CU INC.
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 CU Inc. (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 Canadian Utilities Limited, which in turn is controlled by ATCO Ltd. (ATCO) 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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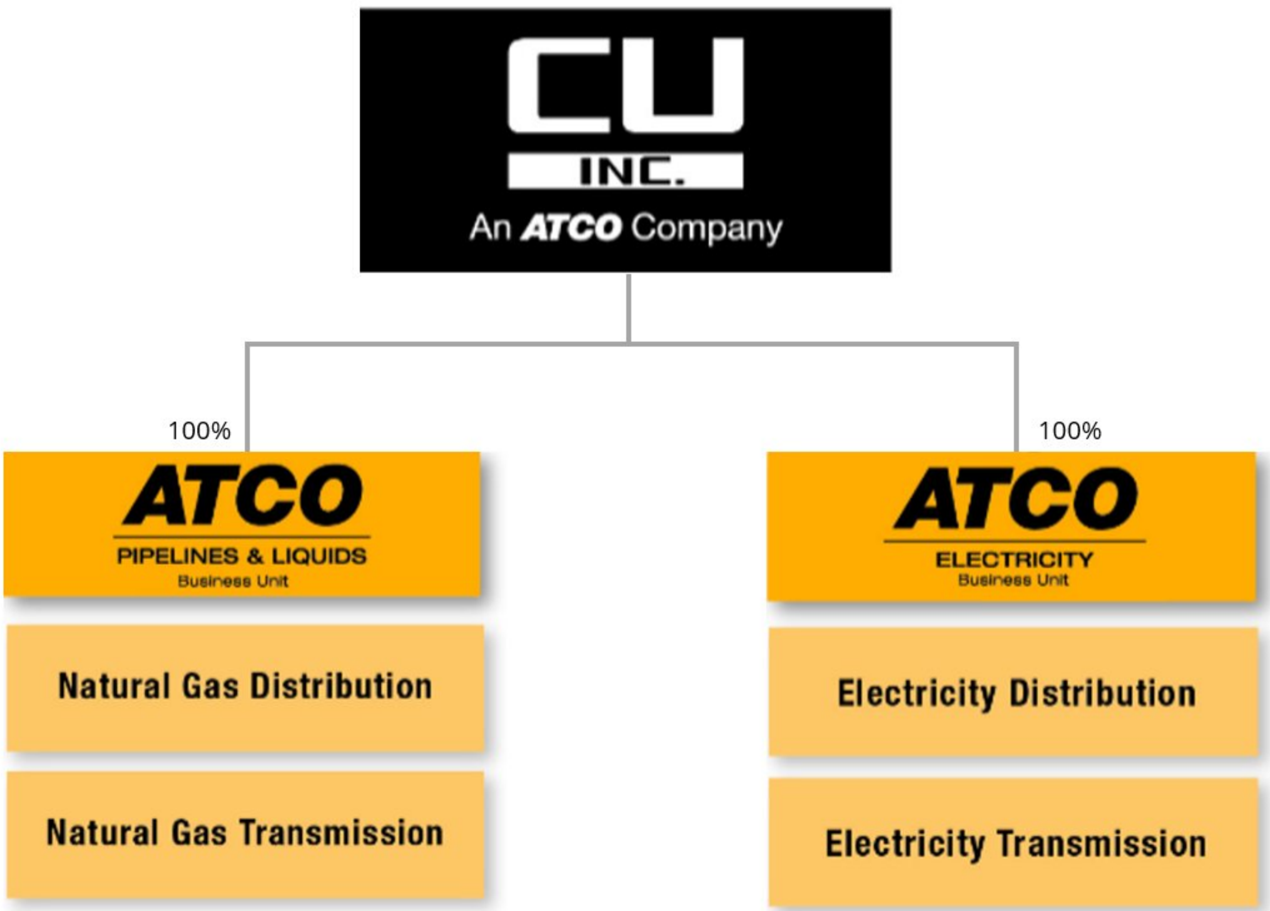
COMPANY OVERVIEW

CU Inc. is a wholly-owned subsidiary of Canadian Utilities Limited, an ATCO Company. CU Inc. is an Alberta-based corporation with approximately 3,500 employees and assets of $16 billion comprised of rate-regulated utility operations in natural gas and electricity distribution and transmission. More information about CU Inc. can be found on the Canadian Utilities Limited website at www.canadianutilities.com.

THE UTILITIES

The Utilities' activities are conducted through regulated businesses in two Business Units within western and northern Canada: Electricity, which includes Electricity Distribution and Electricity Transmission, and Pipelines & Liquids, which includes Natural Gas Distribution and Natural Gas Transmission.

