CU INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2019

March 6, 2020

This Annual Information Form (AIF) is meant to help readers understand the business and operations of CU Inc. (our, we, us, or the Company).

Unless otherwise noted, the information contained within this AIF is presented as at December 31, 2019.

The Company is controlled by Canadian Utilities Limited, which in turn is controlled by ATCO Ltd. and its controlling share owners, Sentgraf Enterprises Ltd. and its controlling share owner, the Southern family.

Terms used throughout this AIF are defined in the Glossary at the end of this document.

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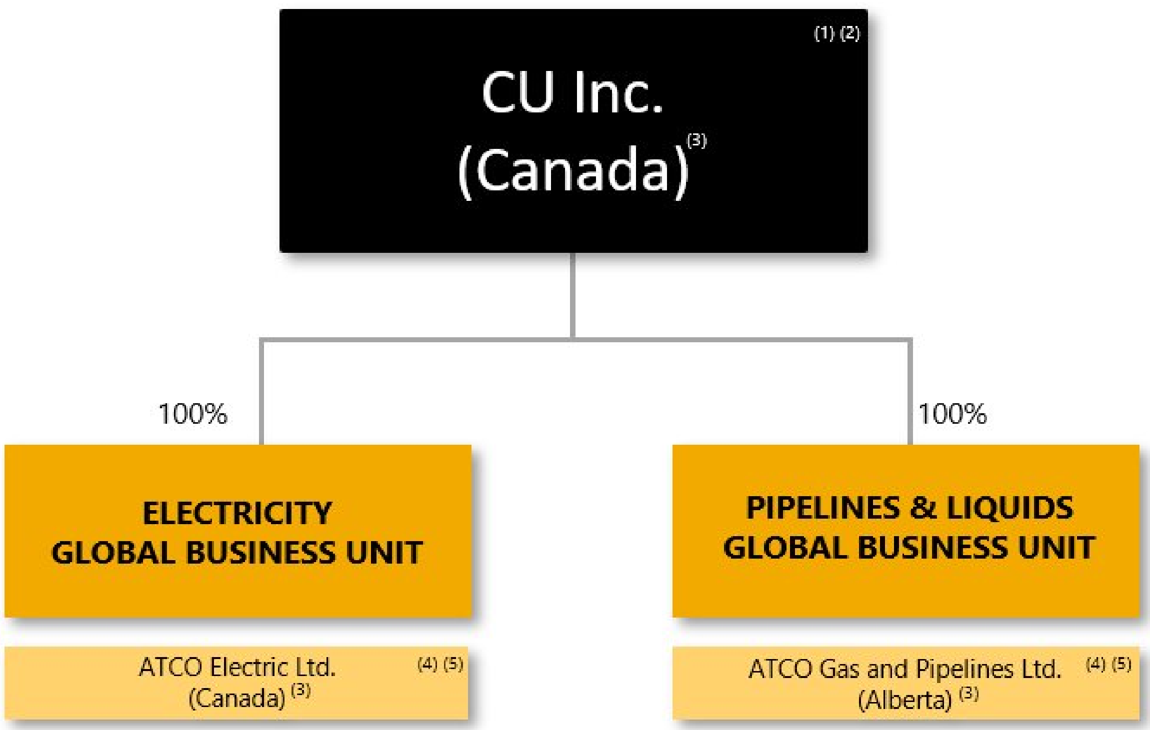
CORPORATE STRUCTURE

CU Inc. was incorporated under the laws of Canada on March 12, 1999. The address of the head office and registered office of the Company is 4th Floor, West Building, 5302 Forand Street S.W., Calgary, Alberta, T3E 8B4.

SIMPLIFIED INTERCORPORATE RELATIONSHIPS

CU Inc. is a wholly-owned subsidiary of Canadian Utilities Limited, an ATCO company. CU Inc. is an Alberta-based corporation with approximately 3,600 employees and assets of $17 billion comprised of rate regulated utility operations in natural gas pipelines and electricity transmission and distribution. More information about CU Inc. can be found on the Canadian Utilities Limited website at www.canadianutilities.com.

The following chart includes the names of the Company's principal Business Units, as well as the principal subsidiaries comprising the Business Units, and the jurisdictions in which they were incorporated. The chart also shows the percentages of such subsidiaries' shares the Company beneficially owns, controls or directs, either directly or indirectly.



(1) *The organizational chart does not include all of the subsidiaries of the Company. The assets and revenues of excluded subsidiaries in the aggregate did not exceed 20 per cent of the total consolidated assets or total consolidated revenues of the Company as at December 31, 2019.*

(2) *The Company owns all of the voting and non-voting shares of the subsidiaries.*

(3) *Jurisdiction in which the company was incorporated.*

(4) *Regulated businesses include Natural Gas Distribution, Natural Gas Transmission, Electric Distribution, and Electric Transmission.*

(5) *ATCO Gas and Pipelines Ltd. and ATCO Electric Ltd. (Alberta Utilities) are wholly owned subsidiaries of CU Inc., which is 100 per cent owned by Canadian Utilities.*

BUSINESS DESCRIPTION

The activities of the Company are conducted through the Utilities' regulated businesses in two Business Units within Western and Northern Canada: Electricity, which includes electricity distribution and transmission and Pipelines & Liquids, which includes natural gas distribution and transmission.

ELECTRICITY BUSINESS UNIT

ELECTRICITY DISTRIBUTION AND TRANSMISSION

The activity areas in which electricity distribution and electricity transmission operate in Western and Northern Canada are shown in the map below.

Electricity distribution and transmission transmit and deliver electricity to 242 communities and rural areas in east-central and Northern Alberta. Among those served are the communities of Drumheller, Lloydminster, Grande Prairie, and Fort McMurray as well as the oil sands areas near Fort McMurray and the heavy oil areas near Cold Lake and Peace River.

Electricity distribution and transmission is headquartered in Edmonton and has 38 offices throughout its service area. Electric utility service is also provided to three communities in Saskatchewan. ATCO Electric Yukon (AEY) serves 19 communities in the Yukon, including the capital city of Whitehorse, and one community in British Columbia. Northland Utilities is a partnership between ATCO Ltd. and Denendeh Investments Incorporated, which represents the 27 Dene First Nations of the Northwest Territories. Northland Utilities has two operating divisions: Northland Utilities (NWT) Limited and Northland Utilities (Yellowknife) Limited (NUY). NUY and NWT serve nine communities in the Northwest Territories, including the capital city of Yellowknife.

Approximately 662,000 people live in the principal markets for electric utility service by electricity distribution and transmission and its subsidiaries NUY, NWT and AEY. Service is provided to approximately 260,000 customers. Electricity distribution and transmission has been assigned approximately 65 per cent of the designated service area within Alberta. This service area contains approximately 14 per cent of the provincial electrical load and 13 per cent of the population.

The numbers of customers served by electricity distribution and transmission, NUY, NWT and AEY at the end of 2019 and 2018 are shown below.

	2019		2018	
	Number	**%**	**Number**	**%**
Industrial	**10,295**	**4**	10,455	4
Commercial	**34,686**	**14**	34,532	14
Residential	**182,726**	**70**	181,373	70
Rural, REA and other	**32,042**	**12**	31,911	12
Total	**259,749**	**100**	258,271	100

Electricity distributed to the various classes of customers in 2019 and 2018 is shown below.

	2019		2018	
	GWh	**%**	**GWh**	**%**
Industrial	**8,392**	**66**	8,586	66
Commercial	**2,395**	**19**	2,438	19
Residential	**1,321**	**10**	1,342	10
Rural, REA and other	**556**	**5**	562	5
Total	**12,664**	**100**	12,928	100

Electricity distribution and transmission, NUY, NWT and AEY own and operate extensive electricity transmission and distribution systems. The systems consist of approximately 11,000 km of transmission lines and 60,000 km of distribution lines. In addition, electricity distribution and transmission delivers power to and operates approximately 4,000 km of distribution lines owned by Rural Electrification Associations (REA).

Electricity distribution and transmission, NUY, NWT and AEY own and operate 23 diesel and hydro-generating plants, with an aggregate nameplate capacity of 40-MW in Alberta, the Yukon and Northwest Territories. The maximum peak load demand for these plants during 2019 was 19-MW.

Electricity distribution and transmission, AEY, NUY and NWT distribute electricity to incorporated communities under the authority of franchises or by-laws. In rural areas, electricity is distributed by approvals, permits or orders under applicable statutes.

The franchises under which service is provided in incorporated communities in Alberta and the Northwest Territories have been granted for up to 20 years. These franchises are exclusive to electricity distribution and transmission, NUY or NWT and are renewable by agreement. If any franchise is not renewed, it remains in effect until either party, with the approval of the regulatory authority, terminates it on six months written notice.

On termination of a franchise, the municipality may purchase the facilities used under that franchise at a price to be agreed on or, failing agreement, to be determined by the regulatory authority. The franchise under which service is provided in the Yukon was granted under the Public Utilities Act (Yukon) and has no set expiry date.

