DISCLAIMER

Due to uncertainty surrounding the application of recent amendments to the Competition Act (Canada), these documents are provided for historical information purposes only and do not constitute active or current representations of Canadian Utilities Limited or any of its related parties. The purpose of these documents is to comply with disclosure requirements that were in effect on the date these documents were filed; Canadian Utilities undertakes no obligation to update such information except as required by applicable law. Canadian Utilities remains committed to taking steps to address climate change and continuing to engage in sustainability initiatives.

CANADIAN UTILITIES LIMITED
An ATCO Company

CANADIAN UTILITIES LIMITED

ANNUAL REPORT

FOR THE YEAR ENDED DECEMBER 31, 2021

CANADIAN UTILITIES LIMITED

An ATCO Company

ANNUAL REPORT 2021

MESSAGE FROM THE CHAIR & CEO

A PROUD PAST AND EXCITING FUTURE OF ENERGY TRANSFORMATION

Dear Canadian Utilities Share Owners,

For more than a century, Canadian Utilities has been at the forefront of the evolving energy industry.

Our story began in 1911, when the Canadian Western Natural Gas, Light, Heat and Power Company began piping in natural gas from Bow Island and Turner Valley to southern Alberta communities. It may seem a modest start by today's technological standards, but to the people we served it was revolutionary.

And, in the decades since, Canadian Utilities has continued to serve in the vanguard of profound and transformative change—we never stopped reimagining the art of the possible.

This is evident across the breadth of our operations, in the contributions made every day in communities where we operate, and in the attitudes and actions of our 4,500 employees.

Over the course of our history, we've brought heat and light to homes and businesses for the very first time—not just in Western Canada, but across the North. We've powered the growth of Alberta's economy, generating reliable, sustainable electricity that energized innovation and industry. Along the way, we've built lasting and prosperous relationships with hundreds of Indigenous communities, thousands of industry partners, and millions of people.

I am very proud of our past—and I am inspired by our future potential.

At Canadian Utilities, we often reference our long track record of operational excellence and financial strength. But what truly drives our enterprise is a collective fearlessness to effect change for the good of our customers and communities—to go beyond the call of duty and make a special effort to do more. This philosophy, combined with our record of creating and seizing opportunities, is how we will shape the future of energy.

For example, our natural gas and electric utilities are well positioned to serve as conduits to decarbonization for our customers and their energy needs. Our successful off-diesel ("onto-solar") projects in remote communities in Northern Canada and our hydrogen blending project in Fort Saskatchewan, Alberta, are inspiring early examples of how we can work with our customers to reduce their emissions. LUMA Energy, our joint venture in Puerto Rico, is yet another striking example of how we are applying our utility expertise to benefit our communities while also accelerating the energy transition. The process of transforming Puerto Rico's transmission and distribution system into a reliable and modern system is no small undertaking. There have certainly been some bumps along the road, but we remain fiercely committed to delivering on our promises for the good of the customers we've been entrusted to serve.

Our energy infrastructure business is also a key component of our strategy and is focused on the arenas of renewable generation, clean fuels and energy storage. Recent examples of our leadership in this line of pursuit include: the announcement of three Alberta solar projects, the receipt of government funding to establish Australia's first commercial scale renewable hydrogen supply chain, our acquisition of the Alberta Hub natural gas storage facility, the announcement of a potential clean hydrogen project with Suncor Energy, and the development of a renewable natural gas facility in Alberta.

How the world generates, transports, consumes, and conserves energy has fundamentally changed. Operating with sterling environmental performance is now table stakes. But we cannot lose sight of the need to ensure energy remains safe, reliable and, above all else, affordable—particularly against a backdrop of escalating geopolitical tensions and rising commodity prices. If we lose sight of these outcomes, we risk eroding public support for decarbonization when we need it most.

We must also ensure that we continue to deliver reliable returns for our share owners. Despite continued market turbulence, our businesses delivered year-over-year earnings improvement and rate base growth in 2021. This was driven by stable results from our core Alberta utilities, the contributions from LUMA Energy and strong performance from ATCO Gas Australia.

Disciplined capital allocation across our portfolio guides our progress. We invested $1.3 billion in 2021, up $0.2 billion from the year before. A total of $1.1 billion was directed to our core utilities, which continue to drive stable growth in earnings and rate base. Total capital expenditures in our regulated utilities over the past three years were $3.0 billion. These investments were critical to ensuring the long-term stability and growth of Canadian Utilities.

As we look to the future, our strategy is predicated upon the production of cleaner fuels, renewable electricity, energy efficiency and critical energy infrastructure. Underpinning this strategic focus are four foundational pillars: leveraging core assets and investments to advance energy transition and to ensure resiliency; optimizing energy infrastructure assets and adding new growth platforms, diversifying geographically in the Americas and Australia; and generating cash flow and earnings to improve financial strength and growth capacity.

Consistent with our strategic focus on the energy transition, we have announced a comprehensive set of 2030 environmental, social and governance targets and a commitment to net-zero emissions by 2050. Our 2030 targets include reducing our operational and customer emissions, growing our renewable energy footprint, increasing economic benefits for Indigenous partners, continuing our focus on safety, and further promoting diversity, equity, and inclusion in the workplace.

Achieving net zero by 2050 is a societal challenge that no individual, business, or government can solve on its own. It will require unprecedented collaboration among all constituents, as well as an informed, pragmatic, and affordable roadmap from policymakers to unlock the necessary scale and pace of private sector investment and expertise.

I am excited about our future and confident in our team, but for all our efforts, there is one thing that keeps me up at night: the potential for a well-intentioned but misaligned regulatory and policy environment to thwart the efforts and innovations needed to reach our goals with urgency and certainty. Increasingly, our regulators will be required to take a greater role in enabling decarbonization and Indigenous reconciliation—an undertaking that will require constructive dialogue with industry and Indigenous communities as well as legislative reform.

We will continue to engage with government and thought leaders about the implications of policies that don't effectively lead to the outcomes our society envisions. And we will continue to pursue our goals unrelentingly.

At the heart of what we do are our people and the customers, partners and communities we work with. None of our achievements would be possible without the courage, resilience and compassion that these groups have shown each other in advancing new business, projects and dreams.

I thank each and every one of our Canadian Utilities team for their determination in continuing to advance our business and vision in such trying times and I would like to pay special tribute to two of our people, Canadian Utilities leaders whose contributions and character will be forever remembered.

I want to congratulate and express my deepest appreciation to Siegfried Kiefer, who retired as President & Chief Executive Officer of Canadian Utilities last July. Siegfried's accomplishments during his 38 years with ATCO and Canadian Utilities are impressive and his sincerity, quiet optimism, mentorship and strength of character were obvious to all of us who worked with him. Thanks to these attributes, Siegfried's legacy rests now in the terrific women and men he has mentored and who now lead our businesses.

Dennis DeChamplain, who held the role of Executive Vice President & Chief Financial Officer of both ATCO and Canadian Utilities Limited, passed away suddenly last August. Over the course of his almost 30 years with us, Dennis was known for his principled leadership, keen insight and unmatched attention to detail. His expertise and resourcefulness in finance, accounting, sustainability and environment have left an indelible mark on our organization and helped position us for success in a rapidly evolving world.

I would like to thank the members of our Executive Team—including Brian Shkrobot who was appointed as Executive Vice President & Chief Financial Officer last October. I also thank our incredible Board of Directors for their expertise and counsel over the course of 2021.

And to you, our share owners, thank you for the continued trust you place in us. I'm so very keen and optimistic about the future of Canadian Utilities. We have an opportunity to drive the energy transition—and we intend to seize it.

Sincerly yours,

Nancy C. Southern
Chair & Chief Executive Officer,
Canadian Utilities Limited

CANADIAN UTILITIES LIMITED
An ATCO Company

CANADIAN UTILITIES LIMITED

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEAR ENDED DECEMBER 31, 2021

This Management's Discussion and Analysis (MD&A) is meant to help readers understand key operational and financial events that influenced the results of Canadian Utilities Limited (Canadian Utilities, our, we, us, or the Company) during the year ended December 31, 2021.

This MD&A was prepared as of February 23, 2022, and should be read with the Company's audited consolidated financial statements (2021 Consolidated Financial Statements) for the year ended December 31, 2021. Additional information, including the Annual Information Form (2021 AIF) is available on SEDAR at www.sedar.com.

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

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

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CANADIAN UTILITIES CORE MISSION AND VALUES

EXCELLENCE: THE HEART & MIND OF ATCO

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

R.D. Southern, Founder, ATCO

CORE MISSION

To build a global portfolio of utilities and energy infrastructure assets that consistently delivers operational excellence and superior returns.

CORE VALUES

It is ATCO's Heart and Mind that drives the Company's approach to service reliability and product quality. Our pursuit of excellence governs the way we act and make decisions.

CANADIAN UTILITIES STRATEGIES

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

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

CORPORATE PILLARS

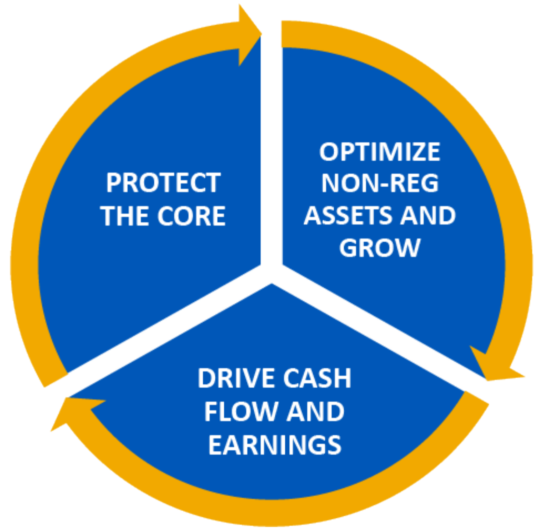
Innovation

We seek to create an inclusive 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

Our long-term strategy is focused on sustainable growth in North America, South America and Australia. We protect our core utility assets and invest in activities aimed at advancing the energy transition and ensuring long-term resiliency. By optimizing Energy Infrastructure assets and adding new growth platforms, while consistently delivering reliable, safe, cleaner, and affordable energy for our customers, Canadian Utilities will continue to drive cash flow and earnings to improve financial strength and growth capacity.

We pursue the acquisition and development of complementary assets and businesses that have future growth potential and provide long-term value for share owners.



Financial Strength

Financial strength is the bedrock of our current and future success. It ensures that we have the financial capacity to fund existing and future capital investments through a combination of predictable cash flows from operations, cash balances on hand, credit facilities and access to capital markets. It enables us to sustain our operations and to grow through economic cycles, thereby providing long-term financial benefits.

We continuously review our 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 the Company.

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 our environmental impact. We ensure the timely supply of goods and services that are critical to our customers' ability to meet their core business objectives.

Community Involvement

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

SUSTAINABILITY PILLARS

Canadian Utilities conducts business in a manner that reflects our values. Integrity, agility, collaboration and caring—these foundational principles help us deliver on our commitment to sustainability. We report on five focus areas: Energy Transition, Climate Change & Environmental Stewardship, Operational Reliability & Resilience, People and Community & Indigenous Relations.

Strategic Environmental, Social and Governance (ESG) Targets For 2030

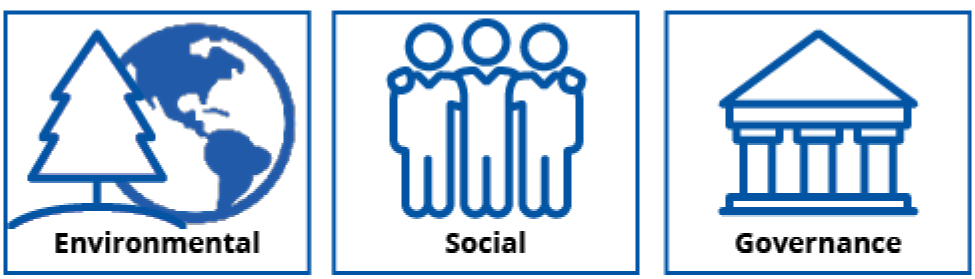
In January 2022, Canadian Utilities' parent company, ATCO, announced an initial set of 2030 environmental, social and governance targets, and a commitment to achieve net-zero greenhouse gas (GHG) emissions by 2050.

ATCO's 2030 ESG targets include reducing its operational and customer emissions, growing its renewable energy footprint, increasing economic benefits for Indigenous partners, continuing its focus on safety, and further promoting diversity, equity, and inclusion in the workplace.

The 2050 net-zero commitment builds upon ATCO's significant progress in recent years in decarbonizing its portfolio, including a 90 per cent reduction in operational GHG emissions from 2019 to 2020 realized primarily through the sale of Canadian Utilities' fossil fuel-based electricity generation portfolio as well as reductions in its retained assets.

ATCO (with the support of Canadian Utilities) is actively pursuing several pathways to further reduce its operational emissions, as well as its customers' emissions, by accelerating the deployment and use of cleaner fuels (hydrogen and renewable natural gas), renewable energy, energy infrastructure and storage (including carbon capture technologies), energy efficiency and carbon offsets. In support of its net-zero commitment, ATCO is also working with all levels of government to advocate for enabling policy and regulation, and to identify barriers that impede cost-effective, economy-wide decarbonization. It will require unprecedented collaboration among all constituents, as well as an informed, pragmatic, and affordable roadmap from policymakers to unlock the necessary scale and pace of private sector investment and expertise.

ATCO continues to evaluate further ESG targets and conduct additional analysis with respect to their 2050 net-zero commitment. Additional information and progress towards the ESG targets will be included in ATCO's annual Sustainability Report, which will be available in May 2022.



FURTHER COMMENTARY REGARDING STRATEGIES AND COMMITMENTS

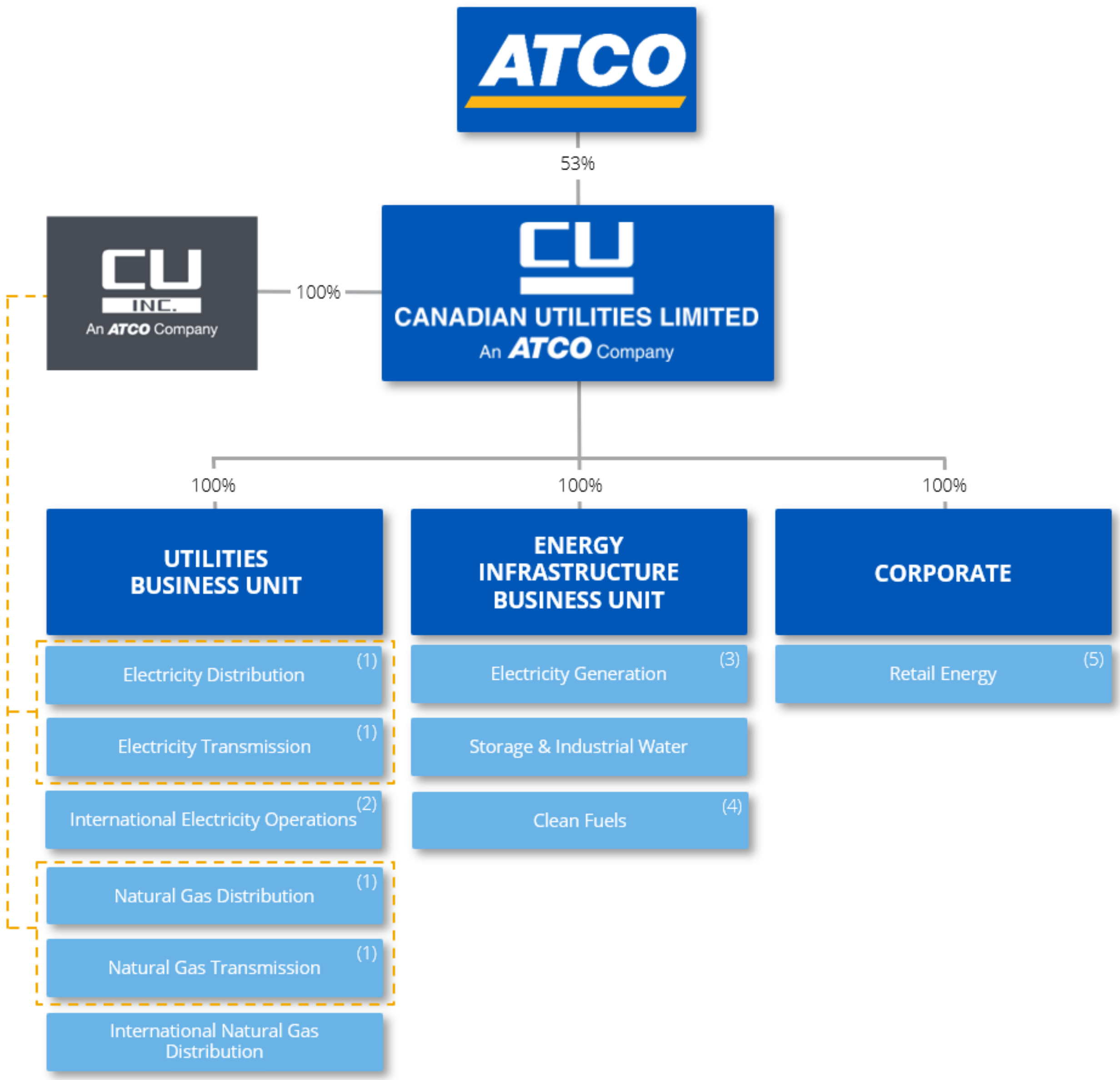
Our financial and operational achievements in 2021 relative to the strategies outlined above are included in this MD&A, the 2021 Consolidated Financial Statements and 2021 AIF. Further commentary regarding strategies and commitments to innovation, growth, financial strength, operational excellence, and community involvement will be provided in the forthcoming 2021 Management Proxy Circular, Year in Review, and Sustainability Report. The 2021 Management Proxy Circular will also contain a discussion of the Company's corporate governance practices.

Canadian Utilities' website, www.canadianutilities.com, is a valuable source for the latest news of the Company's activities. Prior years' reports are also available on this website.

COMPANY OVERVIEW AND OPERATING ENVIRONMENT

We are more than the sum of our many parts. On a global scale, we energize homes, businesses, industries, and deliver customer-focused energy infrastructure solutions. With approximately $21 billion in assets, Canadian Utilities Limited is a company with a diverse, global portfolio of investments in premier energy infrastructure that delivers operational excellence and superior returns. Fueled by the unwavering dedication of approximately 4,800 people, we offer comprehensive solutions and operational excellence in Utilities (electricity and natural gas transmission and distribution, and international operations); Energy Infrastructure (energy storage, energy generation, industrial water solutions and clean fuels); and Retail Energy (electricity and natural gas retail sales, and whole-home solutions).

ORGANIZATIONAL STRUCTURE



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

(2) International Electricity Operations consists of a 50 per cent ownership in LUMA Energy, LLC (LUMA Energy), a company formed to transform, modernize and operate Puerto Rico's 30,000-km electricity transmission and distribution system.

(3) Canadian Utilities owns and operates 348-MW of non-regulated electricity generation assets in Australia, Mexico, Canada and Chile, and 103-MW of assets under development in Canada.

(4) Clean Fuels includes large-scale hydrogen production opportunities, renewable natural gas opportunities, and technical expertise support.

(5) ATCOenergy includes Rümi, Blue Flame Kitchen, and Retail Energy and provides home products, home maintenance services, professional advice, and retail electricity and natural gas services in Alberta.

The 2021 Consolidated Financial Statements include the accounts of Canadian Utilities, and its subsidiaries, including the equity investment in joint ventures and a proportionate share of joint operations.

The 2021 Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards (IFRS) and the reporting currency is the Canadian dollar.

UTILITIES

BUSINESS DESCRIPTION

The Utilities business unit operates in Canada, Australia and Puerto Rico. The four regulated utilities (Electricity Transmission and Distribution, and Natural Gas Transmission and Distribution) in Alberta, Saskatchewan and the northern regions of Canada have delivered reliable electricity and clean-burning natural gas to customers for many decades. International Operations consists of the regulated natural gas distribution business in Western Australia, and the Electricity Operations business in Puerto Rico, which includes Canadian Utilities' 50 per cent ownership in LUMA Energy.

BUSINESS STRATEGY

Our strategy is to invest in regulated electricity and natural gas transmission and distribution assets, capitalize on opportunities to provide long-term contracted electricity and natural gas transmission and distribution services, and consistently deliver safe, reliable, affordable and clean energy for our customers.

MARKET OPPORTUNITIES

The utilities industry is changing with an increased focus on decarbonization, digitalization, decentralization, and evolving customer demand. Continuing climate change concerns, evolving regulations to encourage the advancement of new technologies, emission reduction targets, and government incentives present opportunities for utility companies. Our natural gas and electric utilities are well positioned to capitalize on these trends. Our strategic priorities remain focused on investments that provide lower emissions and clean energy solutions for our customers, and continuing to invest in our core business while maintaining safety, reliability and affordability.

MARKET CHALLENGES

Traditional utility industry challenges 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 invested capital. The increasing move towards decarbonization, arrival of new smart-grid technologies, renewable energy generation, decentralized generation, energy storage and digital transformation has forced the traditional utility sector to reinvent itself and adapt to remain competitive. These new challenges present new policy and technology risks that could lead to disruption of the Company's existing business models and create new competitive market dynamics.

Electricity Transmission Lines

ENERGY INFRASTRUCTURE

BUSINESS DESCRIPTION

The Energy Infrastructure non-regulated businesses include: hydro, solar and natural gas electricity generation in Western Canada, Australia, Mexico, and Chile, as well as non-regulated electricity transmission, natural gas storage and transmission, Natural Gas Liquids (NGL) storage, industrial water solutions, and renewable natural gas (RNG) production in Alberta. Energy Infrastructure is also developing its clean fuels business including hydrogen, RNG, carbon capture and underground storage projects.

BUSINESS STRATEGY

Energy transition is a key component of our growth strategy, focused on the three pillars of renewable generation, clean fuels, and energy storage. We are actively seeking out opportunities that capitalize on the key trends shaping global energy markets, from smaller and rapidly executable projects such as solar and renewable natural gas, to larger and longer lead-time initiatives, including commercial scale hydrogen production, transportation and storage. Additionally, we continue to optimize and drive growth in our energy storage business. Storage is critical to energy stability and to support the reliability of the grid as the world transitions to clean, but more intermittent sources of energy. It is a critical supporting factor to energy transition and to the diversification of industry within Alberta.

MARKET OPPORTUNITIES

In developed markets, the political and societal push to address climate change with decarbonization goals and the energy transition are driving the demand for clean energy, mainly supplied through renewables and clean fuels. Energy markets will be focused on providing firm, reliable and affordable energy supply as the share of renewables grows; this is likely to drive further investment into storage and grid balancing solutions to improve system reliability.

MARKET CHALLENGES

There is significant competition as financial, strategic and traditional fossil fuel-based energy producers become increasingly interested in renewables and clean fuels as part of the global energy transition. Government policy and regulatory constraints present challenges to renewables and clean fuel projects aligned with energy transition strategies. Macroeconomic conditions such as global economic activity, inflation, and political uncertainty pose challenges for investment.

El Resplandor Solar Project, Cabrero, Chile

PERFORMANCE OVERVIEW

FINANCIAL METRICS

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

($ millions, except per share data and outstanding shares)	Year Ended December 31 2021	2020	2019
Key Financial Metrics			
Revenues	**3,515**	3,233	3,905
Adjusted earnings [(1)]	**586**	535	608
Utilities [(1)]	**635**	584	575
Energy Infrastructure	**28**	28	110
Corporate & Other	**(77)**	(77)	(77)
Adjusted earnings ($ per share)	**2.17**	1.96	2.23
Earnings attributable to equity owners of the Company	**393**	427	951
Earnings attributable to Class A and Class B shares	**328**	360	884
Earnings attributable to Class A and Class B shares ($ per share)	**1.21**	1.32	3.24
Diluted Earnings attributable to Class A and Class B shares ($ per share)	**1.21**	1.32	3.24
Total assets	**21,075**	20,296	20,044
Long-term debt	**9,308**	9,053	8,966
Equity attributable to equity owners of the Company	**6,635**	6,621	6,734
Cash dividends declared per Class A and Class B share ($ per share)	**1.76**	1.74	1.69
Cash flows from operating activities	**1,718**	1,631	1,358
Capital investment [(2)]	**1,338**	912	1,226
Capital expenditures	**1,227**	903	1,129
Other Financial Metrics			
Weighted average Class A and Class B shares outstanding *(thousands):*			
Basic	**269,855**	272,758	272,630
Diluted	**270,317**	273,273	273,211

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

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

REVENUES

Revenues in 2021 were $3,515 million, $282 million higher than the same period in 2020. Higher revenues were mainly due to improved performance at ATCOenergy resulting from higher electricity and natural gas commodity prices associated with floating rate energy contracts, and higher flow-through revenues in the Electricity Distribution and Natural Gas Distribution businesses and the timing of prior period costs recovered in Natural Gas Distribution.

ADJUSTED EARNINGS

Our adjusted earnings in 2021 were $586 million or $2.17 per share, compared to $535 million or $1.96 per share for the same period in 2020.

Higher adjusted earnings in 2021 were mainly due to a full 12 months of earnings from International Electricity Operations comprised of ongoing transition work in the first half of 2021 and the June 2021 commencement of a Supplemental Agreement to LUMA Energy's 15-year Operations and Maintenance Agreement. Higher adjusted earnings were also due to inflation in Australia, which positively impacted earnings in the International Natural Gas Distribution business and cost efficiencies within the Electricity Distribution business.

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

EARNINGS ATTRIBUTABLE TO EQUITY OWNERS OF THE COMPANY

Earnings attributable to equity owners of the Company were $393 million in 2021, $34 million lower compared to 2020. Earnings attributable to equity owners of the Company include timing adjustments related to rate-regulated activities, dividends on equity preferred shares of the Company, unrealized gains or losses on mark-to-market forward and swap commodity contracts, one-time gains and losses, impairments, and items that are not in the normal course of business or a result of day-to-day operations. These items are not included in adjusted earnings.

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

Earnings attributable to equity owners of the Company are earnings attributable to Class A and Class B shares plus dividends on equity preferred shares of the Company. Additional information regarding earnings attributable to Class A and Class B shares is presented in Note 8 of the 2021 Consolidated Financial Statements.

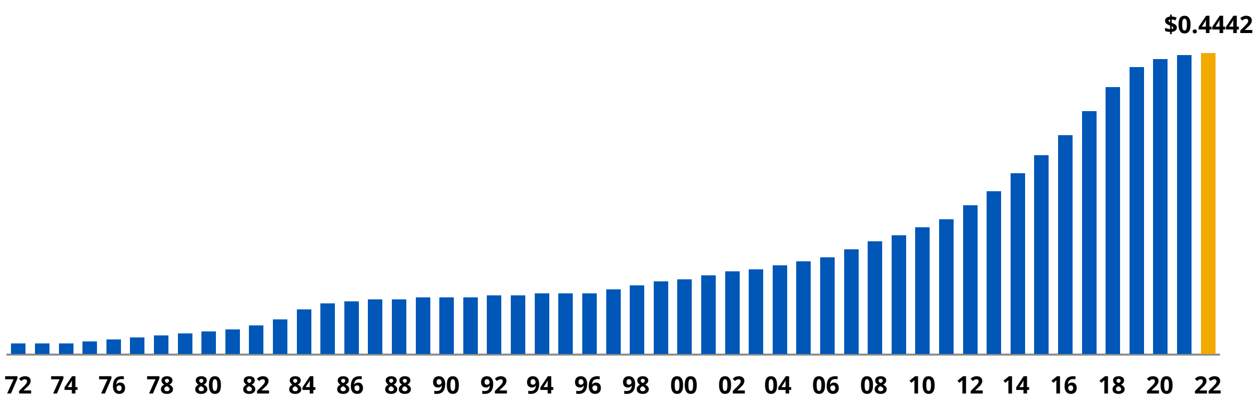
CASH FLOWS FROM OPERATING ACTIVITIES

Cash flows from operating activities were $1,718 million in 2021, $87 million higher than the same period in 2020. The increase was mainly due to higher customer contributions received for Alberta Utilities' capital expenditures. These amounts were partially offset by the Company's decision to provide rate relief to customers through the deferral of rate increases for the Electricity Distribution and Natural Gas Distribution businesses, which will be collected from customers starting in 2022.

COMMON SHARE DIVIDENDS

We have increased our common share dividend every year for the past 50 years, the longest record of annual dividend increases of any Canadian publicly traded company. Dividends paid to Class A and Class B share owners totaled $476 million in 2021. On January 13, 2022, the Board of Directors declared a first quarter dividend of 44.42 cents per share or $1.78 on an annualized basis. We aim to grow dividends in-line with our sustainable earnings growth, which is linked to growth from our regulated and long-term contracted investments.

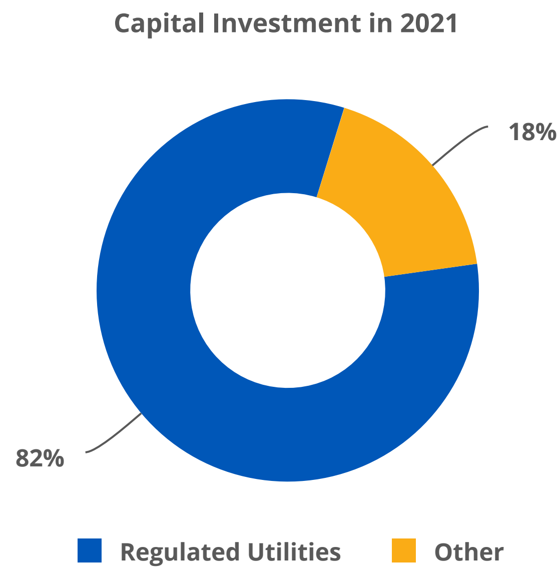
Quarterly Dividend Rate 1972 - 2022
(dollars per share)



CAPITAL INVESTMENT (1)

Total capital investment of $1,338 million in 2021 was $426 million higher compared to the same period in 2020, mainly due to the acquisition of the Pioneer Pipeline in the Natural Gas Transmission business; and the acquisition of the Alberta Hub natural gas storage facility, the acquisition of three solar development projects, and the construction of a long-term contracted hydrocarbon storage cavern in the Energy Infrastructure segment.

Total capital expenditures of $1,227 million in 2021 were $324 million higher compared to the same period in 2020, mainly due to the acquisition of the Pioneer Pipeline in the Natural Gas Transmission business, and the acquisition of three solar development projects in the Energy Infrastructure segment.



Capital spending in the Regulated Utilities accounted for 82 per cent of total capital invested in the full year of 2021. The remaining 18 per cent invested mainly included the acquisition of the Alberta Hub natural gas storage facility, the acquisition of three solar development projects, and the construction of a long-term contracted hydrocarbon storage cavern in the Energy Infrastructure segment.

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

CANADIAN UTILITIES SCORECARD

The following scorecard outlines our performance in 2021.

Target Met   Target Partially Met   Target Not Met

STRATEGIC PRIORITIES	2021 TARGET	2021 PERFORMANCE
INNOVATION		
New and existing products and services	Explore and test new products and methods of energy delivery to meet customers' future needs.	
	• Continue to support communities and customers through the deployment of cleaner energy solutions.	The Vuntut Gwitchin First Nation and Canadian Utilities announced the completion of Canada's most northerly off-grid solar project, reducing diesel use by 189,000 litres annually in Old Crow, Yukon and providing a clean energy source for decades to come.
	• Explore further opportunities to invest in clean fuel initiatives such as hydrogen and renewable natural gas within the Utilities and Energy Infrastructure businesses.	Utilities and Energy Infrastructure 2021 strategies focused on energy transition with a specific emphasis on renewable generation, hydrogen blending, clean fuels and energy storage. Through the calendar year we announced the following projects (further details can be found in the Business Unit Performance section of this MD&A): • Alberta Hub Natural Gas Storage Acquisition • Two Hills RNG Facility • Empress Solar Development Project • Calgary Solar Development Projects • Canadian Utilities - Suncor Clean Hydrogen Project • Clean Energy Innovation Park, Australia • Central West Pumped Storage Hydro Project, Australia • Fort Saskatchewan Hydrogen Blending

STRATEGIC PRIORITIES	2021 TARGET		2021 PERFORMANCE
GROWTH			
Regulated and long-term contracted capital investment	Continue to strategically invest in Canadian Utilities' technology and the modernization of both the natural gas and electricity networks to enhance sustainability and flexibility while reducing the long term need for additional utility infrastructure, resulting in lower costs and an improved experience for customers.		Continued progression on the digitization of the grid: • Continued deployment of Advanced Metering Infrastructure (AMI) across our service territory. The communities of Grande Prairie and Chipewyan Lake are now complete. • Progressing on the Advanced Distribution Management System (ADMS) that will orchestrate the delivery of electricity across a multi-directional flowing grid. Canadian Utilities announced the acquisition of the Pioneer Pipeline in 2020 and closed this transaction on June 30, 2021. The 131-km natural gas pipeline has been incorporated into NOVA Gas Transmission's (NGTL) and ATCO's Alberta regulated natural gas transmission systems to provide reliable natural gas supply to TransAlta's power generating units at Sundance and Keephills, facilitating the conversion of these coal plants to cleaner-burning natural gas. Consistent with the geographic areas defined in the Integration Agreement, Canadian Utilities' Natural Gas Transmission will transfer to NGTL the 30-km segment of pipeline in 2022 that is located in the NGTL footprint. The pipeline transfer was approved by the Canada Energy Regulator on December 22, 2021. LUMA Energy began implementation of the System Remediation Plan and engaged with the Federal Emergency Management Agency (FEMA) and US Department of Housing and Urban Development (HUD) on capital rebuilding programs designed to lift electricity transmission and distribution operations to the standards of a world-class utility.
	Continue to advance replacement and improvement projects in Canadian Utilities to ensure that the safety and reliability of our gas and electricity systems are properly maintained and managed.		The ongoing Urban Pipeline Replacement (UPR) Program in Alberta consists of the removal of the remaining high-pressure service pipe, installation of remaining stations, and clean-up efforts. The project is expected to be completed in 2022 and will have removed a total of 310-km upon completion.

STRATEGIC PRIORITIES	2021 TARGET		2021 PERFORMANCE
Global expansion	Continue expansion into select global markets including: North America, Australia, and Chile.		Canadian Utilities along with its partner, Quanta Services, Inc., announced their joint ownership interest in LUMA Energy in 2020 and commenced a one-year transition period. In June 2021, one month in advance of its anticipated timeline, LUMA Energy commenced operations under a Supplemental Agreement to its 15-year contract to modernize and operate Puerto Rico's electricity transmission and distribution system. Canadian Utilities and its joint venture partner, Australian Gas Infrastructure Group, received notification of conditional grant funding from Australian Renewable Energy Agency (ARENA) of $29 million AUD to contribute financing for the production of hydrogen through a large scale project at Canadian Utilities' proposed Clean Energy Innovation Park (CEIP) in Western Australia. Canadian Utilities acquired the rights to develop the 325-MW Central West Pumped Storage Hydro project, located approximately 175-km west of Sydney, Australia. The acquisition marks Canadian Utilities' first renewable energy investment on Australia's east coast. A final investment decision on project construction is expected in 2023.
	Continue to build upon Canadian Utilities' existing renewables generation platform in the Energy Infrastructure business.		Acquired the rights to the Empress Solar project, a 39-MW solar facility under development near Empress, Alberta with commercial operations expected in 2022. The project will provide enough renewable electricity to power more than 11,000 homes. Acquired the development rights to build two solar projects with a combined capacity of 64-MW in Calgary, Alberta with commercial operations expected in 2022. The Deerfoot and Barlow projects will provide enough renewable electricity to power more than 18,000 homes.
FINANCIAL STRENGTH			
Credit rating	Maintain investment grade credit rating.		Maintained 'A' long-term credit rating with a stable trend with DBRS Limited. Maintained 'A-' long-term issuer credit rating with a negative outlook on Canadian Utilities with Standard & Poors.
Access to capital markets	Access capital at attractive rates.		In 2021, CU Inc. raised $460 million in 30-year debentures at a rate of 3.174 per cent. The issue was oversold and completed at an attractive spread of 138 basis points above Government of Canada 30-year bond rates. Canadian Utilities issued $201 million of 4.75 per cent Cumulative Redeemable Second Preferred Shares Series HH by means of a short form prospectus. The proceeds of the issuance were used for capital expenditures, to repay indebtedness and for other general corporate purposes.

