Long-term committed	**2,233**	610	1,623
Uncommitted	**553**	340	213
Total	**2,786**	950	1,836

Of the $2,786 million in total credit lines, $553 million was in the form of uncommitted credit facilities with no set maturity date. The other $2,233 million in credit lines were committed, with maturities between 2020 and 2023, and may be extended at the option of the lenders.

Of the $950 million credit line usage, $385 million was related to ATCO Gas Australia Pty Ltd., with the majority of the remaining usage pertaining to the issuance of letters of credit. Long-term committed credit lines are used to satisfy all of ATCO Gas Australia Pty Ltd.'s term debt financing needs.



CONSOLIDATED CASH FLOW

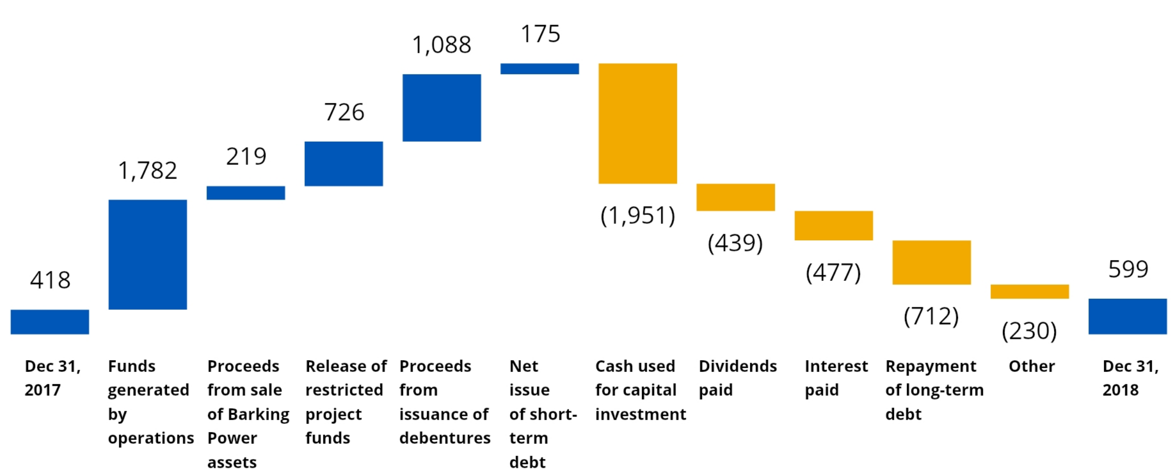
At December 31, 2018, the Company's cash position was $599 million, a increase of $181 million compared to December 31, 2017. Major movements are outlined in the following table.

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2018**	**2017**	**Change**	**2018**	**2017**	**Change**
Funds generated by operations[1]	**460**	450	10	**1,782**	1,761	21
Proceeds from sale of Barking Power assets	**219**	–	219	**219**	–	219
Release of restricted project funds [2]	**81**	374	(293)	**726**	374	352
Proceeds on sales of operation	**–**	–	–	**–**	47	(47)
Proceeds on sale of investment in ATCO Structures & Logistics	**–**	140	(140)	**–**	140	(140)
Issue of long-term debt	**386**	430	(44)	**1,088**	430	658
Net (repayment) issue of short-term debt	**(25)**	(525)	500	**175**	(55)	230
Cash used for capital investment	**(380)**	(546)	166	**(1,951)**	(1,703)	(248)
Dividends paid on equity preferred shares	**(17)**	(17)	–	**(67)**	(67)	–
Dividends paid to non-controlling interests	**(2)**	(2)	–	**(7)**	(7)	–
Dividends paid to Class A and Class B share owners	**(92)**	(83)	(9)	**(365)**	(296)	(69)
Interest paid	**(134)**	(115)	(19)	**(477)**	(413)	(64)
Repayment of long-term debt	**(3)**	(152)	149	**(712)**	(155)	(557)
Other	**(28)**	(89)	61	**(230)**	22	(252)
Increase (decrease) in cash position	**465**	(135)	600	**181**	78	103

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

(2) On October 2, 2017, Alberta PowerLine (APL), a partnership in which Canadian Utilities has an 80 per cent ownership interest, issued non-recourse long-term debt consisting of $1.385 billion Senior Secured Nominal Amortizing Bonds. At December 31, 2018, Alberta PowerLine (APL) had $339 million of funds restricted under the terms of APL's non-recourse long-term debt financing agreement. The restricted project funds are considered not available for general use by the Company. Refer to Note 10 of the 2018 Consolidated Financial Statements for additional information regarding Restricted Project Funds.

Changes in Consolidated Cash Balances in 2018
($ Millions)



Funds Generated by Operations

Funds generated by operations were $460 million and $1,782 million in the fourth quarter and full year of 2018, $10 million and $21 million higher than the same periods in 2017. The increase was mainly due to higher customer contributions for utility capital expenditures and lower cash income taxes paid, partially offset by forgone dividends from the sale of Canadian Utilities' 24.5 per cent interest in Structures & Logistics.

Cash Used for Capital Investment

Cash used for capital investment was $380 million in the fourth quarter of 2018, $166 million lower than the same period in 2017. Lower capital spending was mainly due to decreased spending in Alberta PowerLine, and in natural gas distribution and transmission.

Cash used for capital investment was $1,951 million in 2018, $248 million higher than in 2017. Higher capital investment was mainly due to increased spending in Alberta PowerLine, and the acquisition of the Mexico hydroelectric facility completed in the first quarter of 2018, partially offset by lower capital investment in natural gas distribution and transmission.

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

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2018**	**2017**	**Change**	**2018**	**2017**	**Change**
Electricity						
Electricity Distribution	**63**	66	(3)	**227**	227	–
Electricity Transmission	**81**	83	(2)	**240**	211	29
Electricity Generation	**15**	10	5	**156**	24	132
Alberta PowerLine	**44**	132	(88)	**664**	456	208
Total Electricity	**203**	291	(88)	**1,287**	918	369
Pipelines & Liquids						
Natural Gas Distribution	**80**	113	(33)	**290**	372	(82)
Natural Gas Transmission	**65**	109	(44)	**239**	297	(58)
International Natural Gas Distribution	**24**	27	(3)	**93**	92	1
International Natural Gas Transmission and Storage & Industrial Water	**5**	5	–	**26**	21	5
Total Pipelines & Liquids	**174**	254	(80)	**648**	782	(134)
Corporate & Other	**3**	1	2	**16**	3	13
Canadian Utilities Total (1) (2)	**380**	546	(166)	**1,951**	1,703	248

(1) Includes capital expenditures in joint ventures of $4 million and $19 million (2017 - $5 million and $13 million) for the fourth quarter and full year of 2018.