Under the Electric Utilities Act (Alberta) (EUA), wholesale tariffs for electricity transmission must be approved by the Alberta Utilities Commission (AUC). Transmission tariffs allow any owner of a generating unit to access the Alberta transmission system and thus facilitate the sale of its power. The same transmission tariff is charged to each distribution utility or customer directly connected to the transmission system, regardless of location.

Transmission costs are equalized by having each owner of transmission facilities charge its costs to the Alberta Electric System Operator (AESO). The AESO then aggregates these costs and charges a common transmission rate to all transmission system users.

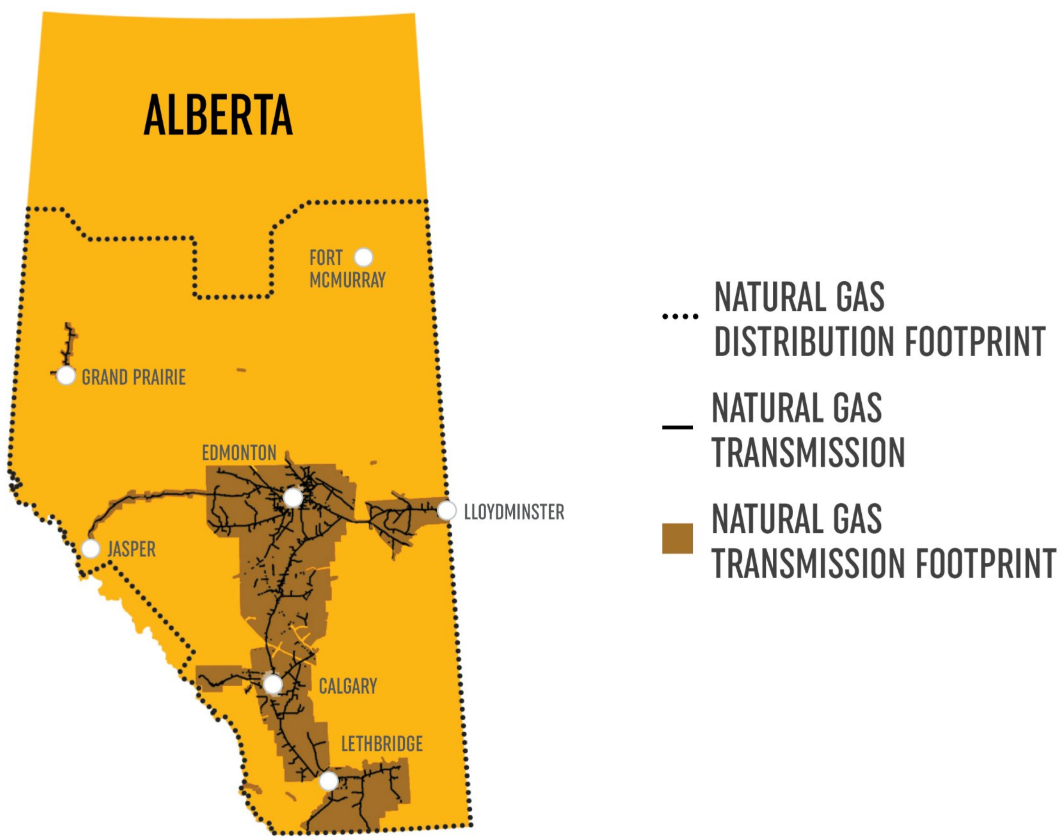
The Transmission Regulation under the EUA stipulates that new transmission projects will be assigned to transmission facility owners based on the service areas of the distribution companies they have been historically affiliated with. Facilities ownership will change at service area boundaries, except where, in the AESO's opinion, only a small portion of the project is in another service area. This rule applies to all transmission projects except inter-provincial inter-tie projects and those deemed "critical" by the Government of Alberta.

PIPELINES & LIQUIDS BUSINESS UNIT

OVERVIEW

Pipelines & Liquids activities are conducted through (i) regulated natural gas distribution by ATCO Gas, a division of ATCO Gas and Pipelines Ltd. (AGP) and (ii) regulated natural gas transmission by ATCO Pipelines, a division of AGP.

The following map shows the areas served by natural gas distribution and natural gas transmission in Alberta.



NATURAL GAS DISTRIBUTION

Natural gas distribution delivers natural gas throughout Alberta and in the Lloydminster area of Saskatchewan and serves approximately 1.2 million customers in nearly 300 Alberta communities.

Natural gas distribution's principal markets for distributing natural gas are in Edmonton, Calgary, Airdrie, Fort McMurray, Grande Prairie, Lethbridge, Lloydminster, Red Deer, Spruce Grove, St. Albert and Sherwood Park. These communities have a combined population of approximately 2.9 million. Approximately 76 per cent of natural gas distribution's customers were located in these 11 communities in 2019. Also served are 279 smaller communities as well as rural areas with a combined population of approximately 770,000.

The number of customers served by natural gas distribution at the end of 2019 and 2018 is shown below.

		2019		2018
	Number	%	Number	%
Residential	**1,131,342**	**92**	1,117,109	92
Commercial	**100,698**	**8**	99,363	8
Industrial	**346**	**–**	344	–
Other	**7**	**–**	3	–
Total	**1,232,393**	**100**	1,216,819	100

The quantity of natural gas distributed by natural gas distribution in 2019 and 2018 is shown below.

		2019		2018
	PJ	%	PJ	%
Residential	**133.3**	**47**	129.5	47
Commercial	**137.3**	**48**	133.3	48
Industrial	**13.7**	**5**	13.9	5
Other	**0.3**	**–**	0.3	–
Total	**284.6**	**100**	277.0	100

Natural gas distribution owns and operates approximately 41,000 km of distribution mains. It also owns service and maintenance facilities in major centres in Alberta.

Natural gas distribution delivers natural gas in incorporated communities under the authority of franchises or by-laws and in rural areas under approvals, permits or orders issued through applicable statutes. It currently has 168 franchise agreements with communities throughout Alberta. These franchise agreements detail the rights granted to natural gas distribution and its obligations to deliver natural gas services to consumers in the municipality.

All franchises are exclusive to natural gas distribution and are renewable by agreement for additional periods of up to 20 years. If any franchise is not renewed, it remains in effect until either party, with the approval of the prevailing regulatory authority, terminates it on six months written notice. On termination, the municipality may purchase the facilities used in connection with that franchise at a price to be agreed on or, failing agreement, to be determined by the prevailing regulatory authority.

In Edmonton, distribution of natural gas is carried on under the authority of an exclusive franchise. Natural gas distribution has a 20-year franchise agreement with Edmonton that will expire on July 21, 2030. The franchises under which service is provided in other incorporated communities in Alberta have been granted for up to 20 years.

In Calgary, the distribution of natural gas operates under a municipal by-law. The rights of natural gas distribution under this by-law, while not exclusive, are unrestricted as to term. The by-law does not confer any right for Calgary to acquire the facilities used in providing the service.

NATURAL GAS TRANSMISSION

Natural gas transmission owns and operates natural gas transmission pipelines and facilities in Alberta. The business receives natural gas on its pipeline system from various gas processing plants as well as from connections with other natural gas transmission systems, and transports the gas to end users within the province such as local distribution utilities and industrial customers, or to other transmission pipeline systems, primarily for export out of the province.

Natural gas transmission owns and operates an extensive natural gas transmission system. The system currently consists of approximately 9,100 km of pipelines, 16 compressor sites, approximately 3,700 receipt and delivery points, and a salt cavern natural gas storage peaking facility near Fort Saskatchewan, Alberta. The system has 179 producer receipt points, one interconnection with Alliance Pipeline, and one interconnection with Many Islands Pipelines. Peak delivery capability of the natural gas transmission system is 3.9 billion cubic feet per day.

THREE YEAR HISTORY

Summarized below are major events that occurred in the Company and the significant conditions that influenced the Company's development during the past three years.

FINANCIAL RESULTS SUMMARY

Each Business Unit's contribution to the Company's consolidated revenues and adjusted earnings is shown in the charts below.

Revenues [1]		**2019**		**2018**		**2017**
	($ millions)	*%*	*($ millions)*	*%*	*($ millions)*	*%*
Electricity	**1,418**	**51**	1,318	53	1,273	48
Pipelines & Liquids	**1,371**	**49**	1,190	47	1,355	52
Corporate & Other and Intersegment Eliminations	**(2)**	–	(1)	–	(2)	-
Total	**2,787**	**100**	2,507	100	2,626	100

(1) The above data has been extracted from Note 4 ("Segmented Information") of the 2019 Consolidated Financial Statements which are prepared in accordance with International Financial Reporting Standards (IFRS).

Revenues in 2018 were $119 million lower compared to 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.

Revenues in 2019 were $280 million higher compared to 2018. Higher revenues were mainly due to higher flow-through revenues in natural gas distribution for third party franchise and transmission fees, and higher revenue from growth in the regulated rate base and number of natural gas distribution customers.

Adjusted Earnings [1] [2]		**2019**		**2018**		**2017**
	($ millions)	***%***	*($ millions)*	***%***	*($ millions)*	***%***
Electricity	**329**	**63**	288	61	330	61
Pipelines & Liquids	**194**	**37**	182	38	212	39
Corporate & Other and Intersegment Eliminations	**1**	–	5	1	-	-
Total	**524**	**100**	475	100	542	100

(1) The above data has been extracted from Note 4 ("Segmented Information") of the 2019 Consolidated Financial Statements which are prepared in accordance with International Financial Reporting Standards (IFRS).