STRATEGIC PRIORITIES	2021 TARGET		2021 PERFORMANCE
OPERATIONAL EXCELLENCE			
Lost-time incident frequency: employees **Total recordable incident frequency: employees**	Compare favourably to safety benchmarks.		Our lost-time incident frequency compares favourably to benchmarks such as Alberta Occupational Health and Safety, US private industry, and industry best practice rates. Our lost-time incident frequency in 2021 was 0.17/200,000 hours worked. Our total recordable incident frequency in 2021 compares favourably to benchmarks such as US private industry and industry best practice rates. Our total recordable incident frequency in 2021 was 1.48 incidents/200,000 hours worked.
Customer satisfaction	Achieve high service for the customers and communities we serve. Results from customer satisfaction surveys should be consistent with or better than prior years.		Within Electricity and Natural Gas Distribution, approximately 97 per cent of customers agreed that Canadian Utilities provides good service. Within our energy retail operations, 75 per cent of customers who interact with call centres are "very satisfied". These results compare favourably to industry averages and are consistent with previous years. ATCO Gas Australia's Customer Satisfaction (CSAT) was 8.9 out of a possible 10, above a national industry benchmark of 8.5. ATCO Gas Australia consistently outperforms the broader energy industry in terms of both customer satisfaction and also a second measurement, the 'ease of implementation' of its services. ATCO Gas Australia has improved its CSAT score from 8.7 in 2020 to 8.9 in 2021. LUMA Energy had a six per cent increase in overall customer satisfaction, and a 13 per cent increase in both in-person customer service and power quality and reliability as measured by J.D. Power CSAT score.

STRATEGIC PRIORITIES	2021 TARGET		2021 PERFORMANCE
Organizational transformation	Streamline and gain operational efficiencies.		
	• Continue to optimize enterprise resource planning, workforce and asset management, customer information systems and computerized maintenance management systems within Canadian Utilities.		Canadian Utilities continued implementation of a Workforce and Asset Management program for its electricity and natural gas businesses to advance digitalization and data analytics. This technology will help to optimize resources, and digitize information and processes thereby providing a means to track, manage, and dispatch work to field-based employees more efficiently. The natural gas business is expected to complete implementation by 2022, followed by the electricity business in 2023. ATCO Gas Australia commenced an upgrade of its billing and metering system to comply with Australian Energy Market Operator (AEMO) regulations. This project will provide stakeholders with added functionality and upgrade the software to the latest version. The upgrade is being run in two phases, with Phase 1 complete and Phase 2 due for completion in 2022. The Alberta Utilities implemented a Customer Information System (CIS) replacement program. CIS holds our metering asset information, collects meter reads, calculates billing, and applies rates and production tariff bills for retailers. The replacement for both Natural Gas and Electricity is well underway, and the projects are on-track to go-live in 2022.
COMMUNITY INVOLVEMENT			
Indigenous relations	Continue to work together with Indigenous communities to contribute to economic and social development in their communities.		Across our operations, we awarded contracts of approximately $100 million for Indigenous and Indigenous-affiliated contractors in 2021. $64,500 was awarded to 52 students across Canada, including the territories, through the ATCO Indigenous Education Awards Program. A total of 5,280 employees participated in one of the many Indigenous training courses offered in 2021 through virtual classroom and training platforms. ATCO Australia implemented its 'Innovate Reconciliation Action Plan' (RAP). This plan strengthens our approach to driving reconciliation through business activities and community programs, and develops mutually beneficial relationships with Aboriginal and Torres Strait Islander stakeholders and organizations. Recognizing the continuing connection to land, sea and culture, ATCO Australia have invited Elders to welcome our employees to their country through Cultural Smoking Ceremonies for events and projects. Canadian Utilities announced the completion of Canada's most northerly off-grid solar project in Old Crow, Yukon. The facility will provide the Vuntut Gwitchin First Nations with a clean energy source for decades to come and fosters community ownership and self-sustaining economic development through job creation, investment in infrastructure, and revenue from the sale of renewable energy.

STRATEGIC PRIORITIES	2021 TARGET		2021 PERFORMANCE
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.		With the combined efforts of our employees around the world, ATCO pledged more than $2.97 million to support hundreds of community charities through our annual ATCO EPIC campaign, taking the program’s cumulative fundraising total to over $50 million since its inception in 2006. The ATCO Giving Gardens at Spruce Meadows was created in spring 2021 as a way to weave sustainability, volunteerism and generosity into one great initiative by providing fresh produce to Calgary's vulnerable seniors and veterans. ATCO provided 4,720 meals to seniors and veterans through our partnerships with the Calgary Seniors' Resource Society and the Homes For Heroes Foundation in Calgary. ATCO's Giving Gardens supplied the beets, potatoes, and squash towards these meals.
Community Investment	Invest in the health and safety of LUMA Energy's people and communities by opening a state-of-the-art electricity and lineworkers college in Puerto Rico.		In 2021, LUMA Energy obtained all permits and began construction on the LUMA College for Technical Training – a state-of-the-art lineworkers’ college within Puerto Rico aimed at training LUMA Energy’s current and future employees. The College's 24-acre site in Canóvanas will include an outdoor skills training field, indoor learning laboratory, administrative and classroom operations building, and covered equipment and personnel parking structures. Collectively, this will create approximately 22,000 square feet of usable building space for the purpose of training, education and administration. During construction activities in 2021, the College innovated by using off-site locations in Puerto Rico to commence its training programs and graduated the first pre-apprentice class of 14 students in October.

STRATEGIC PRIORITIES FOR 2022

The following table outlines our strategic priorities for 2022.

INNOVATION	
New and existing products and services	Continue to progress Canadian Utilities’ energy transition strategies across the regulated and non-regulated energy businesses to increase ownership, develop or manage renewable generation, energy storage and/or clean fuel facilities, and/or modernize natural gas and/or electricity delivery. Continue to prioritize Canadian Utilities’ strategic role in working with remote communities to reduce their reliance on diesel fuels in a way that continues to support economic growth, energy independence, reconciliation and community building with Indigenous peoples.
GROWTH	
Regulated and long-term contracted capital investment	Continue to strategically invest in Canadian Utilities' technology and the modernization of both the natural gas and electricity networks to enhance sustainability and flexibility. Continue to advance replacement and improvement projects in Canadian Utilities to ensure that the safety and reliability of our gas and electricity systems are properly maintained and managed. Continue to implement the System Remediation Plan in LUMA Energy; designed to lift the Transmission & Distribution System to the standards of a world-class utility. Increase the average contracted life of the in-service renewable generation portfolio by securing new power purchase agreements.
Global expansion	Continue expansion into select global markets including: North America, South America, and Australia by building upon Canadian Utilities' existing renewables generation and energy storage, and invest in Clean Fuels innovation in the Energy Infrastructure business.
FINANCIAL STRENGTH	
Credit rating	Maintain investment grade credit rating.
Access to capital markets	Continue to manage liquidity and access to capital in a prudent manner that facilitates strong access to capital at appropriate rates.

OPERATIONAL EXCELLENCE	
Lost-time and total recordable incident frequency: employees	Compare favourably to safety benchmarks.
Customer satisfaction	Achieve high service for the customers and communities we serve. Results from customer satisfaction surveys should be consistent with or better than prior years. Continue to prioritize improvements in LUMA Energy based on customer input and measure effectiveness via overall Customer Satisfaction scores.
Organizational transformation	Streamline and gain operational efficiencies: • Continue to demonstrate progress in leadership development, succession planning, and diversity, equity and inclusion initiatives across the organization • Continue to optimize enterprise resource planning, workforce and asset management, customer information systems and computerized maintenance management systems within Canadian Utilities. • LUMA Energy will advance its integrated safety culture and programs that will allow prioritization of safety risks and mitigations across business functions and enable employee safety, compliance and continual improvement. • LUMA Energy has developed baseline performance metrics and will monitor progress in, among other areas, customer service, safety, reliability and the delivery of budgeted results.

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. LUMA Energy will establish the LUma Committed with EmployeeS (“LUCES”) program.
Community investment	Invest in the health and safety of LUMA Energy's people and communities by opening a state-of-the-art electricity and distribution lineworkers college in Puerto Rico. The formal college is expected to open in the second quarter of 2022. LUMA Energy will continue its grassroots community investment program across Puerto Rican municipalities through partnership with the American Red Cross of Puerto Rico and the Boys & Girls Club of Puerto Rico.

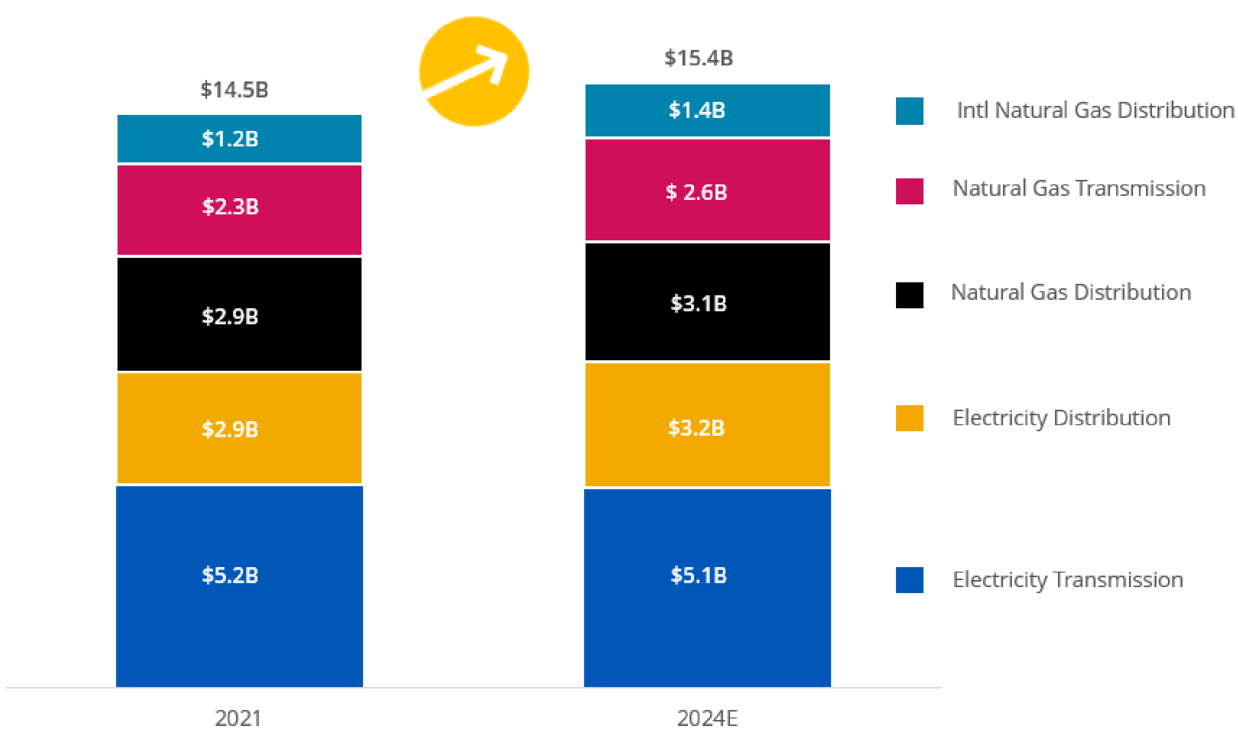
CAPITAL INVESTMENT PLANS [1]

In the 2022 to 2024 period, Canadian Utilities expects to invest $3.5 billion in regulated utility and commercially secured energy infrastructure capital growth projects. This capital investment is expected to contribute significant earnings and cash flows and create long-term value for share owners.

The three year plan includes $3.3 billion of planned capital investment in the Regulated Utilities of which $1.0 billion relates to Electricity Distribution, $0.7 billion to Electricity Transmission, $0.9 billion to Natural Gas Distribution, $0.5 billion to Natural Gas Transmission and $0.2 billion to International Natural Gas Distribution.

Mid-year rate base is equal to the total net capital investment less depreciation. Growth in mid-year rate base is a leading indicator of a utility's earnings trend, depending on changes in the equity ratio of the mid-year rate base and the rate of return on common equity.

MID-YEAR RATE BASE GROWTH (C$ Billions)



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

CORPORATE GOVERNANCE

Ensuring that our business operates in a transparent, ethical and accountable manner is at the core of creating strong and sustainable value for our share owners and in promoting the Company's well-being over the long term.

We do not believe in a one-size-fits-all approach to governance. Our Board of Directors has designed and implemented a unique and effective system of checks and balances that recognize the need to provide autonomy to our various business units, while prudently managing our financial resources.

This fit-for-purpose approach to governance has worked exceedingly well over the years, providing our Board of Directors and senior management team with the foundation to create long-term intergenerational value for our share owners.

Following are some of the highlights of our model for corporate governance. For a more complete picture, please see the Governance section of the 2021 Management Proxy Circular, which will be available in April 2022.

Our Board of Directors

The role of our Board of Directors has evolved alongside our business, providing oversight to an organization with a growing global footprint and a diverse, yet complementary suite of premier products and services. The Board strives to ensure that its corporate governance practices provide for the effective stewardship of the Company, and it regularly evaluates these practices to ensure they are in keeping with the highest standards.

Key elements of our corporate governance system include the oversight and diligence provided by the Board, the Lead Director, the Audit & Risk Committee, the Corporate Governance - Nomination, Compensation and Succession Committee (GOCOM), and Pension Fund Committee. Although not required by securities laws, some of our governance tools, such as the use of Designated Audit Directors (DADs), also reinforce the effectiveness and rigor of our governance model.

Much like our business operations, the strength of our Board of Directors is due in no small part to the diverse nature of skills, talent and experience each member brings to Board deliberations.

In 1995, Canadian Utilities was among the first public companies in Canada to introduce the concept of a Lead Director. Dr. Roger J. Urwin is the current Lead Director for Canadian Utilities, and was appointed to this position on May 6, 2020. The Lead Director provides the Board with the leadership necessary to ensure independent oversight of management. The Lead Director is an independent director and must be a member of GOCOM.

Designated Audit Directors

Distinctly unique to ATCO and Canadian Utilities are the Designated Audit Directors who are directors of Canadian Utilities or ATCO Ltd. Each DAD is assigned to one of our business units to provide oversight based on their strengths and experience in various industry sectors.

Each DAD meets quarterly with the senior leadership of their business unit and holds annual meetings with internal and external auditors. In addition, they review their respective businesses' financial statements and operating results, discuss risks with management, and report on both operating results and risks to our Audit & Risk Committee.

BUSINESS UNIT PERFORMANCE

REVENUES

Utilities revenues of $884 million and $3,041 million in the fourth quarter and full year of 2021 were $100 million and $109 million higher compared to the same periods in 2020 mainly due to higher flow-through revenues in the Electricity Distribution and Natural Gas Distribution businesses, and the timing of prior period costs recovered in Natural Gas Distribution.

Revenue growth for Electricity and Natural Gas Distribution in the fourth quarter and full year of 2021 has been deferred as a result of our decision to provide rate relief to customers in light of the current COVID-19 global pandemic and the economic situation in Alberta. The AUC issued a decision directing ATCO to collect the 2021 deferred amounts commencing January 1, 2022.

ADJUSTED EARNINGS

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2021**	**2020**	**Change**	**2021**	**2020**	**Change**
Electricity						
Electricity Distribution [1]	**37**	38	(1)	**151**	132	19
Electricity Transmission [1]	**35**	42	(7)	**152**	174	(22)
International Electricity Operations [1]	**16**	6	10	**44**	12	32
Total Electricity	**88**	86	2	**347**	318	29
Natural Gas						
Natural Gas Distribution [1]	**72**	79	(7)	**142**	146	(4)
Natural Gas Transmission [1]	**20**	22	(2)	**81**	89	(8)
International Natural Gas Distribution [1]	**26**	8	18	**65**	31	34
Total Natural Gas	**118**	109	9	**288**	266	22
Total Utilities [2]	**206**	195	11	**635**	584	51

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

(2) Additional information regarding these total of segments measures is provided in the Other Financial and Non-GAAP Measures section of this MD&A.

Utilities adjusted earnings of $206 million in the fourth quarter of 2021 were $11 million higher than the same period in 2020 mainly due to higher earnings from International Electricity Operations as a result of the June 2021 commencement of a Supplemental Agreement to LUMA Energy's 15-year Operations and Maintenance Agreement, and inflation indexing in International Natural Gas Distribution. Higher earnings were partially offset by timing of operating costs.

Utilities adjusted earnings of $635 million in the full year of 2021 were $51 million higher than the same period in 2020 mainly due to higher earnings from International Electricity Operations as a result of ongoing transition work in the first half of 2021 and the June 2021 commencement of a Supplemental Agreement to LUMA Energy's 15-year Operations and Maintenance Agreement. Higher earnings were also due to inflation indexing in International Natural Gas Distribution, and cost efficiencies within the Electricity Distribution business. Higher earnings were partially offset by the impact of the Electricity Transmission 2018-2019 GTA Compliance Filing decision and the 2020-2022 GTA Compliance Filing decision received in 2021. Combined, these decisions included a $12 million reduction of earnings related to prior periods.

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

Electricity Distribution

Electricity Distribution provides regulated electricity distribution and distributed generation mainly in Northern and Central East Alberta, the Yukon, the Northwest Territories and in the Lloydminster area of Saskatchewan.

Electricity Distribution adjusted earnings of $37 million in the fourth quarter of 2021 were $1 million lower than the same period in 2020 mainly due timing of operating costs.

Electricity Distribution adjusted earnings of $151 million in the full year of 2021 were $19 million higher compared to the same period in 2020 mainly due to cost efficiencies.

Electricity Transmission

Electricity Transmission provides regulated electricity transmission mainly in Northern and Central East Alberta, and in the Lloydminster area of Saskatchewan. Electricity Transmission has a 35-year contract to be the operator of Alberta PowerLine, a 500-km electricity transmission line between Wabamun, near Edmonton and Fort McMurray, Alberta.

Electricity Transmission adjusted earnings of $35 million in the fourth quarter of 2021 were $7 million lower than the same period in 2020 mainly due to timing of operating costs.

Electricity Transmission adjusted earnings of $152 million in the full year of 2021 were $22 million lower than the same period in 2020. Lower earnings were mainly due to the impact of the Electricity Transmission 2018-2019 GTA Compliance Filing decision received in the second quarter of 2021, and the 2020-2022 GTA Compliance Filing decision received in the third quarter of 2021. Combined, these decisions included a $12 million reduction of earnings related to prior periods.

International Electricity Operations

International Electricity Operations includes a 50 per cent ownership in LUMA Energy, a company formed to transform, modernize and operate Puerto Rico's 30,000-km electricity transmission and distribution (T&D) system under an Operations and Maintenance Agreement with the Puerto Rico Public-Private Partnerships Authority (P3A) and the Puerto Rico Electric Power Authority (PREPA).

LUMA Energy has assumed operations under terms of a Supplemental Agreement as PREPA remains in bankruptcy. This Agreement can span up to 18 months and allows LUMA Energy to collect an annualized fixed fee equivalent of $115 million USD. Should PREPA emerge from bankruptcy during this period, LUMA Energy will transition to year one of the previously outlined Operations and Maintenance Agreement.

International Electricity Operations adjusted earnings of $16 million and $44 million in the fourth quarter and full year of 2021 were $10 million and $32 million higher than the same periods in 2020. Higher earnings were mainly due to ongoing transition work in the first half of 2021 and the June 1, 2021 commencement of operations under a Supplemental Agreement to LUMA Energy's 15-year contract to modernize and operate Puerto Rico's electricity T&D system.

Natural Gas Distribution

Natural Gas Distribution serves municipal, residential, commercial and industrial customers throughout Alberta and in the Lloydminster area of Saskatchewan.

Natural Gas Distribution adjusted earnings of $72 million in the fourth quarter of 2021 were $7 million lower than the same period in 2020 mainly due to timing of operating costs.

Natural Gas Distribution adjusted earnings of $142 million in the full year of 2021 were $4 million lower than the same period in 2020 mainly due to higher operating costs, partially offset by growth in rate base.

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.

Natural Gas Transmission adjusted earnings of $20 million and $81 million in the fourth quarter and full year of 2021 were $2 million and $8 million lower than the same periods in 2020. Lower earnings were mainly due to the impact of the 2021-2023 General Rate Application which included operating cost efficiencies implemented in prior periods that are being passed on to customers, partially offset by growth in rate base.

International Natural Gas Distribution

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

International Natural Gas Distribution adjusted earnings of $26 million and $65 million in the fourth quarter and full year of 2021 were $18 million and $34 million higher compared to the same periods in 2020. Higher earnings were mainly due to the impact of inflation indexing and increased customer volumes.

UTILITIES RECENT DEVELOPMENTS THROUGHOUT 2021

Old Crow Solar Development Project

In August 2021, the Vuntut Gwitchin First Nation and Canadian Utilities announced the completion of Canada's most northerly off-grid solar project, reducing diesel use by 189,000 litres annually in Old Crow, Yukon and providing a clean energy source for decades to come.

This project showcases a first-of-its-kind Electricity Purchase Agreement. Vuntut Gwitchin will serve as the Independent Power Producer, owner and operator of the solar facility and ATCO Electric Yukon will purchase the solar electricity generated for the next 25 years and feed it into the grid for redistribution to the community.

Old Crow Solar Project - Old Crow, Yukon

This facility, similar to the Fort Chipewyan Solar Farm in Northern Alberta, fosters community ownership and self-sustaining economic development through job creation, investment in infrastructure, and revenue from the sale of renewable energy.

Energy projects like this are models of effective collaboration to enable and accelerate the clean energy transition. The Company intends to replicate its success with many of the other Northern Communities reliant on diesel power.

UTILITIES REGULATORY INFORMATION

UTILITIES REGULATORY FRAMEWORKS

Regulated Business Models

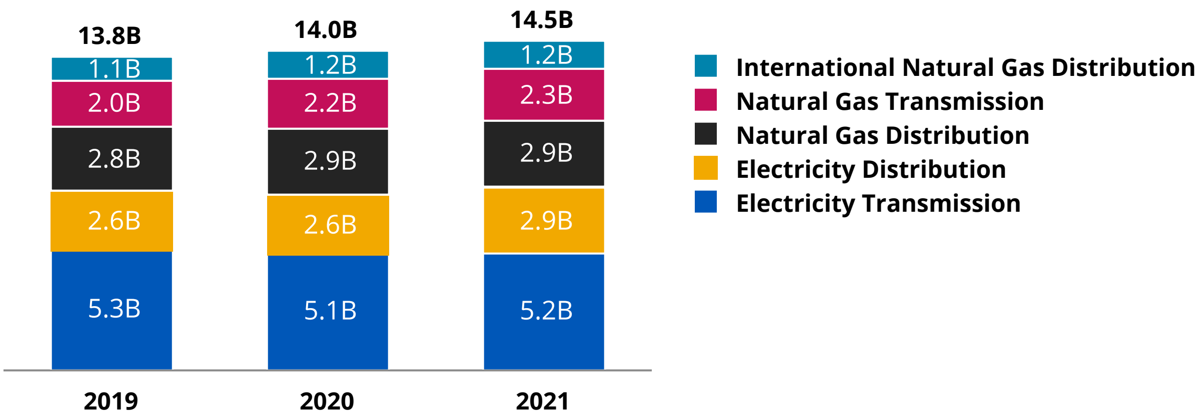
The business operations of Electricity Distribution, Electricity Transmission, Natural Gas Distribution and Natural Gas Transmission are regulated mainly by the Alberta Utilities Commission (AUC). The AUC administers acts and regulations covering such matters as rates, financing and service area.

Natural Gas Transmission and Electricity Transmission operate under 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 approved equity component 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 uses 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 approved going-in rates and on the formula that adjusts rates for inflation and productivity improvements.

International Natural Gas Distribution is regulated mainly by the Economic Regulation Authority (ERA) of Western Australia. International Natural Gas Distribution operates under incentive based regulation (IBR) under which the ERA establishes the prices for a five-year period to recover a return on forecasted rate base, including income taxes, depreciation on the forecasted rate base, and forecasted operating costs based on forecasted throughput. 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 within approved forecasts.

Regulated Utilities Mid-Year Rate Base ($ Billions)



Generic Cost of Capital Proceeding (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. On October 13, 2020 and March 4, 2021, the AUC issued the decisions for 2021 and 2022, respectively, approving the extension of the current ROE of 8.5 per cent and capital structure of 37 per cent equity on a final basis. The AUC commenced a new GCOC process in January 2022 to address the ROE and equity thickness for 2023 and beyond.

Performance Based Regulation

Under the 2018 to 2022 second generation PBR framework, electricity and natural gas distribution utility rates are adjusted by a formula that estimates annual inflation and assumes productivity improvements.

	PBR Second Generation
Timeframe	2018 to 2022
Inflation Adjuster (I Factor)	Inflation indices (AWE and CPI) adjusted annually
Productivity Adjuster (X Factor)	0.30%
O&M	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 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 weighted average cost of capital (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	• 8.5% • + 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 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
ROE Used for Reopener Calculation	2018: 8.5% excluding impact of ECM 2019: 8.5% excluding impact of ECM 2020 - 2022: 8.5%

Access Arrangement - International Natural Gas Distribution

On November 15, 2019, the ERA published its final rate of return guidelines which outlined the parameters for the WACC applicable to International Natural Gas Distribution's Access Arrangement period (AA5).

The AA5 ROE is 5.02 per cent compared to 7.21 per cent in the previous Access Arrangement. The final decision also includes rebasing of revenues for the recovery of operating costs, the approved capital expenditure program, and the forecast of demand and throughput. The common equity ratio for AA5 is 45 per cent compared to 40 per cent in the previous Access Arrangement.

The tariffs included in the AA5 final decision are applicable for the period January 1, 2020 to December 31, 2024.

Under the existing Access Arrangement, ATCO Gas Australia is using the Post-Tax Revenue Model method to determine revenue requirement and customer rates. Under this method, the impact of inflation is added to the rate base annually. The inflation impact is reflected in customer rates in future periods through the recovery of depreciation. Customer rates are adjusted annually through a mechanism, which adjusts the approved rates in real dollars for actual inflation.

ALBERTA REGULATORY UPDATES

Common Matters

2021 Rate Relief Application

On March 1, 2021, Canadian Utilities filed a 2021 Rate Relief Application for Electricity Distribution and Natural Gas Distribution to postpone rate increases for the full year 2021 and collect the deferred amounts commencing in 2023 for no more than a 5-year period. On June 18, 2021, the AUC issued a decision approving the requested rate relief, but directed Canadian Utilities to collect the 2021 deferred amounts commencing January 1, 2022, over a short duration, without exceeding a prescribed maximum increase in any year during the collection process. Canadian Utilities filed its 2022 PBR Rates applications on September 10, 2021, requesting recovery over the years 2022 and 2023 for Electricity Distribution and full recovery in 2022 for Natural Gas Distribution. The AUC issued its decisions in December 2021, approving the 2022 PBR rates for Electricity Distribution and Natural Gas Distribution as filed.

Distribution Regulatory Framework - Post 2022

On June 18, 2021, the AUC issued a decision providing direction regarding the 2023 COS application process. Each distribution utility is to present its application using an AUC-developed template with a prescribed minimum level of detail. On November 15, 2021, Electricity Distribution filed a 2023 COS application requesting, among other things, approval of a new grid modernization capital program to ensure that the grid can safely and reliably accommodate changing customer behaviours associated with decarbonization. On December 15, 2021, Natural Gas Distribution filed a 2023 COS application which includes a request for approval of a new capital program for the introduction of hydrogen into its distribution system in order to meet government-mandated net-zero emissions targets. Decisions from the AUC are expected in the third quarter of 2022.

On June 30, 2021, the AUC issued a decision relating to the Evaluation of Performance-Based Regulation in Alberta. The Commission determined that PBR has achieved many of the set principle objectives and that a third PBR term (PBR3) will commence in 2024 after a one year COS rebasing in 2023. A future generic proceeding will be initiated in the third quarter of 2022 to determine the parameters of the third generation PBR plan, including a review of incremental capital funding provisions, the inflation (I) and productivity (X) factors, and consideration of an earnings sharing mechanism.

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 decision was received in March 2021 approving the vast majority of requested capital expenditures and operating costs, as filed. Electricity Transmission filed its compliance filing on April 19, 2021 and on September 1, 2021, the AUC issued a decision which determined Electricity Transmission’s final revenue requirement for 2020 and 2021. The impact to 2021 adjusted earnings as a result of this decision included a decrease of $4 million, all of which relates to prior periods.

2018-2019 General Tariff Application

On June 29, 2021, the AUC issued a decision on the 2018-2019 GTA Compliance Filing which determined Electricity Transmission’s final revenue requirement for 2018 and 2019. The impact of this decision is a decrease to 2021 adjusted earnings of $8 million, all of which relates to prior periods.

Application of AUC Enforcement Staff for the Commencement of Proceeding Pursuant to Sections 8 and 63 of the Alberta Utilities Commission Act

On November 29, 2021, the AUC enforcement branch filed an application with the AUC recommending an enforcement proceeding be initiated. This proceeding is to determine whether ATCO Electric failed to comply with AUC decisions and enactments under the AUC's jurisdiction with respect to the sole source contract for the Jasper interconnection project and the actions leading up to and including the filing of the 2018-2020 Deferral Account Application. This proceeding will also determine any future remedies that may be required.

AUC Enforcement and Electricity Transmission are pursuing settlement discussions prior to the AUC determining the next process steps. In 2021, the Company recognized expenses of $14 million (after-tax) due to the potential outcome of the proceeding. As this proceeding is not in the normal course of business, these costs have been excluded from adjusted earnings.

Natural Gas Transmission

Pioneer Pipeline Acquisition

In the third quarter of 2020, Natural Gas Transmission entered into an agreement to acquire the Pioneer Pipeline from Tidewater Midstream & Infrastructure Ltd. and its partner TransAlta Corporation, subject to customary conditions including regulatory approvals by the AUC and Alberta Energy Regulator.

The 131-km natural gas pipeline runs from the Drayton Valley area to the Wabamun area west of Edmonton. On June 15, 2021, the AUC issued a decision approving the acquisition of the pipeline and associated integration costs, totaling $265 million, and the corresponding revenue requirement for 2021 to be included in Natural Gas Transmission's rates.

Consistent with the geographic areas defined in the Integration Agreement, Natural Gas Transmission will transfer to Nova Gas Transmission Ltd. (NGTL) the 30-km segment of pipeline that is located in the NGTL footprint for approximately $65 million.

The transaction to acquire the Pioneer Pipeline closed in 2021. The transfer to NGTL received approval from the Canada Energy Regulator on December 22, 2021, and is expected to close in the first quarter of 2022. The Pioneer Pipeline has been incorporated into NGTL's and Canadian Utilities' Alberta regulated natural gas transmission systems to provide reliable natural gas supply to TransAlta's power generating units at Sundance and Keephills, facilitating the conversion of these coal plants to cleaner-burning natural gas.

Natural Gas Transmission 2021-2023 General Rate Application (GRA)

In June 2020, Natural Gas Transmission filed a GRA for the period 2021-2023. An AUC decision was received in March 2021, approving the vast majority of requested capital expenditures and operating costs as filed, which included operating cost efficiencies implemented in prior periods that are being passed on to customers. On June 15, 2021, the AUC approved the acquisition of the Pioneer Pipeline including the associated integrated costs. On January 12, 2022, the AUC approved Natural Gas Transmission’s application reflecting the acquisition of Pioneer Pipeline in its 2021-2023 revenue requirement.

REVENUES

Energy Infrastructure revenues of $74 million and $209 million in the fourth quarter and full year of 2021 were $15 million and $14 million higher than the same periods in 2020 mainly due to higher natural gas prices at the Carbon, Alberta natural gas storage facility.

ADJUSTED EARNINGS

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2021**	**2020**	**Change**	**2021**	**2020**	**Change**
Electricity Generation [1]	**—**	4	(4)	**13**	13	—
Storage & Industrial Water [1]	**4**	8	(4)	**15**	15	—
Total Energy Infrastructure	**4**	12	(8)	**28**	28	—

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

Energy Infrastructure adjusted earnings of $4 million in the fourth quarter of 2021 were $8 million lower than the same period in 2020 mainly due to the costs associated with the purchase of the Alberta Hub natural gas storage facility, Central West Pumped Hydro development costs, non-recurring recoveries in 2020, and lower demand for natural gas storage services.

Energy Infrastructure adjusted earnings of $28 million in the full year of 2021 were comparable to the same period in 2020.

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

Electricity Generation

Non-regulated electricity activities include the supply of electricity from solar, hydroelectric, and natural gas generating plants in Western Canada, Australia, Mexico, and Chile and non-regulated electricity transmission in Alberta.

Electricity Generation adjusted earnings in the fourth quarter of 2021 were $4 million lower compared to the same period in 2020. Lower earnings were mainly due to Central West Pumped Hydro development costs, and non-recurring recoveries in 2020.

Electricity Generation adjusted earnings of $13 million in the full year of 2021 were comparable to the same period in 2020.

Storage & Industrial Water

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

Storage & Industrial Water adjusted earnings of $4 million in the fourth quarter of 2021 were $4 million lower compared to the same period in 2020 mainly due to costs associated with the purchase of the Alberta Hub natural gas storage facility and lower demand for natural gas storage services.

Storage & Industrial Water adjusted earnings of $15 million in the full year of 2021 were comparable to the same period in 2020.

ENERGY INFRASTRUCTURE RECENT DEVELOPMENTS THROUGHOUT 2021

Alberta Hub Natural Gas Storage Acquisition

In December 2021, Canadian Utilities announced the acquisition of the Alberta Hub natural gas storage facility near Edson, Alberta. The Alberta Hub underground natural gas storage facility has a capacity of approximately 49 petajoules and is connected to the NOVA Gas Transmission (NGTL) system. Complementing our existing natural gas storage facility at Carbon, Alberta, the Alberta Hub facility will provide customized storage solutions tailored to our customers' needs.

Calgary Solar Development Projects

In September 2021, Canadian Utilities announced that it had acquired the development rights to build two solar projects, the Deerfoot and Barlow projects in Calgary Alberta, with a combined capacity of 64-MW. Electricity from these solar projects may be sold through a contracted Power Purchase Agreement with any uncontracted electricity sold into the Alberta power market. The projects will be the largest urban solar developments in Western Canada and will provide enough renewable electricity to power more than 18,000 homes. The Barlow and Deerfoot projects have received all major permits. Detailed design and procurement for both projects has begun and commercial operations are expected to commence in the fourth quarter of 2022.

Rendering of Deerfoot Solar Development Project - Calgary, AB

Empress Solar Development Project

In September 2021, Canadian Utilities announced that it had acquired the rights to the Empress Solar project, a 39-MW solar facility under development near Empress, Alberta. Electricity from this solar project may be sold through a contracted Power Purchase Agreement with any uncontracted electricity sold into the Alberta power market. The project will provide enough renewable electricity to power more than 11,000 homes. Project execution is underway with all major permits received. Commercial operations are expected to commence in the fourth quarter of 2022.

Two Hills Renewable Natural Gas (RNG) Facility

In July 2021, Canadian Utilities announced its partnership with Future Fuel Ltd. to build and operate the Two Hills RNG facility north of Vegreville, Alberta. The RNG facility will combine organic waste from nearby municipalities with agricultural byproducts to produce approximately 230,000 gigajoules per year of renewable natural gas (enough to fuel 2,500 homes). Detailed design is currently underway and the facility is targeting to commence commercial operations in the fourth quarter of 2022.

The RNG produced will be delivered into the local gas distribution network and sold under a 15-year sales contract between Pacific Northern Gas Ltd. (PNG) and ATCO Future Fuel RNG Limited Partnership (ATCO Future Fuel).

Two Hills Renewable Natural Gas (RNG) Facility - Vegreville, AB

Canadian Utilities - Suncor Clean Hydrogen Project

In May 2021, Canadian Utilities and Suncor Energy announced the decision to collaborate on early stage design and engineering of a potential clean hydrogen project. The project will produce more than 300,000 tonnes per year of clean hydrogen, while capturing greater than 90 per cent of the carbon emissions, reducing Alberta's carbon dioxide emissions by more than two million tonnes per year. The hydrogen production facility will be located at ATCO's Heartland Energy Centre near Fort Saskatchewan, Alberta, and is expected to be operational as early as 2028. Although several provincial and federal policies, fiscal programs and regulations have already been put in place to support significant decarbonization and the development of a leading low-carbon fuels industry, further regulatory certainty and fiscal support is required for the project to progress to a sanctioning decision (which is expected in 2024). In addition to supplying clean hydrogen to Suncor and the Alberta gas grid, the project will make hydrogen volumes available for Alberta's other industrial, municipal and commercial transport users.