SIMPLIFIED ORGANIZATIONAL STRUCTURE

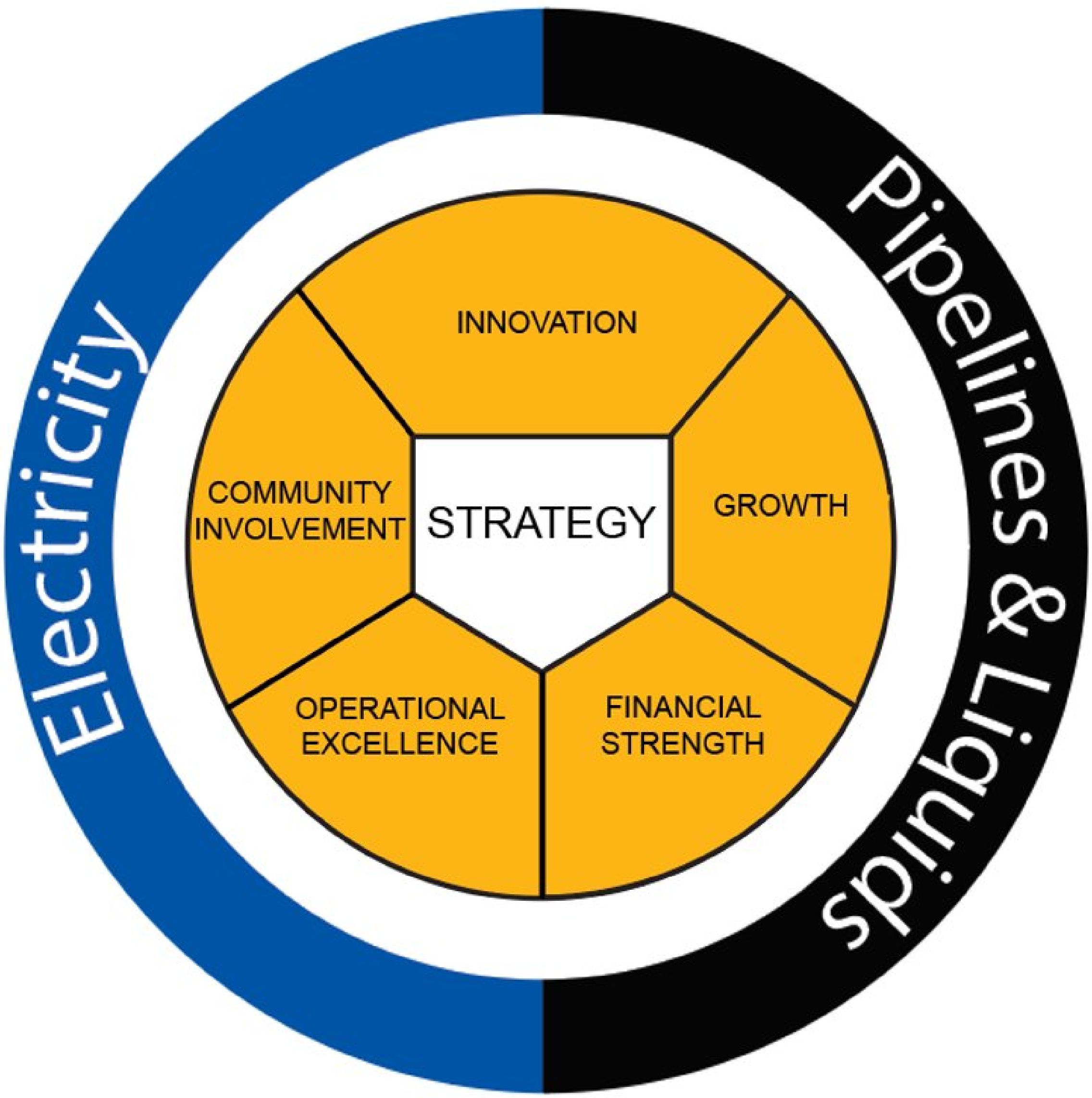


The 2018 Consolidated Financial Statements include the accounts of CU Inc. and all of its subsidiaries. The 2018 Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards (IFRS) and the reporting currency is the Canadian dollar. Certain comparative figures throughout this MD&A have been reclassified to conform to the current presentation.

CU INC. 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."

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 developing significant, value-creating greenfield projects; and fostering continuous improvement.

Acquisition opportunities provide CU Inc. 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 CU Inc. 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 CU Inc. to sustain our operations and to grow through economic cycles, thereby providing long-term financial benefits.

We continuously review CU Inc.'s 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 CU Inc.

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

CU Inc. 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 involves developing partnerships with Indigenous and community groups that may be affected by projects and operations, and building 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 that will serve to benefit non-profit organizations through volunteer efforts, and provide products and services in-kind.

FURTHER COMMENTARY REGARDING STRATEGIES AND COMMITMENTS

CU Inc.'s 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.

More information about CU Inc. can be found on the Canadian Utilities Limited website at www.canadianutilities.com.

CU INC. 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.	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.
GROWTH		
Regulated and long-term contracted capital investment	Invest $1.1 billion across our Utilities.	Invested $1 billion in regulated and long-term contracted assets.
FINANCIAL STRENGTH		
Credit rating	Maintain investment grade credit rating.	Maintained 'A (high)' credit rating with stable outlook with DBRS. Maintained 'A-' with a stable outlook with Standard & Poor's.
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 operating units.	Achieved a 35 per cent reduction in total recordable injury frequency of 1.59 cases/200,000 hours worked. This was achieved through awareness and injury prevention campaigns. These incident rate reductions were achieved across Canadian Utilities and we continue to compare favourably to industry benchmarks.