(2) 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 in 2018 were $67 million lower compared to 2017, 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.

Adjusted earnings in 2019 were $49 million higher than 2018. Higher earnings were mainly due to favourable electricity and natural gas transmission regulatory decisions, continued growth in the rate base, the continued implementation of cost efficiencies across the company, and lower income taxes.

ELECTRICITY BUSINESS UNIT

PERFORMANCE OVERVIEW

Electricity Distribution and Transmission

In addition to the continued investment in utility infrastructure in Alberta, the financial results of electricity distribution and transmission have been influenced by several regulatory decisions. Electricity distribution achieved lower earnings in 2018 compared to 2017, mainly due to regulatory decisions specific to its performance based regulation (PBR) rebasing on a new five-year term. The lower earnings from PBR rebasing were partially offset by earnings from continued growth in the rate base, additional return on equity (ROE) due to the PBR efficiency carry-over mechanism (ECM), and continued cost 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.

Adjusted earnings in 2019 were higher compared to 2018 mainly due to continued growth in the rate base, additional earnings from the 2018-2019 electricity transmission general tariff application decision, cost efficiencies and lower income taxes.

Regulatory decisions are described in the Regulatory Developments section of this AIF.

CAPITAL INVESTMENT

Total capital expenditure for Electricity in the last three years is provided in the table below.

			Year Ended	December 31
($ millions)	**Total**	**2019**	**2018**	**2017**
Electricity Distribution	678	**224**	227	227
Electricity Transmission	616	**165**	240	211
Total	1,294	**389**	467	438

Electricity's total capital expenditures over the last three years were $1.3 billion.

In addition to the continued investment in utility infrastructure, the financial results of electricity distribution have also been influenced by several regulatory decisions. The regulatory decisions are described in the "Regulatory Developments" section in the Company's Management's Discussion and Analysis (MD&A) and are incorporated herein by reference. The MD&A may be found on SEDAR at www.sedar.com.

PIPELINES & LIQUIDS BUSINESS UNIT

PERFORMANCE OVERVIEW

Natural Gas Distribution

Natural gas distribution's financial results in the last three years were impacted by regulatory decisions, rate base growth from capital investments, cost efficiencies and lower income taxes. Natural gas distribution achieved lower earnings in 2018 compared to 2017, mainly due to regulatory decisions specific to its performance based regulation (PBR) rebasing on a new five-year term. The lower earnings from PBR rebasing were partially offset by earnings from continued growth in the rate base and customers, additional return on equity (ROE) due to the PBR efficiency carry-over mechanism (ECM), and continued cost 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.

Adjusted earnings in 2019 were higher compared to 2018 mainly due to cost efficiencies, ongoing growth in the rate base, an increase in customers, and regulatory decisions.

Regulatory decisions are described in the Regulatory Developments section of this AIF.

Natural Gas Transmission

Natural gas transmission's financial results in the last three years were affected by rate base growth from capital investments and regulatory decisions. Natural gas transmission achieved higher earnings in 2019 compared to 2018 and 2017, mainly due to continued growth in the rate base.

Regulatory decisions are described in the Regulatory Developments section of this AIF.

CAPITAL INVESTMENT

Total capital expenditure for Pipelines & Liquids in the last three years is provided in the table below.

				Year Ended December 31
($ millions)	**Total**	**2019**	**2018**	**2017**
Natural Gas Distribution	946	**284**	290	372
Natural Gas Transmission	829	**293**	239	297
Total	1,775	**577**	529	669

Pipelines & Liquids' total capital investment over the last three years amounted to $1.8 billion. The largest expenditures were the replacement of aging infrastructure, installation of new customer connections as well as the AUC-approved Urban Pipeline Replacement program.

Urban Pipelines Replacement Program

Under the Urban Pipelines Replacement (UPR) program, Pipelines & Liquids 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 program is estimated to be approximately $900 million. Natural gas distribution and natural gas transmission have invested $795 million in the UPR program since its inception.

Mains Replacement Program

Natural gas distribution has two mains replacement programs which were approved in 2011, the plastic mains and the steel mains replacement programs. The plastic mains program includes 8,000-km of polyvinyl chloride (PVC) and early generation polyethylene (PE) pipe that are planned for replacement by 2031. Natural gas distribution has replaced 2,015-km of PVC and PE pipe since the approval of this program. The steel mains program includes 9,000-km of steel pipe that is monitored and continually evaluated for replacement based on the performance history. Natural gas distribution has replaced 327-km of steel pipe since the approval of this program.

Pembina-Keephills Transmission Pipeline

In August 2018, natural gas transmission filed a facilities application requesting approval for the installation of the Pembina-Keephills transmission pipeline. The 59-km high-pressure natural gas pipeline 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. A decision was received on August 6, 2019 approving the project as filed. Construction has commenced and the pipeline is expected to be in service by mid-2020. The estimated cost to construct this project is approximately $230 million and is included in natural gas transmission's three year capital investment plan.

Pembina-Keephills transmission pipeline construction, near Wabamun Lake, Alberta

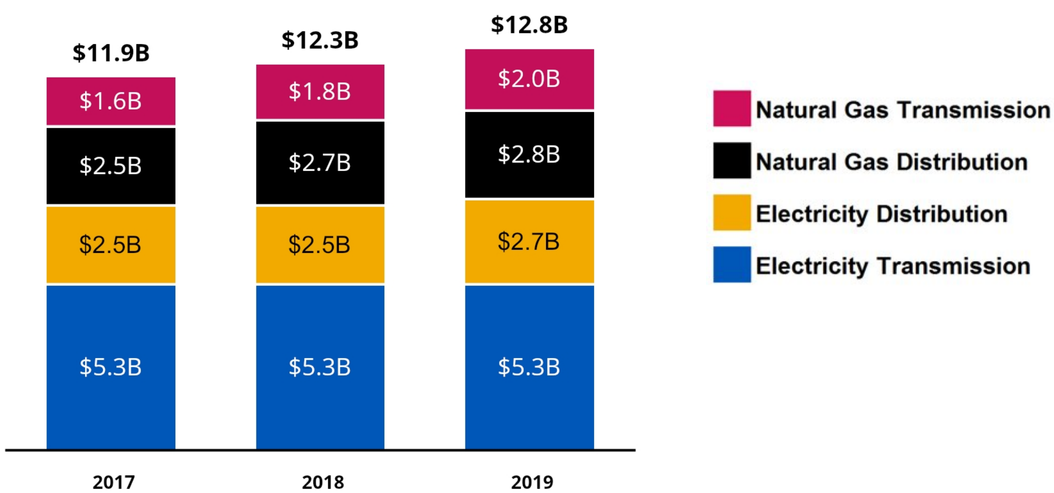
REGULATORY DEVELOPMENTS

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 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 changes in 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 on the formula that adjusts rates for inflation and productivity improvements.

Regulated Utilities Mid-Year Rate Base



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.

The following table contains the ROE and deemed common equity ratios resulting from the most recent GCOC decisions and also contains the mid-year rate base for each CU Inc. utility.

	Year	AUC Decision	Rate of Return on Common Equity (%) (1)	Common Equity Ratio (%) (2)	Mid-Year Rate Base ($ millions)
Electricity Distribution	**2019**	**2018 GCOC (4)**	**8.50**	**37.0**	**2,669 (5)**
	2018	2018 GCOC (4)	8.50	37.0	2,498 (6)
	2017	2016 GCOC (3)	8.50	37.0	2,471 (7)
Electricity Transmission	**2019**	**2018 GCOC (4)**	**8.50**	**37.0**	**5,262 (8)**
	2018	2018 GCOC (4)	8.50	37.0	5,280 (6)
	2017	2016 GCOC (3)	8.50	37.0	5,287 (7)
Natural Gas Distribution	**2019**	**2018 GCOC (4)**	**8.50**	**37.0**	**2,847 (5)**
	2018	2018 GCOC (4)	8.50	37.0	2,715 (6)
	2017	2016 GCOC (3)	8.50	37.0	2,549 (7)
Natural Gas Transmission	**2019**	**2018 GCOC (4)**	**8.50**	**37.0**	**1,971 (9)**
	2018	2018 GCOC (4)	8.50	37.0	1,791 (6)
	2017	2016 GCOC (3)	8.50	37.0	1,614 (7)

(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 2016 GCOC decision for the periods 2016 to 2017 on October 7, 2016.

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

(5) The mid-year rate base for 2019 is equal to the year over year growth in rate base reflected in the 2020 PBR Annual Rate Filings applied to the 2018 actual mid-year rate base and includes mid-year work in progress.

(6) The mid-year rate base for 2018 is based on the Rule 005 Actuals Package and includes mid-year work in progress.

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

(8) The mid-year rate base for 2019 is based on the electricity transmission 2018-2019 General Tariff Application Compliance Filing and includes estimated mid-year work in progress.

(9) The mid-year rate base for 2019 is based on the natural gas transmission 2019-2020 General Rate Application Compliance Filing and includes estimated mid-year work in progress.