Clean Energy Innovation Park

In May 2021, Canadian Utilities and its joint venture partner, Australian Gas Infrastructure Group, received notification of $29 million AUD in conditional funding from the Australian Renewable Energy Agency (ARENA) to kick start the production of hydrogen through a large scale project at Canadian Utilities' proposed Clean Energy Innovation Park (CEIP) in Western Australia. The proposed project will leverage Canadian Utilities' learnings from its Clean Energy Innovation Hub, a pilot project which saw the company become the first in Australia to generate and use green hydrogen. The CEIP will include a 10-MW electrolyser and plant capable of producing up to four tonnes of hydrogen per day, along with storage and delivery to gas network injection points. The facility is planned to be co-located with a 180-MW wind farm in Western Australia, which will provide the renewable energy to power the electrolyser. A final investment decision for this project is expected in the first half of 2022.

Chile Solar Generation Facility

In 2019, Canadian Utilities entered into a partnership with Impulso Capital, a Chilean developer, to build and operate the El Resplandor solar project. This project, located in Cabrero, Chile, provides solar energy to the Chilean electricity grid. The 3-MW of solar generation capacity was completed at the end of the second quarter of 2020 for a total investment of $4 million. In the second quarter of 2021, Canadian Utilities made the decision to cancel the remaining planned 6-MW of the project due to land zoning concerns.

Central West Pumped Storage Hydro Project

In February 2021, Canadian Utilities announced an agreement to acquire the rights to develop the 325-MW Central West Pumped Storage Hydro project, located approximately 175-km west of Sydney, Australia. The acquisition marks Canadian Utilities' first renewable energy investment on Australia’s east coast. The project is in close proximity to significant renewable energy resources and will be integral in supporting the development of new renewable generation capacity in the state of New South Wales. A final investment decision on project construction is expected in 2023.

CORPORATE & OTHER

Canadian Utilities' Corporate & Other segment includes Rümi, Blue Flame Kitchen and Retail Energy through ATCOenergy which provides home products, home maintenance services, professional advice, and retail electricity and natural gas services in Alberta. Corporate & Other also includes the global corporate head office in Calgary, Canada, the Australia corporate head office in Perth, Australia and the Mexico corporate head office in Mexico City, Mexico. Canadian Utilities' Corporate & Other includes CU Inc. and Canadian Utilities preferred share dividend and debt expenses.

ADJUSTED EARNINGS

	Three Months Ended December 31			Year Ended December 31		
($ millions)	2021	2020	Change	2021	2020	Change
Canadian Utilities Corporate & Other	**(18)**	(21)	3	**(77)**	(77)	—

Canadian Utilities' Corporate & Other adjusted earnings in the fourth quarter of 2021 were $3 million higher compared to the same period in 2020 mainly due to the timing of certain expenses and improved earnings from ATCOenergy resulting from increased commodity margins.

Canadian Utilities' Corporate & Other adjusted earnings in the full year of 2021 were comparable to the same period in 2020.

CANADIAN UTILITIES CORPORATE & OTHER RECENT DEVELOPMENTS THROUGHOUT 2021

Rümi Launch

On June 3, 2021, Canadian Utilities launched Rümi, a solutions provider for home and business owners, offering lifestyle products, home maintenance services and professional advice for homeowners. Rümi currently offers approximately 60 services in Edmonton and Calgary, and more than 750 products for purchase online.

Executive Appointment

On October 6, 2021, the Canadian Utilities Board of Directors announced the appointment of Brian Shkrobot to the position of Executive Vice President & Chief Financial Officer of Canadian Utilities Limited.

New Board of Directors Appointee

Effective September 1, 2021, Robert Hanf, Q.C. was appointed to the Board of Directors for Canadian Utilities Limited.

SUSTAINABILITY, CLIMATE CHANGE AND ENERGY TRANSITION

Within the ATCO group of companies (including Canadian Utilities), we balance the short- and long-term economic, environmental and social considerations of our businesses while creating value for our customers, employees, share owners, and Indigenous and community partners. As a provider of essential services in diverse communities around the world, we operate in an inclusive manner to meet the needs of society today and for generations to come while consistently delivering safe, reliable and affordable services.

The following section outlines commitments made by Canadian Utilities' parent company, ATCO. Canadian Utilities is supportive of the commitments made by ATCO and will play a key part in achieving the ESG targets set by ATCO.

Sustainability Reporting and ESG Targets

ATCO's 2021 Sustainability Report, which will be published in May 2022, will focus on the following material topics:

- Energy Transition - energy transition and innovation, and energy access and affordability;
- Climate Change and Environmental Stewardship - climate change and GHG emissions, and environmental stewardship;
- Operational Reliability and Resilience - system reliability and availability, emergency preparedness and response, and supply chain resilience and responsibility;
- People - diversity, equity and inclusion, occupational health and safety, public health and safety; and
- Community and Indigenous Relations - Indigenous engagement, economic opportunity and reconciliation, and community engagement and investment.

In January 2022, ATCO released their net zero by 2050 commitment as well as an initial set of 2030 ESG Targets. ATCO's Board of Directors recognizes and fully supports the net-zero commitment and 2030 targets, and agrees that these commitments and targets align with our strategic direction. More detailed information and progress towards these targets will be found in the 2021 Sustainability Report. Achieving net zero by 2050 is a societal challenge that no individual, business, or government can solve on its own. It will require unprecedented collaboration among all constituents, as well as an informed, pragmatic, and affordable roadmap from policymakers to unlock the necessary scale and pace of private sector investment and expertise.

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

The 2021 Sustainability Report, Sustainability Framework Reference Document, Corporate Governance, materiality assessment, and additional details and other disclosures will be available on our website at www.canadianutilities.com.

Climate Change and Energy Transition

To contribute to a net-zero future, we continue to pursue initiatives to integrate cleaner fuels, renewable energy and energy storage. This includes looking at ways to modernize our energy infrastructure to accommodate new and innovative sources of energy as well as ways to further use energy more efficiently. We are decarbonizing our operations and enabling our customers to transition to lower emitting sources of energy, while maintaining safety, reliability and affordability.

POLICY/REGULATORY UPDATE

ATCO actively and constructively works with all levels of government to advocate for enabling policy and regulation, and to identify barriers that impede cost-effective, economy-wide decarbonization. ATCO participates in a wide number of discussions, and the following are examples of where we are focusing our efforts.

Carbon Pricing/Output-Based Pricing Systems

In April 2021, the carbon price in Canada increased from $30 to $40 per tonne, and by 2022 it is expected to reach $50 per tonne. In December 2020, the Government of Canada announced their plan on climate change, proposing to increase the carbon price by $15 per tonne each year starting in 2023, rising to $170 per tonne by 2030.

In December 2021, the Government of Alberta, confirmed that the Technology, Innovation and Emissions Reduction (TIER) regulation will increase from $40 per tonne in 2021 to $50 per tonne in 2022, meeting the federal government's stringency requirements for the emission sources they cover. Accordingly, the federal fuel charge continues to apply in Alberta, but not the federal Output-Based Pricing System. In the future, as carbon price increases and new updated initiatives are put in place by the federal government, TIER will also need to be updated to meet the federal government's stringency requirements.

In Australia, under the National Greenhouse and Energy Reporting scheme, a safeguard mechanism applies to facilities with direct covered emissions of more than 100,000 tonnes of carbon dioxide equivalent per year and affects our natural gas-fired power generation facilities. These facilities are required to keep their net emissions at or below emissions baselines set by the Clean Energy Regulator or surrender Australia Carbon Credit Units to offset their emissions and stay below their baseline.

Net-Zero Emissions Accountability Act

On June 29, 2021, the Net-Zero Emissions Accountability Act came into effect outlining the Government of Canada's commitment to achieve net-zero GHG emissions by 2050, as well as a 2030 target under the Paris Agreement to reduce GHG emissions by 40 to 45 per cent from 2005 levels. The Act establishes a legally binding process to set five-year national emissions-reduction targets, with the 2030 plan due by the end of March 2022. The Act also requires national emissions reduction targets for 2035, 2040, and 2045, ten years in advance, with credible, science-based emissions reduction plans to achieve it.

The Government of Canada is currently consulting on initiatives in early 2022 as part of their commitments to the emission-reduction targets. If these initiatives move forward, it may create both opportunities and challenges directly and indirectly for Canadian Utilities. Some of these initiatives include: transitioning to a net-zero emitting electricity grid by 2035; developing emission standards for different categories of vehicles and mandating a percentage of zero emission vehicles by specific dates; capping emissions from the oil and gas sector at current levels and declining at the pace to get to net zero by 2050; and developing a plan to reduce methane emissions across the broader Canadian economy in support of the Global Methane Pledge and Canada's climate plan goals to reduce oil and gas methane emissions by at least 75 percent below 2012 levels by 2030.

Methane Reductions

In December 2020, Alberta reached equivalency with federal methane regulations to reduce methane emissions by 40 to 45 per cent from 2012 levels by 2025. Canadian Utilities continues to implement programs to reduce or eliminate fugitive and venting emissions in our Natural Gas Transmission and Distribution businesses.

In January 2020, a new estimation method to report Unaccounted for Gas (UAFG) emissions resulting from natural gas distribution activities was introduced in Australia. This approach enables site/network specific UAFG values to be used, allowing Canadian Utilities to translate network maintenance and replacement activities into reportable reductions in UAFG emissions.

Clean Fuel Standards

In July 2021, the Government of Canada announced that the scope of the Clean Fuel Standards (CFS) was further refined to cover only gasoline and diesel liquid fossil fuels used predominately in transportation (with an exemption for diesel used in space heating). The regulations are expected to come into effect in late 2022.

Hydrogen Roadmap

In December 2020, the Government of Canada released their Hydrogen Strategy for Canada. In November 2021, the Government of Alberta released the Alberta Hydrogen Roadmap outlining the Government's approach to developing hydrogen use and production in Alberta. The Hydrogen Roadmap is an action plan that integrates hydrogen with the province's existing energy infrastructure. It is a key part of Alberta's Recovery Plan and will be implemented in a phased approach. In the first phase, Alberta will establish policy foundations, close technology gaps with research and innovation, reduce the carbon intensity of existing hydrogen production, and deploy clean hydrogen into end-use markets. The second phase will focus on growth and commercialization. These actions will be implemented by working closely with partner agencies, federal, provincial and municipal governments, industries and other key partners and stakeholders.

ENERGY TRANSITION HIGHLIGHTS

To support the energy transition, we continue to explore and implement opportunities in cleaner fuels, renewable energy, energy infrastructure and storage, and energy efficiency. We intend to expand our ownership, management and development of clean energy solutions, as well as enable our customers to transition to lower-emitting sources of energy.

Renewable Energy

Canadian Utilities continues to build its renewable energy portfolio and enable customers to integrate renewable energy options. Renewable energy initiatives are discussed in the "Business Unit Performance" section, under the "Utilities" and "Energy Infrastructure" sections in this MD&A, and include the examples highlighted below.

In February 2021, Canadian Utilities acquired the rights to develop the 325-MW Central West Pumped Storage Hydro project, located approximately 175-km west of Sydney, Australia. The project is in close proximity to significant renewable energy resources and will be integral in supporting the development of new renewable generation capacity in the state of New South Wales.

In August 2021, the Vuntut Gwitchin First Nation and Canadian Utilities completed Canada's most northerly off-grid solar project, reducing diesel use by 189,000 litres annually in Old Crow, Yukon and providing the community with clean energy for decades to come.

In September 2021, Canadian Utilities acquired the rights to the Empress Solar Project, a 39-MW photovoltaic solar facility under development near the village of Empress, Alberta. Canadian Utilities also acquired the rights to build two solar installations in Calgary. Once complete, the Barlow and Deerfoot solar projects will be the largest solar installation in a major urban centre in Western Canada, with a combined capacity of 64-MW.

Cleaner Fuels

Canadian Utilities continues to pursue opportunities in cleaner fuels including RNG and hydrogen, and below are examples that are included in the "Business Unit Performance - Energy Infrastructure" section in this MD&A.

Building on our hydrogen blending project in Fort Saskatchewan, in May 2021 Canadian Utilities and Suncor Energy announced the decision to collaborate on early stage design and engineering of a potential clean hydrogen project. The project will produce more than 300,000 tons per year of clean hydrogen, while capturing greater than 90 per cent of the carbon emissions, reducing Alberta's carbon dioxide emissions by more than two million tons per year.

In May 2021, Canadian Utilities and its joint venture partner, Australian Gas Infrastructure Group, received notification of conditional grant funding from Australian Renewable Energy Agency of $29 million AUD to contribute financing for the production of hydrogen through a large scale project at Canadian Utilities' proposed Clean Energy Innovation Park in Western Australia. The proposed project will leverage Canadian Utilities' learnings from its Clean Energy Innovation Hub, a pilot project which saw the company become the first in Australia to generate and use green hydrogen.

In July 2021, Canadian Utilities partnered with Future Fuel Ltd. to build and operate a RNG facility in Alberta with Emissions Reduction Alberta committing $8 million to the project through its Natural Gas Challenge. Located north of Vegreville, Alberta, the Two Hills RNG Facility is Canadian Utilities' first commercial RNG production facility and a strategic investment in Canadian Utilities's clean fuels strategy. Detailed design is currently underway and full commercial operation is expected to be achieved in late 2022.

Our Performance

As our portfolio of assets and businesses evolves, so too does our environmental footprint. Since 2005, we have significantly decarbonized our portfolio through a combination of asset sales, implementation of fuel-switching, GHG reduction initiatives and other efficiency programs.

CLIMATE CHANGE RESILIENCY

We carefully manage climate-related risks, including preparing for, and responding to, extreme weather events through activities such as proactive route and site 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 our 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. Wildfire Management Plans include requirements to conduct annual patrols of all transmission 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 our Natural Gas Transmission and Distribution businesses, the majority of the 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. We have also mapped and continue to regularly inspect pipeline water crossings.

We have streamlined our Crisis Response and Emergency Preparedness systems, and we continuously improve our ability to rapidly mobilize and effectively respond to crises globally. We incorporate learnings from responding to extreme weather events which enables us to continue to strengthen our emergency response capabilities.

CLIMATE CHANGE CHALLENGES AND OPPORTUNITIES

While climate-related challenges and opportunities are integrated throughout our strategy and risk management processes, we understand that specifically disclosing climate-related information aligned with the TCFD recommendations is also useful for the investment community.

In addition to the material risks described in the Business Risks and Risk Management section of this MD&A, the following table provides further information on how we address specific climate-related challenges and opportunities.

Category/Driver		Challenges	Opportunities	Mitigation Options/ Measures
Transitional	**Policy/Regulatory**	Operations in several jurisdictions subject to emissions limiting regulations Aggressive shifts in policy which do not allow for transition in an effective, affordable manner	Continued fuel switching to lower-emitting options Coal-to-gas electricity generation conversions by other companies present opportunities for increased demand for natural gas transmission infrastructure investment in the near to medium term Electricity grid modernization Hydrogen economy development	Active participation in policy development, industry groups, and regulatory discussions Business diversification Removal of coal-fired electricity generation from our portfolio in 2019 Hydrogen research and development
	Market	Changes in carbon policy, costs of operations, and commodity prices Changing customer behaviour	Increasing demand for lower-emitting technologies Hydrogen market development Distributed energy solutions	Participation in carbon markets Business diversification Removal of coal-fired electricity generation from our portfolio in 2019
	Technology	Replacement of current products/services with lower-emitting options Prosumer movement may affect energy load profiles in the future	A transition to lower-emitting energy systems provides opportunities to utilize expertise in: generation, integration and delivery of new energy sources including hydrogen, renewable natural gas, EV networks; and transmission and distribution infrastructure to ensure energy network reliability and security	Providing a suite of lower-emitting technology solutions so our customers can pick the right solutions for their unique situation
	Reputational	Public perception of carbon risk	Increase in demand for trusted long-term partners to deliver lower-emitting solutions	Transparent reporting Authentic engagement and collaboration
Physical	**Physical**	Extreme weather events Long-term changes in temperature and weather patterns	Climate change mitigation and adaptation Rapidly deployable structures and logistics services	Climate change resiliency efforts Emergency Response & Preparedness plans and training

OTHER EXPENSES AND INCOME

A financial summary of other consolidated expenses and income items for the fourth quarter and full year of 2021 and 2020 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)	**2021**	**2020**	**Change**	**2021**	**2020**	**Change**
Operating costs	**553**	499	54	**1,982**	1,682	300
Depreciation, amortization and impairment	**138**	158	(20)	**651**	610	41
Earnings from investment in joint ventures	**22**	12	10	**58**	31	27
Net finance costs	**112**	98	14	**402**	386	16
Income tax expense	**69**	32	37	**138**	152	(14)

OPERATING COSTS

Operating costs, which are total costs and expenses less depreciation, amortization and impairment, increased by $54 million in the fourth quarter of 2021 compared to the same period in 2020. Higher operating costs were mainly due to increased consumption and higher energy prices in ATCO Energy, and higher flow-through natural gas transmission costs.

Operating costs increased by $300 million for the full year of 2021 compared to the same period in 2020. Higher operating costs were mainly due to increased consumption and higher energy prices in ATCO Energy, higher flow-through natural gas transmission costs, and higher unrealized and realized losses on derivative financial instruments in 2021.

DEPRECIATION, AMORTIZATION AND IMPAIRMENT

Depreciation, amortization and impairment decreased by $20 million in the fourth quarter of 2021 compared to the same period in 2020 mainly due to project cost recoveries related to the conclusion of an international project, partially offset by higher depreciation in Electricity Transmission as a result of a project cancellation.

Depreciation, amortization and impairment increased by $41 million in the the full year of 2021 compared to the same period in 2020 mainly due to the second quarter 2021 impairment of assets in Canadian Utilities' Energy Infrastructure segment as part of the continued assessment of our assets.

EARNINGS FROM INVESTMENT IN JOINT VENTURES

Earnings from investment in joint ventures is mainly comprised of Canadian Utilities' ownership positions in electricity generation plants, LUMA Energy electricity operations and maintenance in Puerto Rico, and the Strathcona Storage Limited Partnership, which operates hydrocarbon storage facilities at the ATCO Heartland Energy Centre near Fort Saskatchewan, Alberta.

Earnings from investment in joint ventures increased by $10 million in the fourth quarter of 2021 compared to the same period in 2020 mainly due to earnings from LUMA Energy related to the commencement on June 1, 2021 of the Supplemental Agreement to LUMA Energy's 15-year Operations and Maintenance Agreement.

Earnings from investment in joint ventures increased by $27 million in the full year of 2021 compared to the same period in 2020 mainly due to earnings from LUMA Energy related to ongoing transition work in the first half of 2021, and the commencement on June 1, 2021 of the Supplemental Agreement to LUMA Energy's 15-year Operations and Maintenance Agreement, partially offset by an impairment of an investment in Canadian Utilities' Energy Infrastructure segment as part of the continued assessment of our assets.

NET FINANCE COSTS

Net finance costs increased by $14 million and $16 million in the fourth quarter and full year of 2021 compared to the same periods in 2020 mainly due to recognition of accretion expense on asset retirement obligations related to an international project and lower interest income resulting from lower interest rates received on cash balances.

INCOME TAX EXPENSE

Income taxes were higher by $37 million in the fourth quarter of 2021 compared to the same period in 2020 mainly due to higher IFRS earnings before income taxes and a write down of deferred tax assets in ATCO Mexico.

Income taxes were lower by $14 million in the full year of 2021 compared to the same period in 2020 mainly due to lower IFRS earnings before income taxes, partially offset by a write down of deferred tax assets in ATCO Mexico.

LIQUIDITY AND CAPITAL RESOURCES

Our financial position is supported by our Regulated Utilities and our portfolio of energy infrastructure businesses, which are structured to be highly regulated and long-term contracted. Our business strategies, funding of operations, and planned future growth are supported by maintaining strong investment grade credit ratings and access to capital markets at competitive rates. Primary sources of capital are cash flow from operations and capital markets.

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

CREDIT RATINGS

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

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

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

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

On August 31, 2021, S&P Global Ratings affirmed its 'A-' long-term issuer credit rating and negative outlook on Canadian Utilities. On July 30, 2021, S&P Global Ratings affirmed Canadian Utilities subsidiary CU Inc.'s 'A-' long-term issuer credit rating and stable outlook, reflecting S&P's view that CU Inc. is an insulated entity to ATCO Ltd. and Canadian Utilities.

On August 13, 2021, DBRS Limited affirmed its 'A' long-term corporate credit rating and stable outlook on Canadian Utilities. On July 22, 2021, DBRS Limited affirmed its ‘A (high)’ long-term corporate credit rating and stable outlook on Canadian Utilities’ subsidiary CU Inc.

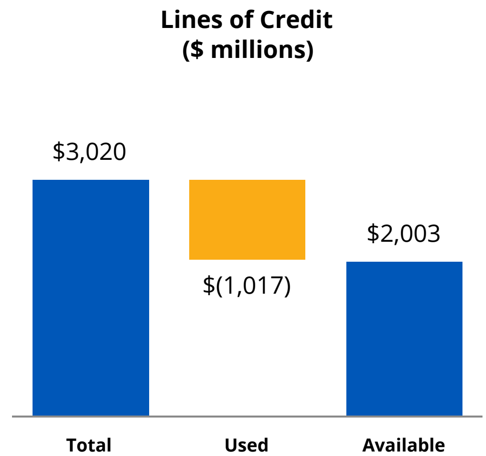
LINES OF CREDIT

At December 31, 2021, Canadian Utilities and its subsidiaries had the following lines of credit.

($ millions)	**Total**	**Used**	**Available**
Long-term committed	**2,467**	832	1,635
Uncommitted	**553**	185	368
Total	**3,020**	1,017	2,003

Of the $3,020 million in total lines of credit, $553 million was in the form of uncommitted credit facilities with no set maturity date. The other $2,467 million in credit lines was committed, with maturities between 2023 and 2026, and may be extended at the option of the lenders.

Of the $1,017 million in lines of credit used, $626 million was related to ATCO Gas Australia Pty Ltd. Long-term committed credit lines are used to satisfy all of ATCO Gas Australia Pty Ltd.'s term debt financing needs. The majority of the remaining usage is for the issuance of letters of credit.



CONSOLIDATED CASH FLOW

At December 31, 2021, the Company's cash position was $750 million, a decrease of $28 million compared to December 31, 2020. Major movements are outlined in the following table:

		Year Ended December 31	
($ millions)	**2021**	**2020**	**Change**
Cash flows from operating activities	**1,718**	1,631	87
Net issue of long-term debt	**294**	46	248
Issue of short-term debt	**206**	—	206
Cash used for capital investment [(1)]	**(1,338)**	(912)	(426)
Issue of equity preferred shares	**201**	—	201
Redemption of equity preferred shares by subsidiary company	**(110)**	—	(110)
Dividends paid on equity preferred shares	**(65)**	(67)	2
Dividends paid to non-controlling interests	**(7)**	(7)	—
Dividends paid to Class A and Class B share owners	**(476)**	(477)	1
Interest paid	**(385)**	(393)	8
Other	**(66)**	(20)	(46)
(Decrease) in cash position	**(28)**	(199)	171

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

Cash Flows from Operating Activities

Cash flows from operating activities were $510 million in the fourth quarter of 2021, $90 million higher compared to the same period in 2020 mainly due to higher cash flows in the Natural Gas Distribution business as a result of higher revenues.

Cash flows from operating activities were $1,718 million in the full year of 2021, $87 million higher compared to the same period in 2020 mainly due to higher customer contributions received for Alberta Utilities' capital expenditures. These amounts were partially offset by the Company's decision to provide rate relief to customers through the deferral of rate increases for the Electricity Distribution and Natural Gas Distribution businesses, which will be collected from customers starting in 2022.

Cash flows from operating activities in 2021 are adversely impacted as a result of Canadian Utilities' decision to provide rate relief to customers through the deferral of rate increases for Electricity Distribution and Natural Gas Distribution which will be collected from customers starting in 2022.

Cash Used for Capital Investment (1) and Capital Expenditures

Cash used for capital investment was $426 million in the fourth quarter of 2021, $173 million higher compared to the same period in 2020 mainly due to the acquisition of the Alberta Hub natural gas storage facility in the Energy Infrastructure segment and a strategic land purchase.

Cash used for capital expenditures was $334 million in the fourth quarter of 2021, $83 million higher compared to the same period in 2020 mainly due to a strategic land purchase.

Cash used for capital investment was $1,338 million in the full year of 2021, $426 million higher compared to the same period in 2020 mainly due to the acquisition of the Pioneer Pipeline in the Natural Gas Transmission business; and the acquisition of the Alberta Hub natural gas storage facility, the acquisition of three solar development projects, and the construction of a long-term contracted hydrocarbon storage cavern in the Energy Infrastructure segment.

Total capital expenditures were $1,227 million in the full year of 2021, $324 million higher compared to the same period in 2020, mainly due to the acquisition of the Pioneer Pipeline in the Natural Gas Transmission business, and the acquisition of three solar development projects in the Energy Infrastructure segment.

Capital investment and capital expenditures for the fourth quarter and full year of 2021 and 2020 is shown in the table below.

	Three Months Ended December 31			Year Ended December 31		
($ millions)	**2021**	**2020**	**Change**	**2021**	**2020**	**Change**
Utilities						
Electricity	**92**	95	(3)	**350**	366	(16)
Natural Gas	**159**	148	11	**747**	510	237
	251	243	8	**1,097**	876	221
Energy Infrastructure (1)	**80**	5	75	**120**	19	101
CU Corporate & Other	**3**	3	—	**10**	8	2
Canadian Utilities Total Capital Expenditures (2) (3)	**334**	251	83	**1,227**	903	324
Capital Expenditures in joint ventures						
Utilities						
Electricity	**2**	—	2	**5**	—	5
Energy Infrastructure	**6**	2	4	**22**	9	13
Business Combinations						
Energy Infrastructure	**84**	—	84	**84**	—	84
Canadian Utilities Total Capital Investment (4)	**426**	**253**	**173**	**1,338**	**912**	**426**

(1) In the fourth quarter of 2021, Storage and Industrial Water purchased land from an ATCO affiliate for project development.

(2) Includes additions to property, plant and equipment, intangibles and $(3) million and $6 million (2020 - $3 million and $13 million) of capitalized interest during construction for the fourth quarter and full year of 2021. The $(3) million of capitalized interest during construction recognized in the fourth quarter relates to a project cancellation.

(3) Includes $38 million and $169 million for the fourth quarter and full year of 2021 (2020 - $37 million and $82 million) of capital expenditures, mainly in the Utilities, that were funded with the assistance of customer contributions.

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

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

Base Shelf Prospectus - CU Inc. Debentures

On September 16, 2020, CU Inc. filed a base shelf prospectus that permits it to issue up to an aggregate of $1.2 billion of debentures over the 25-month life of the prospectus. As of February 22, 2022, aggregate issuances of debentures were $610 million.

Preferred Shares - CU Inc.

Effective June 1, 2021, the annual dividend rate on CU Inc.'s Cumulative Redeemable Preferred Shares Series 4 was reset from 2.243 per cent to 2.292 per cent for a five-year period.

Redemption of Equity Preferred Shares

On August 27, 2021, the Company redeemed all of the issued 4.60 per cent Series V preferred shares for $110 million plus accrued dividends. $79 million of Series V was allocated to the Alberta Utilities under CU Inc. and this portion was subsequently replaced with long-term debt as part of CU Inc.’s September 2021 debenture issue.

Preferred Shares Issuances

On December 9, 2021, Canadian Utilities issued $175 million of 4.75 per cent Cumulative Redeemable Second Preferred Shares Series HH by means of a short form prospectus and granted an underwriter option to purchase an additional $26 million. This option was exercised in December 2021 increasing the total gross proceeds to $201 million. The Company intends to use the proceeds for capital expenditures, to repay indebtedness and for other general corporate purposes.

Dividends and Common Shares

We have increased our common share dividend each year since 1972, a 50-year track record. Dividends paid to Class A and Class B share owners totaled $119 million in the fourth quarter of 2021 and $476 million in the full year of 2021.

On January 13, 2022, the Board of Directors declared a first quarter dividend of 44.42 cents per share. The payment of any dividend is at the discretion of the Board of Directors and depends on our financial condition and other factors.

Normal Course Issuer Bid

We believe that, from time to time, the market price of our Class A shares may not fully reflect the value of our business, and that purchasing Class A shares represents a desirable use of available funds. The purchase of Class A shares, at appropriate prices, will also minimize any dilution resulting from the exercise of stock options.

On July 22, 2020, we commenced a normal course issuer bid to purchase up to 3,996,004 outstanding Class A shares. This bid expired on July 21, 2021. During this period, 3,996,004 shares were purchased for $132 million, of which 3,576,004 shares for $119 million were purchased in 2021.

On July 29, 2021, we commenced a normal course issuer bid to purchase up to 3,930,623 outstanding Class A shares. The bid will expire on July 28, 2022. To date, no shares have been purchased.

SHARE CAPITAL

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

At February 22, 2022, we had outstanding 196,977,347 Class A shares, 72,373,274 Class B shares, and options to purchase 1,521,250 Class A shares.

CLASS A NON-VOTING SHARES AND CLASS B COMMON SHARES

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

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

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

Of the 12,800,000 Class A shares authorized for grant of options under our stock option plan, 2,905,900 Class A shares were available for issuance at December 31, 2021. Options may be granted to officers and key employees of the Company and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the grant date. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant.

QUARTERLY INFORMATION

The following table shows financial information for the eight quarters ended March 31, 2020 through December 31, 2021.

($ millions, except for per share data)	Q1 2021	Q2 2021	Q3 2021	Q4 2021
Revenues	907	790	790	**1,028**
Earnings attributable to equity owners of the Company	141	5	71	**176**
Earnings (loss) attributable to Class A and B shares	124	(11)	55	**160**
Earnings (loss) per Class A and Class B share *($)*	0.46	(0.04)	0.20	**0.59**
Diluted earnings (loss) per Class A and Class B share *($)*	0.46	(0.04)	0.20	**0.59**
Adjusted earnings per Class A and Class B share *($)*	0.70	0.43	0.33	**0.71**
Adjusted earnings (loss)				
Utilities [(1)]	201	124	104	**206**
Energy Infrastructure	10	7	7	**4**
Corporate & Other and Intersegment Eliminations	(20)	(16)	(23)	**(18)**
Total adjusted earnings [(1)]	191	115	88	**192**

($ millions, except for per share data)	Q1 2020	Q2 2020	Q3 2020	Q4 2020
Revenues	885	740	727	881
Earnings attributable to equity owners of the Company	160	72	91	104
Earnings attributable to Class A and Class B shares	143	56	74	87
Earnings per Class A and Class B share *($)*	0.52	0.21	0.27	0.32
Diluted earnings per Class A and Class B share *($)*	0.52	0.21	0.27	0.32
Adjusted earnings per Class A and Class B share *($)*	0.66	0.34	0.28	0.68
Adjusted earnings (loss)				
Utilities [(1)]	189	111	89	195
Energy Infrastructure	5	4	7	12
Corporate & Other and Intersegment Eliminations	(15)	(21)	(20)	(21)
Total adjusted earnings [(1)]	179	94	76	186

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

Our financial results for the previous eight quarters reflect the timing of utility regulatory decisions, and the seasonal nature of demand for natural gas and electricity.

ADJUSTED EARNINGS

UTILITIES [(1)]

In the first quarter of 2020, Utilities adjusted earnings were positively impacted by cost efficiencies, rate base growth, and lower income taxes. Higher earnings were partially offset by the completion of ECM funding in 2019 for Electricity Distribution and Natural Gas Distribution.

In the second quarter of 2020, adjusted earnings in the Utilities were adversely impacted by the prior period impact of the Electricity Transmission 2018-2019 GTA decision received in the second quarter of 2019, the adverse earnings impact of the new five-year Access Arrangement regulatory decision in International Natural Gas Distribution, the transition to APL operating activities by Electricity Transmission with completion of project management construction activities at the end of the first quarter of 2019, and the completion of the incremental ECM funding in 2019 for Electricity Distribution and Natural Gas Distribution.

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

In the third quarter of 2020, adjusted earnings in the Utilities were adversely impacted by the adverse earnings impact of the five-year Access Arrangement regulatory decision, an adjustment for the impact of forecasted inflation rates in International Natural Gas Distribution and the transition to APL operating activities by Electricity Transmission. Lower earnings were partially offset by ongoing cost efficiencies and rate base growth across the Utilities, and contributions in International Electricity Operations from Canadian Utilities' 50 per cent joint venture ownership in LUMA Energy which commenced work in Puerto Rico at the end of the second quarter of 2020.

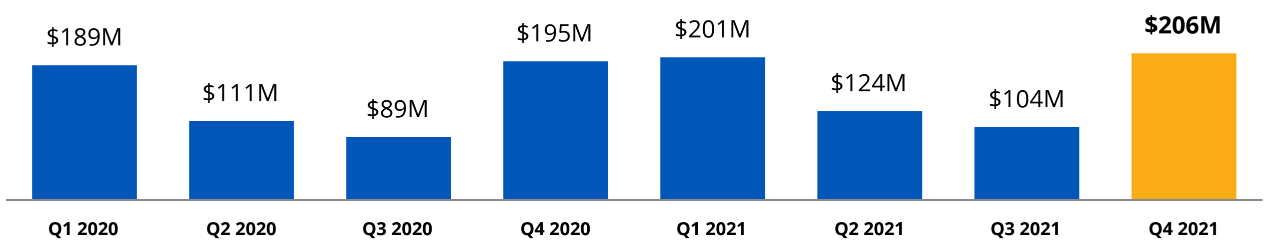
In the fourth quarter of 2020, adjusted earnings in the Utilities were positively impacted by cost efficiencies, rate base growth, and contributions in International Electricity Operations from Canadian Utilities' 50 per cent joint venture ownership in LUMA Energy.

In the first quarter of 2021, adjusted earnings in the Utilities were higher than the same period in 2020. Higher earnings were mainly due to cost efficiencies and continued growth in the regulated rate base, earnings from International Electricity Operations, and inflation indexing and foreign exchange adjustments in International Natural Gas Distribution.

In the second quarter of 2021, adjusted earnings in the Utilities were higher than the same period in 2020. Higher earnings were mainly due to contributions from International Electricity Operations, a higher inflation rate in International Natural Gas Distribution, and cost efficiencies, partially offset by the impact of the Electricity Transmission 2018-2019 General Tariff Application (GTA) Compliance Filing decision received in the second quarter of 2021.

In the third quarter of 2021, adjusted earnings in the Utilities were higher than the same period in 2020. Higher earnings were mainly due to higher earnings from International Electricity Operations, inflation indexing in International Natural Gas Distribution, and cost efficiencies within the Electricity Distribution business.

In the fourth quarter of 2021, adjusted earnings in the Utilities were higher than the same period in 2020 mainly due to higher earnings from International Electricity Operations, and inflation indexing in International Natural Gas Distribution. Higher earnings were partially offset by timing of operating costs.



ENERGY INFRASTRUCTURE

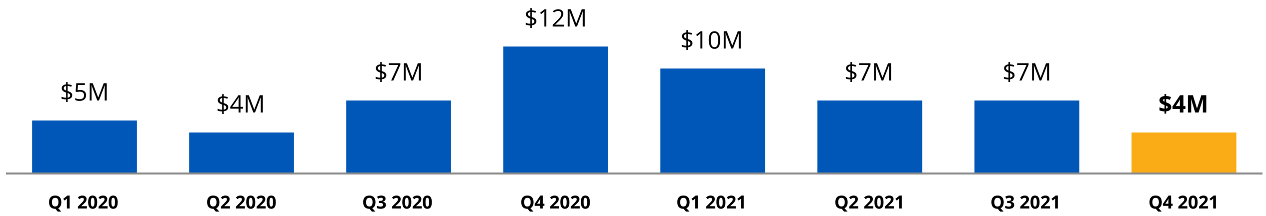
In all quarters of 2020, Energy Infrastructure earnings were adversely impacted due to the sale of the Canadian fossil fuel-based electricity generation business in the third quarter of 2019 and the sale of APL in the fourth quarter of 2019.