(2) Includes additions to property, plant and equipment, intangibles and $4 million and $20 million (2017 - $4 million and $17 million) of interest capitalized during construction for the fourth quarter and full year of 2018.

Debt Issuances and Repayments

On November 21, 2018, CU Inc. issued $385 million of 3.95 per cent 30-year debentures. Proceeds from this issuance were used to fund capital investments, to repay existing indebtedness, and for other general corporate purposes of the Alberta Utilities.

Base Shelf Prospectuses

CU Inc. Debentures

On June 11, 2018, CU Inc. filed a base shelf prospectus that permits it to issue up to an aggregate of $1.5 billion of debentures over the 25-month life of the prospectus. As of February 27, 2019, aggregate issuances of debentures were $385 million.

Canadian Utilities Debt Securities and Preferred Shares

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

ATCO Gas Australia Refinancing

In July 2018, ATCO Gas Australia completed the refinancing of A$275 million and A$450 million in committed credit lines, extending the maturities to 2021 and 2023.

Dividends and Common Shares

We have increased our common share dividend each year since 1972, a 47-year track record. Dividends paid to Class A and Class B share owners totaled $92 million in the fourth quarter and $365 million in the full year of 2018.

On January 10, 2019, the Board of Directors declared a first quarter dividend of 42.27 cents per share. The payment of any dividend is at the discretion of the Board of Directors and depends on our financial condition and other factors.

47 year
track record of increasing common share dividends

Canadian Utilities Dividend Reinvestment Plan

In the fourth quarter of 2018, Canadian Utilities issued 505,611 (2017 - 367,059) Class A non-voting shares under its DRIP in lieu of cash dividend payments of $15 million (2017 - $14 million).

In 2018, Canadian Utilities issued 2,000,420 (2017 - 2,388,770) Class A non-voting shares under its DRIP in lieu of cash dividend payments of $63 million (2017 - $90 million).

Effective January 10, 2019, Canadian Utilities' DRIP was suspended.

SHARE CAPITAL

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

At February 26, 2019, we had outstanding 199,380,595 Class A shares, 73,760,880 Class B shares, and options to purchase 796,400 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, 5,146,900 Class A shares were available for issuance at December 31, 2018. Options may be granted to officers and key employees of the Company and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the grant date. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant.

QUARTERLY INFORMATION

The following table shows financial information for the eight quarters ended March 31, 2017 through December 31, 2018.

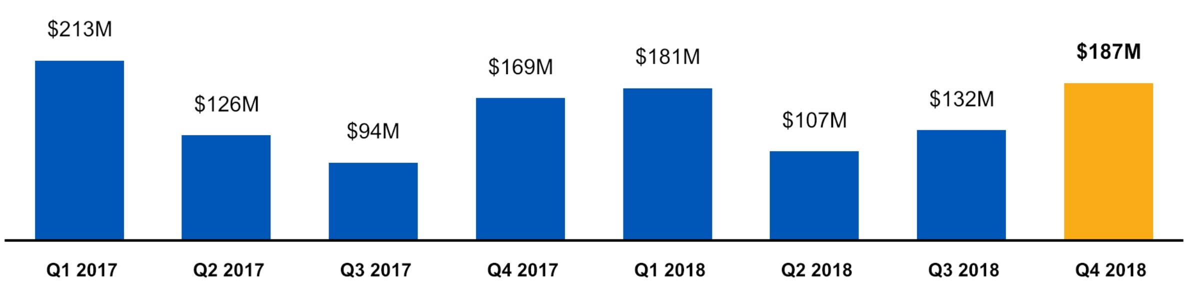
($ millions, except for per share data)	Q1 2018	Q2 2018	Q3 2018	Q4 2018
Revenues	1,385	967	990	**1,035**
Earnings (loss) attributable to equity owners of the Company	179	(3)	202	**256**
Earnings (loss) attributable to Class A and B shares	162	(19)	185	**239**
Earnings per Class A and Class B share *($ per share)*	0.60	(0.07)	0.68	**0.87**
Diluted earnings per Class A and Class B share *($ per share)*	0.60	(0.07)	0.68	**0.87**
Adjusted earnings per share per Class A and Class B share *($)*	0.67	0.39	0.49	**0.69**
Adjusted earnings				
Electricity	97	100	134	**103**
Pipelines & Liquids	101	27	17	**102**
Corporate & Other and Intersegment Eliminations	(17)	(20)	(19)	**(18)**
Total adjusted earnings	181	107	132	**187**

($ millions, except for per share data)	Q1 2017[(1)]	Q2 2017[(1)]	Q3 2017[(1)]	Q4 2017[(1)]
Revenues	1,005	942	930	1,208
Earnings attributable to equity owners of the Company	228	90	94	102
Earnings attributable to Class A and Class B shares	211	73	78	85
Earnings per Class A and Class B share *($ per share)*	0.78	0.27	0.29	0.32
Diluted earnings per Class A and Class B share *($ per share)*	0.78	0.27	0.29	0.32
Adjusted earnings per share per Class A and Class B share *($)*	0.79	0.47	0.35	0.63
Adjusted earnings				
Electricity	116	98	88	95
Pipelines & Liquids	112	43	24	94
Corporate & Other and Intersegment Eliminations	(15)	(15)	(18)	(20)
Total adjusted earnings	213	126	94	169

(1) These numbers have been restated to account for the impact of IFRS 15. Additional detail on IFRS 15 is discussed in Note 3 of the 2018 Consolidated Financial Statements.

Adjusted Earnings

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



Electricity

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

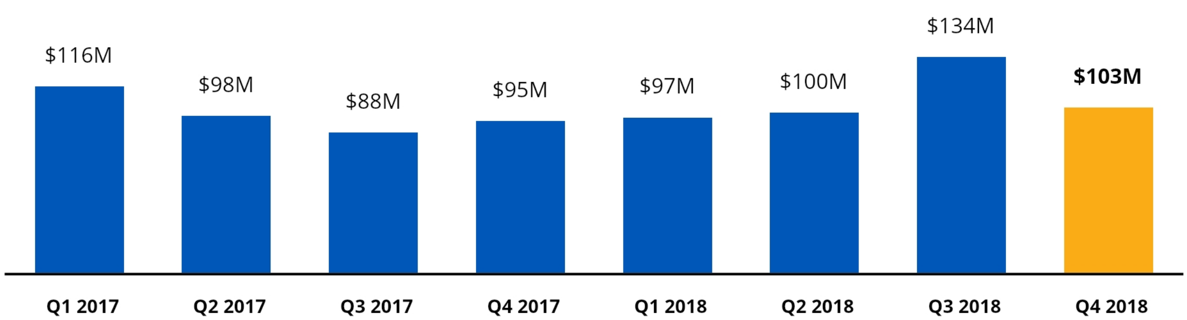
In 2017, first quarter earnings were mainly due to continued capital investment and rate base growth within Regulated Electricity and lower operating costs. Lower second quarter earnings were mainly due to the timing of operating and other costs in electricity distribution, and the impact of the 2015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

In the third quarter of 2018, earnings increased primarily due to the completion of performance obligations and additional availability incentive earnings which resulted from the Battle River unit 5 PPA termination, and improved market conditions for Independent Power Plants. These improved earnings were partially offset by lower earnings from rate rebasing under Alberta's regulated model in electricity distribution, lower electricity transmission interim rates approved by the AUC, and lower earnings from lower scheduled construction activity at Alberta PowerLine.