GCOC (POST-2020)

In December 2018, the AUC initiated the 2021 GCOC proceeding. The main focus of the proceeding will be to determine the rate of return for the years 2021 and 2022, as well as consideration of returning to a formula-based approach. Initial evidence was filed in January 2020 focusing on comparability to other investments, capital attractiveness and financial integrity. The AUC expects to issue a decision in 2020.

PERFORMANCE BASED REGULATION

In December 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.

In February 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. On January 30, 2020, the AUC issued a decision, which provided updated clarification on what would qualify for anomaly adjustments. Parties can now re-apply for applicable anomalies, which if approved, would re-establish 2018 going in rates. Applications are to be submitted in early 2020 with a decision from the AUC expected before the end of the year.

	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	• Based on inflation adjusted average historical costs for the period 2013-2016, capital costs are recovered through going-in rates inflated by I-X and a K Bar. 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

ALBERTA REGULATORY UPDATES

ELECTRICITY TRANSMISSION AND DISTRIBUTION REGULATORY UPDATES

ELECTRICITY DISTRIBUTION DEPRECIATION PROCEEDING

In the third quarter of 2019, the AUC issued a decision on depreciation parameters that extends the overall depreciable life of the electricity distribution assets and incorporates historical retirements related to severe weather events. The AUC determined the depreciation parameters as filed are reasonable, resulting in an electricity distribution depreciation rate change and lower depreciation expense in the third and fourth quarters of 2019.

ELECTRICITY TRANSMISSION AND ELECTRICITY DISTRIBUTION RECOVERY OF 2016 REGIONAL MUNICIPALITY OF WOOD BUFFALO WILDFIRE COSTS

In October 2019, the AUC issued its decisions associated with electricity transmission and electricity distribution's application for the recovery of costs related to the 2016 Regional Municipality of Wood Buffalo wildfire.

Electricity transmission's applied-for cost recoveries were all substantially approved as part of the electricity transmission 2018-2019 GTA.

Approximately 90 per cent of the applied-for cost recoveries were approved in electricity distribution's application. The capital cost to replace the destroyed assets was approved as filed as were the majority of the operating and maintenance costs and recovery for lost revenues. However, the value of electricity distribution's destroyed assets was deemed to be an extraordinary retirement and was not approved for recovery in customer rates, resulting in a reduction to 2019 adjusted earnings of $2 million.

ELECTRICITY TRANSMISSION 2020-2022 GENERAL TARIFF APPLICATION (GTA)

In October 2019, electricity transmission filed a GTA for its operations for 2020, 2021, and 2022. The application requests, among other things, additional revenues to recover higher depreciation costs. The application also requests, at electricity transmission's discretion, the ability to advance an application to establish 2023 and 2024 revenue requirements by escalating the 2022 approved revenue requirement. A decision from the AUC is expected by the fourth quarter of 2020.

ELECTRICITY TRANSMISSION HANNA REGION TRANSMISSION DEVELOPMENT DEFERRAL APPLICATION

In February 2017, electricity transmission filed an application seeking approval of approximately $688 million of capital additions related to the Hanna Regional Transmission Development program incurred between 2012 and 2015. A decision from the AUC was received in June 2019 approving the vast majority of capital additions into rate base as prudently incurred.

ELECTRICITY TRANSMISSION 2018-2019 GTA

In June 2017, electricity transmission filed a GTA for its operations for 2018 and 2019. The decision was received in July 2019 approving the majority of requested capital expenditures and operating costs as filed. The impact of this decision was an increase to second quarter 2019 adjusted earnings of $17 million.

ELECTRICITY TRANSMISSION 2015-2017 DIRECT ASSIGNED PROJECTS DEFERRAL APPLICATION

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

NATURAL GAS TRANSMISSION REGULATORY UPDATES

NATURAL GAS TRANSMISSION 2019-2020 GENERAL RATE APPLICATION (GRA)

In July 2018, natural gas transmission filed a GRA for 2019 and 2020. The decision was received in June 2019 approving the majority of requested capital expenditures and operating costs requested as filed. The adjustments directed by the AUC in the decision had a $3 million positive impact in the second quarter 2019 adjusted earnings.

PBR REGULATORY UPDATES

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

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

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

COMMON MATTERS REGULATORY UPDATES

INFORMATION TECHNOLOGY (IT) COMMON MATTERS

In August 2014, Canadian Utilities sold its IT services business to Wipro Ltd. (Wipro) and signed a ten-year IT Master Services Agreement (MSA) effective January 1, 2015. Proceeds of the sale were $204 million, resulting in a one-time after-tax gain of $138 million. In 2014, the Company did not include this gain on sale in adjusted earnings because it was a significant one-time event.

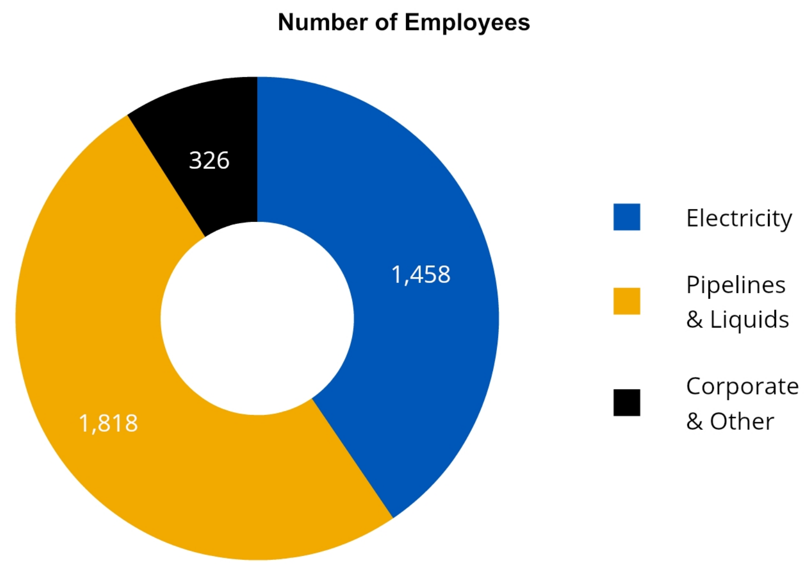
In 2015, the AUC commenced an Information Technology Common Matters (IT Common Matters) proceeding to review the recovery of information technology costs by the Alberta Utilities from January 1, 2015 going forward. In June 2019, the AUC issued its decision regarding the IT Common Matters proceeding and directed the Alberta Utilities to reduce the first-year of the Wipro MSA by 13 per cent and to apply a glide path that reduces pricing by 4.61 per cent in each of years 2 through 10. For natural gas distribution and electricity distribution, the AUC’s direction impacts the PBR 2018 going-in rates and treatment of capital costs. For the natural gas transmission and electricity transmission utilities, the AUC's direction impacts the revenue requirement dating back to 2015. The Alberta Utilities presented a considerable amount of evidence, including independent expert benchmarking and price review studies, to show that the Wipro MSA rates were at fair market value (FMV). As such, there was no cross subsidization between the sale price of Canadian Utilities' IT services business to Wipro in the 2014 transaction and the establishment of IT rates under the MSA. Despite these efforts, the AUC determined that the Alberta Utilities failed to demonstrate that the IT pricing in the MSA would result in just and reasonable rates.

As a result of the AUC’s IT Common Matters decision, a $23 million reduction to the previously recorded 2014 after-tax gain on sale of $138 million was recorded in 2019. Going forward, the IT Common Matters decision is expected to further reduce the previously recorded gain. Consistent with the treatment in 2014, the $23 million reduction recognized in 2019, along with ongoing impacts associated with this decision, are not included in adjusted earnings.

In July 2019, the Alberta Utilities filed a leave to appeal application with the Alberta Court of Appeal in relation to the AUC Decision on the IT Common Matters proceeding. In October 2019, the Alberta Court of Appeal denied the Alberta Utilities leave to appeal application.

EMPLOYEE INFORMATION

At December 31, 2019, the Company had 3,602 employees. The accompanying chart represents the employee numbers in each segment.



SUSTAINABILITY, CLIMATE CHANGE AND ENERGY TRANSITION

Sustainability, Climate Change and the Energy Transition is described in the "Sustainability, Climate Change and the Energy Transition" section in CU Inc.'s MD&A and is incorporated herein by reference. The MD&A may be found on SEDAR at www.sedar.com.

BUSINESS RISKS

Business risks are described in the "Utilities Performance" and "Business Risks and Risk Management" sections in CU Inc.'s MD&A and are incorporated herein by reference. The MD&A may be found on SEDAR at www.sedar.com.

DIVIDENDS

Cash dividends declared during the past three years for all series and classes of shares were as follows.

(Canadian dollars per share)	Date of Issue	2019	2018	2017
Series Preferred Shares				
Series 1	Apr 18, 2007	**1.1500**	1.1500	1.1500
Series 4	Dec 2, 2010	**0.5608**	0.5608	0.5608
Class A and Class B Shares		**66.8600**	58.1700	48.6300

CAPITAL STRUCTURE

SHARE CAPITAL

The share capital of the Company at February 25, 2020 is as shown below.