In the first quarter of 2021, Energy Infrastructure earnings were higher than the same period in 2020 mainly due to increased demand for natural gas storage services and recovered business development costs.

In the second quarter of 2021, Energy Infrastructure earnings were higher than the same period in 2020 mainly due to recovered business development costs, partially offset by lower demand for natural gas storage services.

In the third quarter of 2021, Energy Infrastructure earnings were comparable to the same period in 2020.

In the fourth quarter of 2021, Energy Infrastructure earnings were lower than the same period in 2020 mainly due to the costs associated with the purchase of the Alberta Hub natural gas storage facility, Central West Pumped Hydro development costs, non-recurring recoveries in 2020, and lower demand for natural gas storage services.



EARNINGS ATTRIBUTABLE TO EQUITY OWNERS OF THE COMPANY

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

- In the second quarter of 2020, impairment and other costs not in the normal course of business of $30 million (after-tax) were recorded. These costs mainly related to certain assets that no longer represent strategic value for the Company.
- Early Termination of the Master Service Agreements for Managed IT Services
    - In the fourth quarter of 2020 and first quarter of 2021, the Company signed MSAs with IBM Canada Ltd. (subsequently novated to Kyndryl Canada Ltd.) and IBM Australia Limited (IBM), respectively, to provide managed IT services. These services were previously provided by Wipro under a ten-year MSA expiring in December 2024. The Company recognized termination costs of $55 million and $4 million (after-tax) in the fourth quarter of 2020 and first quarter of 2021, respectively, which represents managements' best estimate of the costs to exit the Wipro MSAs.
    - The transition of the managed IT services from Wipro to IBM commenced on February 1, 2021 and is now complete. In the fourth quarter and full year of 2021, Canadian Utilities recognized transition costs of $8 million and $42 million (after-tax), respectively.
- In the second quarter of 2021, impairments and other costs not in the normal course of business of $65 million (after-tax) were recorded. The Company incurred $54 million of these costs in Mexico, related mainly to its Veracruz hydro facility within its Energy Infrastructure segment. The charge reflects an adverse arbitration decision, changes in market regulations, ongoing political uncertainty, and a challenging operating environment, resulting in an impairment of the carrying value of the assets. Other costs recorded were individually immaterial.
- AUC Enforcement Proceeding
    - In the fourth quarter of 2021, the AUC enforcement branch filed an application with the AUC recommending an enforcement proceeding be initiated. This proceeding is to determine whether ATCO Electric failed to comply with AUC decisions and enactments under the AUC's jurisdiction with respect to the sole source contract for the Jasper interconnection project and the actions leading up to and including the filing of the 2018-2020 Deferral Account Application. This proceeding will also determine any future remedies that may be required.
    - AUC Enforcement and Electricity Transmission are pursuing settlement discussions prior to the AUC determining the next process steps. In 2021, the Company recognized expenses of $14 million (after-tax) due to the potential outcome of the proceeding.
- During the fourth quarter and full year of 2021, the Company recorded earnings of $17 million (after-tax) following the conclusion of the Company's involvement in an international project.

BUSINESS RISKS AND RISK MANAGEMENT

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

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

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

Business Risk: Capital Investment		
Businesses Impacted:	**Associated Strategies:**	
• All businesses	• Growth	• Financial Strength

Description & Context

The Company is subject to the normal risks associated with major capital projects, including cancellations, delays and cost increases. As it relates to the Company's energy transition investments, the Company faces additional risks including policy certainty, pace of energy transition, commodity and environmental attribute price risk and climate risk.

Risk Management Approach

The Company attempts to reduce the risks of project delays and cost increases by careful project feasibility, development and management processes, procurement practices and entering into fixed price contracts when possible.

International Natural Gas Distribution's planned capital investment is approved by the regulator. Planned capital investments for the Alberta Utilities are based on the following significant assumptions: projects identified by the AESO will proceed as currently scheduled; the remaining planned capital investments are required to maintain safe and reliable service and meet planned growth in the Alberta Utilities' service areas; regulatory approval for capital projects can be obtained in a timely manner; and access to capital market financings can be maintained.

The Company reduces risks associated with policy certainty, pace of energy transition, commodity and environmental attribute price risk and climate-related risk by leveraging our competitive advantages and assigning clear accountability and leadership for executing and realizing capital investment. Planned capital investments for Energy Infrastructure are based on the following significant assumptions: a diversified approach to business development focused on multiple pillars (energy storage, clean fuels, renewables) and development in areas closest to economic feasibility; ensuring long-term assets are matched with appropriate customer offtake agreements with investment grade counterparties; pursuing projects in markets where fundamentals and competitive advantage enable us to be successful; and self-performing or working with Engineering, Procurement and Construction firms and partners to ensure construction activities are completed by parties with the competencies to ensure successful project delivery.

The Company believes these assumptions are reasonable.

Business Risk: Climate Change		
Businesses Impacted:	**Associated Strategies:**	
• All businesses	• Operational Excellence	• Innovation

Description & Context - Policy Risks

Canadian Utilities has operations in several jurisdictions subject to emission regulations, including carbon pricing, output-based performance standards, and other emission management policies. For example, in Alberta the output-based Technology Innovation and Emissions Reduction Regulations replaced the federal Output-Based Pricing System as of January 1, 2020.

Energy Infrastructure has pivoted its growth strategy to largely focus on energy transition assets. A lack of clarity on proposed regulations creates revenue uncertainty for these projects.

Risk Management Approach - Policy Risks

The Company's exposure is mitigated for the Regulated Utilities because GHG emission charges are generally recovered in rates. In addition, future requirements, such as upgrading equipment to further reduce methane emissions in the natural gas utilities, are expected to be included in rate base on a go-forward basis.

Energy Infrastructure is targeting investments that benefit from climate change. In addition, we are actively and constructively working with all levels of government as well as Indigenous communities to ensure ongoing communication and that the impacts and costs of proposed policy changes are identified and understood. Where appropriate, the Company is also working with its peers and industry associations to develop common positions and strategies.

Description & Context - 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 ongoing impacts to seasonal temperatures. Assets across all of Canadian Utilities' businesses are exposed to extreme weather events.

Risk Management Approach - 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 and site 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.

Prevention activities include Wildfire Management Plans and vegetation management at Electricity Transmission and Distribution operations. The majority of the Company's natural gas 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. 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.

These are the material climate related risks. For more detailed information on additional climate-related risks please refer to the Sustainability, Climate Change and Energy Transition section of this MD&A.

Business Risk: Credit Risk	
Businesses Impacted:	**Associated Strategies:**
• All businesses	• Financial Strength

Description & Context

For cash and cash equivalents and accounts receivable and contract assets, credit risk represents the carrying amount on the consolidated balance sheet. Derivative and finance lease receivable credit risk arises from the possibility that a counterparty to a contract fails to perform according to the terms and conditions of that contract. The maximum exposure to credit risk is the carrying value of loans and receivables and derivative financial instruments.

Risk Management Approach

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.

Geographically, a significant portion of loans and receivables are from the Company's operations in Alberta, followed by operations in Australia and Mexico. The largest credit risk concentration is from the Alberta Utilities, which 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 the retailers beyond the retailer security mandated by provincial regulations.

Business Risk: Cybersecurity		
Businesses Impacted:	**Associated Strategies:**	
• All businesses	• Operational Excellence	• Innovation

Description & Context

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.

Risk Management Approach

The Company has an enterprise wide cybersecurity program covering all technology assets. The cybersecurity program includes employee awareness, layered access controls, continuous monitoring, network threat detection, and coordinated incident response through a centralized Security Operations Centre. The Company's cybersecurity management is consolidated under a common, centralized organization structure to increase effectiveness and compliance across the entire enterprise.

Business Risk: Energy Commodity Price		
Businesses Impacted:		**Associated Strategies:**
• Retail Energy	• Energy Infrastructure	• Financial Strength

Description & Context

Retail Energy's earnings are affected by short-term price volatility.

Storage & Industrial Water's natural gas storage facility in Carbon, Alberta, and the Alberta Hub natural gas storage facility near Edson, Alberta are exposed to storage price differentials.

Risk Management Approach

In conducting its business, the Company may use various instruments, including forward physical contracts, financial swaps, and storage service contracts to manage the risks arising from fluctuations in commodity prices.

To manage its exposure to natural gas storage spreads the Company uses a combination of storage service contracts to lease space and to capture future storage spreads.

The Company enters into natural gas physical contracts and forward power swap contracts as the hedging instrument to manage the exposure to electricity and natural gas market price movements.

Under IFRS accounting, entering into hedging instruments may result in mark-to-market adjustments that are recorded as unrealized gains or losses on the income statement. Realized gains or losses are recognized in adjusted earnings and IFRS earnings when the commodity contracts are settled.

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

Business Risk: Financing	
Businesses Impacted:	**Associated Strategies:**
• All businesses	• Financial Strength

Description & Context

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

Risk Management Approach

To address this risk, the Company manages its capital structure to maintain strong investment grade 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 flows from operations and supported by appropriate levels of cash and available committed credit facilities.

Business Risk: Foreign Currency Exchange Rate Risk	
Businesses Impacted:	**Associated Strategies:**
• All businesses	• Financial Strength

Description & Context

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

Risk Management Approach

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

Business Risk: Interest Rate	
Businesses Impacted:	**Associated Strategies:**
• All businesses	• Financial Strength

Description & Context

The interest rate risk faced by the Company is largely a result of its long-term debt at variable rates as well as cash and cash equivalents. The Company also has exposure to interest rate movements that occur beyond the term of maturity of the fixed-rate investments.

Risk Management Approach

In conducting its business, the Company may use swap agreements to manage the risks arising from fluctuations in interest rates. All such instruments are used only to manage risk and not for trading purposes. The Company has converted certain variable rate long-term debt to fixed rate debt through interest rate swap agreements. At December 31, 2021, the Company had fixed interest rates, either directly or through interest rate swap agreements, on 100 per cent (2020 - 100 per cent) of total long-term debt. Consequently, the exposure to fluctuations in future cash flows, with respect to debt, from changes in market interest rates was limited. The Company's cash and cash equivalents include fixed rate instruments with maturities of generally 90 days or less that are reinvested as they mature.

Business Risk: Pandemic Risk		
Businesses Impacted:	**Associated Strategies:**	
• All businesses	• Growth • Financial Strength	• Operational Excellence • Community

Description & Context

An outbreak of infectious disease, a pandemic or a similar public health threat, such as the COVID-19 pandemic, or a fear of any of the foregoing, could adversely impact the Company by causing operating, supply chain and project development delays and disruptions, inflation risk, labour shortages and shutdowns as a result of government regulation and prevention measures, increased strain on employees and compromised levels of customer service, any of which could have a negative impact on the Company's operations.

Any deterioration in general economic and market conditions resulting from a public health threat could negatively affect demand for electricity and natural gas, revenue, operating costs, timing and extent of capital expenditures, results of financing efforts, or credit risk and counterparty risk; any of which could have a negative impact on the Company's business.

Risk Management Approach

Canadian Utilities' investments in essential services are largely focused on regulated utilities and long-term contracted businesses with strong counterparties, creating a resilient investment portfolio. In response to the COVID-19 pandemic, Canadian Utilities' Pandemic Plan was activated in February 2020. The plan includes travel restrictions, limited access to facilities, a direction to work from home whenever possible, physical distancing measures and other protocols (including the use of personal protective equipment while at a work premise). Additionally, the Company has been following recommendations by local and national public health authorities across the globe to adjust operational requirements as needed to ensure a coordinated approach across Canadian Utilities. As a result of these efforts and the Company's experience in crisis response, Canadian Utilities has been able to minimize the impact of the current COVID-19 pandemic on the Company's businesses and the essential services it provides to customers.

Business Risk: Pipeline Integrity		
Businesses Impacted:	**Associated Strategies:**	
• Utilities	• Operational Excellence	• Community Involvement

Description & Context

Natural Gas Transmission, Natural Gas Distribution and International Gas Distribution have significant pipeline infrastructure. Although the probability of a pipeline rupture is very low, the consequences of a failure can be severe.

Risk Management Approach

Programs are in place to monitor the integrity of the pipeline infrastructure and replace pipelines or pipeline infrastructure as required to address safety, reliability, and future growth. These programs include Natural Gas Distribution and Natural Gas Transmission's Urban Pipeline Replacement and Integrity programs, and Natural Gas Distribution and International Natural Gas Distribution's Mains Replacement programs. The Company also carries property and liability insurance. The Company actively engages in damage prevention initiatives including proactive direct engagement with the building and excavation communities. The Company also promotes ground disturbance and excavation safety to homeowners and the excavation community.

Business Risk: Political		
Businesses Impacted:	**Associated Strategies:**	
• All businesses	• Growth • Financial Strength	• Operational Excellence

Description & Context

Operations are exposed to a risk of change in the business environment due to political change. Legislative or policy changes may impact the financial performance of operations. This could negatively impact earnings, return on equity and assets, and credit metrics.

Risk Management Approach

Participation in policy consultations with governments and engagement of stakeholder groups ensure ongoing communication and that the impacts and costs of proposed policy changes are identified and understood. Where appropriate, the Company works with its peers and industry associations to develop common positions and strategies. Geographic diversification of assets by region and by country reduces the impact of political and legislative changes.

Business Risk: Regulated Operations		
Businesses Impacted:	**Associated Strategies:**	
• Utilities	• Growth • Financial Strength	• Operational Excellence

Description & Context

The Regulated Utilities are subject to the risks associated with 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. They are also subject to risk of the regulator's potential disallowance of costs incurred. Electricity Distribution and Natural Gas Distribution operate under PBR. Under PBR, utility revenues are formula driven, which raises the uncertainty of cost recovery. In Australia, the ERA assesses appropriate returns, prudent levels of operating costs, capital expenditures and expected throughput on the network through an Access Arrangement proceeding.

Risk Management Approach

The Regulated Utilities file forecasts in the rate-setting process to recover the costs of providing services and earn a fair rate of return. The determination of a fair rate of return on the common equity component of rate base is determined in a generic cost of capital proceeding in Alberta and an Access Arrangement proceeding in Australia. The Regulated Utilities continuously monitor various regulatory decisions and cases to assess how they might impact the Company's regulatory applications for the recovery of costs. The Regulated Utilities are proactive in demonstrating prudence and continuously look for ways to lower operating costs while maintaining service levels.

Business Risk: Technological Transformation and Disruption		
Businesses Impacted:	**Associated Strategies:**	
• All businesses	• Growth • Financial Strength	• Operational Excellence • Innovation

Description & Context

The introduction and rapid, widespread adoption of transformative technology could lead to disruption of the Company's existing business models and introduce new competitive market dynamics. Failure to effectively identify and manage 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.

Risk Management Approach

The strategic plans of each business unit incorporate transformative technology into the evolution of their business and ensure that the best available technology is deployed to support current state operational efficiency and reliability. The business seeks opportunities to minimize costs by monitoring trends occurring in other jurisdictions that may be ahead of the technological curve.

Business Risk: Liquidity	
Businesses Impacted:	**Associated Strategies:**
• All businesses	• Financial Strength

Description & Context

Liquidity risk is the risk that the Company will not be able to meet its financial obligations.

Risk Management Approach

Cash flow from operations provides a substantial portion of the Company's cash requirements. Additional cash requirements are met with the use of existing cash balances and externally through bank borrowings and the issuance of long-term debt, non-recourse long-term debt and preferred shares. Commercial paper borrowings and short-term bank loans under available credit lines are used to provide flexibility in the timing and amounts of long-term financing. At December 31, 2021, the Company's cash position was approximately $0.8 billion and there were available committed and uncommitted lines of credit of approximately $2.0 billion which can be utilized for general corporate purposes.

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

($ millions)	2022	2023	2024	2025	2026	2027 and thereafter
Financial Liabilities						
Accounts payable and accrued liabilities	739	—	—	—	—	—
Short-term debt	206	—	—	—	—	—
Long-term debt:						
Principal	331	148	448	30	429	7,969
Interest expense (1)	357	354	347	342	345	6,422
Derivatives (2)	32	9	4	1	—	—
	1,665	511	799	373	774	14,391
Commitments						
Purchase obligations:						
Operating and maintenance agreements	338	324	283	51	39	96
Capital expenditures	328	—	—	—	—	—
Other	6	—	—	—	—	—
	672	324	283	51	39	96
Total	2,337	835	1,082	424	813	14,487

(1) Interest payments on floating rate debt have been estimated using rates in effect at December 31, 2021. Interest payments on debt that has been hedged have been estimated using hedged rates.

(2) Payments on outstanding derivatives have been estimated using exchange rates and commodity prices in effect at December 31, 2021.

OTHER FINANCIAL AND NON-GAAP MEASURES

Other financial measures presented in this MD&A consist of:

1. Adjusted earnings which are a key measure of segment earnings that are used to assess segment performance and allocate resources; and
2. Total of segments measures, which are defined as financial measures disclosed by an issuer that are a subtotal or total of two or more reportable segments.

Adjusted earnings are defined as earnings attributable to equity owners of the Company after adjusting for the timing of revenues and expenses associated with rate-regulated activities, dividends on equity preferred shares of the Company, and unrealized gains or losses on mark-to-market forward and swap commodity contracts. Adjusted earnings also exclude one-time gains and losses, 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 US accounting principles for rate-regulated activities. Adjusted earnings are presented in Note 3 of the 2021 Consolidated Financial statements. Adjusted earnings per Class A and Class B share is calculated by dividing adjusted earnings by the weighted average number of shares outstanding for the period.

Adjusted earnings are most directly comparable to earnings attributable to equity owners of the Company but is not a standardized financial measure under the reporting framework used to prepare our financial statements. Adjusted earnings may not be comparable to similar financial measures disclosed by other issuers. Management's view is that adjusted earnings allow for a more effective analysis of operating performance and trends. For investors, adjusted earnings may provide value as they exclude items that are not in the normal course of business and, as such, provide insight as to earnings resulting from the issuer's usual course of business. A reconciliation of adjusted earnings to earnings attributable to equity owners of the Company is presented in this MD&A.

Total of segments measures are most directly comparable to total earnings attributable to equity owners of the Company. Comparable total of segments measures from 2020 have been calculated using the same composition and are disclosed alongside the current total of segments measures in this MD&A. A reconciliation of the total of segments measures with total earnings attributable to equity owners of the Company is presented in this MD&A.

Non-GAAP financial measures presented in this MD&A are defined as financial measures disclosed by an issuer that are not disclosed in the financial statements.

Capital investment is a non-GAAP measure defined as cash used for capital expenditures, business combinations, and cash used in the Company's proportional share of capital expenditures in joint ventures. Capital expenditures includes additions to property, plant and equipment and intangibles as well as interest capitalized during construction. Capital investment is most directly comparable to capital expenditures. Capital investment is not a standardized financial measure under the reporting framework used to prepare our financial statements. Capital investment may not be comparable to similar financial measures disclosed by other issuers. Management views capital investment as the Company's total cash investment in assets. For investors, capital investment is useful because it identifies how much cash is being used to acquire, invest in and finance assets. A reconciliation of capital investments to capital expenditures is presented in this MD&A.

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

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

Adjusted earnings are a key measure of segment earnings that management uses to assess segment performance and allocate resources. It is management's view that adjusted earnings allow a better assessment of the economics of rate regulation in Canada and Australia than IFRS earnings. Additional information regarding this measure is provided in the Other Financial and Non-GAAP Measures section of this MD&A.

($ millions) **Three Months Ended December 31**

2021 2020	**Utilities**	**Energy Infrastructure**	**Corporate & Other**	**Intersegment Eliminations**	**Consolidated**
Revenues	**884**	**74**	**103**	**(33)**	**1,028**
	784	59	55	(17)	881
Adjusted earnings (loss)	**206**	**4**	**(18)**	**—**	**192**
	195	12	(21)	—	186
Unrealized gains (losses) on mark-to-market forward and swap commodity contracts	**—**	**—**	**7**	**—**	**7**
	—	—	(8)	—	(8)
Rate-regulated activities	**(27)**	**—**	**—**	**—**	**(27)**
	(29)	—	2	—	(27)
IT Common Matters decision	**(4)**	**—**	**—**	**—**	**(4)**
	(9)	—	—	—	(9)
Transition of managed IT services	**(8)**	**—**	**—**	**—**	**(8)**
	(52)	(1)	(2)	—	(55)
Dividends on equity preferred shares of Canadian Utilities Limited	**—**	**—**	**16**	**—**	**16**
	2	—	15	—	17
AUC enforcement proceeding	**(14)**	**—**	**—**	**—**	**(14)**
	—	—	—	—	—
Project cost recovery	**—**	**17**	**—**	**—**	**17**
	—	—	—	—	—
Other	**—**	**(3)**	**—**	**—**	**(3)**
	—	—	—	—	—
Earnings (loss) attributable to equity owners of the Company	**153**	**18**	**5**	**—**	**176**
	107	11	(14)	—	104

($ millions) 2021 / 2020	Utilities	Energy Infrastructure	Corporate & Other	Intersegment Eliminations	Consolidated (Year Ended December 31)
Revenues	**3,041**	**209**	**351**	**(86)**	**3,515**
	2,932	195	207	(101)	3,233
Adjusted earnings (loss)	**635**	**28**	**(77)**	**—**	**586**
	584	28	(77)	—	535
Impairment and other costs	**—**	**(64)**	**(1)**	**—**	**(65)**
	(8)	(3)	(19)	—	(30)
Unrealized losses on mark-to-market forward and swap commodity contract	**—**	**(2)**	**(16)**	**—**	**(18)**
	—	(4)	(4)	—	(8)
Rate-regulated activities	**(118)**	**—**	**—**	**—**	**(118)**
	(65)	—	6	—	(59)
IT Common Matters decision	**(14)**	**—**	**—**	**—**	**(14)**
	(19)	—	—	—	(19)
Transition of managed IT services	**(39)**	**(1)**	**(2)**	**—**	**(42)**
	(52)	(1)	(2)	—	(55)
Dividends on equity preferred shares of Canadian Utilities Limited	**2**	**—**	**63**	**—**	**65**
	5	—	62	—	67
AUC enforcement proceeding	**(14)**	**—**	**—**	**—**	**(14)**
	—	—	—	—	—
Project cost recovery	**—**	**17**	**—**	**—**	**17**
	—	—	—	—	—
Other	**—**	**(4)**	**—**	**—**	**(4)**
	—	(4)	—	—	(4)
Earnings (loss) attributable to equity owners of the Company	**452**	**(26)**	**(33)**	**—**	**393**
	445	16	(34)	—	427

IMPAIRMENT AND OTHER COSTS

In 2021, impairments and other costs not in the normal course of business of $65 million (after-tax) were recorded. The Company incurred $54 million of these costs in Mexico, related mainly to its Veracruz hydro facility within its Energy Infrastructure segment. The charge reflects an adverse arbitration decision, changes in market regulations, ongoing political uncertainty, and a challenging operating environment, resulting in an impairment of the carrying value of the assets. Other costs recorded were individually immaterial.

In 2020, impairment and other costs not in the normal course of business of $30 million (after-tax) were recorded. These costs mainly related to certain assets that no longer represented strategic value to the Company. The Company's subsidiary ATCO Oil & Gas Ltd. holds a five per cent working interest in oil and gas assets in Northern Canada. With oil price volatility and the COVID-19 pandemic continuing to cause economic uncertainty, an impairment of $18 million was recorded in 2020, reflecting the reduced likelihood of future recovery of these costs. The remaining costs relate to the continued transformation and realignment of certain functions in the Company.

UNREALIZED GAINS AND LOSSES ON MARK-TO-MARKET FORWARD AND SWAP COMMODITY CONTRACTS

The Company’s retail electricity and natural gas business in Alberta enters into fixed-price swap commodity contracts to manage exposure to electricity and natural gas prices and volumes. These contracts are measured at fair value. Unrealized gains and losses due to changes in the fair value of the fixed-price swap commodity contracts are recognized in the earnings of the Corporate & Other segment.

The CODM believes that removal of the unrealized gains or losses on mark-to-market forward and swap commodity contracts provides a better representation of operating results for the Company's operations.

Realized gains or losses are recognized in adjusted earnings when the commodity contracts are settled.

RATE-REGULATED ACTIVITIES

Electricity Distribution and Transmission and their subsidiaries, ATCO Electric Yukon, Northland Utilities (NWT) and Northland Utilities (Yellowknife), as well as Natural Gas Distribution, Natural Gas Transmission, and International Natural Gas Distribution are collectively referred to as the Regulated Utilities.

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

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

Rate-regulated accounting differs from IFRS in the following ways:

Timing Adjustment	Items	RRA Treatment	IFRS Treatment
Additional revenues billed in current year	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 years	Deferred income taxes, impact of warmer temperatures, and impact of inflation on rate base	The Company recognizes revenues associated with recoverable costs in advance of future billings to customers.	The Company recognizes costs when they are incurred, but does not recognize their recovery until customer rates are changed and amounts are collected through future billings.
Regulatory decisions received	Regulatory decisions received which relate to current and prior periods	The Company recognizes the earnings from a regulatory decision pertaining to current and prior years when the decision is received.	The Company does not recognize earnings from a regulatory decision when it is received as regulatory assets and liabilities are not recorded under IFRS.
Settlement of regulatory decisions and other items	Settlement of amounts receivable or payable to customers and other items	The Company recognizes the amount receivable or payable to customers as a reduction in its regulatory assets and liabilities when collected or refunded through future billings.	The Company recognizes earnings when customer rates are changed and amounts are recovered or refunded to customers through future billings.

For the year ended 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)	**2021**	**2020**	**Change**	**2021**	**2020**	**Change**
Additional revenues billed in current period						
Future removal and site restoration costs [1]	**22**	20	2	**107**	78	29
Impact of colder temperatures [2]	**—**	—	—	**—**	2	(2)
Revenues to be billed in future periods						
Deferred income taxes [3]	**(32)**	(32)	—	**(105)**	(105)	—
Distribution rate relief [4]	**(24)**	—	(24)	**(119)**	—	(119)
Impact of warmer temperatures [2]	**4**	(5)	9	**(1)**	—	(1)
Impact of inflation on rate base [5]	**(17)**	(3)	(14)	**(31)**	(6)	(25)
Settlement of regulatory decisions and other items [6]	**20**	(7)	27	**31**	(28)	59
	(27)	(27)	—	**(118)**	(59)	(59)

(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 years.

(2) Natural Gas Distribution's 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 normal temperatures 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) During the fourth quarter and year ended December 31, 2021, Electricity Distribution and Natural Gas Distribution recorded a decrease in earnings of $24 million and $119 million related to interim rate relief for customers as applied for by the Company and approved by the AUC to hold current distribution base rates in place. These amounts will be recovered from customers in 2022 and 2023.

(5) The inflation-indexed portion of International Natural Gas Distribution's rate base is billed to customers through the recovery of depreciation in subsequent years based on the actual or forecasted annual rate of inflation. Under rate-regulated accounting, revenue is recognized in the current year for the inflation component of rate base when it is earned. Differences between the amounts earned and the amounts billed to customers are deferred and recognized in revenues over the service life of the related assets.

(6) In 2021, Natural Gas Distribution collected $53 million related to depreciation and transmission rate riders which was partly offset by a decrease in earnings of $28 million related to payments for transmission costs. In 2020, Electric Distribution recorded a decrease in earnings of $26 million related to payments to customers for transmission costs and capital related items.

IT COMMON MATTERS DECISION

Consistent with the treatment of the gain on sale in 2014 from the IT services business by the Company, financial impacts associated with the IT Common Matters decision are excluded from adjusted earnings. The amount excluded from adjusted earnings in 2021 was $4 million and $14 million (after-tax) (2020 - $9 million and $19 million).

TRANSITION OF MANAGED IT SERVICES

In the fourth quarter of 2020 and first quarter of 2021, the Company signed MSAs with IBM Canada Ltd. (subsequently novated to Kyndryl Canada Ltd.) and IBM Australia Limited (IBM), respectively, to provide managed IT services. These services were previously provided by Wipro under a ten-year MSA expiring in December 2024. The transition of the managed IT services from Wipro to IBM commenced on February 1, 2021 and is complete.

In the fourth quarter and full year of 2021, the Company recognized termination and transition costs of $8 million and $42 million (after-tax) (2020 - $55 million and $55 million).

AUC ENFORCEMENT PROCEEDING

On November 29, 2021, the AUC enforcement branch filed an application with the AUC recommending an enforcement proceeding be initiated. This proceeding is to determine whether ATCO Electric failed to comply with AUC decisions and enactments under the AUC's jurisdiction with respect to the sole source contract for the Jasper interconnection project and the actions leading up to and including the filing of the 2018-2020 Deferral Account Application. This proceeding will also determine any future remedies that may be required.

AUC Enforcement and Electricity Transmission are pursuing settlement discussions prior to the AUC determining the next process steps. In the fourth quarter and full year of 2021, the Company recognized expenses of $14 million (after-tax) due to the potential outcome of the proceeding.

PROJECT COST RECOVERY

During the fourth quarter and full year of 2021, the Company recorded earnings of $17 million (after-tax) following the conclusion of the Company's involvement in an international project.

OTHER

The Company adjusts the deferred tax asset which was recognized as a result of the 2015 Tula Pipeline Project impairment. In the full year of 2021, the Company recorded a foreign exchange loss of $4 million (2020 - a foreign exchange loss of $4 million), due to a difference between the tax base currency, which is the Mexican peso, and the US dollar functional currency.

UTILITIES

The following tables reconcile adjusted earnings for the Utilities business unit to the directly comparable financial measure, earnings attributable to equity owners of the Company.

($ millions) | **Three Months Ended December 31**

2021 / 2020	**Canadian Utilities Ltd.**								
	Electricity				**Natural Gas**				**Utilities**
	Electric Distribution	**Electric Transmission**	**International Electricity**	**Consolidated Electricity**	**Natural Gas Distribution**	**Natural Gas Transmission**	**International Natural Gas**	**Consolidated Natural Gas**	
Adjusted earnings	**37**	**35**	**16**	**88**	**72**	**20**	**26**	**118**	**206**
	38	42	6	86	79	22	8	109	195
Rate-regulated activities	**(25)**	**8**	**—**	**(17)**	**15**	**(6)**	**(19)**	**(10)**	**(27)**
	(11)	5	—	(6)	(12)	(8)	(3)	(23)	(29)
IT Common Matters decision	**(1)**	**(1)**	**—**	**(2)**	**(2)**	**—**	**—**	**(2)**	**(4)**
	(3)	(2)	—	(5)	(3)	(1)	—	(4)	(9)
Transition of managed IT services	**(1)**	**(1)**	**—**	**(2)**	**(4)**	**—**	**(2)**	**(6)**	**(8)**
	(16)	(7)	—	(23)	(25)	(4)	—	(29)	(52)
Dividends on equity preferred shares of the Company	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
	1	1	—	2	—	—	—	—	2
AUC enforcement proceeding	**—**	**(14)**	**—**	**(14)**	**—**	**—**	**—**	**—**	**(14)**
	—	—	—	—	—	—	—	—	—
Other	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
	—	(1)	—	(1)	—	1	—	1	—
Earnings attributable to equity owners of the Company	**10**	**27**	**16**	**53**	**81**	**14**	**5**	**100**	**153**
	9	38	6	53	39	10	5	54	107

($ millions) — Year Ended December 31

2021
2020

	Canadian Utilities Ltd.								
	Electricity				Natural Gas				Utilities
	Electric Distribution	Electric Transmission	International Electricity	Consolidated Electricity	Natural Gas Distribution	Natural Gas Transmission	International Natural Gas	Consolidated Natural Gas	
Adjusted earnings	**151**	**152**	**44**	**347**	**142**	**81**	**65**	**288**	**635**
	132	174	12	318	146	89	31	266	584
Impairments and other costs	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
	(2)	(2)	—	(4)	(4)	—	—	(4)	(8)
Rate-regulated activities	**(75)**	**20**	**—**	**(55)**	**(9)**	**(20)**	**(34)**	**(63)**	**(118)**
	(54)	8	—	(46)	10	(28)	(1)	(19)	(65)
IT Common Matters decision	**(4)**	**(4)**	**—**	**(8)**	**(5)**	**(1)**	**—**	**(6)**	**(14)**
	(6)	(5)	—	(11)	(6)	(2)	—	(8)	(19)
Transition of managed IT services	**(10)**	**(4)**	**—**	**(14)**	**(16)**	**(2)**	**(7)**	**(25)**	**(39)**
	(16)	(7)	—	(23)	(25)	(4)	—	(29)	(52)
Dividends on equity preferred shares of the Company	**—**	**1**	**—**	**1**	**—**	**1**	**—**	**1**	**2**
	—	3	—	3	—	2	—	2	5
AUC enforcement proceeding	**—**	**(14)**	**—**	**(14)**	**—**	**—**	**—**	**—**	**(14)**
	—	—	—	—	—	—	—	—	—
Other	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
	—	—	—	—	(4)	—	4	—	—
Earnings attributable to equity owners of the Company	**62**	**151**	**44**	**257**	**112**	**59**	**24**	**195**	**452**
	54	171	12	237	117	57	34	208	445

ENERGY INFRASTRUCTURE

The following tables reconciles adjusted earnings for the Energy Infrastructure business unit to the directly comparable financial measure, earnings attributable to equity owners of the Company.

($ millions)			**Three Months Ended December 31**
2021 / 2020	**Canadian Utilities Ltd.**		
	Electricity Generation	**Storage & Industrial Water**	**Energy Infrastructure**
Adjusted earnings	**—**	**4**	**4**
	4	8	12
Transition of managed IT services	**—**	**—**	**—**
	—	(1)	(1)
Project cost recovery	**—**	**17**	**17**
	—	—	—
Other	**—**	**(3)**	**(3)**
	—	—	—
Earnings attributable to equity owners of the Company	**—**	**18**	**18**
	4	7	11

($ millions)			**Year Ended December 31**
2021 / 2020	**Canadian Utilities Limited**		
	Electricity Generation	**Storage & Industrial Water**	**Energy Infrastructure**
Adjusted earnings	**13**	**15**	**28**
	13	15	28
Impairments and other costs	**(64)**	**—**	**(64)**
	(1)	(2)	(3)
Unrealized losses on mark-to-market forward and swap commodity contract	**—**	**(2)**	**(2)**
	—	(4)	(4)
Transition of managed IT services	**—**	**(1)**	**(1)**
	—	(1)	(1)
Project cost recovery	**—**	**17**	**17**
	—	—	—
Other	**—**	**(4)**	**(4)**
	—	(4)	(4)
Loss (earnings) attributable to equity owners of the Company	**(51)**	**25**	**(26)**
	12	4	16

RECONCILIATION OF CAPITAL INVESTMENT TO CAPITAL EXPENDITURES

Capital investment is a non-GAAP measure defined as cash used for capital expenditures, business combinations, 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. Additional information regarding this non-GAAP measure is provided in the Other Financial and Non-GAAP Measures section of this MD&A.

($ millions)				**Three Months Ended December 31**
2021 2020	**Utilities**	**Energy Infrastructure**	**CUL Corporate & Other**	**Consolidated**
Capital Investment	**253**	**170**	**3**	**426**
	243	7	3	253
Capital Expenditure in joint ventures [(1)]	**(2)**	**(6)**	**—**	**(8)**
	—	(2)	—	(2)
Business Combination [(2)]	**—**	**(84)**	**—**	**(84)**
	—	—	—	—
Capital Expenditures	**251**	**80**	**3**	**334**
	243	5	3	251

(1) Capital expenditures in joint ventures relates mainly to the construction of a long-term contracted hydrocarbon storage cavern in the Energy Infrastructure segment.

(2) Business combination in 2021 is due to an acquisition of the Alberta Hub natural gas storage facility in the Energy Infrastructure segment.

($ millions)				**Year Ended December 31**
2021 2020	**Utilities**	**Energy Infrastructure**	**CUL Corporate & Other**	**Consolidated**
Capital Investment	**1,102**	**226**	**10**	**1,338**
	876	28	8	912
Capital Expenditure in joint ventures [(1)]	**(5)**	**(22)**	**—**	**(27)**
	—	(9)	—	(9)
Business Combination [(2)]	**—**	**(84)**	**—**	**(84)**
	—	—	—	—
Capital Expenditures	**1,097**	**120**	**10**	**1,227**
	876	19	8	903

(1) Capital expenditures in joint ventures relates mainly to the construction of a long-term contracted hydrocarbon storage cavern in the Energy Infrastructure segment.