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

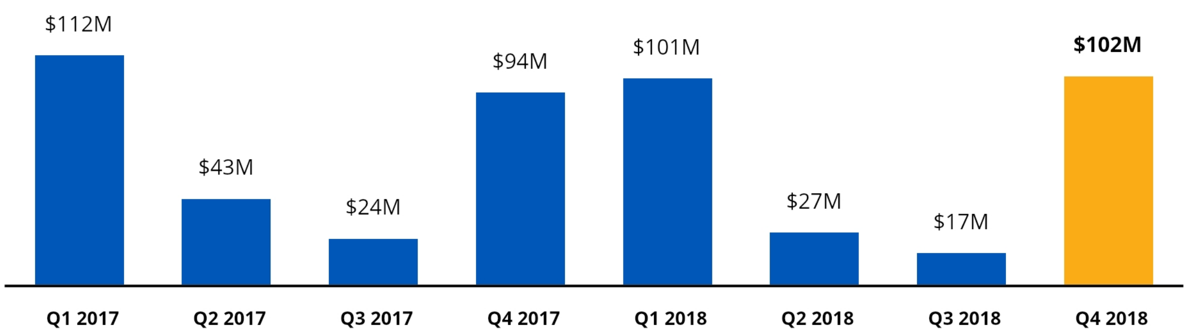
Pipelines & Liquids' adjusted earnings are impacted by the timing of certain major regulatory decisions, seasonality, and demand for hydrocarbon and natural gas storage and water services.

In the first quarter of 2017, 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 a higher rate base and an increased number of 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 the impact of rate rebasing under Alberta's regulated model.

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

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



Earnings attributable to equity owners of the Company

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

- In the first quarter of 2017, we recorded a gain of $30 million on the sale of our 100 per cent investment in ATCO Real Estate Holdings Ltd.
- In the fourth quarter of 2017, Structures & Logistics recognized an impairment relating to workforce housing assets in Canada and space rental assets in the U.S. Structures & Logistics determined these assets were impaired due to a reduction in utilization, sustained decreases in key commodity prices as well as a significant reduction in the capital expenditure programs of key customers. The Company's 24.5 per cent share of the impairment decreased equity earnings by $7 million in the Corporate & Other segment.
- In the fourth quarter of 2017, the Company recorded an increase to earnings of $31 million on derecognition of customer contributions related to a sale of electricity generation assets on transitioning to finance lease accounting which resulted from the implementation of IFRS 15.
- In the second quarter of 2018, restructuring and other costs not in the normal course of business of $60 million after-tax were recorded. These costs mainly relate to staff reductions and associated severance costs, as well as costs related to decisions to discontinue certain projects that no longer represent long-term strategic value to the Company.
- In the third quarter of 2018, the Battle River unit 5 PPA was terminated by the Balancing Pool and dispatch control was returned to Canadian Utilities. Canadian Utilities received a payment from the Balancing Pool and also recorded additional coal-related costs and Asset Retirement Obligations associated with the Battle River generating facility. This one-time receipt and costs in the net amount of $36 million after-tax was excluded from adjusted earnings.
- In the fourth quarter of 2018, Canadian Utilities sold its 100 per cent ownership interest in Barking Power assets. An after-tax gain in the amount of $87 million was excluded from adjusted earnings.

BUSINESS RISKS AND RISK MANAGEMENT

The Board of Directors (Board) is responsible for understanding the principal risks of the businesses in which the Company is engaged. The Board also must achieve a prudent balance between risks incurred and the potential return to share owners. It must confirm controls are in place that effectively monitor and manage those risks for the Company's long-term viability.

The Board has an Audit & Risk Committee, which reviews significant risks associated with future performance and growth. This committee is responsible for confirming that management has procedures in place to mitigate identified risks.

We have an established enterprise risk management process that allows us to identify and evaluate our risks by both severity of impact and probability of occurrence. Materiality thresholds are reviewed annually by the Audit & Risk Committee. Non-financial risks that may have an impact on the safety of our employees, customers or the general public and reputation risks are also evaluated. The following table outlines our current significant risks and associated mitigations.

Business Risk: Capital Investment	
Businesses Impacted: • All businesses	**Associated Strategies:** • Growth • Financial Strength
Description and Context	***Risk Management Approach***
The Company is subject to the normal risks associated with major capital projects, including cancellations, delays and cost increases.	The Company attempts to reduce the risks of project delays and cost increases by careful planning, diligent procurement practices and entering into fixed price contracts when possible. International Natural Gas Distribution's capital investment is planned and approved by the regulator. Planned capital investments for the Alberta Utilities are based on the following significant assumptions: projects identified by the AESO will proceed as currently scheduled; the remaining planned capital investments are required to maintain safe and reliable service and meet planned growth in the Alberta Utilities' service areas; regulatory approval for capital projects can be obtained in a timely manner; and access to capital market financings can be maintained. The Company believes these assumptions are reasonable.

Business Risk: Climate Change	
Businesses Impacted: • All businesses	**Associated Strategies:** • Operational Excellence • Innovation
Description and Context	***Risk Management Approach***
Legislative Risks In November 2015, the Government of Alberta announced its Climate Leadership Plan, a framework which includes the phasing out of coal-fired electricity, the accelerated phasing in of renewable energy, an economy-wide tax on carbon emissions that started in 2017, and the reduction of methane emissions.	**Legislative Risks** Compensation for the early phase out of any coal units was resolved with the Alberta provincial government in the fourth quarter of 2016. Canadian Utilities is proceeding with coal-to-natural gas conversion of its coal-fired electricity. This conversion involves modest capital expenditures and extends the life span of the units. Broader coal-to-gas conversions present an opportunity for increased demand for natural gas transmission and distribution infrastructure investment in the near to medium term. Carbon taxes assessed to the natural gas-fired generation fleet are largely recovered through the market. The Company's exposure is limited for the Alberta Utilities because GHG emission charges are recovered in rates, and because future requirements to upgrade equipment to further reduce methane emissions are expected to be included in rate base on a go-forward basis.
Physical Risks Physical risks associated with climate change may include an increase in extreme weather events such as heavy rainfall, floods, wildfires, extreme winds and ice storms, or changing weather patterns that cause on-going impacts to seasonal temperatures. Electricity transmission, distribution and pipeline assets above ground or on water crossings are exposed to extreme weather events.	**Physical Risks** The Company continues to carefully manage physical risks, including preparing for, and responding to, extreme weather events through activities such as proactive route selection, asset hardening, regular maintenance, and insurance. The Company follows regulated engineering codes, continues to evaluate ways to create greater system reliability and resiliency and, where appropriate, submits regulatory applications for capital expenditures aimed at creating greater system reliability and resiliency within the code. When planning for capital investment or acquiring assets we consider site specific climate and weather factors, such as flood plain mapping and extreme weather history. Prevention activities include Wildfire Management Plans and vegetation management at electricity transmission and distribution operations. The majority of the Company's pipeline network is in the ground, making it less susceptible to extreme weather events. The Company maintains in-depth emergency response measures for extreme weather events.