Share Description	Authorized	Outstanding
Series Preferred Shares	Unlimited	7,600,000
Class A Shares	Unlimited	3,570,322
Class B Shares	Unlimited	2,188,262

All of the Class A and Class B shares are owned by Canadian Utilities Limited.

SERIES PREFERRED SHARES

An unlimited number of Series Preferred Shares are issuable in series, each series consisting of such number of shares and having such provisions attaching thereto as may be determined by the directors. The Series Preferred Shares as a class have, among others, provisions to the following effect:

i. The Series Preferred Shares are, with respect to priority in payment of dividends and in the distribution of assets in the event of liquidation, dissolution or winding up of the Company, entitled to preference over the Class A shares and the Class B shares and any other shares of the Company ranking junior to the Series Preferred Shares. The Series Preferred Shares may also be given such other preference over the Class A shares and the Class B shares and any other junior shares as may be determined for any series authorized to be issued.

ii. The owners of the Series Preferred Shares are not entitled as such (except as provided in any series) to any voting rights nor to receive notice of or to attend share owners' meetings unless dividends on the Series Preferred Shares of any series are in arrears to the extent of eight quarterly dividends or four half-yearly dividends, as the case may be, whether or not consecutive. Until all arrears of dividends have been paid, such owners will be entitled to receive notice of and to attend all share owners' meetings at which directors are to be elected (other than separate meetings of owners of another class of shares) and to one vote in respect of each Series Preferred Share held.

iii. The class provisions attaching to the Series Preferred Shares may be amended with the written approval of all the owners of the Series Preferred Shares outstanding or by at least two-thirds of the votes cast at a meeting of the owners of such shares duly called for the purpose and at which a quorum is present.

The following Series Preferred Shares are currently outstanding:

	Stated Value	Shares	Amount *($ millions)*
Series Preferred Shares:			
4.60% Series 1	$25.00	4,600,000	115
2.24% Series 4	$25.00	3,000,000	75
		7,600,000	190

SERIES PREFERRED SHARE REDEMPTION

Series 1 Preferred Shares

The Series 1 Preferred Shares became redeemable at the option of the Company beginning on June 1, 2012 at the stated value plus a 4 per cent premium per share for the following 12 months plus accrued and unpaid dividends. The redemption premium declined by 1 per cent in each succeeding 12-month period until June 1, 2016.

Series 4 Preferred Shares

The Series 4 Preferred Shares became redeemable at the option of the Company on June 1, 2016, and are redeemable on June 1 of every fifth year thereafter at the stated value per share plus accrued and unpaid dividends. The dividend rate will reset every five years to the then current 5-year Government of Canada bond yield plus 1.36 per cent. Owners may elect to convert any or all of their Series 4 Preferred Shares into an equal number of Cumulative Redeemable Preferred Shares Series 5 on June 1, 2021, and on June 1 of every fifth year thereafter. The dividend rate on the Series 5 Preferred Shares will be equal to the then current 3-month Government of Canada Treasury Bill yield plus 1.36 per cent. On June 1, 2026, and on June 1 of every fifth year thereafter, the Company may redeem the Series 5 Preferred Shares in whole or in part at par. The Company may redeem the Series 5 Preferred Shares in whole or in part by the payment of $25.50 for each share to be redeemed in the case of redemption on any other date.

CLASS A SHARES AND CLASS B SHARES

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

If a qualifying offer to purchase Class B shares is made to all, or substantially all owners of Class B shares, and such offer is not made concurrently to owners of Class A shares, then owners of Class A shares have the ability to convert their Class A shares into Class B shares on a one-for-one basis which Class B shares will, as a result of such conversion, be automatically tendered to the offer. Any converted for Class B shares shall be automatically converted back into Class A shares on a one-for-one basis if the owner withdraws the conversion during the term of the offer or pursuant to the terms of the offer such converted for Class B shares are not taken up.

CREDIT RATINGS

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities. The ratings indicate the likelihood of payment and an issuer’s capacity and willingness to meet its financial commitment on an obligation. A security rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the credit rating organization.

As is customary, the Company makes payments to the credit ratings organizations for the assignment of ratings as well as other services. The Company expects to make similar payments in the future.

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.

	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 17, 2019, DBRS Limited (DBRS) affirmed its 'A (high)' long-term corporate credit rating and stable outlook on CU Inc. On October 3, 2019, S&P Global Ratings (S&P) affirmed its 'A-' long-term issuer credit rating and stable outlook on CU Inc.

ISSUER CREDIT RATINGS AND LONG-TERM DEBT

An “A” issuer rating by DBRS is the third highest of ten categories. An issuer rated “A” is of good credit quality. The capacity for the payment of financial obligations is substantial, but of lesser credit quality than “AA”. A-rated issuers may be vulnerable to future events, but qualifying negative factors are considered manageable. Each rating category other than “AAA” and “D” contains the subcategories “high” and “low". The absence of either a “high” or “low” designation indicates the rating is in the “middle” of the category.

An “A” issuer rating by S&P is the third highest of ten categories. An entity rated “A” by S&P has a strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than an entity in higher-rated categories. Ratings from “AA” to “CCC” may be modified by the addition of a plus or minus sign to show relative standing within the major rating categories.

COMMERCIAL PAPER AND SHORT-TERM DEBT CREDIT RATINGS

An “R-1 (low)” rating by DBRS is the lowest subcategory in the highest of six categories and is granted to short-term debt of good credit quality. The capacity for the payment of short-term financial obligations as they fall due is substantial. Overall strength is not as favourable as higher rating subcategories and may be vulnerable to future events, but qualifying negative factors are considered manageable. Rating categories “R-1” and “R-2” are denoted by the subcategories “high”, “middle”, and “low”.

An “A-1 (Low)” rating by S&P is the third highest of eight categories in its Canadian commercial paper ratings scale. A short-term obligation rated “A-1 (Low)” is slightly more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher rating categories. However, the obligor's capacity to meet its financial commitments on the obligation is satisfactory.

PREFERRED SHARE CREDIT RATINGS

A “PFD-2” rating by DBRS is the second highest of six categories granted by DBRS. Preferred shares rated in this category are generally of good credit quality. Protection of dividends and principal is still substantial, but earnings, the balance sheet, and coverage ratios are not as strong as “Pfd-1” rated companies. Each rating category is denoted by the subcategories “high” and “low". The absence of either a “high” or “low” designation indicates the rating is in the “middle” of the category.

A “P-2” rating by S&P is the second highest of eight categories S&P uses in its Canadian preferred share rating scale. An obligation rated “P-2” exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to weaken the obligor's capacity to meet its financial commitments on the obligation. A “high” or “low” designation shows relative standing within a rating category. The absence of either a “high” or “low” designation indicates the rating is in the “middle” of the category.

MARKET FOR SECURITIES OF THE COMPANY

The Company's Cumulative Redeemable Preferred Shares Series 1 and Series 4 are listed on the Toronto Stock Exchange (TSX).

The following table sets forth the high and low prices and volume of the Company's shares traded on the TSX under the symbols CIU.PR.A for Series 1 shares and CIU.PR.C for Series 4 shares, during 2019.

			Series 1			Series 4
2019	**High ($)**	**Low ($)**	**Volume**	**High ($)**	**Low ($)**	**Volume**
January	21.56	20.27	30,968	16.05	14.67	108,600
February	21.00	20.30	20,694	14.80	13.32	29,138
March	21.50	20.50	142,965	13.67	13.30	14,700
April	21.83	21.16	89,246	14.00	13.59	90,000
May	21.47	20.99	183,788	13.67	13.48	51,900
June	21.47	20.52	24,825	13.30	12.49	15,238
July	21.49	21.25	252,711	13.50	12.70	61,968
August	21.65	20.82	34,913	13.40	12.50	68,000
September	21.60	20.99	66,018	13.33	12.50	43,800
October	21.67	21.27	71,785	13.10	12.22	25,410
November	21.70	21.32	29,430	13.20	12.27	164,000
December	21.80	21.45	44,691	13.24	12.66	192,740

DIRECTORS AND OFFICERS

DIRECTORS (1)

Name, Province or State and Country of Residence	Position	Position Held and Principal Occupation	Director Since
R.T. Booth (2) Alberta, Canada	Director	Partner, Bennett Jones LLP	2014
L.M. Charlton (2) Alberta, Canada	Director	Vice President & Chief Financial Officer, Lintus Resources Limited	2008
S.W. Kiefer Alberta, Canada	Director	President , ATCO Ltd. and President & Chief Executive Officer, Canadian Utilities Limited	2011
N.C. Southern Alberta, Canada	Executive Chair & Director	Chair & Chief Executive Officer, ATCO Ltd. and Executive Chair, Canadian Utilities Limited	1999
L.A. Southern-Heathcott Alberta, Canada	Vice Chair & Director	President & Chief Executive Officer of Spruce Meadows Ltd.	2017
R.J. Urwin, PhD, C.B.E. (2) London, England	Director	Corporate Director	2008

(1) All directors hold office until their successors are elected on an annual basis.

(2) Member of the Audit Committee.