(2) Business combination in 2021 is due to an acquisition of the Alberta Hub natural gas storage facility in the Energy Infrastructure segment.

OTHER FINANCIAL INFORMATION

OFF BALANCE SHEET ARRANGEMENTS

Canadian Utilities 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 2021 Consolidated Financial Statements.

SIGNIFICANT ACCOUNTING ESTIMATES

The Company's significant accounting estimates are described in Note 23 of the 2021 Consolidated Financial Statements, which are prepared in accordance with IFRS. Management makes judgments and estimates 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 judgments and estimates 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

At December 31, 2021, there are no new or amended standards issued, or interpretations that need to be adopted in future periods, which will have a material effect on the 2022 Consolidated Financial Statements once adopted.

DISCLOSURE CONTROLS AND PROCEDURES

As of December 31, 2021, 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, 2021.

INTERNAL CONTROL OVER FINANCIAL REPORTING

There was no change in the Company's internal control over financial reporting that occurred during the period beginning on January 1, 2021, and ended on December 31, 2021, that materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

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.

As of December 31, 2021, 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.

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, 2021.

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", "goals", "targets", "strategy", "future", and similar expressions. In particular, forward-looking information in this MD&A includes, but is not limited to, references to general strategic plans and targets, including with respect to reducing GHG emissions; projected expenses in connection with the described Alberta Utilities Commission proceedings; forecast cost recoveries; expected capital investment; and mid-year rate base growth forecasts.

Although the Company believes that the expectations reflected in the forward-looking information are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and no assurance can be given that these expectations will prove to be correct. Forward-looking information should not be unduly relied upon. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties, and other factors, which may cause actual results, levels of activity, and achievements to differ materially from those anticipated in such forward-looking information. The forward-looking information reflects the Company's beliefs and assumptions with respect to, among other things, the Company's ability to successfully achieve its net-zero GHG target by 2050; the development and performance of technology and technological innovations and the ability to otherwise access and implement all technology necessary to achieve GHG and other environmental, social and governance targets; continuing collaboration with certain regulatory and environmental groups; the performance of assets and equipment; demand levels for oil, natural gas, gasoline, diesel and other energy sources; certain levels of future energy use; future production rates; future revenue and earnings; the ability to meet current project schedules, and other assumptions inherent in management's expectations in respect of the forward-looking information identified herein.

The Company's actual results could differ materially from those anticipated in this forward-looking information as a result of, among other things, risks inherent in the performance of assets; capital efficiencies and cost savings; applicable laws and government policies; regulatory decisions; competitive factors in the industries in which the Company operates; prevailing economic conditions (including as may be affected by the COVID-19 pandemic); credit risk; interest rate fluctuations; the availability and cost of labour, materials, services, and infrastructure; the development and execution of projects; prices of electricity, natural gas, natural gas liquids, and renewable energy; the development and performance of technology and new energy efficient products, services, and programs including but not limited to the use of zero-emission and renewable fuels, carbon capture, and storage, electrification of equipment powered by zero-emission energy sources and utilization and availability of carbon offsets; the occurrence of unexpected events such as fires, severe weather conditions, explosions, blow-outs, equipment failures, transportation incidents, and other accidents or similar events; and other risk factors, many of which are beyond the control of the Company. Due to the interdependencies and correlation of these factors, the impact of any one material assumption or risk on a forward-looking statement cannot be determined with certainty. Readers are cautioned that the foregoing lists are not exhaustive. For additional information about the principal risks that the Company faces, see "Business Risks and Risk Management" in this MD&A.

This MD&A may contain information that constitutes future-oriented financial information or financial outlook information, all of which are subject to the same assumptions, risk factors, limitations and qualifications set forth above. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise or inaccurate and, as such, undue reliance should not be placed on such future-oriented financial information or financial outlook information. The Company's actual results, performance and achievements could differ materially from those expressed in, or implied by, such future-oriented financial information or financial outlook information. The Company has included such information in order to provide readers with a more complete perspective on its future operations and its current expectations relating to its future performance. Such information may not be appropriate for other purposes and readers are cautioned that such information should not be used for purposes other than those for which it has been disclosed herein. Future-oriented financial information or financial outlook information contained herein was made as of the date of this MD&A.

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

ADDITIONAL INFORMATION

Canadian Utilities has published its 2021 Consolidated Financial Statements and MD&A for the year ended December 31, 2021. Copies of these documents may be obtained upon request from Investor Relations at 3rd Floor, West Building, 5302 Forand Street S.W., Calgary, Alberta, T3E 8B4, telephone 403-292-7500, fax 403-292-7532 or email investorrelations@atco.com.

GLOSSARY

AESO means Alberta Electric System Operator.

Alberta Utilities means Electricity Distribution, Electricity Transmission, Natural Gas Distribution and Natural Gas Transmission.

AUC means the Alberta Utilities Commission.

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

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 & Chief Executive Officer, and the other members of the Executive Committee.

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

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

Customer Contributions are non-refundable cash contributions made by customers for certain additions to property, plant and equipment, mainly in the Utilities. These contributions are made when the estimated revenue is less than the cost of providing service.

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

GAAP means Canadian generally accepted accounting principles.

GHG means greenhouse gas.

IFRS means International Financial Reporting Standards.

I-X means the Inflation adjuster (I Factor) and Productivity Adjuster (X Factor).

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

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

PBR means Performance Based Regulation.

RNG means renewable natural gas. It is a renewable fuel produced by capturing methane emissions which would otherwise be released to the atmosphere.

Regulated Utilities means Electricity Distribution, Electricity Transmission, Natural Gas Distribution, Natural Gas Transmission and International Natural Gas Distribution.

APPENDIX 1
FOURTH QUARTER FINANCIAL INFORMATION

Financial information for the three months ended December 31, 2021 and 2020 is shown below.

CONSOLIDATED STATEMENT OF EARNINGS

	Three Months Ended December 31	
(millions of Canadian Dollars except per share data)	**2021**	**2020**
Revenues	**1,028**	881
Costs and expenses		
Salaries, wages and benefits	**(96)**	(82)
Energy transmission and transportation	**(68)**	(57)
Plant and equipment maintenance	**(67)**	(44)
Fuel costs	**(46)**	(22)
Purchased power	**(78)**	(55)
Depreciation and amortization	**(138)**	(158)
Franchise fees	**(76)**	(64)
Property and other taxes	**(18)**	(16)
Other	**(104)**	(159)
	(691)	(657)
Earnings from investment in joint ventures	**22**	12
Operating profit	**359**	236
Interest income	**3**	4
Interest expense	**(115)**	(102)
Net finance costs	**(112)**	(98)
Earnings before income taxes	**247**	138
Income taxes	**(69)**	(32)
Earnings for the period	**178**	106
Earnings attributable to:		
Equity Owners of the Company	**176**	104
Non-controlling interests	**2**	2
	178	106
Earnings per Class A and Class B share	**$0.59**	$0.32
Diluted Earnings per Class A and Class B share	**$0.59**	$0.32

CONSOLIDATED STATEMENT OF CASH FLOWS

	Three Months Ended December 31	
(millions of Canadian Dollars)	**2021**	**2020**
Operating activities		
Earnings for the period	**178**	106
Adjustments to reconcile earnings to cash flows from operating activities	**335**	372
Changes in non-cash working capital	**(3)**	(58)
Cash flows from operating activities	**510**	420
Investing activities		
Additions to property, plant and equipment	**(310)**	(213)
Additions to intangibles	**(27)**	(35)
Acquisition net of cash acquired	**(84)**	—
Investment in joint ventures	**(6)**	—
Changes in non-cash working capital	**—**	(3)
Other	**99**	5
Cash flows used in investing activities	**(328)**	(246)
Financing activities		
Issue of short-term debt	**206**	—
Issue of long-term debt	**1**	2
Repayment of long-term debt	**(163)**	(104)
Repayment of lease liabilities	**(2)**	(3)
Net purchase of Class A shares	**2**	(12)
Issue of equity preferred shares	**201**	—
Dividends paid on equity preferred shares	**(16)**	(17)
Dividends paid to non-controlling interests	**(2)**	(2)
Dividends paid to Class A and Class B share owners	**(119)**	(120)
Interest paid	**(112)**	(117)
Other	**(3)**	(2)
Cash flows used in financing activities	**(7)**	(375)
Increase (decrease) in cash position	**175**	(201)
Foreign currency translation	**(4)**	(1)
Beginning of period	**579**	980
End of period	**750**	778

CANADIAN UTILITIES LIMITED

An ATCO Company

CANADIAN UTILITIES LIMITED

CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2021

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MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

Management is responsible for preparing the consolidated financial statements of Canadian Utilities Limited (the Company) in accordance with International Financial Reporting Standards, which include amounts based on estimates and judgments. Management is also responsible for the preparation of the Management's Discussion and Analysis and other financial information contained in the Company's Annual Report, and ensures that it is consistent with the consolidated financial statements.

Management has established internal accounting and financial reporting control systems, which are subject to periodic review by the Company’s internal auditors, to meet its responsibility for reliable and accurate reporting. Integral to these control systems are a code of ethics and management policies that provide guidance and direction to employees, as well as a system of corporate governance that provides oversight to the Company’s operating, reporting and risk management activities.

The consolidated financial statements are approved by the Board of Directors on the recommendation of the Audit & Risk Committee. The Audit & Risk Committee is comprised entirely of independent Directors. The Audit & Risk Committee meets regularly with management and the independent auditors to review significant accounting and financial reporting matters, to assure that management is carrying out its responsibilities and to review and approve the consolidated financial statements.

PricewaterhouseCoopers LLP, our independent auditors, are engaged to perform an audit of the consolidated financial statements and expresses a professional opinion on the results. The Independent Auditor's Report to the Share Owners appears on the following page. PricewaterhouseCoopers LLP have full and independent access to the Audit & Risk Committee and management to discuss their audit and related matters.

[Original signed by N.C. Southern]
Chair & Chief Executive Officer

[Original signed by B.P. Shkrobot]
Executive Vice President & Chief Financial Officer

February 23, 2022

Independent auditor's report

To the Share Owners of Canadian Utilities Limited

Our opinion

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of Canadian Utilities Limited and its subsidiaries (together, the Company) as at December 31, 2021 and 2020, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (IFRS).

What we have audited
The Company's consolidated financial statements comprise:

- the consolidated statements of earnings for the years ended December 31, 2021 and 2020;
- the consolidated statements of comprehensive income for the years ended December 31, 2021 and 2020;
- the consolidated balance sheets as at December 31, 2021 and 2020;
- the consolidated statements of changes in equity for the years ended December 31, 2021 and 2020;
- the consolidated statements of cash flows for the years ended December 31, 2021 and 2020; and
- the notes to the consolidated financial statements, which include significant accounting policies and other explanatory information.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence
We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

PricewaterhouseCoopers LLP

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pwc

Key audit matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the consolidated financial statements for the year ended December 31, 2021. These matters were addressed in the context of our audit of the consolidated financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

Key audit matter	How our audit addressed the key audit matter
Assessment of retirement benefit obligations *Refer to note 14 – Retirement Benefits and note 23 – Significant Judgments, Estimates and Assumptions to the consolidated financial statements.* The Company maintains registered defined benefit or defined contribution pension plans for most of its employees. It also provides other post-employment benefits for retirees and their dependents. The Company accrues for its obligations under defined benefit pension and other post-employment benefits plans (the retirement benefit obligations). As at December 31, 2021, total accrued benefit obligations were \$3,173 million and the market value of plan assets was \$2,992 million. These balances are presented net on the consolidated balance sheet, resulting in retirement benefit asset of \$87 million and retirement benefit obligations of \$268 million. In determining the retirement benefit obligations, management consults with independent actuaries when setting the assumptions used to estimate retirement benefit obligations and the cost of providing retirement benefits during the period. The significant assumptions used by management in determining the Company's retirement benefit obligations include discount rate, long-term inflation rate, future compensation rates, health care cost trend rates and life expectancy rates. We determined that this is a key audit matter due to the significance of the retirement benefit obligations and the significant judgment made by management in estimating the Company's retirement benefit obligations. In addition, our audit effort involved the use of professionals with specialized skill and knowledge in the field of actuarial services.	Our approach to addressing the matter involved the following procedures, among others: • Tested how management determined the retirement benefit obligations, which included the following: – Utilized professionals with specialized skill and knowledge in the field of actuarial services, who assisted in testing management's process for estimating the total accrued benefit obligations, appropriateness of the methodology and assessed the reasonableness of management's assumptions such as: discount rate, long-term inflation rate, future compensation rates, health care costs trend rates and life expectancy rates; – Tested certain underlying data used in the determination of retirement benefit obligations; and – The work of management's independent actuaries was used in performing the procedures to evaluate the reasonableness of the retirement benefit obligations. As a basis for using this work, the competence, capabilities and objectivity of management's independent actuaries were evaluated, the work performed was understood and the appropriateness of the work as audit evidence was evaluated. The procedures performed also included evaluation of the methods and assumptions used by management's independent actuaries, tests of the data used by management's independent actuaries and an evaluation of their findings. • Tested disclosures related to the sensitivity assumptions used in estimating retirement benefit obligations.

Key audit matter	How our audit addressed the key audit matter
Assessment of unbilled revenue related to the Utilities segment *Refer to note 4 – Revenues and note 23 – Significant Judgments, Estimates and Assumptions to the consolidated financial statements.* The Company had $156 million of unbilled revenue related to the Utilities segment as at December 31, 2021. The revenue recognized by the Company includes an estimate of consumption by customers of natural gas and electricity that has not yet been billed (unbilled revenue). The estimate is derived from unbilled gas and electricity distribution services supplied to customers and is based on historical consumption patterns. Management applies judgment to the measurement and value of the estimated consumption. We determined that this is a key audit matter due to (i) the significance of the unbilled revenue, (ii) the judgment applied by management to estimate the consumption and (iii) the significant auditor effort in performing procedures to test the estimated amount of unbilled revenue.	Our approach to addressing the matter included the following procedures, among others: • Tested the reasonableness of the estimate of unbilled revenue through evidence obtained from events occurring up to the date of the auditor's report, which included the following: – Tested a sample of billings made after December 31, 2021 and compared the relevant amounts of these billings to the corresponding estimate of unbilled revenue recorded. – Agreed the pricing applied to a sample of billings to externally published rates. • Tested the operating effectiveness of internal controls relating to unbilled revenue, including information technology (IT) general controls of the relevant IT systems that management uses for meter readings and billings.

Other information

Management is responsible for the other information. The other information comprises the Management’s Discussion and Analysis, which we obtained prior to the date of this auditor’s report and the information, other than the consolidated financial statements and our auditor’s report thereon, included in the annual report, which is expected to be made available to us after that date.

Our opinion on the consolidated financial statements does not cover the other information and we do not and will not express an opinion or any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed on the other information that we obtained prior to the date of this auditor's report, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard. When we read the information, other than the consolidated financial statements and our auditor's report thereon, included in the annual report, if we conclude that there is a material misstatement therein, we are required to communicate the matter to those charged with governance.

Responsibilities of management and those charged with governance for the consolidated financial statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

From the matters communicated with those charged with governance, we determine those matters that were of most significance in the audit of the consolidated financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

The engagement partner on the audit resulting in this independent auditor's report is Shannon Ryhorchuk.

[Original signed by "PricewaterhouseCoopers LLP"]

Chartered Professional Accountants

Calgary, Alberta
February 23, 2022

CONSOLIDATED STATEMENTS OF EARNINGS

		Year Ended December 31	
(millions of Canadian Dollars except per share data)	**Note**	**2021**	**2020**
Revenues	4	**3,515**	3,233
Costs and expenses			
Salaries, wages and benefits		**(362)**	(341)
Energy transmission and transportation		**(266)**	(225)
Plant and equipment maintenance		**(203)**	(196)
Fuel costs		**(116)**	(86)
Purchased power		**(296)**	(211)
Depreciation, amortization and impairment	10,11,16	**(651)**	(610)
Franchise fees		**(263)**	(243)
Property and other taxes		**(70)**	(68)
Other	5	**(406)**	(312)
		(2,633)	(2,292)
Earnings from investment in joint ventures	26	**58**	31
Operating profit		**940**	972
Interest income		**11**	15
Interest expense	6	**(413)**	(401)
Net finance costs		**(402)**	(386)
Earnings before income taxes		**538**	586
Income tax expense	7	**(138)**	(152)
Earnings for the year		**400**	434
Earnings attributable to:			
Equity owners of the Company		**393**	427
Non-controlling interests	27	**7**	7
		400	434
Earnings per Class A and Class B share	8	**$1.21**	$1.32
Diluted earnings per Class A and Class B share	8	**$1.21**	$1.32

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian Dollars)	Note	Year Ended December 31 2021	2020
Earnings for the year		**400**	434
Other comprehensive income, net of income taxes			
Items that will not be reclassified to earnings:			
Re-measurement of retirement benefits (1)	14	**181**	–
Items that are or may be reclassified subsequently to earnings:			
Cash flow hedges (2)		**57**	(9)
Foreign currency translation adjustment (3)		**(49)**	26
		8	17
Other comprehensive income		**189**	17
Comprehensive income for the year		**589**	451
Comprehensive income attributable to:			
Equity owners of the Company		**582**	444
Non-controlling interests		**7**	7
		589	451

(1) Net of income taxes of $(54) million for the year ended December 31, 2021 (2020 - nil).

(2) Net of income taxes of $(19) million for the year ended December 31, 2021 (2020 - $5 million).

(3) Net of income taxes of nil.

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

(millions of Canadian Dollars)	Note	December 31 2021	2020
ASSETS			
Current assets			
Cash and cash equivalents	19	**753**	781
Accounts receivable and contract assets	15	**759**	649
Finance lease receivables	16	**10**	9
Inventories	9	**21**	28
Prepaid expenses and other current assets	10	**188**	92
		1,731	1,559
Non-current assets			
Property, plant and equipment	10	**18,008**	17,563
Intangibles	11	**726**	656
Retirement benefit asset	14	**87**	–
Right-of-use assets	16	**51**	56
Investment in joint ventures	26	**204**	165
Finance lease receivables	16	**149**	164
Deferred income tax assets	7	**33**	72
Other assets		**86**	61
Total assets		**21,075**	20,296
LIABILITIES			
Current liabilities			
Bank indebtedness	19	**3**	3
Accounts payable and accrued liabilities		**739**	549
Lease liabilities	16	**7**	9
Provisions and other current liabilities	3	**132**	129
Short-term debt	12	**206**	–
Long-term debt	13	**331**	166
		1,418	856
Non-current liabilities			
Deferred income tax liabilities	7	**1,588**	1,416
Retirement benefit obligations	14	**268**	411
Customer contributions	15	**1,870**	1,756
Lease liabilities	16	**44**	47
Other liabilities		**88**	115
Long-term debt	13	**8,977**	8,887
Total liabilities		**14,253**	13,488
EQUITY			
Equity preferred shares	17	**1,571**	1,483
Class A and Class B share owners' equity			
Class A and Class B shares	18	**1,216**	1,232
Contributed surplus		**8**	8
Retained earnings		**3,862**	3,928
Accumulated other comprehensive loss		**(22)**	(30)
Total equity attributable to equity owners of the Company		**6,635**	6,621
Non-controlling interests	27	**187**	187
Total equity		**6,822**	6,808
Total liabilities and equity		**21,075**	20,296

See accompanying Notes to Consolidated Financial Statements.

[Original signed by N.C. Southern]
DIRECTOR

[Original signed by R.J. Normand]
DIRECTOR

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

		Attributable to Equity Owners of the Company							
(millions of Canadian Dollars)	Note	Class A and Class B Shares	Equity Preferred Shares	Contributed Surplus	Retained Earnings	Accumulated Other Comprehensive Loss	Total	Non-Controlling Interests	Total Equity
December 31, 2019		1,228	1,483	16	4,054	(47)	6,734	187	6,921
Earnings for the year		–	–	–	427	–	427	7	434
Other comprehensive income		–	–	–	–	17	17	–	17
Shares issued	18	1	–	–	–	–	1	–	1
Shares redeemed	18	(2)	–	–	(11)	–	(13)	–	(13)
Dividends	17,18	–	–	–	(544)	–	(544)	(7)	(551)
Share-based compensation	28	5	–	(8)	–	–	(3)	–	(3)
Other		–	–	–	2	–	2	–	2
December 31, 2020		1,232	1,483	8	3,928	(30)	6,621	187	6,808
Earnings for the year		**–**	**–**	**–**	**393**	**–**	**393**	**7**	**400**
Other comprehensive income		**–**	**–**	**–**	**–**	**189**	**189**	**–**	**189**
Gains on retirement benefits transferred to retained earnings	14	**–**	**–**	**–**	**181**	**(181)**	**–**	**–**	**–**
Shares issued	17,18	**2**	**198**	**–**	**–**	**–**	**200**	**–**	**200**
Shares redeemed	17,18	**(20)**	**(110)**	**–**	**(99)**	**–**	**(229)**	**–**	**(229)**
Dividends	17,18	**–**	**–**	**–**	**(541)**	**–**	**(541)**	**(7)**	**(548)**
Share-based compensation	28	**2**	**–**	**–**	**–**	**–**	**2**	**–**	**2**
December 31, 2021		**1,216**	**1,571**	**8**	**3,862**	**(22)**	**6,635**	**187**	**6,822**

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian Dollars)	Note	Year Ended December 31 2021	2020
Operating activities			
Earnings for the year		**400**	434
Adjustments to reconcile earnings to cash flows from operating activities	19	**1,270**	1,194
Changes in non-cash working capital	19	**48**	3
Cash flows from operating activities		**1,718**	1,631
Investing activities			
Additions to property, plant and equipment		**(1,078)**	(803)
Proceeds on disposal of property, plant and equipment		**30**	6
Additions to intangibles		**(143)**	(87)
Acquisition, net of cash acquired	24	**(84)**	–
Investment in joint ventures	26	**(27)**	(9)
Changes in non-cash working capital	19	**8**	(4)
Other	3, 10	**32**	(8)
Cash flows used in investing activities		**(1,262)**	(905)
Financing activities			
Issue of short-term debt	12	**206**	–
Issue of long-term debt	13,19	**461**	209
Repayment of long-term debt	13,19	**(167)**	(163)
Issue of equity preferred shares	17	**201**	–
Redemption of equity preferred shares	17	**(110)**	–
Repayment of lease liabilities	16	**(10)**	(11)
Net purchase of Class A shares	18	**(117)**	(12)
Dividends paid on equity preferred shares	17	**(65)**	(67)
Dividends paid to non-controlling interests	27	**(7)**	(7)
Dividends paid to Class A and Class B share owners	18	**(476)**	(477)
Interest paid		**(385)**	(393)
Other		**(9)**	(3)
Cash flows used in financing activities		**(478)**	(924)
Decrease in cash position [1]		**(22)**	(198)
Foreign currency translation		**(6)**	(1)
Beginning of year		**778**	977
End of year	19	**750**	778

(1) Cash position includes $7 million which is not available for general use by the Company (2020 - $5 million).

See accompanying Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2021

(Tabular amounts in millions of Canadian Dollars, except as otherwise noted)

1. THE COMPANY AND ITS OPERATIONS

Canadian Utilities Limited was incorporated under the laws of Canada and is listed on the Toronto Stock Exchange. Its head office is at 4th floor, West Building, 5302 Forand Street SW, Calgary, Alberta T3E 8B4 and its registered office is 20th Floor, 10035 - 105 Street, Edmonton, Alberta T5J 2V6. The Company is controlled by ATCO Ltd. and its controlling share owner, the Southern family.

Canadian Utilities Limited is engaged in the following business activities:

- Utilities (electricity and natural gas transmission and distribution, and international electricity operations);
- Energy Infrastructure (electricity generation, energy storage, and industrial water solutions); and
- Retail Energy (electricity and natural gas retail sales and whole-home solutions) (included in the Corporate & Other segment).

The consolidated financial statements include the accounts of Canadian Utilities Limited and its subsidiaries (see Note 25), and the accounts of a proportionate share of the Company's investment in joint ventures (see Note 26). In these financial statements, "the Company" means Canadian Utilities Limited, its subsidiaries and joint arrangements.

2. BASIS OF PRESENTATION

STATEMENT OF COMPLIANCE

The consolidated financial statements are prepared according to International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and interpretations of the IFRS Interpretations Committee (IFRIC).

The Board of Directors (Board) authorized these consolidated financial statements for issue on February 23, 2022.

BASIS OF MEASUREMENT

The consolidated financial statements are prepared on a historic cost basis, except for derivative financial instruments, retirement benefit obligations and cash-settled share-based compensation liabilities which are carried at remeasured amounts or fair value. The Company's significant accounting policies are described in Note 32.

Certain comparative figures have been reclassified to conform to the current presentation.

FUNCTIONAL AND PRESENTATION CURRENCY

The consolidated financial statements are presented in Canadian dollars. Each entity within the Company determines its own functional currency based on the primary economic environment in which it operates.

USE OF JUDGMENTS AND ESTIMATES

Management makes judgments and estimates 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 judgments and estimates concern matters that are inherently complex and uncertain. Judgments and estimates are reviewed on an on-going basis; changes to accounting estimates are recognized prospectively. The significant judgments, estimates and assumptions are described in Note 23.

ADOPTION OF NEW ACCOUNTING INTERPRETATION

In April 2021, the IFRS Interpretations Committee published a final agenda decision with respect to recognition of certain configuration and customization expenditures related to cloud computing with retrospective application. Costs that do not meet the capitalization criteria should be expensed as incurred. Any changes resulting from the decision were required to be implemented by December 31, 2021.

The analysis of the impacts of the decision did not result in a material change to the consolidated financial statements for the year ended December 31, 2021.

3. SEGMENTED INFORMATION

The Company's operating segments are reported in a manner consistent with the internal reporting provided to the Chief Operating Decision Maker (CODM). The CODM is comprised of the Chair and Chief Executive Officer, and the other members of the Executive Committee.

The accounting policies applied by the segments are the same as those applied by the Company, except for those used in the calculation of adjusted earnings. Intersegment transactions are measured at the exchange amount, as agreed to by the related parties.

Management has determined that the operating subsidiaries in the reportable segments below share similar economic characteristics, as such, they have been aggregated.

The descriptions and principal operating activities of the segments are as follows:

Utilities	**Electricity**	The Utilities (Electricity) segment includes ATCO Electric, which provides regulated electricity transmission and distribution services in northern and central east Alberta, the Yukon, and the Northwest Territories, and the Company's 50 per cent ownership interest in LUMA Energy LLC which provides international electricity operations (see Note 26).
	Natural Gas	The Utilities (Natural Gas) segment includes ATCO Gas, ATCO Pipelines and ATCO Gas Australia. These businesses provide integrated natural gas transmission and distribution services throughout Alberta, in the Lloydminster area of Saskatchewan and in Western Australia.
Energy Infrastructure		The Energy Infrastructure segment includes ATCO Power (2010), ATCO Energy Solutions and ATCO Power Australia. Together these businesses provide electricity generation, natural gas storage, industrial water solutions and related infrastructure development throughout Alberta, the Yukon, the Northwest Territories, Australia, Mexico and Chile.
Corporate & Other		Canadian Utilities Limited Corporate & Other includes intersegment eliminations and ATCO Energy, a retail electricity and natural gas business, and a whole-home solution provider.

Results by operating segment for the year ended December 31 are shown below.

2021 2020	**Utilities**				**Energy Infrastructure**	**Corporate & Other**	**Intersegment eliminations**	**Consolidated**
	Electricity	**Natural Gas**	**Eliminations**	**Total**				
Revenues - external	**1,402**	**1,628**	**–**	**3,030**	**162**	**323**	**–**	**3,515**
	1,368	1,539	–	2,907	149	177	–	3,233
Revenues - intersegment	**12**	**4**	**(5)**	**11**	**47**	**28**	**(86)**	**–**
	19	9	(3)	25	46	30	(101)	–
Revenues	**1,414**	**1,632**	**(5)**	**3,041**	**209**	**351**	**(86)**	**3,515**
	1,387	1,548	(3)	2,932	195	207	(101)	3,233
Operating expenses (1)	**(575)**	**(943)**	**5**	**(1,513)**	**(180)**	**(375)**	**86**	**(1,982)**
	(545)	(866)	3	(1,408)	(159)	(207)	92	(1,682)
Depreciation, amortization and impairment	**(322)**	**(277)**	**–**	**(599)**	**(42)**	**(10)**	**–**	**(651)**
	(309)	(259)	–	(568)	(20)	(31)	9	(610)
Earnings from investment in joint ventures	**47**	**–**	**–**	**47**	**11**	**–**	**–**	**58**
	14	–	–	14	17	–	–	31
Net finance costs	**(232)**	**(149)**	**–**	**(381)**	**(18)**	**(3)**	**–**	**(402)**
	(229)	(144)	–	(373)	(10)	(3)	–	(386)
Earnings (loss) before income taxes	**332**	**263**	**–**	**595**	**(20)**	**(37)**	**–**	**538**
	318	279	–	597	23	(34)	–	586
Income tax (expense) recovery	**(71)**	**(65)**	**–**	**(136)**	**(6)**	**4**	**–**	**(138)**
	(77)	(68)	–	(145)	(7)	–	–	(152)
Earnings (loss) for the year	**261**	**198**	**–**	**459**	**(26)**	**(33)**	**–**	**400**
	241	211	–	452	16	(34)	–	434
Adjusted earnings (loss)	**347**	**288**	**–**	**635**	**28**	**(77)**	**–**	**586**
	318	266	–	584	28	(77)	–	535
Total assets	**10,405**	**8,581**	**(2)**	**18,984**	**1,194**	**1,103**	**(206)**	**21,075**
	10,326	7,985	(1)	18,310	993	1,090	(97)	20,296
Capital expenditures (2)	**350**	**747**	**–**	**1,097**	**120**	**10**	**–**	**1,227**
	366	510	–	876	19	8	–	903

(1) *Includes total costs and expenses, excluding depreciation, amortization, and impairment expense.*
(2) *Includes additions to property, plant and equipment, intangibles and $6 million of interest capitalized during construction for the year ended December 31, 2021 (2020 - $13 million).*

GEOGRAPHIC SEGMENTS

Financial information by geographic area is summarized below.

Revenues - external

	2021	**2020**
Canada	**3,262**	3,005
Australia	**200**	191
Other	**53**	37
Total	**3,515**	3,233

Non-current assets

	Property, Plant and Equipment		Intangible Assets		Other Assets (1)		Total	
	2021	**2020**	**2021**	**2020**	**2021**	**2020**	**2021**	**2020**
Canada	**16,698**	16,116	**715**	642	**221**	218	**17,634**	16,976
Australia	**1,242**	1,272	**11**	13	**17**	25	**1,270**	1,310
Other	**68**	175	**–**	1	**55**	23	**123**	199
Total	**18,008**	17,563	**726**	656	**293**	266	**19,027**	18,485

(1) Other assets exclude retirement benefit assets, financial instruments and deferred income tax assets.

ADJUSTED EARNINGS

Adjusted earnings are earnings attributable to equity owners of the Company after adjusting for:

- the timing of revenues and expenses for rate-regulated activities;
- dividends on equity preferred shares of the Company;
- one-time gains and losses;
- unrealized gains and losses on mark-to-market forward and swap commodity contracts;
- impairments; and
- items that are not in the normal course of business or a result of day-to-day operations.

Adjusted earnings are a key measure of segment earnings used by the CODM to assess segment performance and allocate resources. Other accounts in the consolidated financial statements have not been adjusted as they are not used by the CODM for those purposes.

The reconciliation of adjusted earnings and earnings for the year ended December 31 is shown below.

2021 2020	Utilities	Energy Infrastructure	Corporate & Other	Intersegment Eliminations	Consolidated
Adjusted earnings (loss)	**635**	**28**	**(77)**	–	**586**
	584	28	(77)	–	535
Transition of managed IT services	**(39)**	**(1)**	**(2)**	–	**(42)**
	(52)	(1)	(2)	–	(55)
AUC enforcement proceeding	**(14)**	–	–	–	**(14)**
	–	–	–	–	–
Impairment and other costs	–	**(64)**	**(1)**	–	**(65)**
	(8)	(3)	(19)	–	(30)
Unrealized losses on mark-to-market forward and swap commodity contracts	–	**(2)**	**(16)**	–	**(18)**
	–	(4)	(4)	–	(8)
Rate-regulated activities	**(118)**	–	–	–	**(118)**
	(65)	–	6	–	(59)
Project cost recovery	–	**17**	–	–	**17**
	–	–	–	–	–
IT Common Matters decision	**(14)**	–	–	–	**(14)**
	(19)	–	–	–	(19)
Dividends on equity preferred shares of Canadian Utilities Limited	**2**	–	**63**	–	**65**
	5	–	62	–	67
Other	–	**(4)**	–	–	**(4)**
	–	(4)	–	–	(4)
Earnings (loss) attributable to equity owners of the Company	**452**	**(26)**	**(33)**	–	**393**
	445	16	(34)	–	427
Earnings attributable to non-controlling interests					**7**
					7
Earnings for the year					**400**
					434

Transition of managed IT services

In 2020, and in the first quarter of 2021, the Company signed Master Services Agreements (MSA) with IBM Canada Ltd. (subsequently novated to Kyndryl Canada Ltd.) and IBM Australia Limited (IBM), respectively, to provide managed information technology (IT) services. These services were previously provided by Wipro Ltd. (Wipro) under a ten-year MSA expiring in December 2024. The transition of the managed IT services from Wipro to IBM commenced on February 1, 2021 and was complete at December 31, 2021.

In 2020, and during the first quarter of 2021, the Company recognized onerous contract provisions of $71 million ($55 million after-tax) and $6 million ($4 million after-tax), respectively, which represents management's best estimate of the costs to exit the Wipro MSAs. The provisions are included in provisions and other current liabilities in the consolidated balance sheets. The provision of $6 million was recorded in the first quarter of 2021 and is included in other expenses in the consolidated statements of earnings for the year ended December 31, 2021. The onerous contract provision is not in the normal course of business and has been excluded from adjusted earnings.

In addition, the Company recognized transition costs of $49 million ($38 million after-tax) in 2021. The transition costs related to activities to transfer the managed IT services from Wipro to IBM. As these costs are not in the normal course of business, they have been excluded from adjusted earnings.

Alberta Utilities Commission (AUC) enforcement proceeding

On November 29, 2021, the AUC enforcement branch filed an application with the AUC recommending an enforcement proceeding be initiated. This proceeding is to determine whether ATCO Electric Transmission failed to comply with AUC decisions and enactments under the AUC's jurisdiction with respect to the sole source contract for the Jasper interconnection project and the actions leading up to and including the filing of the 2018-2020 Deferral Account Application. This proceeding will also determine any future remedies that may be required.

AUC Enforcement and Electricity Transmission are pursuing settlement discussions prior to the AUC determining the next process steps. In 2021, the Company recognized expenses of $16 million ($14 million after-tax) related to the potential outcome of the proceeding. As this proceeding is not in the normal course of business, these costs have been excluded from adjusted earnings.

Impairment and other costs recorded in 2021

In 2021, impairments and other costs not in the normal course of business of $65 million after tax were recorded, mainly in Mexico, related to Energy Infrastructure's Veracruz hydro facility in the amount of $54 million after tax. Other costs recorded were individually immaterial.

The charge reflects an adverse arbitration decision, changes in market regulations, ongoing political uncertainty, and a challenging operating environment, resulting in an impairment of the carrying value of the assets.

The recoverable amount of Energy Infrastructure's Veracruz hydro facility was determined based on fair value less costs of disposal. The expected future cash flows were estimated under an assumption of 43 years of operations, representing the useful life of the Veracruz hydro facility, and were discounted at an after-tax rate of approximately 10 per cent. The fair value measurement is categorized as level 3 on the fair value hierarchy. The recoverable amount of Energy Infrastructure's Veracruz hydro facility was estimated to be $22 million.

As the charges relate to impairments, they have been excluded from adjusted earnings.