Business Risk: Credit Risk	
Businesses Impacted: • All businesses	**Associated Strategies:** • Financial Strength
Description and Context	***Risk Management Approach***
For cash and cash equivalents and accounts receivable and contract assets, credit risk represents the carrying amount on the consolidated balance sheet. Derivative, finance lease receivables and receivable under service concession arrangement credit risk arises from the possibility that a counterparty to a contract fails to perform according to the terms and conditions of that contract. The maximum exposure to credit risk is the carrying value of loans and receivables and derivative financial instruments.	Cash and cash equivalents credit risk is reduced by investing in instruments issued by credit-worthy financial institutions and in federal government issued short-term instruments. The Company minimizes other credit risks by dealing with credit-worthy counterparties, following established credit-approval policies, and requiring credit security, such as letters of credit. A significant portion of loans and receivables are from the Company's operations in Alberta, except for the finance lease receivable for the Karratha power plant in Australia. The Alberta Utilities are able to recover an estimate for doubtful accounts through approved customer rates and to request recovery through customer rates for any material losses from retailers beyond the retailer security mandated by provincial regulations.

Business Risk: Cybersecurity	
Businesses Impacted: • All businesses	**Associated Strategies:** • Operational Excellence • Innovation
Description and Context	***Risk Management Approach***
The Company's reliance on technology, which supports its information and industrial control systems, is subject to potential cyber attacks including unauthorized access of confidential information and outage of critical infrastructure.	Canadian Utilities has an enterprise wide cybersecurity program covering all technology assets. The cybersecurity program includes employee awareness, layered access controls, continuous monitoring, network threat detection, and coordinated incident response through a centralized Security Operations Centre. The Company's cybersecurity management is consolidated under a common, centralized organization structure to increase effectiveness and compliance across the entire enterprise.

Business Risk: Energy Commodity Price

Businesses Impacted:

- Non-regulated Electricity
- Non-regulated Pipelines & Liquids
- Retail Energy

Associated Strategies:

- Financial Strength

Description and Context

Independent Power Plant's, merchant Thermal Power Plant's, and Retail Energy's earnings are affected by short-term price volatility. Changes to the power reserve margin (electricity supply relative to demand) and natural gas prices can result in volatility in Alberta Power Pool Prices and spark spreads. A number of key factors contribute to price volatility including electricity demand and electricity supply, primarily from Alberta's coal and wind generation.

Storage & Industrial Water's natural gas storage facility in Carbon, Alberta, is also exposed to storage price differentials.

Risk Management Approach

In conducting its business, the Company may use various instruments, including forward contracts, swaps, and options to manage the risks arising from fluctuations in commodity prices. The Company enters into natural gas purchase contracts and forward power sales contracts as the hedging instrument to manage the exposure to electricity and natural gas market price movements. Under IFRS accounting, entering into hedging instruments may result in mark-to-market adjustments that are recorded as unrealized gains or losses on the income statement. Realized gains or losses are recognized in adjusted earnings and IFRS earnings when the commodity contracts are settled.

In addition, Retail Energy monitors forward curves in order to ensure it is not promoting product offerings that are unfavourable to the Company.

Business Risk: Financing

Businesses Impacted:

- All businesses

Associated Strategies:

- Financial Strength

Description and Context

The Company's financing risk relates to the price volatility and availability of external financing to fund the capital expenditure program and refinance existing debt maturities. Financing risk is directly influenced by market factors. As financial market conditions change, these risk factors can affect the availability of capital and also the relevant financing costs.

Risk Management Approach

To address this risk, the Company manages its capital structure to maintain strong credit ratings which allow continued ease of access to the capital markets. The Company also considers it prudent to maintain sufficient liquidity to fund approximately one full year of cash requirements to preserve strong financial flexibility. This liquidity is generated by cash flow from operations and supported by appropriate levels of cash and available committed credit facilities.

Business Risk: Foreign Currency Exchange Rate

Businesses Impacted:

- All businesses

Associated Strategies:

- Financial Strength

Description and Context

The Company's earnings from, and carrying values of, its foreign operations are exposed to fluctuations in exchange rates. The Company is also exposed to transactional foreign exchange risk through transactions denominated in a foreign currency.

Risk Management Approach

In conducting its business, the Company may use various instruments, including forward contracts, swaps, and options, to manage the risks arising from fluctuations in exchange rates. All such instruments are used only to manage risk and not for trading purposes. This foreign exchange impact is partially offset by foreign denominated financing and by hedging activities. The Company manages this risk through its policy of matching revenues and expenses in the same currency. When matching is not possible, the Company may utilize foreign currency forward contracts to manage the risk.

Business Risk: Generation Equipment and Technology		
Businesses Impacted: • Non-regulated Electricity	**Associated Strategies:** • Financial Strength	 • Operational Excellence
Description and Context	***Risk Management Approach***	
Our electricity generating plants are exposed to operational risks which can cause outages due to issues such as boiler, turbine, and generator failures. An extended outage could negatively impact earnings and cash flows. If a generating plant does not meet availability or production targets specified in a PPA or another long-term agreement, the Company may need to compensate the purchaser for the loss of production availability.	To reduce this risk, a proactive maintenance program is regularly carried out with scheduled outages for major overhauls and other maintenance. The Company also carries property insurance and some business interruption insurance for its power plants to protect against extended outages. PPAs are designed to provide force majeure relief for plant outages beyond specified time periods and certain circumstances.	