OFFICERS (IN ALPHABETICAL ORDER)

Name, Province or State and Country of Residence	Position	Principal Occupation
D.A. DeChamplain Alberta, Canada	Executive Vice President & Chief Financial Officer	Executive Vice President & Chief Financial Officer, ATCO Ltd. & Canadian Utilities Limited
C. Gear Alberta, Canada	Corporate Secretary	Corporate Secretary ATCO Ltd. and Canadian Utilities Limited
C.R. Jackson Alberta, Canada	Vice President, Finance, Treasury & Risk	Vice President, Finance, Treasury & Risk, ATCO Ltd. and Canadian Utilities Limited
S.W. Kiefer Alberta, Canada	President & Chief Executive Officer	President , ATCO Ltd. and President & Chief Executive Officer, Canadian Utilities Limited
G.J. Lidgett Alberta, Canada	Executive Vice President & General Manager	Executive Vice President & General Manager, Utilities, Canadian Utilities Limited
R.A. Penrice (1) Alberta, Canada	Executive Vice President, Corporate Services	Executive Vice President, Corporate Services, Canadian Utilities Limited
B.P. Shkrobot Alberta, Canada	Senior Vice President, Finance & Regulatory	Senior Vice President, Finance & Regulatory, Utilities, Canadian Utilities Limited
N.C. Southern Alberta, Canada	Executive Chair	Chair & Chief Executive Officer, ATCO Ltd. and Executive Chair, Canadian Utilities Limited

(1) Ms. Penrice became an officer of the Company effective January 1, 2020.

POSITIONS HELD BY OFFICERS WITHIN PRECEDING FIVE YEARS

All the officers have been engaged for the last five years in the indicated principal occupations, or in other capacities with the companies or firms referred to, or with their affiliates or predecessors except for Ms. Penrice. Ms. Penrice was appointed Executive Vice President, Corporate Services in January 2020. Prior to joining the Company, Ms. Penrice was Interim CEO for Sears Canada Inc. where she led the wind down of the operations in Canada. Ms. Penrice has held several senior management roles within Sears Canada and at Hudson's Bay Company specializing in Human Resources, Logistics, Merchandising, Store Operations and Marketing.

DIRECTORS' AND OFFICERS' INTEREST IN THE COMPANY

At December 31, 2019, none of the Company's directors and officers, as a group, beneficially owned, or controlled or directed, directly or indirectly, by corporate holdings or otherwise, any of the outstanding Class B shares of the Company.

EXECUTIVE COMPENSATION

Refer to Appendix 1 for the Compensation Discussion and Analysis.

DIRECTORS' COMPENSATION

In 2019, non-employee directors of the Company were paid annual retainers for acting as directors as shown in the table below.

Directors	Annual Retainer	Audit Member	Director Totals
R.T. Booth	$6,500.00	$6,000.00	$12,500.00
L.M. Charlton	$6,500.00	$4,000.00	$10,500.00
L.A. Southern-Heathcott	6,500	—	$6,500.00
R.J. Urwin, PhD, C.B.E. (2)	$6,500.00	$4,000.00	$10,500.00
Total Renumeration	$26,000.00	$14,000.00	$40,000.00

INDEBTEDNESS OF DIRECTORS, EXECUTIVE OFFICERS AND SENIOR OFFICERS

Since January 1, 2019, there has been no indebtedness outstanding to the Company from any of its directors, executive officers, senior officers or associates of any such directors, nominees or senior officers.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director or executive officer of the Company, person or company that beneficially owns, or controls or directs, directly or indirectly, greater than ten per cent of the Company's Class B voting Common shares, nor any associate or affiliate of the foregoing, has, or has had, any material interest, direct or indirect, in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to materially affect the Company.

CORPORATE CEASE TRADE ORDERS, BANKRUPTCIES OR SANCTIONS

Corporate Cease Trade Orders

Except as otherwise disclosed herein, no director, executive officer or controlling security holder of the Company is, as at the date of this AIF, or has been, within the past 10 years before the date hereof, a director or executive officer of any other issuer that, while that person was acting in that capacity:

i. was the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation for a period of more than 30 consecutive days; or

ii. was subject to an event that resulted, after the person ceased to be a director or executive officer, in the Company being the subject of a cease trade or similar order or an order that denied the relevant company access to an exemption under securities legislation for a period of more than 30 consecutive days; or

iii. within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Personal Bankruptcies

No director, executive officer or controlling security holder of the Company has, within the 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or became subject to or instituted any proceedings, arrangements or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold such person's assets.

Penalties or Sanctions

No current director, executive officer or controlling security holder of the Company has:

i. been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, other than penalties for late filing of insider reports; or

ii. been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

CONFLICTS OF INTEREST

Circumstances may arise where members of the Board serve as directors or officers of corporations which are in competition to the interests of the Company. No assurances can be given that opportunities identified by any such member of the Board will be provided to the Company. However, the Company's procedures provide that each director and executive officer must comply with the disclosure requirements of the Canada Business Corporations Act (CBCA) regarding any material interest. If a declaration of material interest is made, the declaring director shall not vote on the matter if put to a vote of the Board. In addition, the declaring director and executive officer may be requested to recuse himself or herself from the meeting when such matter is being discussed.

VOTING SECURITIES AND PRINCIPAL HOLDER THEREOF

The Company has 2,188,262 Class B shares outstanding, all of which are owned by Canadian Utilities. ATCO, directly or indirectly, owns 90.15 per cent of the voting securities of Canadian Utilities. The Southern family controls ATCO.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Cumulative Redeemable Preferred Shares Series 1 and Series 4 is AST Trust Company (Canada) at its principal offices in Calgary and Toronto.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

The Company is occasionally named as a party in claims and legal proceedings which arise during the normal course of its business. The Company reviews each of these claims, including the nature of the claim, the amount in dispute or claimed and the availability of insurance coverage. There can be no assurance that any particular claim will be resolved in the Company's favour or that such claim may not have a material adverse effect on the Company. For further information, please refer to Note 25 of the 2019 Consolidated Financial Statements.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business (unless otherwise required by applicable securities requirements to be disclosed), there were no material contracts entered into by the Company or its subsidiaries during the most recently completed financial year, or before the most recently completed financial year that are still in effect.

INTERESTS OF EXPERTS

PricewaterhouseCoopers LLP has prepared the auditor’s report for the Company’s 2019 Consolidated Financial Statements. PricewaterhouseCoopers LLP is independent in accordance with the Rules of Professional Conduct of the Chartered Professional Accountants of Alberta.

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 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 attributable to Class A and Class B shares is presented in the MD&A. Adjusted earnings is an additional GAAP measure presented in Note 4 of the 2019 Consolidated Financial Statements.

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 the MD&A.

FORWARD-LOOKING INFORMATION

Certain statements contained in this AIF 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.

ADDITIONAL INFORMATION

Additional information relating to the Company may be found on SEDAR at www.sedar.com.

Additional financial information is provided in the Company’s 2019 Consolidated Financial Statements and MD&A for the financial year ended December 31, 2019.

Information relating to ATCO or Canadian Utilities may be obtained on request from Investor Relations at 3rd Floor, West Building, 5302 Forand Street SW, Calgary, Alberta, T3E 8B4, or by telephone (403) 292-7500 or fax (403) 292-7532. Corporate information is also available on ATCO’s website: www.ATCO.com and Canadian Utilities’ website: www.canadianutilities.com

GLOSSARY

AESO means the Alberta Electric System Operator.

AEY means ATCO Electric Yukon.

AGP means ATCO Gas and Pipelines Ltd.

ATCO means ATCO Ltd. and its subsidiaries.

ATCO Electric means ATCO Electric Ltd.

ATCO Gas means the natural gas distribution division of AGP.

ATCO Pipelines means the natural gas transmission division of AGP.

AUC means the Alberta Utilities Commission.

Average weekly earnings (AWE) is an indicator of short-term employee earnings growth.

Board means CU Inc.'s Board of Directors.

Canadian Utilities means Canadian Utilities Limited.

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

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

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

Consumer price index (CPI) measures the average change in prices over time that consumers pay for a basket of goods and services.

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

EUA means the Electric Utilities Act (Alberta).

GAAP means Canadian generally accepted accounting principles.

GHG means greenhouse gas.

IFRS means International Financial Reporting Standards.

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

MD&A means the Company's Management's Discussion and Analysis for the year ended December 31, 2019.

NEB means National Energy Board.

NGTL means NOVA Gas Transmission Ltd.

NUY means Northland Utilities (Yellowknife) Limited.

NWT means Northland Utilities (NWT) Limited.

REA means Rural Electrification Association. REAs are constituted under the Rural Utilities Act (Alberta) by groups of persons carrying on farming operations. Each REA purchases electric power for distribution to its members through a distribution system owned by that REA.

ROE means Return on Equity.

Utilities means ATCO Electric Distribution, ATCO Electric Transmission, ATCO Gas and ATCO Pipelines.

WACC means weighted average cost of capital.

APPENDIX 1

COMPENSATION DISCUSSION AND ANALYSIS

This Compensation Discussion and Analysis (CD&A) discusses the Company's executive compensation program, and how it is structured, governed, and designed to support the corporate business objectives.