STRATEGIC PRIORITIES	2018 TARGET	2018 PERFORMANCE
OPERATIONAL EXCELLENCE		
Customer satisfaction	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.
Organizational transformation	Streamline and gain operational efficiencies.	Integrated natural gas distribution and 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.
COMMUNITY INVOLVEMENT		
Indigenous relations	Continue to work together with Indigenous communities to contribute to economic and social development in their communities.	Canadian Utilities 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.
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

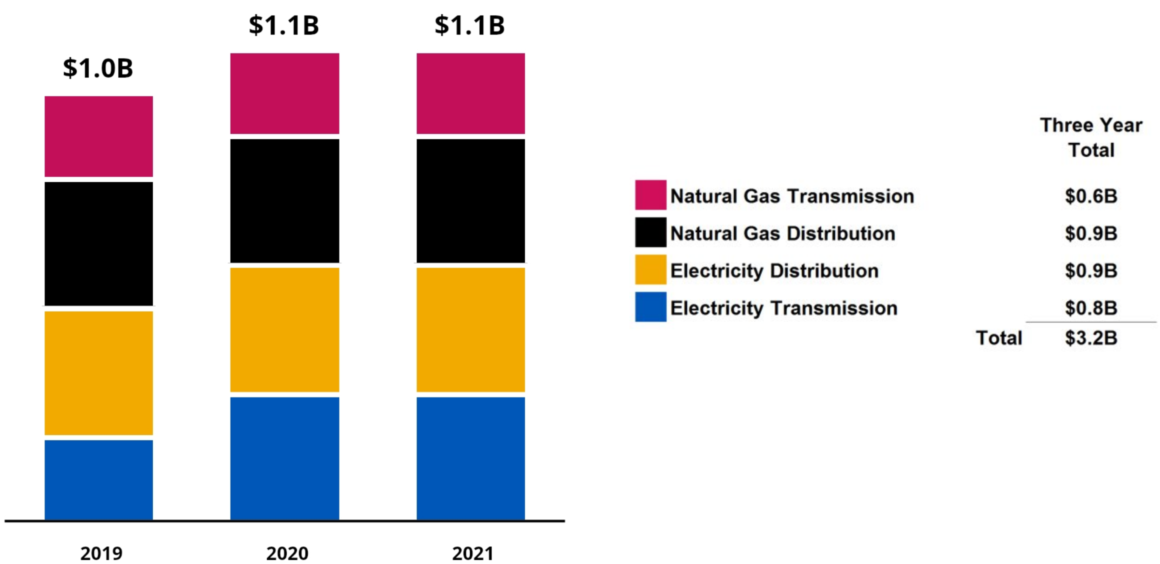
The following table outlines our strategic priorities and targets for 2019.

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. Demonstrate continuous improvement of existing products and services.
GROWTH	
Regulated and long-term contracted capital investment	Invest $1 billion across our Utilities.
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.
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.
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, CU Inc. expects to invest approximately $3.2 billion in regulated utility capital growth projects. This capital expenditure is expected to contribute significant earnings and cash flow. ATCO Electricity Distribution and ATCO Electricity Transmission are planning to invest $1.7 billion, and ATCO Gas and ATCO Pipelines are planning to invest $1.5 billion from 2019 to 2021.

CU Inc. Future Capital Expenditures



UTILITIES PERFORMANCE

REVENUES

Revenues in 2018 were $2,507 million, $119 million lower than in 2017, mainly due to lower flow-through revenues in natural gas distribution for third party transmission rate recovery from customers as well as the revenue impact of Performance Based Regulation rate rebasing in natural gas distribution and electricity distribution.

ADJUSTED EARNINGS

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2018**	**2017**	**Change**	**2018**	**2017**	**Change**
Electricity						
Electricity Distribution	**26**	30	(4)	**112**	134	(22)
Electricity Transmission	**42**	50	(8)	**176**	196	(20)
Total Electricity	**68**	80	(12)	**288**	330	(42)
Pipelines & Liquids						
Natural Gas Distribution	**64**	60	4	**110**	144	(34)
Natural Gas Transmission	**20**	17	3	**72**	68	4
Total Pipelines & Liquids	**84**	77	7	**182**	212	(30)
Corporate & Other and Intersegment Eliminations	**1**	–	1	**5**	–	5
Total Utilities Adjusted Earnings[1]	**153**	157	(4)	**475**	542	(67)

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

In the fourth quarter and full year of 2018, our Utilities earned $153 million and $475 million, $4 million and $67 million lower than the same periods in 2017. Lower earnings were mainly due to the earnings impact of rate rebasing under Alberta's regulated model in electricity distribution and natural gas distribution and lower interim rates approved by the Alberta Utilities Commission (AUC) for electricity transmission, partially offset by growth in rate base across the Utilities.

Detailed information about the activities and financial results of our Utilities businesses is provided in the following sections.

ELECTRICITY

Our electricity activities are conducted by Electricity Distribution and Electricity Transmission and their subsidiaries, ATCO Electric Yukon, Northland Utilities (NWT) and Northland Utilities (Yellowknife). These businesses provide regulated electricity distribution and transmission 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.

PIPELINES & LIQUIDS

Our Pipelines & Liquids activities are conducted through two regulated businesses, Natural Gas Distribution and Natural Gas Transmission.

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 $20 million in the fourth quarter and $72 million in the full year of 2018, $3 million and $4 million higher than the same periods in 2017. Higher earnings were mainly due to continued growth in rate base.

Major Project Updates

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.