Business Risk: Interest Rate	
Businesses Impacted: • All businesses	**Associated Strategies:** • Financial Strength
Description and Context	***Risk Management Approach***
The interest rate risk faced by the Company is largely a result of its recourse and non-recourse long-term debt at variable rates as well as cash and cash equivalents. The Company also has exposure to interest rate movements that occur beyond the term of maturity of the fixed-rate investments.	In conducting its business, the Company may use various instruments, including forward contracts, swaps, and options to manage the risks arising from fluctuations in interest rates. All such instruments are used only to manage risk and not for trading purposes. The Company has converted certain variable rate long-term debt and non-recourse long-term debt to fixed rate debt through interest rate swap agreements. At December 31, 2018, the Company had fixed interest rates, either directly or through interest rate swap agreements, on 100 per cent (2017 - 100 per cent) of total long-term debt and non-recourse long-term debt. Consequently, the exposure to fluctuations in future cash flows, with respect to debt, from changes in market interest rates was limited. The Company's cash and cash equivalents include fixed rate instruments with maturities of generally 90 days or less that are reinvested as they mature.

Business Risk: Natural Gas Supply	
Businesses Impacted: • Non-regulated Electricity • Non-regulated Pipelines & Liquids	**Associated Strategies:** • Financial Strength
Description and Context	***Risk Management Approach***
An Alberta natural gas transportation provider's curtailment protocol in 2017, along with increased supply and warm weather in 2018, contributed to on-going low natural gas prices in Alberta and presents operational risk of natural gas supply for the Company's Alberta natural gas fired power plants without firm transport contracts in place and natural gas storage facilities (all storage in Alberta is under interruptible transport). Further curtailments and maintenance are scheduled for multiple years into the future, which may result in gas transportation constraints.	Our electricity generation natural gas supply management approach is to obtain firm natural gas transport service for our downstream natural gas fired generation assets so that the risk of future gas supply curtailments or restrictions are minimized (curtailment primarily affects interruptible contracts). To reduce the impact to storage operations, Canadian Utilities plans to structure its natural gas storage portfolio around the natural gas transportation provider's planned maintenance schedules to minimize the impact of natural gas supply curtailments.

Business Risk: Pipeline Integrity	
Businesses Impacted: Pipelines & Liquids	**Associated Strategies:** • Operational Excellence • Community Involvement
Description and Context	***Risk Management Approach***
The Pipelines & Liquids Global Business Unit has significant pipeline infrastructure. Although the probability of a pipeline rupture is very low, the consequences of a failure can be severe.	Programs are in place to monitor the integrity of the pipeline infrastructure and replace pipelines as required to address safety, reliability, and future growth. These programs include Natural Gas Distribution's and Natural Gas Transmission's UPR programs and Natural Gas Distribution's and International Natural Gas Distribution's mains replacement programs. The Company also carries property and liability insurance.

Business Risk: Political	
Businesses Impacted: • Pipelines & Liquids • Electricity	**Associated Strategies:** • Growth • Operational Excellence • Financial Strength
Description and Context	***Risk Management Approach***
Operations are exposed to a risk of change in business environment due to political change. Legislative changes may impact the financial performance of operations. This could negatively impact earnings, return on equity and assets, and credit metrics. The Company has a large percentage of its assets in one political jurisdiction (Alberta).	Participation in policy consultations and engagement of stakeholder groups like the AUC, the Alberta Electric System Operator (AESO), and various interveners ensures ongoing communication and that the impacts and costs of proposed changes are identified and understood. Where appropriate, the Company works with other Alberta utilities to develop common strategies. Geographical diversification outside of Alberta will reduce the impact of any political and legislative changes.

Business Risk: Regulated Operations	
Businesses Impacted: • Regulated Pipelines & Liquids • Regulated Electricity	**Associated Strategies:** • Growth • Financial Strength • Operational Excellence
Description and Context	***Risk Management Approach***
The Regulated Utilities are subject to the normal risks faced by regulated companies. These risks include the regulator's approval of customer rates that permit a reasonable opportunity to recover service costs on a timely basis, including a fair return on rate base. These risks also include the regulator's potential disallowance of costs incurred. Electricity Distribution and Natural Gas Distribution operate under performance based regulation (PBR). Under PBR, utility revenues are formula driven, which raises the uncertainty of cost recovery. In Australia, the ERA assesses appropriate returns, prudent levels of operating costs, capital expenditure and expected throughput on the network through an Access Arrangement proceeding.	The Regulated Utilities file forecasts in the rate-setting process to recover the costs of providing services and earn a fair rate of return. The determination of a fair rate of return on the common equity component of rate base is determined in a generic cost of capital proceeding in Alberta and an Access Arrangement proceeding in Australia. The Regulated Utilities continuously monitor various regulatory decisions and cases to assess how they might impact the Company's regulatory applications for the recovery of prudent costs. The Regulated Utilities are proactive in demonstrating prudence and continuously look for ways to lower operating costs while maintaining service levels.

Business Risk: Technological Transformation & Disruption	
Businesses Impacted: • Pipelines & Liquids • Electricity	**Associated Strategies:** • Growth • Financial Strength • Operational Excellence
Description and Context	***Risk Management Approach***
The introduction and rapid, widespread adoption of transformative technology (such as distributed energy generation) could lead to disruption of Canadian Utilities' existing business models and new competitive market dynamics. Failure to effectively identify disruptive technology and / or changing consumer attitudes and preferences may result in disruptions to the business and an inability to achieve strategic and financial objectives.	The strategic plans of each GBU incorporate and address the evolution of our business into areas of transformative technology. Innovation has been adopted as a key strategy for the Company and annual key performance indicators on innovation are monitored to ensure the businesses evolve.

Business Risk: Liquidity	
Businesses Impacted: • All businesses	**Associated Strategies:** • Financial Strength
Description and Context	***Risk Management Approach***
Liquidity risk is the risk that the Company will not be able to meet its financial obligations.	Cash flow from operations provides a substantial portion of the Company's cash requirements. Additional cash requirements are met with the use of existing cash balances and externally through bank borrowings and the issuance of long-term debt, non-recourse long-term debt and preferred shares. Commercial paper borrowings and short-term bank loans under available credit lines are used to provide flexibility in the timing and amounts of long-term financing. The Company does not invest any of its cash balances in asset-backed securities. At December 31, 2018, the Company's cash position was $599 million and there were available committed and uncommitted lines of credit of approximately $1.8 billion which can be utilized for general corporate purposes.

Liquidity Risk includes contractual financial obligations which the Company will meet with cash flow from operations, existing cash balances and external financing, if necessary. These contractual obligations for the next five years and thereafter are shown below.