Impairment and other costs recorded in 2020

In 2020, impairment and other costs not in the normal course of business of $30 million after-tax were recorded. These costs mainly related to certain assets that no longer represent strategic value to the Company.

The Company's subsidiary ATCO Oil & Gas Ltd. holds a five per cent working interest in oil and gas assets in Northern Canada. With oil price volatility and the COVID-19 pandemic continuing to cause economic uncertainty, an impairment of $18 million was recorded in 2020, reflecting the reduced likelihood of future recovery of these costs. The fair value measurement was categorized as level 3 on the fair value hierarchy. The recoverable amount of the oil and gas assets was estimated to be nil.

The remaining costs mainly related to the continued transformation and realignment of certain functions in the Company.

Unrealized gains and losses on mark-to-market forward and swap commodity contracts

The Company's retail electricity and natural gas business in Alberta enters into fixed-price swap commodity contracts to manage exposure to electricity and natural gas prices and volumes. These contracts are measured at fair value. Unrealized gains and losses due to changes in the fair value of the fixed-price swap commodity contracts are recognized in the earnings of the Corporate & Other segment.

The CODM believes that removal of the unrealized gains or losses on mark-to-market forward and swap commodity contracts provides a better representation of operating results for the Company's operations.

Realized gains or losses are recognized in adjusted earnings when the commodity contracts are settled.

Rate-regulated activities

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

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

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

Rate-regulated accounting differs from IFRS in the following ways:

	Timing Adjustment	Items	RRA Treatment	IFRS Treatment
1.	Additional revenues billed in current year	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.
2.	Revenues to be billed in future years	Deferred income taxes, impact of warmer temperatures, and impact of inflation on rate base.	The Company recognizes revenues associated with recoverable costs in advance of future billings to customers.	The Company recognizes costs when they are incurred, but does not recognize their recovery until customer rates are changed and amounts are collected through future billings.
3.	Regulatory decisions received	Regulatory decisions received which relate to current and prior years.	The Company recognizes the earnings from a regulatory decision pertaining to current and prior years when the decision is received.	The Company does not recognize earnings from a regulatory decision when it is received as regulatory assets and liabilities are not recorded under IFRS.
4.	Settlement of regulatory decisions and other items	Settlement of amounts receivable or payable to customers and other items.	The Company recognizes the amount receivable or payable to customers as a reduction in its regulatory assets and liabilities when collected or refunded through future billings.	The Company recognizes earnings when customer rates are changed and amounts are recovered or refunded to customers through future billings.

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

	2021	2020
Additional revenues billed in current period		
Future removal and site restoration costs [1]	**107**	78
Impact of colder temperatures [2]	**–**	2
Revenues to be billed in future periods		
Deferred income taxes [3]	**(105)**	(105)
Distribution rate relief [4]	**(119)**	–
Impact of warmer temperatures [2]	**(1)**	–
Impact of inflation on rate base [5]	**(31)**	(6)
Settlement of regulatory decisions and other items [6]	**31**	(28)
	(118)	(59)

(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 years.

(2) ATCO Gas Distribution's 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 year are refunded to or recovered from customers in future years.

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

(4) In 2021, in response to the ongoing COVID-19 Pandemic, ATCO Electric Distribution and ATCO Gas Distribution applied for interim rate relief for customers to hold current distribution base rates in place. Following approval by the AUC, ATCO Electric Distribution and ATCO Gas Distribution recorded a decrease in earnings of $119 million. This will be recovered from customers in 2022 and 2023.

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

(6) In 2021, ATCO Gas Distribution collected $53 million related to depreciation and transmission rate riders, which was partly offset by a decrease in earnings of $28 million related to payments of transmission costs. In 2020, ATCO Electric Distribution recorded a decrease in earnings of $26 million related to payments to customers for transmission costs and capital related items.

Project cost recovery

During the fourth quarter of 2021, the Company recorded earnings of $17 million ($110 million in project costs recovered net of abandonment costs, accretion and income taxes of $93 million) following the conclusion of the Company's involvement in an international project. As these are not a result of day-to-day operations they have been excluded from adjusted earnings.

IT Common Matters decision

Consistent with the treatment of the gain on sale in 2014 from the IT services business by the Company, financial impacts associated with the IT Common Matters decision are excluded from adjusted earnings. The amount excluded from adjusted earnings in 2021 was $14 million (2020 - $19 million).

Other

The Company adjusts the deferred tax asset which was recognized as a result of the 2015 Tula Pipeline Project impairment. In 2021, the Company recorded a foreign exchange loss of $4 million after-tax (2020 - a foreign exchange loss of $4 million), due to a difference between the tax base currency, which is the Mexican peso, and the U.S. dollar functional currency.

4. REVENUES

The Company disaggregates revenues based on the nature of revenue streams. The disaggregation of revenues by each operating segment for the year ended December 31 is shown below:

2021 / 2020	Utilities Electricity (1)	Utilities Natural Gas (1)	Utilities Total	Energy Infrastructure	Corporate & Other	Consolidated
Revenue Streams						
Rendering of Services						
Distribution services	**548**	**1,036**	**1,584**	**–**	**–**	**1,584**
	531	969	1,500	–	–	1,500
Transmission services	**712**	**308**	**1,020**	**–**	**–**	**1,020**
	716	296	1,012	–	–	1,012
Customer contributions	**33**	**22**	**55**	**–**	**–**	**55**
	34	22	56	–	–	56
Franchise fees	**34**	**229**	**263**	**–**	**–**	**263**
	31	212	243	–	–	243
Retail electricity and natural gas services	**–**	**–**	**–**	**–**	**304**	**304**
	–	–	–	–	162	162
Storage and industrial water	**–**	**–**	**–**	**28**	**–**	**28**
	–	–	–	27	–	27
Total rendering of services	**1,327**	**1,595**	**2,922**	**28**	**304**	**3,254**
	1,312	1,499	2,811	27	162	3,000
Sale of Goods						
Electricity generation and delivery	**–**	**–**	**–**	**38**	**–**	**38**
	–	–	–	31	–	31
Commodity sales	**–**	**–**	**–**	**52**	**–**	**52**
	–	–	–	28	–	28
Total sale of goods	**–**	**–**	**–**	**90**	**–**	**90**
	–	–	–	59	–	59
Lease income						
Finance lease	**–**	**–**	**–**	**16**	**–**	**16**
	–	–	–	17	–	17
Other	**75**	**33**	**108**	**28**	**19**	**155**
	56	40	96	46	15	157
Total	**1,402**	**1,628**	**3,030**	**162**	**323**	**3,515**
	1,368	1,539	2,907	149	177	3,233

(1) For the year ended December 31, 2021, Electricity and Natural Gas segments include $156 million of unbilled revenue (2020 - $132 million). At December 31, 2021, $156 million of the unbilled revenue is included in trade accounts receivable and contract assets (2020 - $132 million).

Remaining performance obligations

The Company is party to performance obligations, which have a duration of more than one year, are not subject to the Right-to-Invoice practical expedient, and do not include variable consideration which is constrained (remaining performance obligations). At December 31, 2021, the most significant remaining performance obligations are as follows:

(i) the Company's 35-year service agreement to operate Fort McMurray 500 kV Transmission project that amounts to $0.8 billion. The Company expects that approximately 2 per cent of the amount will be recognized as revenue during the year ending December 31, 2022, subject to satisfaction of related performance obligations; and

(ii) provision of storage and industrial water services over the life of a contract that in aggregate approximates $0.3 billion. The Company expects that approximately 7 per cent of the amount will be recognized as revenue during the year ending December 31, 2022.

5. OTHER COSTS AND EXPENSES

In addition to rent, utilities, and goods and services such as professional fees, contractor costs, technology related expenses, advertising and other general and administrative expenses, in 2021, other costs and expenses included costs related to the transition of managed information technology services of $55 million (2020 - $71 million) (see Note 3).

6. INTEREST EXPENSE

Interest expense primarily arises from interest on long-term debentures. The components of interest expense are summarized below.

	2021	2020
Long-term debt	**390**	394
Retirement benefits interest expense	**11**	14
Accretion expense on asset retirement obligation	**10**	1
Amortization of deferred financing charges	**4**	3
Short-term debt	**2**	1
Interest expense on lease liabilities (*Note 16*)	**1**	1
Other	**1**	–
	419	414
Less: interest capitalized *(Notes 10, 11)*	**(6)**	(13)
	413	401

Borrowing costs capitalized to property, plant and equipment and intangibles during 2021 were calculated by applying a weighted average interest rate of 4.31 per cent (2020 - 4.45 per cent) to expenditures on qualifying assets.

7. INCOME TAXES

INCOME TAX EXPENSE

The income tax rate for 2021 is 23.0 per cent (2020 - 24.0 per cent).

The components of income tax expense for the year ended December 31 are summarized below.

	2021	2020
Current income tax expense		
Canada	**20**	42
Australia	**(9)**	–
Other	**4**	3
Adjustment in respect of prior years	**5**	(3)
	20	42
Deferred income tax expense		
Reversal of temporary differences	**122**	103
Change in income taxes resulting from decrease in provincial corporate tax rate	**–**	5
Adjustment in respect of prior years	**(4)**	2
	118	110
	138	152

The reconciliation of statutory and effective income tax expense for the year ended December 31 is as follows:

	2021		2020	
Earnings before income taxes	**538**	**%**	586	%
Income taxes, at statutory rates	**124**	**23.0**	141	24.0
Equity earnings	**(8)**	**(1.5)**	(4)	(0.7)
Unrecognized deferred income tax assets	**13**	**2.4**	8	1.4
Tax cost on equity preferred share financing	**5**	**0.9**	5	0.9
Change in income taxes resulting from decrease in provincial corporate tax rate	**–**	**–**	5	0.8
Other	**4**	**0.8**	(3)	(0.5)
	138	**25.6**	152	25.9

INCOME TAX ASSETS AND LIABILITIES

Income tax assets and liabilities in the consolidated balance sheets at December 31 are summarized below.

	Balance Sheet Presentation	2021	2020
Income tax assets			
Current	Prepaid expenses and other current assets	**32**	32
Deferred	Deferred income tax assets	**33**	72
		65	104
Income tax liabilities			
Current	Provisions and other current liabilities	**5**	30
Deferred	Deferred income tax liabilities	**1,588**	1,416
		1,593	1,446

DEFERRED INCOME TAXES

The changes in deferred income tax assets are as follows:

Movements	Property, Plant and Equipment	Intangibles	Reserves	Tax Loss Carry Forwards and Tax Credits	Retirement Benefit Obligations	Other	Total
December 31, 2019	16	(1)	(3)	39	10	5	66
(Charge) credit to earnings	(4)	(1)	2	8	–	1	6
Charge to other comprehensive income	–	–	(2)	–	–	–	(2)
Foreign exchange adjustment	–	–	–	–	–	1	1
Other	–	–	–	–	–	1	1
December 31, 2020	12	(2)	(3)	47	10	8	72
(Charge) credit to earnings	**(17)**	**2**	**5**	**(14)**	**(1)**	**1**	**(24)**
Charge to other comprehensive income	**–**	**–**	**(12)**	**–**	**(1)**	**–**	**(13)**
Other	**–**	**–**	**–**	**–**	**–**	**(2)**	**(2)**
December 31, 2021	**(5)**	**–**	**(10)**	**33**	**8**	**7**	**33**

The Company does not expect any of the deferred income tax assets to reverse within the next twelve months.

The changes in deferred income tax liabilities are as follows:

Movements	Property, Plant and Equipment	Intangibles	Reserves	Tax Loss Carry Forwards and Tax Credits	Retirement Benefit Obligations	Other	Total
December 31, 2019	1,399	95	(11)	(70)	(125)	14	1,302
Charge (credit) to earnings	148	5	(2)	(1)	(3)	(36)	111
Credit to other comprehensive income	–	–	(7)	–	–	–	(7)
Change in income taxes resulting from decrease in provincial corporate tax rate	–	–	–	5	–	–	5
Foreign exchange adjustment	5	–	–	1	–	(2)	4
Other	–	–	–	–	–	1	1
December 31, 2020	1,552	100	(20)	(65)	(128)	(23)	1,416
Charge (credit) to earnings	**118**	**1**	**(1)**	**4**	**2**	**(30)**	**94**
Charge to other comprehensive income	–	–	**7**	–	**53**	–	**60**
Acquisition (*Note 24*)	**24**	–	–	–	–	–	**24**
Foreign exchange adjustment	**(6)**	–	–	–	–	**1**	**(5)**
Other	**(2)**	–	–	–	–	**1**	**(1)**
December 31, 2021	**1,686**	**101**	**(14)**	**(61)**	**(73)**	**(51)**	**1,588**

The Company does not expect any of its deferred income tax liabilities to reverse within the next twelve months.

At December 31, 2021, the Company had $477 million of non-capital tax losses and credits which expire between 2025 and 2041 and $6 million of tax losses and credits which do not expire. The Company recognized deferred income tax assets of $94 million for these losses and credits. The Company had $93 million of aggregate temporary differences for which deferred income tax assets were not recognized (2020 - $86 million).

8. EARNINGS PER SHARE

Earnings per Class A non-voting (Class A) and Class B common (Class B) share are calculated by dividing the earnings attributable to Class A and Class B shares by the weighted average shares outstanding. Diluted earnings per share are calculated using the treasury stock method, which reflects the potential exercise of stock options and vesting of shares under the Company's mid-term incentive plan (MTIP) on the weighted average Class A and Class B shares outstanding.

The earnings and average number of shares used to calculate earnings per share for the year ended December 31 are as follows:

	2021	2020
Average shares		
Weighted average shares outstanding	**269,855,016**	272,758,247
Effect of dilutive stock options	**29,268**	33,799
Effect of dilutive MTIP	**432,250**	480,465
Weighted average dilutive shares outstanding	**270,316,534**	273,272,511
Earnings for earnings per share calculation		
Earnings for the year	**400**	434
Dividends on equity preferred shares of the Company	**(65)**	(67)
Dividends to non-controlling interests	**(7)**	(7)
Earnings attributable to Class A and B shares	**328**	360
Earnings and diluted earnings per Class A and Class B share		
Earnings per Class A and Class B share	**$1.21**	$1.32
Diluted earnings per Class A and Class B share	**$1.21**	$1.32

9. INVENTORIES

Inventories at December 31 are comprised of:

	2021	2020
Natural gas and fuel in storage	**15**	20
Raw materials and consumables	**6**	8
	21	28

For the year ended December 31, 2021, inventories of $10 million were used in operations and expensed (2020 - $19 million).

10. PROPERTY, PLANT AND EQUIPMENT

A reconciliation of the changes in the carrying amount of property, plant and equipment is as follows:

	Utility Transmission & Distribution	Energy Infrastructure	Land and Buildings	Construction Work-in-Progress	Other	Total
Cost						
December 31, 2019	20,083	389	708	699	784	22,663
Additions	46	5	–	771	4	826
Transfers	855	8	7	(903)	33	–
Retirements and disposals	(75)	(1)	(17)	1	(24)	(116)
Changes to asset retirement costs	1	(2)	–	–	–	(1)
Foreign exchange rate adjustment	94	(6)	2	(2)	3	91
December 31, 2020	21,004	393	700	566	800	23,463
Additions	**65**	**–**	**44**	**985**	**3**	**1,097**
Transfers	**895**	**8**	**12**	**(942)**	**27**	**–**
Retirements and disposals	**(110)**	**–**	**–**	**(175)**	**(19)**	**(304)**
Acquisition (Note 24)	**–**	**104**	**2**	**–**	**–**	**106**
Foreign exchange rate adjustment	**(83)**	**(4)**	**(2)**	**(3)**	**(2)**	**(94)**
Changes to asset retirement costs	**–**	**(1)**	**–**	**–**	**–**	**(1)**
December 31, 2021	**21,771**	**500**	**756**	**431**	**809**	**24,267**
Accumulated depreciation and impairment						
December 31, 2019	4,720	145	166	78	342	5,451
Depreciation and impairment	455	9	15	–	67	546
Retirements and disposals	(75)	–	(17)	–	(24)	(116)
Foreign exchange rate adjustment	19	(1)	–	1	–	19
December 31, 2020	5,119	153	164	79	385	5,900
Depreciation and impairment	**486**	**32**	**19**	**69**	**50**	**656**
Retirements and disposals	**(110)**	**–**	**–**	**(148)**	**(19)**	**(277)**
Foreign exchange rate adjustment	**(17)**	**(1)**	**–**	**–**	**(2)**	**(20)**
December 31, 2021	**5,478**	**184**	**183**	**–**	**414**	**6,259**
Net book value						
December 31, 2020	15,885	240	536	487	415	17,563
December 31, 2021	**16,293**	**316**	**573**	**431**	**395**	**18,008**

In 2021, the Company reorganized the groups of property, plant and equipment to align presentation with the reportable segments. This resulted in reclassification of comparative figures to conform to the current presentation.

The additions to property, plant and equipment included $2 million of interest capitalized during construction for the year ended December 31, 2021 (2020 - $10 million).

PIONEER NATURAL GAS PIPELINE ACQUISITION

In 2020, ATCO Gas and Pipelines Ltd., a wholly owned subsidiary of CU Inc., entered into an agreement to acquire the Pioneer Pipeline from Tidewater Midstream & Infrastructure Ltd. and its partner TransAlta Corporation, subject to customary conditions including regulatory approvals by the Alberta Utilities Commission (AUC) and Canada Energy Regulator.

The 131 km natural gas pipeline runs from the Drayton Valley area to the Wabamum area west of Edmonton. On June 15, 2021, the AUC issued a decision approving the acquisition of the Pioneer Pipeline and associated costs, totaling $265 million.

Consistent with the geographic areas defined in the Integration Agreement, ATCO Gas and Pipelines Ltd. will transfer to Nova Gas Transmission Ltd. (NGTL) the 30 km segment of pipeline that is located in the NGTL footprint for approximately $65 million.

The transaction to acquire the Pioneer Pipeline closed in 2021. The transfer to NGTL received approval from the Canada Energy Regulator on December 22, 2021, and is expected to close in the first quarter of 2022. As a result, $197 million was recorded in additions to property, plant and equipment in the consolidated balance sheets and the consolidated statements of cash flows. The costs incurred for the segment of the pipeline that will be sold to NGTL, amounting to $64 million, were recorded as assets held-for-sale in prepaid expenses and other current assets in the consolidated balance sheets, and were included in other investing activities in the consolidated statements of cash flows. Pipeline integration costs of $1 million are expected to be incurred in the first half of 2022, which would result in total costs of $262 million, $3 million less than the approved amount of $265 million.

ATCO Gas and Pipelines Ltd. applied the optional IFRS 3 *Business combinations* concentration test to the acquisition of the Pioneer Pipeline, which has resulted in the acquired asset being accounted for as an asset acquisition.

PURCHASE OF LAND FROM RELATED PARTY

Energy Infrastructure Segment

In December 2021, the Company purchased land from ATCO Land and Developments, an entity under common control of the parent company, for a total consideration of $45 million (see Note 31).

IMPAIRMENTS

Impairment recorded in 2021 - Energy Infrastructure Segment

In 2021, impairment of $21 million ($16 million after-tax) was recorded in respect of Energy Infrastructure's Veracruz hydro facility. The charge reflects an adverse arbitration decision, changes in market regulations, ongoing political uncertainty, and a challenging operating environment, resulting in an impairment of the carrying value of the assets. The recoverable amount of Energy Infrastructure's Veracruz hydro facility was determined based on fair value less costs of disposal. The expected future cash flows were estimated under an assumption of 43 years of operations, representing the useful life of the Veracruz hydro facility, and were discounted at an after-tax rate of approximately 10 per cent. The fair value measurement is categorized as level 3 on the fair value hierarchy. The recoverable amount of Energy Infrastructure's Veracruz hydro facility was estimated to be $22 million.

Impairment recorded in 2020 - Corporate & Other Segment

ATCO Oil & Gas Ltd., a subsidiary of Canadian Utilities Limited, holds a five per cent working interest in oil and gas assets in Northern Canada. With oil price volatility and the COVID-19 pandemic continuing to cause economic uncertainty (see Note 21), the Company determined that the total net book value of these assets was not recoverable due to reduced likelihood of future development of the assets, and, therefore, impaired these assets in full, recognizing an after-tax impairment of $18 million in 2020. The impairment was included in depreciation, amortization and impairment expense. After recognizing the impairment, the recoverable amount of these assets was nil.

11. INTANGIBLES

Intangible assets consist mainly of computer software not directly attributable to the operation of property, plant and equipment and land rights. A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Computer Software	Land Rights	Work-in-Progress	Other	Total
Cost					
December 31, 2019	499	383	81	49	1,012
Additions	2	–	87	–	89
Transfers	56	24	(80)	–	–
Retirements	(177)	–	–	(2)	(179)
Foreign exchange rate adjustment	1	–	–	–	1
December 31, 2020	381	407	88	47	923
Additions	**4**	**1**	**140**	**(2)**	**143**
Transfers	**45**	**24**	**(71)**	**2**	–
Acquisition *(Note 24)*	–	**5**	–	–	**5**
Retirements	**(33)**	–	–	**(2)**	**(35)**
Foreign exchange rate adjustment	**(2)**	–	–	–	**(2)**
December 31, 2021	**395**	**437**	**157**	**45**	**1,034**
Accumulated amortization and impairment					
December 31, 2019	317	53	–	13	383
Amortization	50	7	–	3	60
Retirements	(177)	–	–	–	(177)
Foreign exchange rate adjustment	1	–	–	–	1
December 31, 2020	191	60	–	16	267
Amortization and impairment	**45**	**5**	–	**25**	**75**
Retirements	**(31)**	–	–	**(2)**	**(33)**
Foreign exchange rate adjustment	**(1)**	–	–	–	**(1)**
December 31, 2021	**204**	**65**	–	**39**	**308**
Net book value					
December 31, 2020	190	347	88	31	656
December 31, 2021	**191**	**372**	**157**	**6**	**726**

The additions to intangibles include interest capitalized during construction of $4 million for the year ended December 31, 2021 (2020 - $3 million).

IMPAIRMENT

Energy Infrastructure Segment

In 2021, impairment of $24 million ($18 million after-tax) was recorded in respect of Energy Infrastructure's Veracruz hydro facility. The charge reflects an adverse arbitration decision, changes in market regulations, ongoing political uncertainty, and a challenging operating environment, resulting in an impairment of the carrying value of the assets. The recoverable amount of Energy Infrastructure's Veracruz hydro facility was determined based on fair value less costs of disposal. The expected future cash flows were estimated under an assumption of 43 years of operations, representing the useful life of the Veracruz hydro facility, and were discounted at an after-tax rate of approximately 10 per cent. The fair value measurement is categorized as level 3 on the fair value hierarchy. The recoverable amount of Energy Infrastructure's Veracruz hydro facility was estimated to be $22 million.

12. SHORT-TERM DEBT

At December 31, 2021, the Company had $206 million of commercial paper outstanding at an effective interest rate of 0.32 per cent, maturing in January 2022, issued under a long-term committed credit line (Note 21) (2020 - nil). The outstanding balance was fully repaid in January 2022.

The commercial paper is supported by the Company's long-term committed credit facilities.

13. LONG-TERM DEBT

Long-term debt outstanding at December 31 is as follows:

	Effective Interest Rate	2021	2020
CU Inc. debentures - unsecured (1)	4.410% (2020 - 4.487%)	**8,440**	8,140
CU Inc. other long-term obligation, due June 2023 - unsecured (2)	2.45% (2020 - 2.45%)	**7**	6
Canadian Utilities Limited debentures - unsecured, 3.122%, due November 2022	3.187%	**200**	200
ATCO Power Australia credit facility, payable in Australian dollars, at BBSY Rates, due June 2025, secured by a pledge of project assets and contracts, $58 million AUD (2020 - $58 million AUD) (3)	Floating (4)	**47**	56
ATCO Gas Australia revolving credit facility, payable in Australian dollars, at BBSY rates, due August 2024, $350 million AUD (2020 - $275 million AUD) (3)	Floating (4)	**322**	267
ATCO Gas Australia revolving credit facility, payable in Australian dollars, at BBSY rates, due August 2026, $330 million AUD (2020 - $405 million AUD) (3)	Floating (4)	**304**	394
Electricidad del Golfo credit facility, payable in Mexican pesos, at Mexican Interbank rates, due March 2023, $570 million MXP (2020 - $570 million MXP)	Floating (4)	**35**	36
Less: deferred financing charges		**(47)**	(46)
		9,308	9,053
Less: amounts due within one year		**(331)**	(166)
		8,977	8,887

BBSY - Bank Bill Swap Benchmark Rate

(1) *Interest rate is the average effective interest rate weighted by principal amounts outstanding.*

(2) *During 2021, the expiry date of the CU Inc. other long-term obligation was extended from June 2022 to June 2023.*

(3) *During 2021, the above interest rates had additional margin fees at a weighted average rate of 0.92 per cent (2020 - 1.07 per cent). The margin fees are subject to escalation.*

(4) *Floating interest rates have been partially or completely hedged with interest rate swaps (see Note 20).*

DEBENTURE ISSUANCES AND REPAYMENTS

On September 3, 2021, CU Inc., a wholly owned subsidiary of the Company, issued $460 million of 3.174 per cent debentures maturing on September 5, 2051. The Company also repaid repaid $160 million of 4.801 per cent debentures on November 22, 2021.

On September 28, 2020, CU Inc. issued $150 million of 2.609 per cent debentures maturing on September 28, 2050. CU Inc. also repaid $100 million of 11.77 per cent debentures on November 30, 2020.

OTHER LONG TERM DEBT ISSUANCES AND REPAYMENTS

ATCO Power Australia re-financing

In 2020, ATCO Power Australia, the Company's subsidiary, refinanced its credit facility with a new lender at Bank Bill Swap Benchmark Rate (BBSY) plus margin fee, extending the credit facility's maturity from February 2020 to June 2025. The floating BBSY interest rate is hedged to June 23, 2025 with an interest rate swap agreement which fixes the interest rate at 1.68 per cent.

PLEDGED ASSETS

The ATCO Power Australia credit facility is guaranteed by Canadian Utilities Limited and is secured by a mortgage on certain assets of the Karratha Power Plant and an assignment of certain contracts and agreements. The Karratha Power Plant is accounted for as a finance lease receivable.

At December 31, 2021, the book value of assets pledged to maintain the Company's long-term credit facilities was $91 million (2020 - $103 million).

14. RETIREMENT BENEFITS

The Company maintains registered defined benefit or defined contribution pension plans for most of its employees. It also provides other post-employment benefits (OPEB), principally health, dental and life insurance, for retirees and their dependents. The defined benefit pension plans provide for pensions based on employees' length of service and final average earnings. As of 1997, new employees automatically participate in the defined contribution pension plan.

The Company also maintains non-registered, non-funded defined benefit pension plans for certain officers and key employees.

The majority of benefit payments are made from trustee-administered funds; however, there are a number of unfunded plans where the Company makes the benefit payments. Plan assets held in trusts are governed by provincial and federal legislation and regulations, as is the relationship between the Company and the trustee. The Pension Committee of the Board of Directors is responsible for governance of the funded plans and policy decisions related to benefit design, liability management, and funding and investment, including selection of investment managers and investment options for the plans.

BENEFIT PLAN ASSETS, OBLIGATIONS AND FUNDED STATUS

The changes in Company's pension and OPEB plan assets and obligations are as follows:

	2021		2020	
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Market value of plan assets				
Beginning of year	3,015	–	2,819	–
Interest income	**74**	–	84	–
Employee contributions	–	–	1	–
Employer contributions	**11**	–	12	–
Benefit payments	**(134)**	–	(134)	–
Return on plan assets, excluding amounts included in interest income	**26**	–	233	–
End of year	**2,992**	–	3,015	–
Accrued benefit obligations				
Beginning of year	3,292	134	3,097	121
Current service cost	**13**	**3**	15	2
Interest cost	**82**	**3**	94	4
Employee contributions	–	–	1	–
Benefit payments from plan assets	**(134)**	–	(134)	–
Benefit payments by employer	**(7)**	**(4)**	(7)	(4)
Past service cost	–	–	4	–
Actuarial (gains) losses	**(195)**	**(14)**	222	11
End of year	**3,051**	**122**	3,292	134
Funded status				
Net retirement benefit obligations	**59**	**122**	277	134
Included in net retirement benefit obligations are:				
Registered funded defined benefit pension plan (asset) liability [(1)]	**(87)**	–	117	–
Non-registered, non-funded defined benefit pension plan obligation [(2)]	**146**	–	160	–
OPEB Plans	–	**122**	–	134
	59	**122**	277	134

(1) The registered funded defined benefit pension plan was in the asset position of $87 million at December 31, 2021 due to the impacts of returns on plan assets, increase in the liability discount rate, experience adjustments, and the restriction of the net retirement benefit asset by the asset ceiling adjustment.

(2) In the Company's non-registered, non-funded defined benefit pension plans, accrued benefit obligations decreased to $146 million at December 31, 2021 due to an increase in the liability discount rate and experience adjustments (2020 - increased to $160 million due to a decrease in the liability discount rate and experience adjustments).

BENEFIT PLAN COST

The components of benefit plan cost are as follows:

	2021		2020	
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Current service cost	**13**	**3**	15	2
Interest cost	**82**	**3**	94	4
Interest income	**(74)**	**–**	(84)	–
Past service cost	**–**	**–**	4	–
Defined benefit plans cost	**21**	**6**	29	6
Defined contribution plans cost	**27**	**–**	26	–
Total cost	**48**	**6**	55	6
Less: capitalized	**20**	**3**	24	3
Net cost recognized	**28**	**3**	31	3

RE-MEASUREMENT OF RETIREMENT BENEFITS

Re-measurements of the pension and OPEB plans are as follows:

	2021		2020	
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Gains on plan assets from:				
Return on plan assets, excluding amounts included in net interest expense	**26**	**–**	233	–
Gains (losses) on plan obligations from:				
Changes in financial assumptions	**195**	**14**	(222)	(11)
Gains (losses) recognized in other comprehensive income [(1)]	**221**	**14**	11	(11)

(1) Gains net of income taxes were $181 million for the year ended December 31, 2021 (2020 - less than a million).

PLAN ASSETS

The market values of the Company's defined benefit pension plan assets at December 31 are as follows:

				2021				2020
Plan asset mix	**Quoted**	**Un-quoted**	**Total**	**%**	**Quoted**	**Un-quoted**	**Total**	**%**
Equity securities								
Public								
Canada	**3**	**–**	**3**		16	–	16	
United States	**147**	**–**	**147**		358	–	358	
International	**81**	**–**	**81**		273	–	273	
Private	**–**	**2**	**2**		–	3	3	
	231	**2**	**233**	**8**	647	3	650	22
Fixed income securities								
Government bonds	**1,415**	**–**	**1,415**		1,110	–	1,110	
Corporate bonds and debentures	**821**	**–**	**821**		748	–	748	
Securitizations	**50**	**–**	**50**		131	–	131	
Mortgages	**–**	**149**	**149**		–	106	106	
	2,286	**149**	**2,435**	**81**	1,989	106	2,095	69
Real estate								
Land and building [(1)]	**–**	**13**	**13**		–	22	22	
Real estate funds	**–**	**212**	**212**		–	198	198	
	–	**225**	**225**	**8**	–	220	220	7
Cash and other assets								
Cash	**46**	**–**	**46**		15	–	15	
Short-term notes and money market funds	**44**	**–**	**44**		20	–	20	
Accrued interest and dividends receivable	**9**	**–**	**9**		15	–	15	
	99	**–**	**99**	**3**	50	–	50	2
	2,616	**376**	**2,992**	**100**	2,686	329	3,015	100

(1) The land and building are leased by the Company.

FUNDING

In 2021, an actuarial valuation for funding purposes as of December 31, 2020 was completed for the registered defined benefit pension plans. The estimated contribution for 2022 is $10 million. The next actuarial valuation for funding purposes must be completed as of December 31, 2023.

WEIGHTED AVERAGE ASSUMPTIONS

The significant assumptions used to determine the benefit plan cost and accrued benefit obligation are as follows:

		2021		2020
	Pension Benefit Plans	**OPEB Plans**	**Pension Benefit Plans**	**OPEB Plans**
Benefit plan cost				
Discount rate for the year	**2.58 %**	**2.58 %**	3.10 %	3.10 %
Average compensation increase for the year	**2.25 %**	**n/a**	2.50 %	n/a
Accrued benefit obligations				
Discount rate at December 31	**3.16 %**	**3.16 %**	2.58 %	2.58 %
Long-term inflation rate	**2.00 %**	**n/a**	2.00 %	n/a
Health care cost trend rate:				
Drug costs [(1)]	**n/a**	**5.05 %**	n/a	5.11 %
Other medical costs	**n/a**	**4.00 %**	n/a	4.00 %
Dental costs	**n/a**	**4.00 %**	n/a	4.00 %

(1) The Company uses a graded drug cost trend rate, which assumes a 5.05 per cent rate per annum, grading down to 4.00 per cent in and after 2040.

The weighted average duration of the defined benefit obligation is 13.4 years.

RISKS

The Company is exposed to a number of risks related to its defined benefit pension plans and OPEB plans. The most significant risks are described below.

Investment risk

The Company makes investment decisions for its funded plans using an asset-liability matching framework. Within this framework, the Company's objective over time is to increase the proportion of plan assets in fixed income securities with maturities that match the expected benefit payments as they fall due. However, due to the long-term nature of the benefit obligations, the strength of the Company, and the belief that a diversified portfolio offers an appropriate risk-return profile, the Company continues to invest in equity securities, global fixed income and Canadian real estate in addition to Canadian fixed income. The Company has not changed the processes used to manage its risks from previous periods.

Interest rate risk

A decrease in long-term interest rates will increase accrued benefit obligations, which will be partially offset by an increase in the value of the plans' bond holdings. Other things remaining the same, a further decrease in long-term interest rates will cause the funded status to deteriorate, while increases in interest rates will result in gains.

Compensation risk

The present value of the accrued benefit obligations is calculated using the estimated future compensation of plan participants. Should future compensation be higher than estimated, benefit obligations will increase.

Inflation risk

Accrued benefit obligations are linked to inflation, and higher inflation will lead to increased obligations. For the defined benefit pension plans, inflation risk is mitigated because the indexing of benefit payments is capped at an annual increase of 3.0 per cent.

The majority of plan assets are also affected by inflation. As inflation rises, long-term interest rates will likely rise, pushing up bond yields and reducing the value of existing fixed rate bonds. The relationship between equities and inflation is not as clear, but generally speaking, high inflation has a negative impact on equity valuations. Overall, rising inflation will likely reduce a plan surplus or increase a deficit.

Life expectancy

Should pensioners live longer than assumed, benefit obligations and liabilities will be larger than expected.

SENSITIVITIES

The 2021 sensitivities of significant assumptions used in measuring the Company's pension and OPEB plans are as follows:

		Accrued Benefit Obligation		Net Benefit Plan Cost	
Assumption	**Per cent Change**	**Increase in Assumption**	**Decrease in Assumption**	**Increase in Assumption**	**Decrease in Assumption**
Discount rate	1 %	(393)	488	8	(11)
Future compensation rate	1 %	6	(5)	–	–
Long-term inflation rate (1)	1 %	462	(380)	8	(7)
Health care cost trend rate	1 %	11	(9)	–	–
Life expectancy	10 %	(92)	104	(1)	2

(1) The long-term inflation rate for pension plans reflects the fact that pension plan benefit payments have historically been indexed annually to increases in the Canadian Consumer Price Index to a maximum increase of 3.0 per cent per annum.

The above sensitivities have been calculated independently of each other. Actual experience may result in changes in a number of assumptions simultaneously.

15. BALANCES FROM CONTRACTS WITH CUSTOMERS

Balances from contracts with customers are comprised of accounts receivable and contract assets and customer contributions.