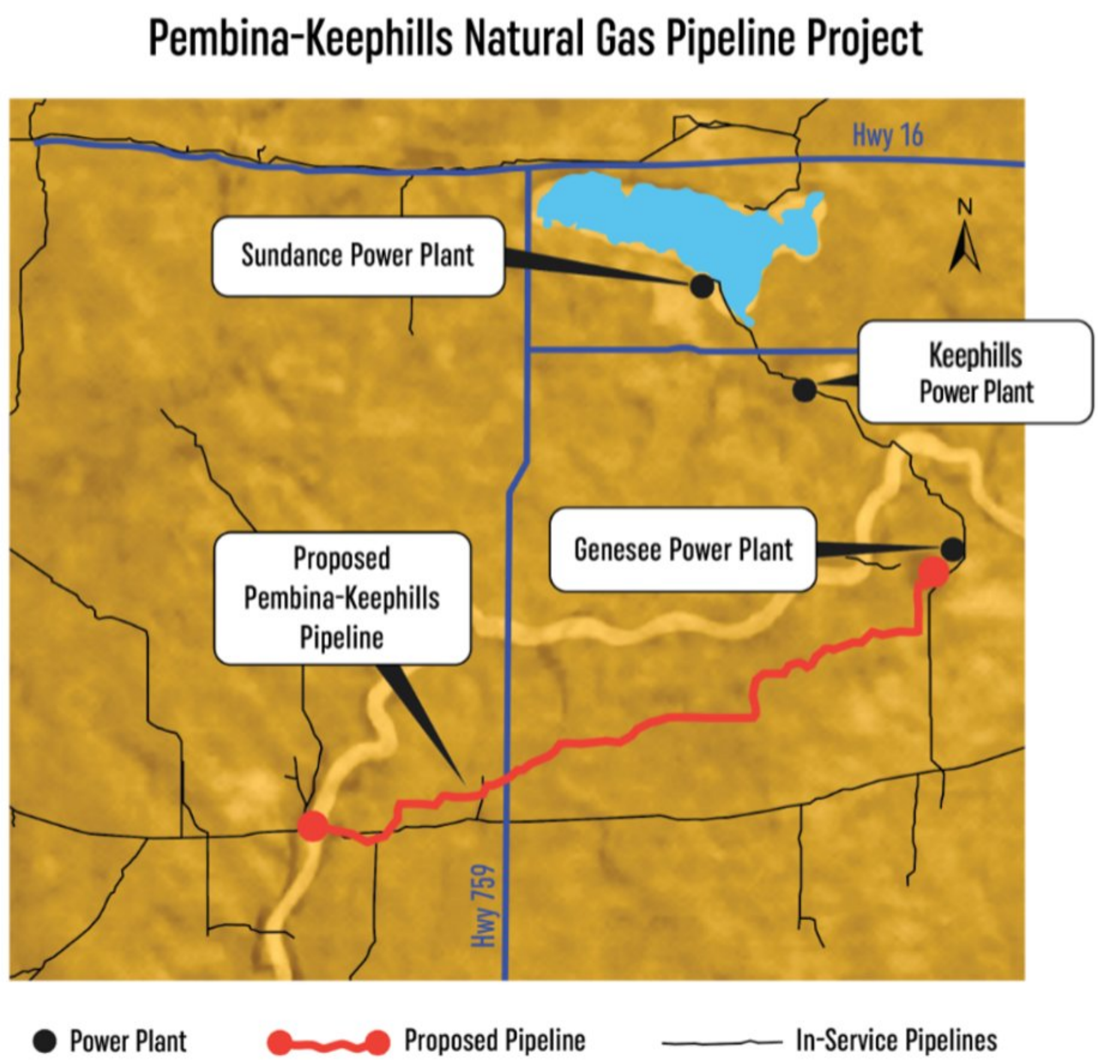
Mains Replacement Program

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.

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.



CORPORATE & OTHER AND INTERSEGMENT ELIMINATIONS

In the fourth quarter and full year of 2018, Corporate & Other and Intersegment Eliminations were $1 million and $5 million higher then the same periods in 2017 mainly due to the timing of certain expenses and interest income.

REGULATORY DEVELOPMENTS

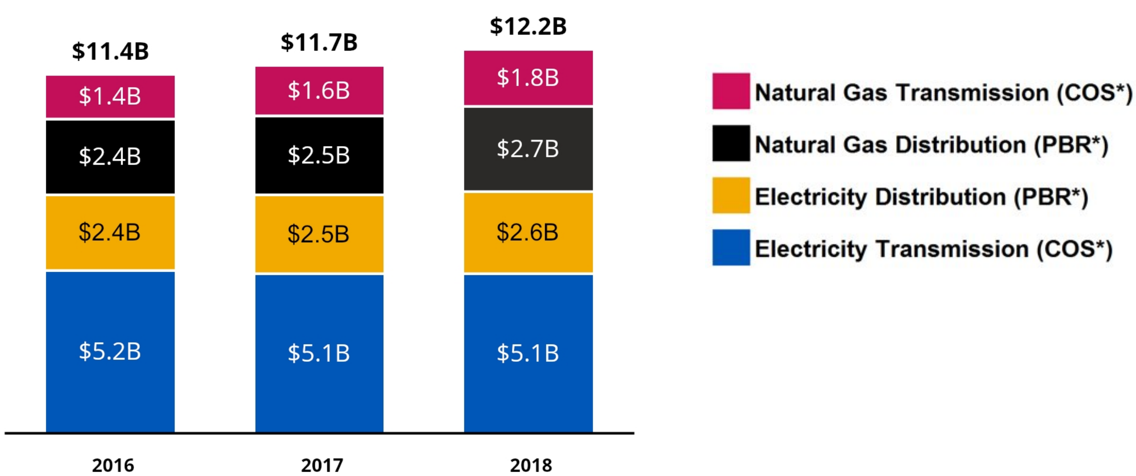
REGULATED BUSINESS MODELS

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.