($ millions)	**2019**	**2020**	**2021**	**2022**	**2023**	**2024 and thereafter**
Financial Liabilities						
Accounts payable and accrued liabilities	845	–	–	–	–	–
Short-term debt	175	–	–	–	–	–
Long-term debt:						
Principal	485	166	424	325	524	7,025
Interest expense [(1)]	412	384	369	351	331	6,530
Non-recourse long-term debt:						
Principal	20	34	32	33	28	1,306
Interest expense	59	58	56	54	53	956
Derivatives [(2)]	65	34	6	–	–	–
	2,061	676	887	763	936	15,817
Commitments						
Operating leases	19	18	16	11	11	63
Purchase obligations:						
Coal purchase contracts	64	66	67	68	27	56
Operating and maintenance agreements	326	324	321	324	323	400
Construction activities related to Fort McMurray West 500-kV Transmission project	118	–	–	–	–	–
Capital expenditures	93	4	2	–	–	–
Other	10	–	–	–	–	–
	630	412	406	403	361	519
Total	2,691	1,088	1,293	1,166	1,297	16,336

(1) Interest payments on floating rate debt have been estimated using rates in effect at December 31, 2018. Interest payments on debt that has been hedged have been estimated using hedged rates.

(2) Payments on outstanding derivatives have been estimated using exchange rates and commodity prices in effect at December 31, 2018.

NON-GAAP AND ADDITIONAL GAAP MEASURES

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

Adjusted earnings present earnings from rate-regulated activities on the same basis as was used prior to adopting IFRS - that basis being the U.S. accounting principles for rate-regulated activities. Management’s view is that adjusted earnings allow for a more effective analysis of operating performance and trends. A reconciliation of adjusted earnings to earnings attributable to equity owners of the Company is presented in this MD&A. Adjusted earnings is an additional GAAP measure presented in Note 4 of the 2018 Consolidated Financial Statements.

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

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

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

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

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

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

($ millions)					**Three Months Ended December 31**
2018 **2017 (1)**	**Electricity**	**Pipelines & Liquids**	**Corporate & Other**	**Intersegment Eliminations**	**Consolidated**
Revenues	**637**	**383**	**50**	**(35)**	**1,035**
	767	447	30	(36)	1,208
Adjusted earnings	**103**	**102**	**(18)**	**–**	**187**
	95	94	(21)	1	169
Derecognition of customer contributions	**–**	**–**	**–**	**–**	**–**
	31	–	–	–	31
Impairment	**–**	**–**	**–**	**–**	**–**
	–	–	(7)	–	(7)
Sale of Barking Power assets	**87**	**–**	**–**	**–**	**87**
	–	–	–	–	–
Unrealized gains (losses) on mark-to-market forward commodity contracts	**2**	**–**	**–**	**–**	**2**
	(53)	–	–	–	(53)
Rate-regulated activities	**14**	**(52)**	**–**	**1**	**(37)**
	(51)	(3)	–	2	(52)
Dividends on equity preferred shares of Canadian Utilities Limited	**1**	**1**	**15**	**–**	**17**
	1	–	16	–	17
Other	**–**	**–**	**–**	**–**	**–**
	–	(3)	–	–	(3)
Earnings (loss) attributable to equity owners of the Company	**207**	**51**	**(3)**	**1**	**256**
	23	88	(12)	3	102

(1) These numbers have been restated to account for the impact of IFRS 15. Additional detail on IFRS 15 is discussed in Note 3 of the 2018 Consolidated Financial Statements.

($ millions)					Year Ended December 31
2018 **2017** (1)	**Electricity**	**Pipelines & Liquids**	**Corporate & Other**	**Intersegment Eliminations**	**Consolidated**
Revenues	**2,858**	**1,470**	**162**	**(113)**	**4,377**
	2,460	1,630	95	(100)	4,085
Adjusted earnings	**434**	**247**	**(74)**	**–**	**607**
	397	273	(69)	1	602
Gain on sale of operation	**–**	**–**	**–**	**–**	**–**
	–	–	30	–	30
Proceeds from termination of PPA	**36**	**–**	**–**	**–**	**36**
	–	–	–	–	–
Restructuring and other costs	**(36)**	**(19)**	**(5)**	**–**	**(60)**
	–	–	–	–	–
Derecognition of customer contributions	**–**	**–**	**–**	**–**	**–**
	31	–	–	–	31
Impairment	**–**	**–**	**–**	**–**	**–**
	–	–	(7)	–	(7)
Sale of Barking Power assets	**87**	**–**	**–**	**–**	**87**
	–	–	–	–	–
Unrealized gains (losses) on mark-to-market forward commodity contracts	**31**	**–**	**–**	**–**	**31**
	(90)	–	–	–	(90)
Rate-regulated activities	**(55)**	**(82)**	**–**	**4**	**(133)**
	(131)	6	–	6	(119)
Dividends on equity preferred shares of Canadian Utilities Limited	**4**	**2**	**61**	**–**	**67**
	3	1	63	–	67
Other	**–**	**(1)**	**–**	**–**	**(1)**
	–	–	–	–	–
Earnings (loss) attributable to equity owners of the Company	**501**	**147**	**(18)**	**4**	**634**
	210	280	17	7	514

(1) These numbers have been restated to account for the impact of IFRS 15. Additional detail on IFRS 15 is discussed in Note 3 of the 2018 Consolidated Financial Statements.

GAIN ON SALE OF OPERATION

In January 2017, Canadian Utilities sold its 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 were used for continued capital investment, to repay indebtedness, and for other general corporate purposes.

PROCEEDS FROM TERMINATION OF PPA

In the third quarter of 2018, the Battle River unit 5 PPA was terminated by the Balancing Pool and dispatch control was returned to Canadian Utilities. Canadian Utilities received a payment from the Balancing Pool and also recorded additional coal-related costs and Asset Retirement Obligations associated with the Battle River generating facility. This one-time receipt and costs in the net amount of $36 million were excluded from adjusted earnings.

RESTRUCTURING AND OTHER COSTS

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.

DERECOGNITION OF CUSTOMER CONTRIBUTIONS

In December 2017, ATCO Power signed a contract amendment that triggered a reassessment of the accounting treatment of the Muskeg River generating plant (Muskeg). Due to the nature of the contract amendment, IFRS requires that this agreement be accounted for as a finance lease. As a result, the Company recorded an increase to earnings of $31 million on derecognition of customer contributions related to a sale of electricity generation assets on transitioning to finance lease accounting which resulted from the implementation of IFRS 15.

IMPAIRMENT

In the fourth quarter of 2017, Structures & Logistics recognized a pre-tax impairment of $34 million relating to certain workforce housing assets in Canada and space rental assets in the U.S. Structures & Logistics' determined these assets were impaired due to a reduction in utilization, sustained decreases in key commodity prices as well as a significant reduction in the capital expenditure programs of key customers. The Company's 24.5 per cent share of the impairment decreased equity earnings by $7 million in the Corporate & Other segment.

SALE OF BARKING POWER ASSETS

In the fourth quarter of 2018, Canadian Utilities sold its 100 per cent ownership interest in Barking Power assets. A gain in the amount of $87 million was excluded from adjusted earnings.