ACCOUNTS RECEIVABLE AND CONTRACT ASSETS

At December 31, accounts receivable and contract assets are as follows:

	2021	2020
Trade accounts receivable and contract assets	**646**	543
Accounts receivable from parent company	**90**	96
Other accounts receivable	**23**	10
	759	649
Contract assets included in other assets	**3**	–
	762	649

A reconciliation of the changes in trade accounts receivable and contract assets during the year ended December 31 are as follows:

	2021	2020
Beginning of year	543	508
Revenue from satisfied performance obligations	**3,358**	3,049
Customer billings and other items not included in revenue	**458**	430
Credit loss allowance	**(1)**	(3)
Acquisition (*Note 24*)	**1**	–
Payments received	**(3,708)**	(3,445)
Foreign exchange rate adjustment and other	**(2)**	4
End of year	**649**	543

CUSTOMER CONTRIBUTIONS

Certain additions to property, plant and equipment, mainly in the utilities, are made with the assistance of non-refundable cash contributions from customers. These contributions are made when the estimated revenue is less than the cost of providing service or where the customer needs special equipment. Since these contributions will provide customers with on-going access to the supply of natural gas or electricity, they represent deferred revenues and are recognized in revenues over the life of the related asset.

Changes in customer contributions balance during the year ended December 31 are summarized below.

	2021	2020
Beginning of year	1,756	1,720
Receipt of customer contributions	**169**	82
Amortization	**(55)**	(56)
Transfers from other liabilities and foreign exchange rate adjustment	**–**	10
End of year	**1,870**	1,756

16. LEASES

THE COMPANY AS LESSEE

Right-of-use assets

The Company's right-of-use assets mainly relate to the lease of land and buildings. A reconciliation of the changes in the carrying amount of right-of-use assets for the year ended December 31 is as follows:

	2021	2020
Cost		
Beginning of year	76	68
Additions	**4**	9
Disposals	**(1)**	(1)
End of year	**79**	76
Accumulated depreciation		
Beginning of year	20	11
Depreciation	**9**	10
Disposals	**(1)**	(1)
End of year	**28**	20
Net book value	**51**	56

Lease liabilities

The Company has recognized lease liabilities in relation to the arrangements to lease the right-of-use assets.
A reconciliation of movements in lease liabilities during the year ended December 31 is as follows:

	Note	2021	2020
Beginning of year		56	58
Additions		**4**	9
Disposals		**–**	(1)
Interest expense	6	**1**	1
Lease payments		**(10)**	(11)
End of year		**51**	56
Less: amounts due within one year		**(7)**	(9)
End of year		**44**	47

The maturity analysis of the undiscounted contractual balances of the lease liabilities is as follows:

In one year or less	**9**
In more than one year, but not more than five years	**35**
In more than five years	**30**
	74

During the year ended December 31, 2021, $3 million was expensed in relation to low-value leases, $1 million was expensed in relation to short-term leases, and no expenses were incurred in relation to leases with variable payments (2020 - $5 million was expensed in relation to low-value leases, less than $1 million in relation to short-term leases, and nil in relation to leases with variable payments).

THE COMPANY AS LESSOR

The Company is party to certain arrangements that convey the right to use electricity generation and non-regulated electricity transmission assets. These arrangements are classified as finance leases, with the Company as the lessor.

Finance leases

The total net investment in finance leases at December 31 is shown below. Finance lease income is recognized in revenues.

	2021	2020
Net investment in finance leases		
Finance lease - gross investment	**275**	313
Unearned finance income	**(116)**	(140)
	159	173
Current portion	**10**	9
Non-current portion	**149**	164
	159	173
Gross receivables from finance leases		
In one year or less	**26**	27
In more than one year, but not more than five years	**102**	107
In more than five years	**147**	179
	275	313
Net investment in finance leases		
In one year or less	**10**	9
In more than one year, but not more than five years	**50**	47
In more than five years	**99**	117
	159	173

During the year ended December 31, 2021, $2 million of contingent rent was recognized as income from these finance leases (2020 - $1 million).

17. EQUITY PREFERRED SHARES

CANADIAN UTILITIES LIMITED EQUITY PREFERRED SHARES

Authorized and issued

Authorized: an unlimited number of Series Second Preferred Shares, issuable in series.

	December 31, 2021		December 31, 2020	
Issued	**Shares**	**Amount**	**Shares**	**Amount**
Cumulative Redeemable Second Preferred Shares				
3.403% Series Y	**13,000,000**	**325**	13,000,000	325
4.90% Series AA	**6,000,000**	**150**	6,000,000	150
4.90% Series BB	**6,000,000**	**150**	6,000,000	150
4.50% Series CC	**7,000,000**	**175**	7,000,000	175
4.50% Series DD	**9,000,000**	**225**	9,000,000	225
5.25% Series EE	**5,000,000**	**125**	5,000,000	125
4.50% Series FF	**10,000,000**	**250**	10,000,000	250
4.75% Series HH	**8,050,000**	**201**	–	–
Perpetual Cumulative Second Preferred Shares				
4.60% Series V	–	–	4,400,000	110
Issuance costs		**(30)**		(27)
		1,571		1,483

On August 27, 2021, the Company redeemed all of the issued 4.60 per cent Series V Preferred Shares for $110 million plus accrued dividends.

In December 2021, the Company issued 8,050,000 Series HH Preferred Shares yielding 4.75 per cent per annum for gross proceeds of $201 million.

Rights and privileges

Preferred shares	Redemption Amount (1)	Quarterly Dividend (2)	Reset Premium (3)	Date Redeemable/ Convertible	Convertible To
Cumulative Redeemable Second Preferred Shares					
Series Y	25.00	0.2126875	2.40 %	June 1, 2022 (4)	Series Z (5)
Series AA	25.00	0.30625	Does not reset	September 1, 2017 (6)	Not convertible
Series BB	25.00	0.30625	Does not reset	September 1, 2017 (6)	Not convertible
Series CC	25.00	0.28125	Does not reset	June 1, 2018 (6)	Not convertible
Series DD	25.00	0.28125	Does not reset	September 1, 2018 (6)	Not convertible
Series EE	25.00	0.328125	Does not reset	September 1, 2020 (6)	Not convertible
Series FF	25.00	0.28125	3.69 %	December 1, 2025 (4)	Series GG (5)
Series HH	25.00	0.296875	Does not reset	March 1, 2027 (6)	Not convertible

(1) Plus accrued and unpaid dividends.

(2) Cumulative, payable quarterly as and when declared by the Board.

(3) Dividend rate will reset on the date redeemable/convertible and every five years thereafter at a rate equal to the Government of Canada yield plus the reset premium noted.

(4) Redeemable by the Company or convertible by the holder on the date noted and every five years thereafter.

(5) If converted, holders will be entitled to receive quarterly floating rate dividends equal to the Government of Canada Treasury Bill yield plus the reset premium noted. Holders have the option to convert back to the original preferred shares series on subsequent redemption dates.

(6) Subject to a redemption premium of 4 per cent per share. The redemption premium declines by 1 per cent in each succeeding twelve month period from the redeemable date.

Dividends

Cash dividends declared and paid per share during the year ended December 31 are as follows:

(dollars per share)	2021	2020
Cumulative Redeemable Second Preferred Shares		
3.403% Series Y	**0.8508**	0.8508
4.90% Series AA	**1.2250**	1.2250
4.90% Series BB	**1.2250**	1.2250
4.50% Series CC	**1.1250**	1.1250
4.50% Series DD	**1.1250**	1.1250
5.25% Series EE	**1.3125**	1.3125
4.50% Series FF	**1.1250**	1.1250
Perpetual Cumulative Second Preferred Shares		
4.60% Series V[1]	**0.7456**	1.1500

(1) The 4.60% Series V Preferred Shares were redeemed on August 27, 2021.

The payment of dividends is at the discretion of the Board and depends on the financial condition of the Company and other factors.

On January 13, 2022, the Company declared first quarter eligible dividends of $0.2126875 per Series Y Preferred Share, $0.30625 per Series AA and Series BB Preferred Share, $0.28125 per Series CC, Series DD, and Series FF Preferred Share, $0.328125 per Series EE Preferred Share and $0.26678 per Series HH Preferred Share.

18. CLASS A AND CLASS B SHARES

A reconciliation of the number and dollar amount of outstanding Class A and Class B shares at December 31 is shown below.

AUTHORIZED AND ISSUED

	Class A Non-Voting		Class B Common		Total	
	Shares	Amount	Shares	Amount	Shares	Amount
Authorized:	Unlimited		Unlimited			
Issued and outstanding:						
December 31, 2019	199,695,081	1,110	73,550,844	139	273,245,925	1,249
Stock options exercised	34,800	1	–	–	34,800	1
Purchased and cancelled	(420,000)	(2)	–	–	(420,000)	(2)
Converted: Class B to Class A	100,955	–	(100,955)	–	–	–
December 31, 2020	199,410,836	1,109	73,449,889	139	272,860,725	1,248
Stock options exercised	**62,400**	**2**	–	–	**62,400**	**2**
Purchased and canceled	**(3,576,004)**	**(20)**	–	–	**(3,576,004)**	**(20)**
Converted: Class B to Class A	**1,061,615**	**2**	**(1,061,615)**	**(2)**	–	–
December 31, 2021	**196,958,847**	**1,093**	**72,388,274**	**137**	**269,347,121**	**1,230**

Class A and Class B shares have no par value.

MID-TERM INCENTIVE PLAN

The Company's MTIP trust is considered a special purpose entity which is consolidated in these financial statements. The Class A shares, while held in trust, are accounted for as a reduction of share capital. The consolidated Class A and Class B shares outstanding at December 31 is shown below.

	2021		2020	
	Shares	Amount	Shares	Amount
Shares issued and outstanding	**269,347,121**	**1,230**	272,860,725	1,248
Shares held in trust for the mid-term incentive plan	**(435,902)**	**(14)**	(445,041)	(16)
Shares outstanding, net of shares held in trust	**268,911,219**	**1,216**	272,415,684	1,232

DIVIDENDS

The Company declared and paid cash dividends of $1.7592 per Class A and Class B share during 2021 (2020 - $1.7416). The Company's policy is to pay dividends quarterly on its Class A and Class B shares. The payment and amount of any quarterly dividend is at the discretion of the Board and depends on the financial condition of the Company and other factors.

On January 13, 2022, the Company declared a first quarter dividend of $0.4442 per Class A and Class B share.

SHARE OWNER RIGHTS

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

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

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

DIVIDEND REINVESTMENT PROGRAM

On January 13, 2022, the Company reinstated its dividend reinvestment program (DRIP) for eligible Class A non-voting and Class B common share owners who are enrolled in the program. The DRIP was previously suspended effective January 10, 2019.

The DRIP allows eligible Class A non-voting and Class B common share owners of the Company to reinvest all or a specified portion of their dividends in additional Class A non-voting shares.

The Class A non-voting shares are issued from treasury at a two per cent discount to the volume weighted average price of the Class A non-voting shares traded on the Toronto Stock Exchange during the last five qualifying trading days preceding the dividend payment date.

NORMAL COURSE ISSUER BID

On July 29, 2021, the Company began a normal course issuer bid (NCIB), to purchase up to 3,930,623 outstanding Class A Shares. The bid expires on July 28, 2022. The prior NCIB to purchase up to 3,996,004 outstanding Class A Shares began on July 22, 2020 and expired on July 21, 2021.

During the year ended December 31, 2021, 3,576,004 Class A shares were purchased for $119 million, resulting in a decrease to share capital of $20 million and a decrease to retained earnings of $99 million (2020 - 420,000 Class A shares were purchased for $13 million, resulting in a decrease to share capital of $2 million and a decrease to retained earnings of $11 million).

19. CASH FLOW INFORMATION

ADJUSTMENTS TO RECONCILE EARNINGS TO CASH FLOWS FROM OPERATING ACTIVITIES

Adjustments to reconcile earnings to cash flows from operating activities for the year ended December 31 are summarized below.

	2021	**2020**
Depreciation, amortization and impairment	**651**	610
Distributions received from investment in joint ventures	**45**	19
Earnings from investment in joint ventures	**(58)**	(31)
Income tax expense	**138**	152
Unrealized losses on derivative financial instruments	**26**	10
Contributions by customers for extensions to plant	**169**	82
Amortization of customer contributions	**(55)**	(56)
Net finance costs	**402**	386
Income taxes paid	**(47)**	(26)
Provision on early termination of the master service agreement for managed IT services (*Note 3*)	**6**	71
Other	**(7)**	(23)
	1,270	1,194

CHANGES IN NON-CASH WORKING CAPITAL

The changes in non-cash working capital for the year ended December 31 are summarized below.

	2021	2020
Operating activities		
Accounts receivable and contract assets	**(105)**	(13)
Inventories	**7**	2
Prepaid expenses and other current assets	**(7)**	–
Accounts payable and accrued liabilities	**153**	14
	48	3
Investing activities		
Accounts receivable and contract assets	**(12)**	(4)
Accounts payable and accrued liabilities	**20**	–
	8	(4)

DEBT RECONCILIATION

The reconciliation of the changes in debt for the year ended December 31 is shown below.

	Short-term debt	Long-term debt
Liabilities from financing activities		
December 31, 2019	–	8,966
Net issue of debt	–	46
Foreign currency translation	–	41
Debt issue costs	–	(3)
Amortization of deferred financing charges	–	3
December 31, 2020	–	9,053
Net issue of debt	**206**	**294**
Foreign currency translation	–	**(38)**
Debt issue costs	–	**(5)**
Amortization of deferred financing charges	–	**4**
December 31, 2021	**206**	**9,308**

See Note 16 for the reconciliation of the changes in lease liability for the years ended December 31, 2021 and 2020.

CASH POSITION

Cash position at December 31 is comprised of:

	2021	2020
Cash	**744**	771
Short-term investments	**2**	5
Restricted cash (1)	**7**	5
Cash and cash equivalents	**753**	781
Bank indebtedness	**(3)**	(3)
	750	778

(1) Cash balances which are restricted under the terms of joint arrangement agreements are considered not available for general use by the Company.

20. FINANCIAL INSTRUMENTS

FAIR VALUE MEASUREMENT

Financial instruments are measured at amortized cost or fair value. Fair value represents the estimated amounts at which financial instruments could be exchanged between knowledgeable and willing parties in an arm's length transaction. Determining fair value requires management judgment. The valuation methods used to determine the fair value of each financial instrument and its associated level in the fair value hierarchy is described below.

Financial Instruments	Fair Value Method
Measured at Amortized Cost	
Cash and cash equivalents, accounts receivable and contract assets, bank indebtedness, accounts payable and accrued liabilities and short-term debt	Assumed to approximate carrying value due to their short-term nature.
Finance lease receivables	Determined using a risk-adjusted interest rate to discount future cash receipts (Level 2).
Long-term debt	Determined using quoted market prices for the same or similar issues. Where the market prices are not available, fair values are estimated using discounted cash flow analysis based on the Company's current borrowing rate for similar borrowing arrangements (Level 2).
Measured at Fair Value	
Interest rate swaps	Determined using interest rate yield curves at period-end (Level 2).
Foreign currency contracts	Determined using quoted forward exchange rates at period-end (Level 2).
Commodity contracts	Determined using observable period-end forward curves and quoted spot market prices with inputs validated by publicly available market providers (Level 2).
	Determined using statistical techniques to derive period-end forward curves using unobservable inputs or extrapolation from spot prices in certain commodity contracts (Level 3).

FINANCIAL INSTRUMENTS MEASURED AT AMORTIZED COST

The fair values of the Company's financial instruments measured at amortized cost at December 31 are as follows:

		2021		2020
Recurring Measurements	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial Assets				
Finance lease receivables	**159**	**215**	173	251
Financial Liabilities				
Long-term debt	**9,308**	**10,830**	9,053	11,396

FINANCIAL INSTRUMENTS MEASURED AT FAIR VALUE

The Company's derivative instruments are measured at fair value. At December 31, 2021 and 2020, the following derivative instruments were outstanding:

- interest rate swaps for the purpose of limiting interest rate risk on the variable future cash flows of long-term debt;
- foreign currency forward contracts for the purpose of limiting exposure to exchange rate fluctuations;
- natural gas and forward power sale and purchase contracts for the purpose of limiting exposure to electricity and natural gas market price movements.

The balance sheet classification and fair values of the Company's derivative financial instruments are as follows:

	Subject to Hedge Accounting		Not Subject to Hedge Accounting	
Recurring Measurements	**Interest Rate Swaps**	**Commodities**	**Commodities**	**Total Fair Value of Derivatives**
December 31, 2021				
Financial Assets				
Prepaid expenses and other current assets [1]	**–**	**52**	**2**	**54**
Other assets [1]	**8**	**35**	**6**	**49**
Financial Liabilities				
Provisions and other current liabilities [1]	**1**	**12**	**20**	**33**
Other liabilities [1]	**–**	**8**	**6**	**14**
December 31, 2020				
Financial Assets				
Prepaid expenses and other current assets [1]	–	25	5	30
Other assets [1]	–	12	4	16
Financial Liabilities				
Provisions and other current liabilities [1]	1	6	8	15
Other liabilities [1]	20	4	3	27

(1) At December 31, 2021, financial liabilities and financial assets include $26 million and $8 million, respectively, of Level 3 derivative financial instruments (2020 - financial liabilities and financial assets include $9 million and $8 million, respectively, of Level 3 derivative financial instruments).

During the year ended December 31, 2021, gains before income taxes of $106 million were recognized in other comprehensive income (OCI) (2020 - losses of $17 million), and $30 million were reclassified to the statement of earnings (2020 - $3 million).

Hedge ineffectiveness of $14 million was recognized in the consolidated statements of earnings during 2021 (2020 - $3 million). Over the next 12 months, the Company estimates that gains before income taxes of $34 million will be reclassified from accumulated other comprehensive income (AOCI) to earnings.

Notional and maturity summary

The notional value and maturity dates of the Company's derivative instruments outstanding are as follows:

	Subject to Hedge Accounting				Not Subject to Hedge Accounting		
Notional value and maturity	**Interest Rate Swaps**	**Natural Gas (1)**	**Power (2)**	**Foreign Currency Forward Contracts**	**Natural Gas (1)**	**Power (2)**	**Foreign Currency Forward Contracts**
December 31, 2021							
Purchases (3)	–	**23,062,900**	**3,240,005**	–	–	–	–
Sales (3)	–	**2,313,227**	**526,314**	–	**11,015,969**	**1,232,616**	–
Currency							
Australian dollars	**732**	–	–	–	–	–	–
Mexican pesos	**570**	–	–	–	–	–	**79**
U.S. dollars	–	–	–	**2**	–	–	–
Maturity	**2023-2025**	**2022-2026**	**2022-2026**	**2022**	**2022-2024**	**2022-2024**	**2022**
December 31, 2020							
Purchases (3)	–	10,593,800	2,203,836	–	–	–	–
Sales (3)	–	3,238,242	759,246	–	7,867,560	1,089,495	–
Currency							
Australian dollars	738	–	–	–	–	–	–
Mexican pesos	570	–	–	–	–	–	100
Maturity	2023-2025	2021-2025	2021-2025	–	2021-2024	2021-2024	2021

(1) Notional amounts for the natural gas purchase contracts are the maximum volumes that can be purchased over the terms of the contracts.

(2) Notional amounts for the forward power sale and purchase contracts are the commodity volumes committed in the contracts.

(3) Volumes for natural gas and power derivatives are in GJ and MWh, respectively.

OFFSETTING FINANCIAL ASSETS AND LIABILITIES

Netting arrangements and similar agreements provide counterparties the legal right to set-off liabilities against assets received. The following financial assets and financial liabilities are subject to offsetting at December 31:

	Effects of Offsetting on the Balance Sheet		
	Gross Amount	**Gross Amount Offset**	**Net Amount Recognized**
2021			
Financial Assets			
Derivative assets (1) (2)	**95**	–	**95**
Accounts receivable and contract assets	**65**	**(39)**	**26**
Financial Liabilities			
Derivative liabilities (1) (3)	**46**	–	**46**
2020			
Financial Assets			
Derivative assets (1) (2)	45	–	45
Accounts receivable and contract assets	61	(39)	22
Financial Liabilities			
Derivative liabilities (1) (3)	20	–	20

(1) The Company enters into derivative transactions based on master agreements in which there is a set-off provision under certain circumstances, such as default. The agreements do not meet the criteria for offsetting in the consolidated balance sheet since the Company does not presently have a legally enforceable right to set-off. This right is enforceable only if certain credit events occur in the future.

(2) At December 31, 2021, $54 million is included in prepaid expenses and other assets, and $41 million is included in other assets in the consolidated balance sheets (2020 - $29 million and $16 million).

(3) At December 31, 2021, $32 million is included in provisions and other current liabilities, and $14 million is included in other liabilities in the consolidated balance sheets (2020 - $13 million and $7 million).

21. RISK MANAGEMENT

The Company's Board is responsible for understanding the principal risks of the Company's business, achieving a proper balance between risks incurred and the potential return to share owners, and confirming there are controls in place to effectively monitor and manage those risks with a view to the long-term viability of the Company. The Board established the Audit & Risk Committee to review significant risks associated with future performance, growth and lost opportunities identified by management that could materially affect the Company's ability to achieve its strategic or operational targets. This committee is responsible for confirming that management has procedures in place to mitigate identified risks.

The Company is exposed to a variety of risks associated with the use of financial instruments: market risk, credit risk and liquidity risk. The Company may use various derivative financial instruments to manage its exposure in these areas. All such instruments are used to manage risk and are not for trading purposes.

The source of risk exposure and how each is managed is outlined below.

MARKET RISK

Interest rate risk

Interest rate risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate due to changes in interest rates. The Company's interest-bearing assets and liabilities include cash and cash equivalents, bank indebtedness and long-term debt. The interest rate risk faced by the Company is primarily due to its cash and cash equivalents and floating rate long-term debt.

Cash and cash equivalents include fixed rate instruments with maturities of generally 90 days or less that are reinvested as they mature. The Company is exposed to interest rate movements after these investments mature.

The Company's risk management policy is to hedge all material interest rate risk exposures related to long-term financings when the risk is incurred, unless commercial arrangements or mechanisms are in place to offset such interest rate risk. The Company has fixed interest rates, either directly or through interest rate swap agreements, on 100 per cent (2020 - 100 per cent) of total long-term debt. Consequently, the exposure to fluctuations in market interest rates is limited.

A 25 basis point increase or decrease in interest rates would increase or decrease earnings by less than $1 million. This analysis has been determined based on the exposure to interest rates for financial instruments outstanding at December 31, 2021.

Foreign exchange risk

Foreign exchange risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in foreign exchange rates. The Company operates internationally and is exposed to foreign exchange risk from financial instruments denominated in currencies other than the functional currency of an operation and on its net investments in foreign subsidiaries. The majority of this currency risk arises from exposure to the U.S. dollar and Australian dollar. The Company offsets foreign exchange volatility in part by entering into foreign currency derivative contracts and by financing with foreign-denominated debt. The Company's risk management policy is to hedge all material transactions with foreign exchange risks arising from the sale or purchase of goods and services where revenue or the costs to be incurred are denominated in a currency other than the functional currency of the transacting company.

A 10 per cent increase or decrease in foreign exchange rates would each increase or decrease OCI by the following:

	OCI
U.S dollar	5
Australian dollar	58

The sensitivity analysis is based on management's assessment that an average 10 per cent increase or decrease in these currencies relative to the Canadian dollar is a reasonable potential change over the next year. This analysis has been determined based on the exposure to foreign exchange for financial instruments outstanding at December 31, 2021.

The sensitivity analysis excludes translation risk associated with the translation of subsidiaries that have a different functional currency than the functional currency of the Company.

Energy commodity price risk

Energy commodity price risk is the risk that the fair value or future cash flows of natural gas and electricity sales and purchases will fluctuate due to changes in market prices. Fluctuations in market prices result from changes in supply and customer demand, fuel costs, market conditions, weather, regulatory policies, and other factors. The Company's retail energy and natural gas storage businesses are exposed to commodity price movements, particularly to the market price of natural gas and electricity.

Anticipated price risks are calculated based on the Company's customer demand requirements and supply requirements to natural gas and electricity. These are consistently observed and analyzed to ensure that operational and commercial strategic policies to mitigate pricing risk are met.

The Company manages its price risk as part of its strategy by entering into hedging contracts, including short-term and long-term fixed price sale and purchase contracts. Management actively monitors its derivative transactions in accordance with its risk management policy. This policy sets out pre-defined risks and financial parameters so that price fluctuations do not materially affect the margins the Company ultimately receives.

The Company is also exposed to seasonal natural gas price spreads in its natural gas storage operations. Management mitigates this risk by entering into short-term and long-term firm capacity arrangements, where appropriate.

The Company's natural gas and electricity contracts associated with financial derivatives are significantly influenced by the variability of forward spot prices.

A 10 per cent increase or decrease in the forward price of natural gas or electricity would increase or decrease earnings by $11 million, and would increase or decrease OCI by $21 million. This analysis assumes that changes in the forward price of natural gas and electricity affects the mark-to-market adjustment of the purchase and sale contracts.

CREDIT RISK

Credit risk is the risk of financial loss due to a counterparty's inability to discharge their contractual obligations to the Company. The Company is exposed to credit risk on its cash and cash equivalents, accounts receivable and contract assets, finance lease receivable and derivative instrument assets. The exposure to credit risk represents the total carrying amount of these financial instruments in the consolidated balance sheet.

The Company manages its credit risk on cash and cash equivalents by investing in instruments issued by credit-worthy financial institutions and in short-term instruments issued by the federal government.

Accounts receivable and contract assets and finance lease receivable credit risk is reduced by transacting with credit-worthy customers in accordance with the established credit approval policies, diversified customer base and through collateral arrangements such as letters of credit, corporate guarantees and cash deposits. The utilities are also able to recover an estimate for their credit loss allowances through approved customer rates and to request recovery through customer rates for any losses from retailers beyond the retailer security mandated by provincial regulations.

Derivative credit risk arises from the possibility that a counterparty to a contract fails to perform according to its terms and conditions. This risk is mitigated by dealing with large, credit-worthy counterparties and continuous monitoring of the counterparty risk exposure. The Company has in certain instances entered into master netting agreements with its derivative counterparties, which provides a right to offset for certain exposures between the parties.

The Company does not have a concentration of credit risk with any counterparty, except for finance lease receivables, which by its nature is with a single counterparty.

Depending on the nature of accounts receivable and contract assets, the Company estimates credit losses based on the expected credit loss rates for respective credit ratings. At December 31, the summary of the expected credit loss rates for respective credit ratings is as follows:

	High (AA to AAA)	Medium (BBB to A)	(BB and below)
December 31, 2021	0%-0.02%	0.05%-0.15%	0.48%-3.13%
December 31, 2020	0%-0.02%	0.05%-0.16%	0.51%-3.20%

At December 31, 2021, the Company had approximately $24 million of accounts receivable and contract assets classified as Low (BB and below) (2020 - approximately $50 million).

Where the Company believes there is a high probability of a customer default, additional credit allowances are recorded.

The credit loss recognized during 2021 was $1 million (2020 - $3 million). As at December 31, 2021, the expected credit loss allowance balance was $5 million (2020 - $6 million).

The aging analysis of trade receivables that are past due but not impaired at December 31 is as follows:

	2021	2020
Up to 30 days	**611**	521
31 to 60 days	**7**	9
61 to 90 days	**4**	2
Over 90 days	**24**	11
	646	543

At December 31, 2021, the Company held $285 million in letters of credit for certain counterparty receivables (2020 - $237 million). The Company did not take possession of any collateral it holds as security in 2021 or 2020. The Company has also entered into guarantee arrangements with the parent company of Direct Energy Partnership (NRG Energy) relating to the retail energy supply functions performed by Direct Energy (see Note 29).

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations associated with its financial liabilities that are settled in cash or another financial asset. Liquidity risk arises from the Company's general funding needs and in the management of its assets, liabilities and capital structure. The Company considers it prudent to maintain sufficient liquidity to fund approximately one full year of cash requirements to preserve strong financial flexibility. 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, bank borrowings and issuance of long-term debt and preferred shares. Commercial paper borrowings and short-term bank loans are also used under available credit lines to provide flexibility in the timing and amounts of long-term financing.

Lines of credit

At December 31, the Company has the following lines of credit that enable it to obtain financing for general business purposes:

	2021			2020		
	Total	Used	Available	Total	Used	Available
Long-term committed	**2,467**	**832**	**1,635**	2,505	661	1,844
Uncommitted	**553**	**185**	**368**	553	152	401
	3,020	**1,017**	**2,003**	3,058	813	2,245

Long-term committed credit facilities have maturities greater than one year. Uncommitted credit facilities have no set maturity and the lender can demand repayment at any time.

Lines of credit utilized at December 31 are comprised of:

	2021	2020
Short-term debt	**206**	–
Long-term debt	**626**	661
Letters of credit	**185**	152
	1,017	813

Commercial paper

The Company is authorized to issue $1.2 billion of commercial paper against its long-term committed credit facilities.

Maturity analysis of financial obligations

The table below analyzes the remaining contractual maturities at December 31, 2021, of the Company's financial liabilities based on the contractual undiscounted cash flows.

	2022	2023	2024	2025	2026	2027 and thereafter
Accounts payable and accrued liabilities	739	–	–	–	–	–
Short-term debt	206	–	–	–	–	–
Long-term debt:						
Principal	331	148	448	30	429	7,969
Interest expense (1)	357	354	347	342	345	6,422
Derivatives (2)	32	9	4	1	–	–
	1,665	511	799	373	774	14,391

(1) Interest payments on floating rate debt have been estimated using rates in effect at December 31, 2021. Interest payments on debt that has been hedged have been estimated using hedged rates.

(2) Payments on outstanding derivatives have been estimated using exchange rates and commodity prices in effect at December 31, 2021.

The table below analyzes the remaining contractual maturities at December 31, 2020, of the Company's financial liabilities based on the contractual undiscounted cash flows, as reported in the consolidated financial statements for the year ended December 31, 2020.

	2021	2022	2023	2024	2025	2026 and thereafter
Accounts payable and accrued liabilities	549	–	–	–	–	–
Long-term debt:						
Principal	166	337	804	126	32	7,634
Interest expense (1)	377	368	348	327	327	6,396
Derivatives (2)	13	5	2	–	–	–
	1,105	710	1,154	453	359	14,030

(1) Interest payments on floating rate debt have been estimated using rates in effect at December 31, 2020. Interest payments on debt that has been hedged have been estimated using hedged rates.

(2) Payments on outstanding derivatives have been estimated using exchange rates and commodity prices in effect at December 31, 2020.

PANDEMIC RISK

An outbreak of infectious disease, a pandemic or a similar public health threat, such as the COVID-19 pandemic, could adversely impact the Company. This includes causing operating, supply chain and project development delays and disruptions, labor shortages and shutdowns as a result of government regulation and prevention measures, increased strain on employees and compromised levels of customer service, any of which could have a negative impact on the Company’s operations.

Any deterioration in general economic and market conditions resulting from a public health threat could negatively affect demand for electricity and natural gas, revenue, operating costs, timing and extent of capital expenditures, results of financing efforts, or credit risk and counterparty risk; any of which could have a negative impact on the Company's business.

While the Company's investments are largely focused on regulated utilities and long-term contracted businesses with strong counterparties creating a resilient investment portfolio, the extent of the COVID-19 pandemic and its future impact on the Company remains uncertain. In response to the evolving situation, the Company's Pandemic Plan was activated in February 2020. The plan included travel restrictions, limited access to facilities, a direction to work from home whenever possible, physical distancing measures and other protocols (including the use of personal protective equipment while at a work premise). Since then, the Company has been following recommendations by local and national public health authorities across the globe to adjust operational requirements as needed to ensure a coordinated approach across the Company. As a result of these efforts and the Company's experience in crisis response, the Company's operations, financial position and performance have not been significantly impacted for the year ended December 31, 2021.

CLIMATE CHANGE RISK

The Company manages climate risks related to assets, including preparing for, and responding to, extreme weather events through activities such as proactive route and site 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 expenditures or acquiring assets, the Company considers site specific climate and weather factors, such as flood plain mapping and extreme weather history.

The Company also continues to explore and implement opportunities in clean fuels, renewable energy, and energy efficiency. This includes looking at ways to modernize the Company's energy infrastructure to accommodate new and innovative sources of energy as well as ways to further use energy more efficiently. This process is associated with risks and uncertainties, and is highly dependent on changes in legislation, market price volatility, local and global demand on energy, as well as the timing of when the local and global markets transition to a more energy efficient and cleaner fuels-based economy. The extent and significance of the future impact of such risks and uncertainties remain unknown.

22. CAPITAL DISCLOSURES

The Company's objectives when managing capital are to:

1. Safeguard the Company's ability to continue as a going concern so it can continue to provide returns to share owners and benefits for other stakeholders.
2. Maintain strong investment-grade credit ratings in order to provide efficient and cost-effective access to funds required for operations and growth.

The Company considers both its regulated and non-regulated operations, as well as changes in economic conditions and risks impacting its operations, in managing its capital structure. The Company may adjust the dividends paid to share owners, issue or purchase Class A and Class B shares, issue or redeem preferred shares, and issue or repay short-term debt, long-term debt and non-recourse long-term debt. Financing decisions are based on assessments by management in line with the Company's objectives, with a goal of managing the financial risk to the Company as a whole.

While the Alberta based Utilities have as their objective to be capitalized according to the AUC-approved capital structure, the Company as a whole is not restricted in the same manner. The Company sets its capital structure relative to risk and to meet financial and operational objectives, while factoring in the decisions of the regulator.

The Company also manages capital to comply with the customary covenants on its debt. A common financial covenant for the Company's debentures and credit facilities is that total debt divided by total capitalization must be less than 75 per cent. The Company defines total debt as the sum of bank indebtedness, short-term debt and long-term debt (including its respective current portion). It defines total capitalization as the sum of Class A and Class B shares, contributed surplus, retained earnings, AOCI, equity preferred shares, NCI and total debt. Management maintains the debt capitalization ratio well below 75 per cent to sustain access to cost-effective financing.

Debt capitalization does not have standardized meaning under IFRS and might not be comparable to similar measures presented by other companies. Also, the definitions of total debt and total capitalization vary slightly in the Company's debt-related agreements.

The Company's capitalization at December 31 is as follows:

	2021	2020
Bank indebtedness	**3**	3
Short-term debt	**206**	–
Long-term debt	**9,308**	9,053
Total debt	**9,517**	9,056
Class A and Class B shares	**1,216**	1,232
Contributed surplus	**8**	8
Retained earnings	**3,862**	3,928
Accumulated other comprehensive loss	**(22)**	(30)
Equity preferred shares	**1,571**	1,483
Non-controlling interests	**187**	187
Total equity	**6,822**	6,808
Total capitalization	**16,339**	15,864
Debt capitalization	**58 %**	57 %

For the year ended December 31, 2021, the Company complied with externally imposed requirements on its capital, including covenants related to debentures and credit facilities.

23. SIGNIFICANT JUDGMENTS, ESTIMATES AND ASSUMPTIONS

Significant judgments, estimates and assumptions made by the Company are outlined below.

SIGNIFICANT ACCOUNTING JUDGMENTS

Revenue related items

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

Impairment of financial assets

The impairment loss allowance for financial assets is based on assumptions about risk of default and expected loss rates. The Company makes judgments in making these assumptions and selecting the inputs to the impairment calculation, based on the Company's past history, existing market conditions as well as forward looking estimates at the end of each reporting period.

Joint arrangements

Judgment is required when assessing the classification of a joint arrangement as a joint operation or a joint venture. When making this assessment, the Company considers the structure of the arrangements, the legal form of any separate vehicles, the contractual terms of the arrangements, and other facts and circumstances.

Impairment of long-lived assets

Indicators of impairment are considered when evaluating whether or not an asset is impaired. Factors which could indicate an impairment exists include: significant underperformance relative to historical or projected operating results, significant changes in the way in which an asset is used or in the Company's overall business strategy, significant negative industry or economic trends, or adverse decisions by regulators. Events indicating an impairment may be clearly identifiable or based on an accumulation of individually insignificant events over a period of time. Measurement uncertainty is increased where the Company is not the operator of a facility. The Company continually monitors its operating facilities and the markets and business environment in which it operates. Judgments and assessments about conditions and events are made in order to conclude whether a possible impairment exists.

Property, plant and equipment and intangibles

The Company makes judgments to: assess the nature of the costs to be capitalized and the time period over which they are capitalized in the purchase or construction of an asset; evaluate the appropriate level of componentization where an asset is made up of individual components for which different depreciation and amortization methods and useful lives are appropriate; distinguish major overhauls to be capitalized from repair and maintenance activities to be expensed; and determine the useful lives over which assets are depreciated and amortized.