Regulated Utilities Mid-Year Rate Base



** 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.

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.

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, the controlling share owner of CU Inc., has been publishing external sustainability reports since 2008. These reports include CU Inc.'s operations sustainability performance data. The ATCO 2018 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 will be available on ATCO's website, at www.ATCO.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.

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.

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).

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. CU Inc. 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.

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. 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**	**Change**	**2018**	**2017**	**Change**
Operating costs	**290**	324	(34)	**1,175**	1,189	(14)
Depreciation and amortization	**125**	125	–	**512**	478	34
Net finance costs	**89**	89	–	**347**	339	8
Income taxes	**47**	44	3	**128**	169	(41)

OPERATING COSTS

Operating costs, which are total costs and expenses less depreciation and amortization, decreased by $34 million in the fourth quarter and $14 million in the full year of 2018 compared to the same periods in 2017. Lower operating costs were mainly due to lower flow-through expenses in natural gas distribution and franchise fees.

DEPRECIATION AND AMORTIZATION

In the fourth quarter 2018, depreciation and amortization was comparable to the same period in 2017.

In 2018, depreciation and amortization was $34 million higher compared to 2017. This increase is mainly due to the ongoing capital investment program in the Utilities.

NET FINANCE COSTS

In the fourth quarter 2018, net finance costs were comparable to the same period in 2017.

In 2018, net finance costs were $8 million higher compared to 2017, mainly as a result of incremental debt issued to fund the ongoing capital investment program in the Utilities.

INCOME TAXES

Income taxes increased by $3 million in the fourth quarter of 2018 when compared to the same period in 2017 mainly due to higher earnings before income taxes during the quarter.

Income taxes decreased by $41 million in 2018 when compared to 2017 mainly due to lower earnings before income taxes.

LIQUIDITY AND CAPITAL RESOURCES

Our financial position is supported by Utility 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, the debt and preferred share capital markets and injections of equity from Canadian Utilities Limited. 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 CU Inc. by DBRS and S&P.

	DBRS	S&P
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

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

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

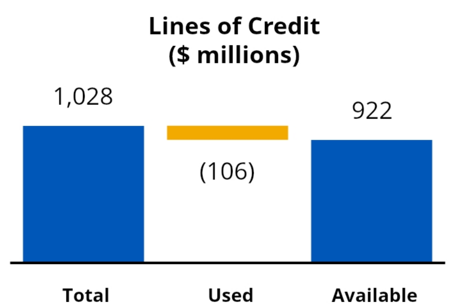
LINES OF CREDIT

At December 31, 2018, CU Inc. and its subsidiaries had the following lines of credit.

($ millions)	Total	Used	Available
Long-term committed	**900**	25	875
Uncommitted	**128**	81	47
Total	**1,028**	106	922

Of the $1,028 million in total credit lines, $128 million was in the form of uncommitted credit facilities with no set maturity date.

The other $900 million in credit lines were committed with maturities between 2020 and 2021, unless extended at the option of the lenders. The majority of the credit lines are provided by Canadian banks.