This CD&A discloses compensation of the Executive Chair, Chief Executive Officer, Chief Financial Officer and the next two executives that received the highest pay as of December 31, 2019 (our named executives):

- Nancy C. Southern, Executive Chair
- Dennis A. DeChamplain, Executive Vice President & Chief Financial Officer
- Siegfried W. Kiefer, President & Chief Executive Officer
- George J. Lidgett, Executive Vice President & General Manager, Utilities
- Wayne K. Stensby, Executive Vice President, Corporate Development

In 2019, all of the named executives had multiple roles for CU Inc., Canadian Utilities, and ATCO, the Company's ultimate parent company. The exceptions were George J. Lidgett for all of 2019 and Wayne. K. Stensby while in his previous role of Managing Director, Electricity Global Business Unit until June 30, 2019. Mr. Stensby moved into the role of Executive Vice President, Corporate Development on July 1, 2019, in which he has multiple roles.

Every year, the Company apportions compensation for executives with multiple roles based on each company's contribution to total consolidated revenues, labour expenses and total assets. This allocation method, which has been approved by the Alberta Utilities Commission, represents an estimate of the amount of time the Company expects the executives will devote to each entity.

Throughout this CD&A, when we refer to senior executives, we mean the Executive Chair, the CEO and the CEO's direct reports (only some of whom are named executives).

The table below shows how CU Inc., Canadian Utilities and ATCO have shared the compensation expense of executives with multiple roles over the past three years:

	Amount paid and reported by CU Inc. (%)	Amount paid by Canadian Utilities (%)	Amount paid by ATCO (%)	Combined total reported by ATCO (%)
2019	**70.7**	**19.2**	**10.1**	**100**
2018	70.4	17.1	12.5	100
2017	72.7	15.4	11.9	100

EXECUTIVE COMPENSATION PROGRAM ELEMENTS

The Company's executive compensation program includes direct and indirect compensation. Direct compensation is made up of:

- Fixed compensation (base salary); and
- Variable compensation (short-term incentives).

Indirect compensation includes a pension plan and other benefits.

Discretionary incentives may also be awarded to senior executives for their contribution to particularly notable accomplishments.

Total direct compensation is targeted at the median (50th percentile) of the comparator group. Pay mix varies from year to year. The target ranges depend on the executive's responsibilities and ability to influence business results. The actual pay mix depends on corporate, business unit and individual performance. This mix provides a competitive total direct compensation package while ensuring that a significant portion of each executive's compensation is performance-based, and therefore, pay at risk.

FIXED COMPENSATION

Base salaries are targeted at the median (50th percentile) of the comparator group, and can be up to the 75th percentile for executives who consistently perform above the role's expectations.

VARIABLE COMPENSATION

Variable compensation makes up a significant portion of each senior executive's total compensation. Awards and payouts are tied to corporate, Business Unit and individual performance.

Nancy C. Southern

Executive Chair
Age: 63
Location: Calgary, Canada
Years of Service: 30

Ms. Southern is Executive Chair of CU Inc. She is accountable for the Company's strategic direction, vision and governance. She reports to the Board of Directors and has been a director of CU Inc. since 1989.

Under Ms. Southern's guidance, adjusted earnings have increased from $246 million in 2009 to $524 million in 2019.
CU Inc.'s total assets have grown from approximately $7 billion in 2009 to $17 billion in 2019.

	2019	2018	2017
Cash			
Base salary	**707,000**	704,000	727,000
Short-term incentive	**989,800**	844,800	727,000
Total direct compensation	**1,696,800**	1,548,800	1,454,000

EMPLOYMENT AGREEMENT

Ms. Southern has an employment agreement with Canadian Utilities that is reviewed and approved regularly. It is currently effective to February 28, 2024. The agreement includes insurance benefits if Ms. Southern dies or becomes disabled before she retires or employment is terminated. The amount is based on her salary, using formulas that take into account the amounts payable to her under Canadian Utilities' group life insurance policies and disability income programs. It also includes supplemental pension benefits.

Dennis A. DeChamplain

Executive Vice President & Chief Financial Officer
Age: 56
Location: Calgary, Canada
Years of Service: 27

Mr. DeChamplain is Executive Vice President & Chief Financial Officer of CU Inc. He is responsible for Finance, Accounting, Treasury, Taxation, Pension & Risk Management, Information Technology and the administration of Internal Audit. He was appointed to his current role in June 2017.

	2019	2018	2017
Cash			
Base salary	**334,058**	268,137	262,365
Short-term incentive	**226,240**	193,600	132,548
Total direct compensation	**560,298**	461,737	394,913

Siegfried W. Kiefer

President & Chief Executive Officer
Age: 61
Location: Calgary, Canada
Years of Service: 37

Mr. Kiefer is President & Chief Executive Officer of CU Inc. He is responsible for leading the development and execution of the Company's growth strategy, and ensuring its alignment with short and long-term objectives. He joined ATCO in 1983 and has held progressively senior roles in ATCO and Canadian Utilities. He was appointed to the role of President & Chief Executive Officer of CU Inc. in 2019.

	2019	2018	2017
Cash			
Base salary	**627,463**	589,600	574,330
Short-term incentive	**565,600**	352,000	272,625
Total direct compensation	**1,193,063**	941,600	846,955

EMPLOYMENT AGREEMENT

Mr. Kiefer has an employment agreement with Canadian Utilities in his new role as Chief Executive Officer of Canadian Utilities. His employment agreement came into effect on March 1, 2019 and is reviewed regularly. It is currently effective until February 28, 2022. The agreement includes insurance benefits if Mr. Kiefer dies or becomes disabled before he retires or employment is terminated. The amount is based on his salary, using formulas that take into account the amounts payable to him under Canadian Utilities' group life insurance policies and disability income programs. It also includes supplemental pension benefits.

George J. Lidgett

Executive Vice President & General Manager, Utilities
Age: 58
Location: Calgary, Alberta
Years of Service: 34

Mr. Lidgett is Executive Vice President & General Manager, Utilities. Mr. Lidgett oversees the company's natural gas and electric utilities in Alberta and Canada's North, focusing on building upon the Company's track record of operational and regulatory excellence. Mr. Lidgett joined ATCO in 1985 and has held a variety of leadership positions across Canadian Utilities and ATCO. He was appointed to his current role in July 2019.

	2019	2018	2017
Cash			
Base salary	**465,613**	435,938	410,363
Short-term incentive	**279,850**	213,900	255,750
Total direct compensation	**745,463**	649,838	666,113

Wayne K. Stensby

Executive Vice President, Corporate Development
Age: 53
Location: Calgary, Canada
Years of Service: 31

Mr. Stensby is Executive Vice President, Corporate Development. He is responsible for growing the company's portfolio of investments in premier energy infrastructure in strategic global markets, the ongoing operations of energy storage and industrial water businesses, as well as Government and Indigenous Relations. Mr. Stensby joined ATCO in 1988 and has held a variety of leadership positions across Canadian Utilities and ATCO. He was appointed to his current role in July 2019.

	2019	2018	2017
Cash			
Base salary	**344,726**	360,000	354,000
Short-term incentive	**233,585**	200,000	160,000
Total direct compensation	**578,311**	560,000	514,000

2019 COMPENSATION DETAILS

Summary Compensation Table

The table below summarizes the total compensation of each of the named executives received or awarded for the years ended December 31, 2017, 2018 and 2019.

	Salary [1]	Share based awards	Option based awards	Non-equity incentive plan compensation [1]		Pension value [2]	All Other Compensation [3]	Total Compensation
				Annual incentive plans	Long term incentive plans			
Nancy C. Southern								
Executive Chair								
2019	**707,000**	**N/A**	**N/A**	**989,800**	**N/A**	**(1,732,942)[4]**	**24,745**	**(11,397)**
2018	704,000	N/A	N/A	844,800	N/A	844,161	24,640	2,417,601
2017	727,000	N/A	N/A	727,000	N/A	1,752,389	25,445	3,231,834
Dennis A. DeChamplain								
Executive Vice President & Chief Financial Officer								
2019	**334,058**	**N/A**	**N/A**	**226,240**	**N/A**	**19,252**	**11,362**	**590,912**
2018	268,137	N/A	N/A	193,600	N/A	18,656	4,994	485,387
2017	262,365	N/A	N/A	132,548	N/A	19,856	0	414,769
Siegfried W. Kiefer								
President & Chief Executive Officer								
2019	**627,463**	**N/A**	**N/A**	**565,600**	**N/A**	**(689,444)[5]**	**21,961**	**525,580**
2018	589,600	N/A	N/A	352,000	N/A	308,031	20,636	1,270,267
2017	574,330	N/A	N/A	272,625	N/A	279,926	20,102	1,146,983
George J. Lidgett								
Executive Vice President & General Manager, Utilities								
2019	**465,613**	**N/A**	**N/A**	**279,850**	**N/A**	**196,411**	**5,247**	**947,121**
2018	435,938	N/A	N/A	213,900	N/A	234,333	3,270	887,441
2017	410,363	N/A	N/A	255,750	N/A	3,528,193	2,354	4,196,660
Wayne K. Stensby								
Executive Vice President, Corporate Development								
2019	**344,726**	**N/A**	**N/A**	**233,585**	**N/A**	**71,972**	**12,065**	**662,348**
2018	360,000	N/A	N/A	200,000	N/A	66,622	12,600	639,222
2017	354,000	N/A	N/A	160,000	N/A	329,655	12,390	856,045

(1) Compensation figures shown for all named executives are the amounts that have been apportioned to and paid by the Company. All of the Company's executives have had multiple roles for CU Inc., Canadian Utilities, and ATCO, the Company's parent company, over the past three years. The exceptions are Mr. Lidgett for all of 2019 and Mr. Stensby while in his previous role of Managing Director, Electricity Global Business Unit until June 30, 2019. Mr. Stensby moved into the role of Executive Vice President, Corporate Development on July 1, 2019, in which he has multiple roles.