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

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

RATE-REGULATED ACTIVITIES

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

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

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

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

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2018**	**2017**	**Change**	**2018**	**2017**	**Change**
Additional revenues billed in current period						
Future removal and site restoration costs (1)	**16**	7	9	**74**	61	13
Impact of colder temperatures (2)	**–**	–	–	**12**	–	12
Revenues to be billed in future periods						
Deferred income taxes (3)	**(26)**	(27)	1	**(105)**	(102)	(3)
Impact of warmer temperatures (2)	**(6)**	–	(6)	**–**	(4)	4
Impact of inflation on rate base (4)	**(17)**	(5)	(12)	**(17)**	(15)	(2)
Regulatory decisions received (5)	**–**	1	(1)	**–**	17	(17)
Settlement of regulatory decisions and other items (6)	**(4)**	(28)	24	**(97)**	(76)	(21)
	(37)	(52)	15	**(133)**	(119)	(14)

(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) The inflation-indexed portion of ATCO Gas Australia's rate base is billed to customers through the recovery of depreciation in subsequent periods based on the actual rate of inflation. Under rate-regulated accounting, revenue is recognized in the current period for the inflation component of rate base when it is earned. Differences between the amounts earned and the amounts billed to customers are deferred and recognized in revenues over the service life of the related assets.

(5) In 2017, the most significant regulatory decision received was the General Tariff Application related to ATCO Electric Transmission operations.

(6) In 2018, ATCO Electric Transmission operations recorded a decrease in earnings of $38 million mainly related to a refund of deferral account balances relating to 2013 and 2014. ATCO Gas also recorded a reduction in earnings of $59 million mainly related to a refund of previously over-collected transmission costs. In 2017, ATCO Electric Transmission operations recorded a decrease in earnings of $33 million related to the settlement of final 2015-2017 General Tariff Application rate and a decrease to earnings of $27 related to the refund of previously collected capitalized pension 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, and impact of colder temperatures.	The Company defers the recognition of cash received in advance of future expenditures.	The Company recognizes revenues when amounts are billed to customers and costs when they are incurred.
Revenues to be billed in future periods	Deferred income taxes, impact of warmer temperatures, and impact of inflation on rate base.	The Company recognizes revenues associated with recoverable costs in advance of future billings to customers.	The Company recognizes costs when they are incurred, but does not recognize their recovery until customer rates are changed and amounts are collected through future billings.
Regulatory decisions received	For further details on regulatory decisions that caused a timing adjustment financial impact, refer to the Regulatory Developments section in this MD&A.	The Company recognizes the earnings from a regulatory decision pertaining to current and prior periods when the decision is received.	The Company does not recognize earnings from a regulatory decision when it is received as regulatory assets and liabilities are not recorded under IFRS.
Settlement of regulatory decisions and other items	Settlement of amounts receivable or payable to customers and other items.	The Company recognizes the amount receivable or payable to customers as a reduction in its regulatory assets and liabilities when collected or refunded through future billings.	The Company recognizes earnings when customer rates are changed and amounts are recovered or refunded to customers through future billings.

OTHER

Each quarter, the Company adjusts the deferred tax asset which was recognized as a result of the 2015 Tula Pipeline Project impairment. In 2018, the Company recorded a foreign exchange loss of $1 million (2017 - nil) 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** [(1)]	**Three Months Ended December 31**	**Year Ended December 31**
Funds generated by operations	**460**	**1,782**
	450	1,761
Changes in non-cash working capital	**(35)**	**(109)**
	(10)	67
Change in receivable under service concession arrangement	**(93)**	**(803)**
	(156)	(516)
Cash flows from operating activities	**332**	**870**
	284	1,312

(1) These numbers have been restated to account for the impact of IFRS 15. Additional detail on IFRS 15 is discussed in Note 3 of the 2018 Consolidated Financial Statements.

RECONCILIATION OF CAPITAL INVESTMENT TO CAPITAL EXPENDITURES

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

($ millions)				**Three Months Ended December 31**
2018 **2017**	**Electricity**	**Pipelines & Liquids**	**CUL Corporate & Other**	**Consolidated**
Capital Investment	**203**	**174**	**3**	**380**
	291	254	1	546
Capital Expenditure in joint ventures	**(3)**	**(1)**	–	**(4)**
	(4)	(1)	–	(5)
Service concession arrangement	**(44)**	–	–	**(44)**
	(132)	–	–	(132)
Capital Expenditures	**156**	**173**	**3**	**332**
	155	253	1	409

($ millions)				**Year Ended December 31**
2018 **2017**	**Electricity**	**Pipelines & Liquids**	**CUL Corporate & Other**	**Consolidated**
Capital Investment	**1,287**	**648**	**16**	**1,951**
	918	782	3	1,703
Capital Expenditure in joint ventures	**(14)**	**(5)**	–	**(19)**
	(8)	(5)	–	(13)
Business combinations [(1)]	**(112)**	–	–	**(112)**
	–	–	–	–
Service concession arrangement	**(664)**	–	–	**(664)**
	(456)	–	–	(456)
Capital Expenditures	**497**	**643**	**16**	**1,156**
	454	777	3	1,234

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

OTHER FINANCIAL INFORMATION

OFF BALANCE SHEET ARRANGEMENTS

Canadian Utilities Limited does not have any off-balance sheet arrangements that have, or are reasonably likely to have, a current or future effect on the results of operations or financial condition, including, without limitation, the Company's liquidity and capital resources.

CONTINGENCIES

The Company is party to a number of disputes and lawsuits in the normal course of business. The Company believes the ultimate liability arising from these matters will have no material impact on its consolidated financial statements.

SIGNIFICANT ACCOUNTING ESTIMATES

The Company's significant accounting estimates are described in Note 28 of the 2018 Consolidated Financial Statements, which are prepared in accordance with IFRS. Management makes estimates and judgments that could significantly affect how policies are applied, amounts in the consolidated financial statements are reported, and contingent assets and liabilities are disclosed. Most often these estimates and judgments concern matters that are inherently complex and uncertain. Judgments and estimates are reviewed on an ongoing basis; changes to accounting estimates are recognized prospectively.

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. The standards issued, but not yet effective, which the Company anticipates may have a material effect on the 2018 Consolidated Financial Statements are described below. For further information, see Note 39 of the 2018 Consolidated Financial Statements.