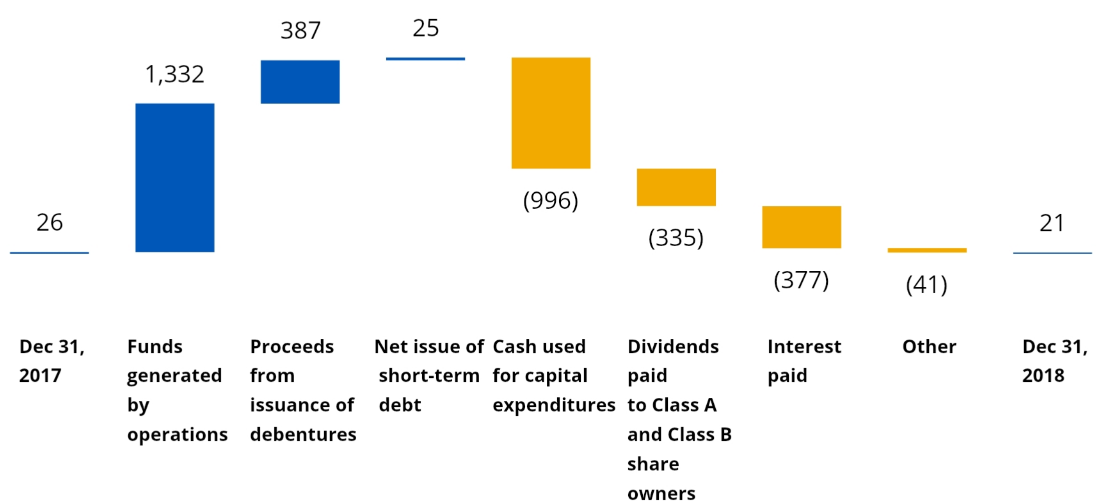
CONSOLIDATED CASH FLOW

At December 31, 2018, the Company's cash position was $21 million, a decrease of $5 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]	**393**	365	28	**1,332**	1,438	(106)
Issue of long-term debt	**386**	430	(44)	**387**	430	(43)
Net issue of short-term debt	**25**	(25)	50	**25**	–	25
Cash used for capital expenditures	**(289)**	(371)	82	**(996)**	(1,107)	111
Dividends paid to Class A and Class B share owners	**(280)**	(100)	(180)	**(335)**	(280)	(55)
Interest paid	**(112)**	(100)	(12)	**(377)**	(363)	(14)
Other	**65**	(127)	192	**(41)**	(116)	75
Increase (decrease) in cash position	**188**	72	116	**(5)**	2	(7)

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

Changes in Consolidated Cash Balances in 2018
($ Millions)



Funds Generated by Operations

Funds generated by operations were $393 million in the fourth quarter of 2018, $28 million higher than the same period in 2017. The increase was mainly due to higher customer contributions for capital expenditures and lower cash income taxes paid.

Funds generated by operations were $1,332 million in 2018, $106 million lower than in 2017. The decrease was mainly due to lower cash earnings as a result of the settlement of regulatory decisions, and the impact of rate re-basing under Alberta's regulated model for natural gas distribution and electricity distribution.

Cash Used for Capital Expenditures

Capital expenditures were $289 million in the fourth quarter and $996 million in the full year of 2018, $82 million and $111 million lower than the same periods in 2017. The decrease was mainly due to lower planned capital spending at natural gas distribution.

Capital expenditures 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		
($ millions)	**2018**	**2017**	**Change**	**2018**	**2017**	**Change**
Electricity Distribution	**63**	66	(3)	**227**	227	–
Electricity Transmission	**81**	83	(2)	**240**	211	29
Natural Gas Distribution	**80**	113	(33)	**290**	372	(82)
Natural Gas Transmission	**65**	109	(44)	**239**	297	(58)
Total [(1)]	**289**	371	(82)	**996**	1,107	(111)

(1) Includes additions to property, plant and equipment, intangibles and $4 million and $19 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

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.

SHARE CAPITAL

CU Inc. equity securities consist of Class A shares and Class B shares.

At February 26, 2019, the Company had outstanding 3,570,322 Class A shares and 2,188,262 Class B shares.

QUARTERLY INFORMATION

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

($ millions)	Q1 2018	Q2 2018	Q3 2018	Q4 2018
Revenues	751	532	547	**677**
Earnings (loss) for the period	169	(10)	60	**126**
Adjusted earnings				
Electricity	73	77	70	**68**
Pipelines & Liquids	85	15	(2)	**84**
Corporate & Other and Intersegment Eliminations	–	–	4	**1**
Total adjusted earnings	158	92	72	**153**

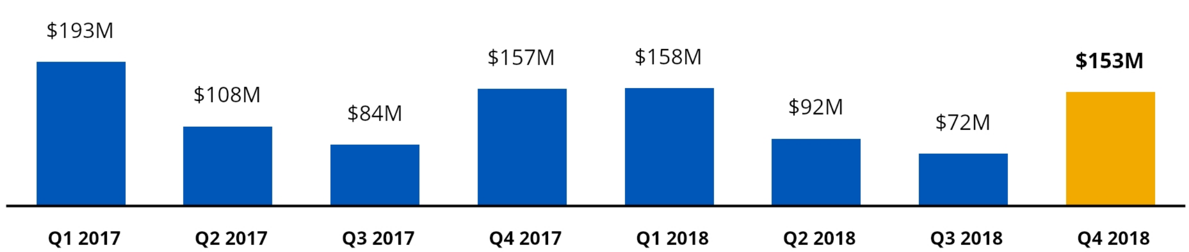
($ millions)	Q1 2017	Q2 2017	Q3 2017	Q4 2017
Revenues	775	588	567	696
Earnings for the period	175	86	76	114
Adjusted earnings				
Electricity	95	81	74	80
Pipelines & Liquids	98	27	10	77
Corporate & Other and Intersegment Eliminations	–	–	–	–
Total adjusted earnings	193	108	84	157

Adjusted Earnings

Our financial results over the previous eight quarters reflect the large capital expenditure made by the Utilities. These investments earn a return under a regulated business model and drive growth in adjusted earnings. Our earnings have also been impacted by the timing of certain major regulatory decisions. In addition, interim results will vary due to the seasonal nature of demand for electricity and natural gas.

In 2017, higher earnings were mainly due to rate base growth. Higher first quarter earnings were in part due to lower operating costs. Lower second quarter earnings were in part 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. Lower third quarter earnings were in part due to the impact of the 2013 to 2014 Deferral Accounts decision in electricity transmission. Higher fourth quarter earnings were mainly due to growth in rate base across our Utilities and growth in customers in our natural gas distribution business.