The table below shows how the compensation expense for executives with multiple roles has been shared over the past three years.

	Amount paid and reported by CU Inc. (%)	Amount paid by Canadian Utilities (%)	Amount paid by ATCO (%)	Combined total reported by ATCO (%)
2019	**70.7**	**19.2**	**10.1**	**100**
2018	70.4	17.1	12.5	100
2017	72.7	15.4	11.9	100

(2) Estimated using a prescribed formula based on several assumptions. Also includes other compensatory items. Mr. Lidgett joined the supplemental pension plan for all service, effective 2017.

(3) Employer contribution to the Employee Share Purchase Plan.

(4) Decrease in value as a result of a change in the assumed retirement date.

(5) Decrease in value as a net result of the increase in Supplemental Employee Retirement Plan service limit and a change in the assumed retirement date.

PENSION PLAN

The named executives participate in the Retirement Plan for Employees of Canadian Utilities Limited and Participating Companies (CU plan), which has both a defined benefit (DB) and defined contribution (DC) component. Nancy C. Southern, Siegfried W. Kiefer, and George J. Lidgett participate in the DB component.

How the DB component works:

- Executives do not contribute to the plan;
- Participants can retire with full benefits when they turn 62, or if their age plus their years of service equals 90 or more. They can retire as early as age 55. However, if they have not achieved 90 points, their pension benefit is reduced by 3 per cent for every year of retirement before age 62, and by another 3 per cent for every year before age 60;
- Pension benefits are paid until the participant dies; then, 60 per cent is paid to the surviving spouse; and
- Retiree benefit payments have historically been increased annually with inflation, to a maximum of 3 per cent.

How we calculate the pension benefit:

[1.4% X average year's maximum pensionable earnings ($55,420 in 2019) **+** 2% X average salary (highest five consecutive years of base salary, not including short-term incentive) *minus* $55,420] **X** Years of service

Dennis A. DeChamplain and Wayne K. Stensby participate in the DC component.

How the DC component works:

- Executives do not contribute to the plan;
- The Company contributes 10 per cent of base salary up to the maximum permitted by the Income Tax Act ($27,230 in 2019); and
- Participants are responsible for the investment decisions in the DC plan and may invest contributions in a broad selection of funds.

SUPPLEMENTAL PENSION BENEFITS

Pension benefits under our pension plans are subject to limits imposed by the Income Tax Act (Canada). Benefits that are higher than these limits are paid to each of the named executives except Dennis A. DeChamplain as a supplemental pension. This supplemental pension is provided by Canadian Utilities and benefits are not pre-funded, it is also inclusive of the benefit under the Canadian Utilities plan. Benefits are paid on the same terms as the plan, with the same survivor benefits and top-up for inflation.

How it works:

- Supplemental pension benefits are provided as a defined benefit plan
- Executives do not contribute to the supplemental plan
- Service is limited to 35 years
- Supplemental benefits are not paid if the named executive is terminated or dies before age 55

Nancy C. Southern's supplemental pension benefit is part of her employment agreement. Her benefits are calculated as 80 per cent of the average of the highest five years of cash compensation (salary and short-term incentives) throughout her career. This change occurred in 2019 and was approved by GOCOM.

Siegfried W. Kiefer's supplemental pension benefit is part of his employment agreement. His benefits are calculated as the average of the highest consecutive five years of salary compensation. Mr. Kiefer's maximum service limit for the supplemental pension benefit increased from 35 to 40 years. This change occurred in 2019 and was approved by GOCOM.

DEFINED BENEFIT

The table below shows the pension benefits and accrued obligations under all registered pension plans and supplemental arrangements for each of the named executives.

		Annual Benefits Payable ($)					
	Number of years credited service	At year end	At age 65	Opening present value of defined benefit obligation ($)	Compensatory Change ($)	Non Compensatory Change ($)	Closing present value of defined benefit obligation ($)
Nancy C. Southern	24.00	1,402,688	1,402,688	20,997,052	(1,732,942) [1]	3,130,954	22,395,064
Siegfried W. Kiefer	36.00	402,332	445,172	9,060,441	(689,444) [2]	1,149,669	9,520,666
George J. Lidgett	34.17	281,653	288,522	6,311,705	196,411	1,282,584	7,790,700
Wayne K. Stensby	30.08	130,821	149,556	3,368,478	51,454	397,734	3,817,666

(1) Decrease in value as a result of a change in the assumed retirement date.

(2) Decrease in value as a net result of the increase in Supplemental Employee Retirement Plan service limit and a change in the assumed retirement date.

Number of years of credited service is the time the executive has been a member of the pension plan, and is used to calculate the pension.

Annual benefits payable at year end is based on the defined benefit credited service and actual average pensionable earnings at December 31, 2019. The benefits are reduced if a named executive is eligible for early retirement.

Annual benefits payable at age 65 is based on actual average pensionable earnings at December 31, 2019, and their projected service at age 65, to a maximum of 35 years service (with the exception to Supplemental Employee Retirement Plan maximum for Siegfried W. Kiefer).

The Company calculates the accrued pension obligation using the method prescribed by International Financial Reporting Standards and based on management's best estimate of future events that affect the cost of pensions, including assumptions about adjustments to base salary in the future.

The compensatory change includes the service cost, differences between actual and estimated earnings, the impact of plan amendments and past service benefits, as well as changes in expected future retirement dates.

The non-compensatory change includes interest on the obligation, the impact of assumption changes, and the impact of changing the CU Inc. allocation from 70.4 per cent in 2018 to 70.7 per cent in 2019. See Note 14, Retirement Benefits, in the Company's consolidated financial statements for the year ended December 31, 2019, for more information about the methods and assumptions used to calculate accrued obligations.

DEFINED CONTRIBUTION

The table below shows the defined contribution disclosure for the named executives.

	Accumulated value at start of year	Compensatory ($)	Accumulated value at year end ($)
Dennis A. DeChamplain	477,569	19,252	594,272
Wayne K. Stensby	500,531	20,518	591,141

The compensatory amount is the Company's contribution. Participants are responsible for their investments and may invest contributions in a broad selection of funds.

TERMINATION AND CHANGE OF CONTROL

Termination of employment of an executive is subject to applicable legislation and common law provisions as there are no employment agreements in place for the named executives, except for Ms. Southern and Mr. Kiefer. The table below shows how a change in employment status affects the different compensation components.

The Company considers there to be a change of control when holders of more than 50 per cent of Canadian Utilities Class B common shares accept an offer for any portion or all of the shares. This change can be by way of a takeover bid or some other means, as long as it is not the result of a transaction to convert Canadian Utilities to a trust with our shareholders owning more than 50 per cent of the voting securities of the trust.

The Company's employment agreements with Ms. Southern, our Executive Chair and Mr. Kiefer, our President & Chief Executive Officer outline the following:

Retirement

- Salary ends.
- Retiring allowance is based on years of service to a maximum of one month's salary.
- Retiree health benefits coverage starts when he or she retires, and continues until six months after the pensioner dies.
- Annual incentive bonus is paid on a pro rata basis to the retirement date.
- All vested options and share appreciation rights can be exercised within 24 months of the retirement date, or on the expiry date if earlier.
- All unvested options, share appreciation rights and mid-term incentive plan awards are forfeited on the retirement date.
- Pension benefits are provided based on membership in the plan.

Resignation

- All salary and benefits end.
- Annual incentive bonus for the current year is forfeited.
- All vested options and share appreciation rights can be exercised within 90 days of the resignation date, or on the expiry date if earlier.
- All unvested options, share appreciation rights and mid-term incentive plan awards are forfeited on the resignation date.
- Pension is paid as a commuted value or deferred benefit.

Termination

- All salary and benefits end.
- Annual incentive bonus for the current year is forfeited.
- All vested options and share appreciation rights can be exercised within 90 days of the termination date, or on the expiry date if earlier.
- All unvested options, share appreciation rights and mid-term incentive plan awards are forfeited on the termination date.
- Pension is paid as a commuted value or deferred benefit.
- If applicable, severance is provided based on employment standards and common law provisions.

Change of Control

- No changes are made to salary, incentives or benefits.
- All vested options and share appreciation rights can be exercised within 90 days of a change of control, or on the expiry date, if earlier.
- All unvested options and share appreciation rights are accelerated and can be exercised within 90 days of a change of control date, or on the expiry date, if earlier.
- All unvested mid-term incentive plan awards vest on the date immediately preceding the change of control.