- IFRS 16 Leases - This standard replaced IAS 17 *Leases* and related interpretations. It introduces a new approach to lease accounting that requires a lessee to recognize right-of-use assets and lease liabilities for the rights and obligations created by leases. It brings most leases on-balance sheet for lessees, eliminating the distinction between operating and finance leases. Lessor accounting under the new standard retains similar classifications to the previous guidance, however, the new standard may change the accounting treatment of certain components of lessor contracts and sub-leasing arrangements. The Company is in the process of finalizing its calculations using the modified retrospective approach effective January 1, 2019, without restatement of comparative information. The Company has elected to use certain practical expedients:

    - Leases of low-value assets and short-term leases that have a lease term of twelve months or less will not be recognized in the consolidated balance sheet on January 1, 2019. Payments on these leases will continue to be recognized as a lease expense generally on a straight-line basis over the lease term; and

    - Right-of-use assets will be measured with an equivalent value recorded for the related lease liabilities.

    The adoption of the new standard is expected to result in the recognition of a right-of-use asset and lease liability of approximately $70 million at January 1, 2019. The estimated impact may change as a result of additional updates on contractual terms, assumptions, and other circumstances arising after the date of the 2018 Consolidated Financial Statements.

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

DISCLOSURE CONTROLS AND PROCEDURES

As of December 31, 2018, management evaluated the effectiveness of the Company's disclosure controls and procedures as required by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the Chief Executive Officer (CEO) and the Chief Financial Officer (CFO).

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in documents filed with securities regulatory authorities is recorded, processed, summarized and reported on a timely basis. The controls also seek to assure this information is accumulated and communicated to management, including the CEO and the CFO, as appropriate, to allow timely decisions on required disclosure.

Management, including the CEO and the CFO, does not expect the Company's disclosure controls and procedures will prevent or detect all errors. The inherent limitations in all control systems are that they can provide only reasonable, not absolute, assurance that all control issues and instances of error, if any, within the Company have been detected.

Based on this evaluation, the CEO and the CFO have concluded that the Company's disclosure controls and procedures were effective at December 31, 2018.

INTERNAL CONTROL OVER FINANCIAL REPORTING

As of December 31, 2018, management evaluated the effectiveness of the Company's internal control over financial reporting as required by the Canadian Securities Administrators. This evaluation was performed under the supervision of, and with the participation of, the CEO and the CFO.

The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. Internal control over financial reporting, no matter how well designed, has inherent limitations. Therefore, internal control over financial reporting can provide only reasonable assurance regarding the reliability of financial statement preparation and may not prevent or detect all misstatements.

Based on this evaluation, the CEO and the CFO have concluded that the Company's internal control over financial reporting was effective at December 31, 2018.

There was no change in the Company's internal control over financial reporting that occurred during the period beginning on January 1, 2018, and ended on December 31, 2018, that materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

FORWARD-LOOKING INFORMATION

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

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

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

ADDITIONAL INFORMATION

Canadian Utilities has published its 2018 Consolidated Financial Statements and its MD&A for the year ended December 31, 2018. Copies of these documents may be obtained upon request from Investor Relations at 3rd Floor, West Building, 5302 Forand Street S.W., Calgary, Alberta, T3E 8B4, telephone 403-292-7500, fax 403-292-7532 or email investorrelations@atco.com.

GLOSSARY

AESO means the Alberta Electric System Operator.

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

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

AUC means the Alberta Utilities Commission.

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

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

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

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

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

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

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

GAAP means Canadian generally accepted accounting principles.

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

IFRS means International Financial Reporting Standards.

K Bar means the AUC allowance for capital additions under performance based regulation.

LNG means liquefied natural gas.

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

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

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

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

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

APPENDIX 1
FOURTH QUARTER FINANCIAL INFORMATION

Financial information for the three months ended December 31, 2018 and 2017 is shown below.

CONSOLIDATED STATEMENT OF EARNINGS

	Three Months Ended December 31	
(millions of Canadian Dollars except per share data)	**2018**	**2017** (1)
Revenues	**1,035**	1,208
Costs and expenses		
Salaries, wages and benefits	**(108)**	(103)
Energy transmission and transportation	**(44)**	(49)
Plant and equipment maintenance	**(62)**	(70)
Fuel costs	**(60)**	(58)
Purchased power	**(52)**	(29)
Service concession arrangement costs	**(44)**	(132)
Depreciation and amortization	**(147)**	(155)
Franchise fees	**(50)**	(55)
Property and other taxes	**(42)**	(28)
Unrealized gains (losses) on mark-to-market forward commodity contracts	**2**	(73)
Cost of sale of electricity generation asset on transition to finance lease	**–**	(115)
Other	**(91)**	(81)
	(698)	(948)
Gain on sale of Barking Power assets	**125**	–
Loss from investment in ATCO Structures & Logistics	**–**	(5)
Earnings from investment in joint ventures	**5**	6
Operating profit	**467**	261
Interest income	**3**	8
Interest expense	**(128)**	(125)
Net finance costs	**(125)**	(117)
Earnings before income taxes	**342**	144
Income taxes	**(84)**	(40)
Earnings for the period	**258**	104
Earnings attributable to:		
Equity Owners of the Company	**256**	102
Non-controlling interests	**2**	2
	258	104
Earnings per Class A and Class B share	**$0.87**	$0.32
Diluted earnings per Class A and Class B share	**$0.87**	$0.32

(1) These numbers have been restated to account for the impact of IFRS 15. Additional detail on IFRS 15 is discussed in Note 3 of the 2018 Consolidated Financial Statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

(millions of Canadian Dollars)	Three Months Ended December 31 2018	2017
Operating activities		
Earnings for the period	**258**	104
Adjustments to reconcile earnings to cash flows from operating activities	**202**	346
Changes in non-cash working capital	**(35)**	(10)
Change in receivable under service concession arrangement	**(93)**	(156)
Cash flows from operating activities	**332**	284
Investing activities		
Additions to property, plant and equipment	**(269)**	(376)
Proceeds on disposal of property, plant and equipment	**2**	1
Proceeds on sale of Barking Power assets	**219**	–
Additions to intangibles	**(59)**	(29)
Proceeds on sale of investment in ATCO Structures & Logistics	**–**	140
Changes in non-cash working capital	**29**	36
Other	**(3)**	(10)
Cash flows used in investing activities	**(81)**	(238)
Financing activities		
Net repayment of short-term debt	**(25)**	(525)
Issue of long-term debt	**386**	430
Release of restricted project funds	**81**	374
Repayment of long-term debt	**(3)**	(152)
Repayment of non-recourse long-term debt	**(5)**	(3)
Dividends paid on equity preferred shares	**(17)**	(17)
Dividends paid to non-controlling interests	**(2)**	(2)
Dividends paid to Class A and Class B share owners	**(92)**	(83)
Interest paid	**(134)**	(115)
Debt issue costs	**(6)**	(11)
Other	**24**	(77)
Cash flows from (used in) financing activities	**207**	(181)
Increase (decrease) in cash position	**458**	(135)
Foreign currency translation	**7**	–
Beginning of period	**134**	553
End of period	**599**	418