In the first quarter of 2018, higher seasonal demand in natural gas distribution and growth in rate base across the Utilities were partially offset by rate rebasing under Alberta's regulated model in electricity distribution and natural gas distribution. In the second, third, and fourth quarters of 2018, lower earnings were mainly due to rate rebasing under Alberta's regulated model in electricity distribution and natural gas distribution and lower interim rates approved by the Alberta Utilities Commission (AUC) for electricity transmission, partially offset by growth in rate base across the Utilities, and the timing of regulatory decisions and higher seasonal demand in natural gas distribution.



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 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 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.

<table>
<tr><td colspan="3">Business Risk: Capital Expenditure</td></tr>
<tr><td>Businesses Impacted:
• Utilities</td><td>Associated Strategies:
• Growth</td><td>
• Financial Strength</td></tr>
<tr><td>Description and Context</td><td colspan="2">Risk Management Approach</td></tr>
<tr><td>The Company is subject to the normal risks associated with major capital projects, including cancellations, delays and cost increases.</td><td colspan="2">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.

Planned capital expenditures for the Utilities are based on the following significant assumptions: projects identified by the AESO will proceed as currently scheduled; the remaining planned capital expenditures are required to maintain safe and reliable service and meet planned growth in the 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.</td></tr>
</table>

<table>
<tr><td colspan="2">Business Risk: Climate Change</td></tr>
<tr><td>Businesses Impacted:
• Utilities</td><td>Associated Strategies:
• Operational Excellence
• Innovation</td></tr>
<tr><td>Description and Context</td><td>Risk Management Approach</td></tr>
<tr><td>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.

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.</td><td>Legislative Risks
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
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.</td></tr>
</table>

<table>
<tr><td colspan="2">Business Risk: Credit Risk</td></tr>
<tr><td>Businesses Impacted:
• Utilities</td><td>Associated Strategies:
• Financial Strength</td></tr>
<tr><td>Description and Context</td><td>Risk Management Approach</td></tr>
<tr><td>For cash and cash equivalents and accounts receivable and contract assets, credit risk represents the carrying amount on the consolidated balance sheet.</td><td>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.

The 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.</td></tr>
</table>

Business Risk: Cybersecurity	
Businesses Impacted: • Utilities	**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.	CU Inc. 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: Financing	
Businesses Impacted: • Utilities	**Associated Strategies:** • Financial Strength
Description and Context	***Risk Management Approach***
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.	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: • Utilities	**Associated Strategies:** • Financial Strength
Description and Context	***Risk Management Approach***
Foreign currency exchange rate risk arises from financial instruments denominated in a currency other than the functional currency.	The Company enters into foreign currency forward contracts to manage its exposure to exchange rate risk arising on certain agreements denominated in U.S. dollars. All such instruments are used only to manage risk and not for trading purposes.

Business Risk: Pipeline Integrity	
Businesses Impacted: • Natural Gas Distribution • Natural Gas Transmission	**Associated Strategies:** • Operational Excellence • Community Involvement
Description and Context	***Risk Management Approach***
The Pipelines & Liquids 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 mains replacement programs. The Company also carries property and liability insurance.

Business Risk: Political	
Businesses Impacted: • Utilities	**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.

Business Risk: Regulated Operations	
Businesses Impacted: • Utilities	**Associated Strategies:** • Growth • Operational Excellence • Financial Strength
Description and Context	***Risk Management Approach***
The 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.	The 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. The 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 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: • Utilities	**Associated Strategies:** • Innovation • Financial Strength • Operational Excellence • Growth
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 CU Inc.'s 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 business unit 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: • Utilities	**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 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 has a policy not to invest any of its cash balances in asset-backed securities. At December 31, 2018, the Company’s cash position was $21 million and there were available committed and uncommitted lines of credit of approximately $922 million 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	410	–	–	–	–	–
Accounts payable to parent and affiliate companies	42	–	–	–	–	–
Long-term debt:						
Principal	480	105	160	125	100	7,025
Interest expense	378	353	341	327	316	6,530
	1,310	458	501	452	416	13,555
Commitments						
Operating leases	7	7	5	3	3	–
Purchase obligations:						
Operating and maintenance agreements	287	296	291	287	285	266
Capital expenditures	68	–	–	–	–	–
Other	10	–	–	–	–	–
	372	303	296	290	288	266
Total	1,682	761	797	742	704	13,821

NON-GAAP AND ADDITIONAL GAAP MEASURES

Funds generated by operations is defined as cash flow from operations before changes in non-cash working capital. 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.

Adjusted earnings are defined as earnings for the period after adjusting for the timing of revenues and expenses associated with rate-regulated activities and dividends on equity preferred shares of the Company. 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 for the period is presented in this MD&A. Adjusted earnings is an additional GAAP measure presented in Note 4 of the 2018 Consolidated Financial Statements.

RECONCILIATION OF ADJUSTED EARNINGS TO EARNINGS FOR THE PERIOD

Adjusted earnings are earnings for the period after adjusting for the timing of revenues and expenses associated with rate-regulated activities and dividends on equity preferred shares of the Company. 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 than IFRS earnings.

($ millions)					Three Months Ended December 31
2018 2017	Electricity	Pipelines & Liquids	Corporate & Other	Intersegment Eliminations	Consolidated
Revenues	**373**	**305**	**–**	**(1)**	**677**
	321	376	–	(1)	696
Adjusted earnings	**68**	**84**	**1**	**–**	**153**
	80	77	–	–	157
Rate-regulated activities	**14**	**(44)**	**–**	**–**	**(30)**
	(51)	6	–	–	(45)
Dividends on equity preferred shares of the Company	**2**	**1**	**–**	**–**	**3**
	1	1	–	–	2
Earnings for the period	**84**	**41**	**1**	**–**	**126**
	30	84	–	–	114

($ millions)					Year Ended December 31
2018 2017	Electricity	Pipelines & Liquids	Corporate & Other	Intersegment Eliminations	Consolidated
Revenues	**1,318**	**1,190**	**–**	**(1)**	**2,507**
	1,273	1,355	–	(2)	2,626
Adjusted earnings	**288**	**182**	**1**	**4**	**475**
	330	212	–	–	542
Restructuring and other costs	**(25)**	**(14)**	**–**	**–**	**(39)**
	–	–	–	–	–
Rate-regulated activities	**(55)**	**(47)**	**–**	**–**	**(102)**
	(131)	30	–	–	(101)
Dividends on equity preferred shares of the Company	**6**	**5**	**–**	**–**	**11**
	5	5	–	–	10
Earnings for the period	**214**	**126**	**1**	**4**	**345**
	204	247	–	–	451

RESTRUCTURING AND OTHER COSTS

In the second quarter of 2018, the Company recorded restructuring and other costs of $39 million, after-tax, that were not in the normal course of business. These costs mainly relate to staff reductions and associated severance costs, as well as costs related to decisions to discontinue certain projects that no longer represent long-term strategic value to the Company.

RATE-REGULATED ACTIVITIES

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

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

The Company uses standards issued by the Financial Accounting Standards Board (FASB) in the United States as another source of generally accepted accounting principles to account for rate-regulated activities in its internal reporting provided to the CODM. The CODM believes that earnings presented in accordance with the FASB standards are a better representation of the operating results of the Company's rate-regulated activities. Therefore, the Company presents adjusted earnings as part of its segmented disclosures on this basis. Rate-regulated accounting (RRA) standards impact the timing of how certain revenues and expenses are recognized when compared to non-rate regulated activities, to appropriately reflect the economic impact of a 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)	**(25)**	(26)	1	**(103)**	(99)	(4)
Impact of warmer temperatures (2)	**(6)**	–	(6)	**–**	(4)	4
Regulatory decisions received (4)	**–**	1	(1)	**–**	17	(17)
Settlement of regulatory decisions and other items (5)	**(15)**	(27)	12	**(85)**	(76)	(9)
	(30)	(45)	15	**(102)**	(101)	(1)

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

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

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

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

(5) 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 and impact of warmer temperatures.	The Company recognizes revenues associated with recoverable costs in advance of future billings to customers.	The Company recognizes costs when they are incurred, but does not recognize their recovery until customer rates are changed and amounts are collected through future billings.
Regulatory decisions received	For further details on regulatory decisions that caused a timing adjustment financial impact, refer to the Regulatory Developments section in this MD&A.	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 FINANCIAL INFORMATION

OFF BALANCE SHEET ARRANGEMENTS

CU Inc. 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 22 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 27 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 $10 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.

GLOSSARY

AUC means the Alberta Utilities Commission.

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

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 CU Inc. and, unless the context otherwise requires, includes its subsidiaries.

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.

IFRS means International Financial Reporting Standards.

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

Km means kilometre.

PBR means Performance Based Regulation.

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)	**2018**	**2017**
Revenues	**677**	696
Costs and expenses		
Salaries, wages and benefits	**(58)**	(71)
Energy transmission and transportation	**(44)**	(49)
Plant and equipment maintenance	**(34)**	(48)
Fuel costs	**(2)**	(5)
Purchased power	**(23)**	(21)
Depreciation and amortization	**(125)**	(125)
Franchise fees	**(50)**	(55)
Property and other taxes	**(17)**	(15)
Other	**(62)**	(60)
	(415)	(449)
Operating profit	**262**	247
Interest income	**4**	3
Interest expense	**(93)**	(92)
Net finance costs	**(89)**	(89)
Earnings before income taxes	**173**	158
Income taxes	**(47)**	(44)
Earnings for the period	**126**	114

CONSOLIDATED STATEMENT OF CASH FLOWS

	Three Months Ended December 31	
(millions of Canadian Dollars)	**2018**	**2017**
Operating activities		
Earnings for the period	**126**	114
Adjustments to reconcile earnings to cash flows from operating activities	**267**	251
Changes in non-cash working capital	**40**	(6)
Cash flows from operating activities	**433**	359
Investing activities		
Additions to property, plant and equipment	**(229)**	(338)
Additions to intangibles	**(56)**	(29)
Changes in non-cash working capital	**19**	26
Other	**(1)**	1
Cash flows used in investing activities	**(267)**	(340)
Financing activities		
Net issue (repayment) of short-term debt	**25**	(25)
Issue of long-term debt	**386**	430
Repayment of long-term debt	**–**	(150)
Dividends paid on equity preferred shares	**(3)**	(2)
Dividends paid to Class A and Class B share owner	**(280)**	(100)
Interest paid	**(112)**	(100)
Interest received from parent and affiliate companies	**9**	4
Long-term debt issue costs	**(3)**	(3)
Other	**–**	(1)
Cash flows from financing activities	**22**	53
Increase in cash position	**188**	72
Beginning of period	**(167)**	(46)
End of period	**21**	26