Leases

The Company evaluates contract terms and conditions to determine whether they contain or are leases. Where a lease exists, the Company determines whether substantially all of the significant risks and rewards of ownership are transferred to the customer, in which case it is accounted for as a finance lease, or remain with the Company, in which case it is accounted for as an operating lease.

In the situation where the implicit interest rate in the lease is not readily determined, the Company uses judgment to estimate the incremental borrowing rate for discounting the lease payments. The Company's incremental borrowing rate generally reflects the interest rate that the Company would have to pay to borrow a similar amount at a similar term and with a similar security. The Company estimates the lease term by considering the facts and circumstances that create an economic incentive to exercise an extension or termination option. Certain qualitative and quantitative assumptions are used when evaluating these incentives.

Income taxes

The Company makes judgments with respect to changes in tax legislation, regulations and interpretations thereof. Judgment is also applied to estimating probable outcomes, when temporary differences will reverse, and whether tax assets are realizable.

When tax legislation is subject to interpretation, management periodically evaluates positions taken in tax filings and records provisions where appropriate. The provisions are management’s best estimates of the expenditures required to settle the present obligations at the balance sheet date, using a probability weighting of possible outcomes.

SIGNIFICANT ACCOUNTING ESTIMATES AND ASSUMPTIONS

Revenue recognition

An estimate of usage not yet billed is included in revenues from the regulated distribution of natural gas and electricity. The estimate is derived from unbilled gas and electricity distribution services supplied to customers and is based on historical consumption patterns. Management applies judgment to the measure and value of the estimated consumption.

Impairment of financial assets

The impairment loss allowance for financial assets are based on assumptions about risk of default and expected loss rates. For details regarding significant assumptions and key inputs used to calculate impairment loss allowance, see Note 21.

Useful lives of property, plant and equipment and intangibles

Useful lives are estimated based on current facts and past experience taking into account the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecast demand, and the potential for technological obsolescence.

Impairment of long-lived assets

The Company continually monitors its long-lived assets and the markets and business environment in which it operates for indications of asset impairment. Where necessary, the Company estimates the recoverable amount for the cash generating unit (CGU) to determine if an impairment loss is to be recognized. These estimates are based on assumptions, such as the price for which the assets in the CGU could be obtained or future cash flows that will be produced by the CGU, discounted at an appropriate rate. Subsequent changes to these estimates or assumptions could significantly impact the carrying value of the assets in the CGU.

Leases

Useful lives of right-of-use assets are based on current facts and past experience taking into account the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecast demand, and the potential for technological obsolescence.

Onerous contracts

In assessing the unavoidable costs of meeting obligations under an onerous contract at the reporting date, the Company identifies and quantifies any compensation or penalties, other costs arising from the need to terminate a contract or inability to fulfil it. This process involves judgment about the future events, interpretation of legal terms of a contract, as well as estimates on the timing and amount of future cash flows. The change in used estimates and underlying assumptions can significantly impact the amount of recognized provision in relation to onerous contracts.

Retirement benefits

The Company consults with qualified actuaries when setting the assumptions used to estimate retirement benefit obligations and the cost of providing retirement benefits during the period. These assumptions reflect management's best estimates of the long-term inflation rate, projected salary increases, retirement age, discount rate, health care costs trend rates, life expectancy and termination rates. The discount rate is determined by reference to market yields on high quality corporate bonds. Since the discount rate is based on current yields, it is only a proxy for future yields. Significant assumptions used to determine the retirement benefit cost and obligation are shown in Note 14.

Asset retirement obligations

The Company's estimates regarding asset retirement costs and related obligations change as a result of changes in cost estimates, legal and constructive requirements, market rates and technological advancement. The significant assumptions used to record asset retirement obligations include, but are not limited to, expected timing of retirement of an asset, scope and costs of retirement and reclamation activities, rates of inflation and a pre-tax risk-free discount rate. The estimates and assumptions for asset retirement obligations are reviewed at each reporting period. Changes to the estimates or assumptions could significantly impact the carrying values of the asset retirement obligations.

Income taxes

Management periodically evaluates positions taken in tax filings where tax legislation is subject to interpretation, and records provisions where appropriate. The provisions are management's best estimates of the expenditures required to settle the present obligations at the balance sheet date measured using a probability weighting of possible outcomes.

Use of judgments and estimates around the COVID-19 pandemic

For the year ended December 31, 2021, the Company performed an assessment of the impacts of uncertainties around the COVID-19 pandemic on its consolidated financial position, financial performance and cash flows. The assessment required use of judgments and estimates and resulted in no material impacts to the consolidated financial statements.

24. BUSINESS COMBINATIONS

Acquisition of the natural gas storage business in Canada

On December 2, 2021, ATCO Energy Solutions Ltd., a subsidiary of the Company, acquired a 100 per cent ownership interest in Alberta Hub, an underground natural gas storage business in Alberta, Canada. The acquisition is reported in the Energy Infrastructure segment.

The aggregate consideration paid for Alberta Hub was $135 million, which is comprised of $84 million cash paid, net of cash acquired of $51 million. There is no contingent consideration with this acquisition.

The fair values of the identifiable assets acquired and liabilities assumed were as follows:

Accounts receivable and contract assets	1
Property, plant & equipment	106
Intangible assets	5
Deferred income tax liabilities	(24)
Other liabilities	(4)
Total identifiable net assets acquired	84

The fair value of the acquired accounts receivable approximated the carrying value due to their short-term nature. None of the accounts receivable acquired were impaired.

From the date of acquisition, revenues of $1 million and earnings attributable to equity owners of the Company of less than $1 million were included in the consolidated statements of earnings for the year ended December 31, 2021, as a result of the acquisition. Transaction costs of $1 million for incremental legal and advisory services fees were expensed during the year ended December 31, 2021 and included in other costs and expenses in the consolidated statements of earnings.

The Company's pro-forma consolidated revenues and earnings attributable to equity owners of the Company for the year ended December 31, 2021, would have been $3,540 million and $404 million, respectively, if the acquisition had occurred on January 1, 2021. These pro-forma adjustments reflect the Company's historic natural gas storage margin and adjustments for depreciation and amortization assuming the fair values attributed in the purchase price allocation occurred on January 1, 2021. These pro-forma results may not necessarily be indicative of actual results had the acquisition occurred on January 1, 2021.

25. SUBSIDIARIES

Principal operating subsidiaries are listed below. Subsidiaries are wholly owned, unless otherwise indicated.

Principal Operating Subsidiaries	Principal Place of Business	Principal Activity
ATCO Energy Solutions	Canada	Develops, owns and operates non-regulated energy and water-related infrastructure
Electricidad del Golfo	Mexico	Electricity generation and related infrastructure services
ATCO Gas Australia	Australia	Natural gas distribution
ATCO Power Australia	Australia	Electricity generation
ATCO Energy	Canada	Electricity and natural gas retailer and a provider of whole-home solutions
ATCO Power (2010)	Canada	Electricity generation and related infrastructure services
CU Inc.	Canada	Holding company
ATCO Electric	Canada	Electricity transmission, distribution and related infrastructure development
ATCO Gas [1]	Canada	Natural gas distribution and related infrastructure development
ATCO Pipelines [1]	Canada	Natural gas transmission and related infrastructure development

(1) ATCO Gas and ATCO Pipelines are divisions of ATCO Gas and Pipelines Ltd.

26. JOINT ARRANGEMENTS

JOINT VENTURES

The following joint ventures are considered the most significant; however, they are not individually material to the operations of the Company.

Significant Joint Ventures	Segment	Operating Jurisdiction	Ownership %	Principal Activity
LUMA Energy LLC	Utilities, Electricity	Puerto Rico	50	Operations and management services
Osborne Cogeneration Plant	Energy Infrastructure	Australia	50	Electricity generation
Strathcona Storage Limited Partnership	Energy Infrastructure	Canada	60	Hydrocarbon storage

LUMA Energy LLC

On June 22, 2020, LUMA Energy LLC (LUMA), a Commonwealth of Puerto Rico based joint venture between the Company and Quanta Services, Inc., where each party holds a 50 per cent ownership interest, was selected by the Puerto Rico Public-Private Partnerships Authority to modernize and operate Puerto Rico's electric transmission and distribution system over a term of 15 years after a one year transition period which commenced in June 2020.

LUMA contractual arrangements do not assume ownership of any electric transmission and distribution assets. The functional currency of LUMA is US dollars.

The Company has accounted for its 50 per cent ownership interest as a joint venture, whereby the initial investment shall be adjusted for the Company's share of LUMA's earnings, other comprehensive income, dividends received from LUMA, and foreign exchange. When making the assessment on whether LUMA represents a joint venture, the Company considered the structure, legal form and contractual terms of the arrangement with Quanta Services, Inc., as well as other facts and circumstances.

LUMA is reported in the Utilities, Electricity segment.

Joint Ventures financial information

Aggregate information for the Company’s interest in joint ventures is shown below.

	2021	2020
Earnings and comprehensive income for the year	**58**	31
Dividends received	**45**	19
Aggregate carrying amount of interests in joint ventures	**204**	165

Contributions in the Company's joint ventures during the year ended December 31 were as follows:

	2021	2020
LUMA Energy LLC	**8**	–
Strathcona Storage Limited Partnership	**19**	9
	27	9

Commitments

The joint ventures have contractual obligations in the normal course of business. The Company’s total share of these unrecognized commitments, based on the contractual undiscounted cash flows, was $10 million at December 31, 2021 (2020 - $15 million).

Dividends and Distributions

The Company requires approval from its joint venture partners before any dividends or distributions can be paid.

27. NON-CONTROLLING INTERESTS

Non-controlling interests at December 31 are comprised of CU Inc. Equity Preferred Shares.

Authorized and issued

Authorized: an unlimited number of Preferred Shares, issuable in series.

		2021		2020
Issued	**Shares**	**Amount**	**Shares**	**Amount**
Cumulative Redeemable Preferred Shares				
4.60% Series 1	**4,600,000**	**115**	4,600,000	115
2.292% Series 4 [1]	**3,000,000**	**75**	3,000,000	75
Issuance costs		**(3)**		(3)
		187		187

(1) Effective June 1, 2021, the annual dividend rate for the Series 4 Preferred Shares was reset at 2.292 per cent for the five-year period from June 1, 2021 to May 31, 2026. Prior to the reset on June 1, 2021, the annual dividend rate was 2.24 per cent.

Rights and privileges

Preferred shares	Redemption Amount [1]	Quarterly Dividend [2]	Reset Premium [3]	Date Redeemable/Convertible	Convertible To
Cumulative Redeemable Preferred Shares					
Series 1	25.00	0.2875	Does not reset	Currently redeemable	Not convertible
Series 4	25.00	0.14325	1.36 %	June 1, 2026 [4]	Series 5 [5]

(1) Plus accrued and unpaid dividends.

(2) Cumulative, payable quarterly as and when declared by the Board.

(3) Dividend rate will reset on the date redeemable/convertible and every five years thereafter at a rate equal to the Government of Canada yield plus the reset premium noted.

(4) Redeemable by the Company or convertible by the holder on the date noted and every five years thereafter.

(5) If converted, holders will be entitled to receive quarterly floating rate dividends equal to the Government of Canada Treasury Bill yield plus the reset premium noted. Holders have the option to convert back to the original preferred shares series on subsequent redemption dates.

28. SHARE-BASED COMPENSATION PLANS

PLAN FEATURES

Share based forms of compensation are granted at the discretion of the Corporate Governance – Nomination, Compensation and Succession Committee. Plan features are described below.

Form of compensation	Eligibility	Vesting Period	Term	Settlement
Stock options [1][2]	Officers and key employees	20% per year over 5 years	10 years	Class A non-voting shares [4]
		25% per year over 4 years	8 years	Class A non-voting shares [4]
Share appreciation rights [1]	Directors, officers and key employees	20% per year over 5 years	10 years	Cash
Mid-term incentive plan	Officers and key employees	2-3 years [3]	2-3 years	Class A non-voting shares [5]

(1) Exercise price is equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant.

(2) Stock Options granted from 2020 onwards vest over 4 years with a term of 8 years. Stock Options that were granted prior to 2020 vest over 5 years with a term of 10 years.

(3) Based on achieving certain performance criteria.

(4) Issued from Treasury.

(5) Purchased on the secondary market.

STOCK OPTION PLAN

Information about the options outstanding and exercisable at December 31 is summarized below.

	2021		2020	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
Options authorized for grant	**12,800,000**		12,800,000	
Options available for issuance	**2,905,900**		3,240,200	
Outstanding options, beginning of year	1,252,850	$35.26	809,450	$36.91
Granted	**525,000**	**35.75**	488,000	32.09
Exercised	**(62,400)**	**31.97**	(34,800)	28.56
Forfeited	**(190,700)**	**34.72**	(9,800)	37.95
Outstanding options, end of year	**1,524,750**	**$35.63**	1,252,850	$35.26
Options exercisable, end of year	**641,300**	**$36.91**	528,100	$37.32

Options		Outstanding		Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$29.97	4,200	4.0	$29.97	4,200	$29.97
$32.09 - $34.80	532,600	6.7	32.54	184,200	32.93
$35.34 - $39.76	915,850	7.0	37.04	380,900	38.17
$40.78 - $41.54	72,100	3.3	40.81	72,000	40.81
$29.97 - $41.54	1,524,750	6.7	$35.63	641,300	$36.91

Compensation expense related to stock options was $1 million in 2021 (less than $1 million in 2020), with a corresponding increase to contributed surplus.

SHARE APPRECIATION RIGHTS

Information about the share appreciation rights (SARs) outstanding and exercisable at December 31 is summarized below.

	2021		2020	
	SARs	Weighted Average Exercise Price	SARs	Weighted Average Exercise Price
Outstanding SARs, beginning of year	758,850	$37.26	805,950	$36.90
Exercised	**(65,650)**	**32.13**	(37,300)	29.28
Forfeited	**(29,700)**	**38.05**	(9,800)	37.95
Outstanding SARs, end of year	**663,500**	**$37.73**	758,850	$37.26
SARs exercisable, end of year	**535,550**	**$37.84**	522,100	$37.30

SARs		Outstanding		Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$29.97	4,200	4.0	$29.97	4,200	$29.97
$33.07 - $34.80	120,850	5.5	34.02	79,950	33.97
$35.64 - $39.76	466,350	4.5	38.29	379,400	38.17
$40.78 - $41.54	72,100	3.3	40.81	72,000	40.81
$29.97 - $41.54	663,500	4.6	$37.73	535,550	$37.84

In 2021, compensation expense related to SARs was an expense of $1 million (2020 - expense of $1 million). The total carrying value of liabilities arising from SARs at December 31, 2021 was $2 million (2020 - $1 million). The total intrinsic value of all vested SARs at December 31, 2021 and December 31, 2020 was less than $1 million.

STOCK OPTION AND SARS WEIGHTED AVERAGE ASSUMPTIONS

The Company uses the Black-Scholes option pricing model to estimate the weighted average fair value of the stock options and SARs granted. The following weighted average assumptions were used:

		2021		2020
	Options	**SARs** [(2)]	**Options**	**SARs** [(2)]
Class A share price	**$35.75**	**n/a**	$32.09	n/a
Risk-free interest rate	**1.07 %**	**n/a**	0.5 %	n/a
Share price volatility [(1)]	**24.09 %**	**n/a**	22.25 %	n/a
Estimated annual Class A share dividend	**4.89 %**	**n/a**	5.49 %	n/a
Expected holding period prior to exercise	**6.8 years**	**n/a**	6.8 years	n/a

(1) The share price volatility is based on historical data and reflects the assumption that historical volatility over a period similar to the life of the option or SAR is indicative of future trends, which may not necessarily be indicative of exercise patterns that may occur.

(2) No weighted average assumptions are shown for SARs because there were no grants in 2021 or 2020.

MID-TERM INCENTIVE PLAN

Information about the MTIPs outstanding at December 31 is summarized below.

		2021		2020
	MTIPs	**Weighted Average Grant Date Fair Value**	**MTIPs**	**Weighted Average Grant Date Fair Value**
Outstanding MTIPs, beginning of year	445,041	$35.02	579,524	$36.17
Vested	**(29,850)**	**34.38**	(136,933)	38.97
Forfeited [(1)]	**(10,250)**	**34.89**	(341,217)	35.25
Change in unallocated shares [(2)]	**30,961**	**–**	343,667	–
Outstanding MTIPs, end of year	**435,902**	**$35.97**	445,041	$35.02

(1) Forfeitures occur when certain performance criteria are not met.

(2) Unallocated shares are Class A shares held by the trustee which have not been awarded to officers or key employees.

MTIPs			**Outstanding**
Range of Prices	**Number Outstanding**	**Weighted Average Remaining Contractual Life**	**Weighted Average Grant Date Fair Value**
$35.97	21,850	0.6	$35.97
Unallocated shares	414,052	–	–
$35.97	435,902	0.6	$35.97

Compensation expense related to MTIP grants was less than $1 million for 2021 with a corresponding increase to contributed surplus (2020 - credit of $2 million with a corresponding decrease to contributed surplus).

The Company, through a trustee, did not purchase any shares during 2021 to be distributed to employees on vesting of the awards (2020 - nil).

29. CONTINGENCIES

AUC enforcement proceeding

On November 29, 2021, the AUC enforcement branch filed an application with the AUC recommending an enforcement proceeding be initiated. This proceeding is to determine whether ATCO Electric Transmission failed to comply with AUC decisions and enactments under the AUC's jurisdiction with respect to the sole source contract for the Jasper interconnection project and the actions leading up to and including the filing of the 2018-2020 Deferral Account Application. This proceeding will also determine any future remedies that may be required.

AUC Enforcement and Electricity Transmission are pursuing settlement discussions prior to the AUC determining the next process steps. In 2021, the Company recognized expenses of $16 million ($14 million after-tax) related to the proceeding, however, the ultimate outcome of the enforcement proceeding is uncertain and could differ materially from the amount recognized.

Measurement inaccuracies

Measurement inaccuracies occur from time to time on electricity and gas metering facilities. The measurement adjustments relating to the Canadian utilities are settled between the parties according to the Electricity and Gas Inspections Act (Canada) and related regulations. The AUC may disallow recovery of a measurement adjustment if it finds that controls and timely follow-up are inadequate. The measurement adjustments relating to ATCO Gas Australia are reconciled by the market operator and settled between the parties. Recovery of the costs is via a predetermined allowance contained in the current Access Arrangement.

Direct Energy Partnership retail obligation

In 2004, ATCO Gas and ATCO Electric Distribution transferred their retail energy supply businesses to Direct Energy Partnership (Direct Energy). The legal obligations of ATCO Gas and ATCO Electric Distribution for the retail functions transferred to Direct Energy, which include the supply of natural gas and electricity to customers as well as billing and customer care, remain if Direct Energy fails to perform. In certain circumstances, the functions will revert to ATCO Gas and/or ATCO Electric Distribution, with no refund of the transfer proceeds to Direct Energy.

NRG Energy Inc. (NRG), Direct Energy's parent company, provided a $300 million guarantee, supported by a $300 million letter of credit for Direct Energy's obligations to ATCO Gas and ATCO Electric Distribution under the transaction agreements. However, there can be no assurance that the coverage under these agreements will be adequate to defray all costs that could arise if the obligations are not met.

Other

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

30. COMMITMENTS

In addition to commitments disclosed elsewhere in these financial statements, the Company has entered into a number of operating and maintenance agreements and agreements to purchase capital assets. Approximate future undiscounted payments under these agreements are as follows:

	2022	2023	2024	2025	2026	2027 and thereafter
Purchase obligations:						
Operating and maintenance agreements	**338**	**324**	**283**	**51**	**39**	**96**
Capital expenditures	**328**	–	–	–	–	–
Other	**6**	–	–	–	–	–
	672	**324**	**283**	**51**	**39**	**96**

31. RELATED PARTY TRANSACTIONS

TRANSACTIONS WITH PARENT AND AFFILIATE COMPANIES

Transaction	Recorded As	2021	2020
Executive fleet management, rental and other services	Revenues	**13**	11
Administrative expenses, rent expense and licensing fees	Other expenses	**20**	18

At December 31, 2021, accounts receivable and contract assets due from related parties amounted to $90 million (2020 - $96 million) and accounts payable due to related parties amounted to $39 million (2020 - $18 million). These amounts are included in accounts receivable and contract assets and accounts payable and accrued liabilities on the consolidated balance sheets. Receivables and payables with related parties are generally due within 30 days or less from the date of the transaction. The amounts outstanding are unsecured, bear no interest and will be settled in cash. No provisions are held against receivables from related parties.

Purchase of land in 2021

In December 2021, the Company purchased land asset from ATCO Land and Development, an entity under common control of the parent company, for a total consideration of $45 million (see Note 10).

OTHER

In transactions with the Company's joint ventures, the Company recognized revenues of $37 million relating to management fees and other charges (2020 - $20 million).

In transactions with the Company's group pension plans, the Company paid occupancy costs of $5 million relating to property owned by the pension plans (2020 - $7 million).

The Company received $1 million million (2020 - less than $1 million) in retail electricity and natural gas services revenue and incurred less than $1 million (2020 - $1 million) in advertising, promotion and other expenses from entities related through common control.

KEY MANAGEMENT COMPENSATION

Information on management compensation for the year ended December 31 is shown below.

	2021	2020
Salaries and short-term employee benefits	**13**	9
Retirement benefits	**2**	2
Share-based compensation [(1)]	**4**	(3)
	19	8

(1) In 2020, related to certain forfeitures of mid-term incentive plan grants.

Key management personnel comprise members of executive management and the Board, a total of 25 individuals (2020 - 21 individuals).

32. ACCOUNTING POLICIES

PRINCIPLES OF CONSOLIDATION

Subsidiaries are consolidated from the date control is obtained until the date control ends. Control exists where the Company has power over the investee, exposure or rights to variable returns from the investee and the ability to use its power over the investee to affect returns.

All intra-group balances and transactions are eliminated on consolidation.

Interests in subsidiaries owned by other parties are included in NCI. NCI in subsidiaries are identified separately from equity attributable to Class A and Class B owners of the Company. Earnings and each component of OCI are attributed to the Class A and Class B owners of the Company and to NCI, even if this results in the NCI having a deficit balance. Earnings attributable to the Class A and Class B owners are determined after adjusting for dividends on equity preferred shares held by NCI.

Changes in the Company's ownership interests that do not result in a loss of control are accounted for as equity transactions. The carrying amounts of the Company's interest and the NCI are adjusted to reflect the changes in their relative interests in the subsidiaries. Any difference between the amount by which the NCI are adjusted and the fair value of the consideration paid or received is recognized directly in equity and attributed to the Class A and Class B owners of the Company.

JOINT ARRANGEMENTS

A joint arrangement can be classified as either a joint operation or joint venture and represents the contractually agreed sharing of control by two or more parties. A joint operation is an arrangement in which the Company has the rights and obligations to the corresponding assets and liabilities of the arrangement, whereas a joint venture is an arrangement in which the Company has the rights to the net assets of the arrangement.

Joint operations are proportionately consolidated by including the Company's share of assets, liabilities, revenues, expenses and OCI in the respective consolidated accounts.

Joint ventures are equity accounted. Under this method, the Company's interests in joint ventures are initially recognized at cost. The interests are subsequently adjusted to recognize the Company's share of post-acquisition profits or losses, movements in OCI and dividends or distributions received.

The Company's interests in joint ventures are tested for recoverability when events or circumstances indicate a possible impairment. An impairment loss is recognized in earnings when the carrying value of the Company's interest in an individual joint venture is higher than its recoverable amount. The recoverable amount is the higher of fair value less disposal costs and value in use. An impairment loss may be reversed if there is objective evidence that a change in the estimated recoverable amount of the investment is warranted.

BUSINESS COMBINATIONS

Business combinations are accounted for using the acquisition method. Assets acquired and liabilities assumed are measured at their fair value at the acquisition date. Acquisition costs are expensed in the period incurred.

REVENUE RECOGNITION

Revenue is allocated to the respective performance obligations based on relative transaction prices, and is recognized as goods and services are delivered to the customer. Revenue is measured as the amount of consideration expected to be received in exchange for the goods transferred or services delivered. The amount of revenue recognized reflects the time value of money where a significant financing component has been identified.

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

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

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

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

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

Electricity generation and delivery

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

Electricity and natural gas transmission

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

Customer contributions for extensions to plant are recognized as revenue over the life of the related asset.

Electricity and natural gas distribution

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

Customer contributions for extensions to plant are recognized as revenue over the life of the related asset.

Gas storage and transportation

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

Lease revenue

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

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

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

Franchise fees

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

SHORT-TERM EMPLOYEE BENEFITS

Short-term employee benefits are recognized as an expense in salaries, wages and benefits as employees render service. These benefits include wages, salaries, social security contributions, short-term compensated absences, incentives and non-monetary benefits, such as medical care. Costs for employee services incurred in constructing an asset that meet the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

Termination benefits are recognized as an expense in salaries, wages and benefits at the earlier of when the Company can no longer withdraw the offer of those benefits and when the Company recognizes costs for a restructuring that includes the payment of termination benefits. In the case of an offer made to encourage voluntary redundancy, the termination benefits are measured based on the number of employees expected to accept the offer.

INCOME TAXES

Income taxes are the sum of current and deferred taxes. Income tax is recognized in earnings, except to the extent it relates to items recorded in OCI or in equity.

Current tax is calculated on taxable earnings using rates enacted or substantively enacted at the balance sheet date in the jurisdictions in which the Company operates.

The liability method is used to determine deferred income tax on temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred income tax is calculated using the enacted or substantively enacted tax rates that are expected to apply in the period when the liability is settled or the asset is realized. If expected tax rates change, deferred income taxes are adjusted to the new rates.

Deferred income tax assets and liabilities are not recognized if the temporary differences arise from the initial recognition of goodwill or of other assets and liabilities in a transaction, other than a business combination, that does not affect accounting or taxable earnings. The tax effect of temporary differences from investments in subsidiaries and joint arrangements are not accounted for where the Company is able to control the reversal of the temporary differences and it is probable that the temporary differences will not reverse in the foreseeable future.

Deferred income tax assets are recognized only when it is probable that future taxable earnings will be available against which the temporary differences can be applied.

Current income tax assets and liabilities are offset where the Company has the legally enforceable right to offset and the Company intends to either settle on a net basis or realize the asset and settle the liability simultaneously.

Deferred income tax assets and liabilities are offset where the Company has a legally enforceable right to set off tax assets and liabilities, and when the deferred income tax assets and liabilities relate to income taxes levied by the same tax authority.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents consist of cash at bank, bankers' acceptances, certificates of deposit issued or guaranteed by credit worthy financial institutions and federal government issued short-term investments with maturities generally of 90 days or less at purchase.

INVENTORIES

Inventories are valued at the lower of cost or net realizable value. The cost of inventories that are interchangeable is assigned using the weighted average cost method. For inventories that are not interchangeable, cost is assigned using specific identification of their individual costs. Net realizable value is the estimated selling price in the ordinary course of business, less variable selling expenses.

The cost of inventories is comprised of all purchase, conversion and other costs to bring inventories to their present condition and location. Purchase costs consist of the purchase price, import duties, non-recoverable taxes, transport, handling and other costs directly attributable to the purchase of finished goods, materials or services. Conversion costs include direct material and labour costs and a systematic allocation of fixed and variable overheads incurred in converting materials into finished goods.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are recorded at cost less accumulated depreciation and any recognized impairment losses. Cost includes expenditures that are directly attributable to the purchase or construction of the asset, such as materials, labour, borrowing costs incurred during construction, contracted services and asset retirement costs. Subsequent costs are included in the asset's carrying amount or recognized as a separate asset only when it is probable that future economic benefits will flow to the Company and the cost can be measured reliably.

Major overhaul costs are capitalized and depreciated on a straight-line basis over the period to the next major overhaul, which varies from three to eight years. The cost of repair and maintenance activities performed every two years or less which do not enhance or extend the useful life of the asset are expensed when incurred.

Borrowing costs attributable to a construction period of substantial duration are added to the cost of the asset. The effective interest method is used to calculate capitalized interest using specified rates for specific borrowings and a weighted average rate for general borrowings. Interest capitalization starts when borrowing costs and expenditures are incurred at the onset of construction and ends when construction is substantially complete.

The Company allocates the amount initially recognized in property, plant and equipment to its significant components and depreciates each component separately. Assets are depreciated mainly on a straight-line basis over their estimated useful lives. No depreciation is provided on land and construction work-in-progress.

The carrying amount of a replaced asset is derecognized when the cost of replacing the asset is capitalized. When an asset is derecognized, any resulting gain or loss is recorded in earnings.

Depreciation periods for the principal categories of property, plant and equipment are shown in the table below.

	Useful Life	Average Useful Life	Average Depreciation Rate
Utility transmission and distribution:			
Electricity transmission equipment	10 to 67 years	51 years	2.0 %
Electricity distribution equipment	10 to 103 years	43 years	2.3 %
Gas transmission equipment	3 to 57 years	42 years	2.4 %
Gas distribution plant and equipment	3 to 120 years	40 years	2.5 %
Energy infrastructure plant and equipment:			
Gas-fired generation	15 years	14 years	7.4 %
Hydroelectric generation	43 to 50 years	50 years	1.8 %
Solar power generation	10 to 30 years	22 years	4.6 %
Other energy infrastructure	3 to 100 years	36 years	2.8 %
Buildings	10 to 50 years	29 years	3.4 %
Other plant, equipment and machinery	2 to 50 years	16 years	6.1 %

Depreciation methods and the estimated residual values and useful lives of assets are reviewed on an annual basis. Any changes in these accounting estimates are recorded prospectively.

INTANGIBLES

Intangible assets are recorded at cost less accumulated amortization and any recognized impairment losses. The Company amortizes intangible assets on a straight-line basis over their useful lives. Useful life is not longer than 10 years for computer software and between 74 and 80 years for land rights based on the contractual life of the underlying agreements. Software work-in-progress is not amortized as the software is not available for use.

Amortization methods and useful lives of assets are reviewed annually. Any changes in these accounting estimates are recorded prospectively.

IMPAIRMENT OF PROPERTY, PLANT AND EQUIPMENT AND INTANGIBLES

Property, plant and equipment and intangible assets with finite lives are tested for recoverability when events or circumstances indicate a possible impairment. Impairment is assessed at the CGU level, which is the smallest identifiable group of assets that generates independent cash inflows. An impairment loss is recognized in earnings when the CGU's carrying value is higher than its recoverable amount. The recoverable amount is the greater of the CGU's fair value less disposal costs and its value in use. An impairment loss may be reversed in whole or in part if there is objective evidence that a change in the estimated recoverable amount is warranted. A reversal of an impairment loss shall not exceed the carrying amount that would have been determined (net of depreciation) had no impairment loss been recognized for the asset in prior years.

LEASES

The Company as a lessee

At the inception of a contract, the Company assesses whether the contract is, or contains, a lease based on whether the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration.

A right-of-use asset representing the right to use the underlying asset with a corresponding lease liability is recognized when the leased asset becomes available for use by the Company.

The right-of-use asset is recognized at cost and is depreciated on a straight-line basis over the shorter of the estimated useful life of the asset and the lease term on a straight-line basis. The cost of the right-of-use asset is based on the following:

- the amount of initial recognition of related lease liability;
- adjusted by any lease payments made on or before inception of the lease;
- increased by any initial direct costs incurred; and
- decreased by lease incentives received and any costs to dismantle the leased asset.

The lease term includes consideration of an option to extend or to terminate if the Company is reasonably certain to exercise that option. In addition, the right-of-use asset is periodically reduced by impairment losses, if any, and adjusted for certain re-measurements of the lease liability.

Lease liabilities are initially recognized at the present value of the lease payments. The lease payments are discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the Company's incremental borrowing rate. Generally, the Company uses its incremental borrowing rate as the discount rate. Subsequent to recognition, lease liabilities are measured at amortized cost using the effective interest rate method. Lease liabilities are remeasured when there is a change in future lease payments arising mainly from a change in an index or rate, if there is a change in the Company's estimate of the amount expected to be payable under a residual value guarantee, or if the Company changes its assessment of whether it will exercise a purchase, renewal or termination option.

The payments related to short-term leases and low-value leases are recognized as other expenses over the lease term in the consolidated statements of earnings.

The Company as a lessor

A finance lease exists when the terms of the lease transfer substantially all the risks and rewards incidental to ownership of the leased asset to the lessee. Amounts due from lessees under finance leases are recorded as finance lease receivables. They are initially recognized at amounts equal to the present value of the minimum lease payments receivable. Payments that are part of the leasing arrangement are divided between a reduction in the finance lease receivable and finance lease income. Finance lease income is recognized so as to produce a constant rate of return on the Company's investment in the lease and is included in revenues.

ASSETS AND LIABILITIES OF DISPOSAL GROUPS CLASSIFIED AS HELD FOR SALE

Assets and liabilities of disposal groups are classified as held for sale if their carrying amount will be recovered principally through a sale transaction. They are measured at the lower of their carrying value and fair value less costs to sell, except for deferred tax assets, assets arising from employee benefits and financial assets and liabilities that are carried at fair value.

Assets held for sale are not depreciated or amortized while they are classified as held for sale. Interest and other expenses attributable to the liabilities of a disposal group classified as held for sale continue to be recognized.

PROVISIONS

The Company recognizes provisions when:

(i) there is a current legal or constructive obligation as a result of a past event;

(ii) a probable outflow of economic benefits will be required to settle the obligation; and

(iii) a reliable estimate of the obligation can be made.

Current legal or constructive obligations arising from onerous contracts are recognized as provisions when the unavoidable cost of meeting the obligation under the contract exceeds the economic benefits expected to be received.

If the effect is material, provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. If discounting is used, the increase in the provision due to the passage of time is recognized in interest expense.

CONTINGENCIES

A contingent liability is a possible obligation, and a contingent asset is a possible asset, that arises from past events and whose existence will be confirmed only by the occurrence or non-occurrence of one or more uncertain future events not wholly within the control of the Company. A contingent liability may also be a present obligation that arises from past events that is not recognized because it is not probable that an outflow of economic resources will be required to settle the obligation or the amount of the obligation cannot be measured reliably.

Neither contingent liabilities nor assets are recognized in the consolidated financial statements. However, a contingent liability is disclosed, unless the possibility of an outflow of resources is remote. A contingent asset is only disclosed where an inflow of economic benefits is probable.

Management evaluates the likelihood of contingent events based on the probability of exposure to potential loss. Actual results could differ from these estimates.

ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations (AROs) are legal and constructive obligations connected with the retirement of tangible long-lived assets. These obligations are measured at management's best estimate of the expenditure required to settle the obligation and are discounted to present value when the effect is material. Cash flows for AROs are adjusted to take risks and uncertainties into account and are discounted using a pre-tax, risk-free discount rate.

Initially, an ARO is recorded in provisions, included in other liabilities, with a corresponding increase to property, plant and equipment. Subsequently, the carrying amount of the provision is accreted over the estimated time period until the obligation is to be settled; the accretion expense is recognized as interest expense. The asset is depreciated over its estimated useful life. Revaluations of the ARO at each reporting period take into account changes in estimated future cash flows and the discount rate.

FINANCIAL INSTRUMENTS

The Company classifies financial assets when they are first recognized as amortized cost or fair value through profit or loss. Classification is determined based on the Company's business model for managing financial assets and the contractual cash flow characteristics of the financial assets. Financial assets are measured at amortized cost if the financial asset is:

(i) held for the purpose of collecting contractual cash flows, and

(ii) the contractual cash flows of the financial asset solely represent payments of principal and interest.

All other financial assets are classified as fair value through profit or loss.

Financial liabilities are classified as amortized cost or fair value through profit or loss.

Amortized cost

Financial instruments classified as amortized cost are initially measured at fair value and subsequently measured at their amortized cost using the effective interest method.

Fair value through profit or loss

Financial instruments classified as fair value through profit or loss are initially measured at fair value with subsequent changes in fair value recognized in earnings.

Transaction costs

Transaction costs directly attributable to the purchase or issue of financial assets or financial liabilities that are not classified as fair value through profit or loss are added to the fair value of such assets or liabilities when initially recognized. Transaction costs for long-term debt are amortized over the life of the respective financial liability using the effective interest method. The Company's long-term debt and equity preferred shares are presented net of their respective transaction costs.

Offsetting financial instruments

Financial assets and financial liabilities are offset and the net amount is reported in the consolidated balance sheet:

(i) if there is a legally enforceable right to offset the recognized amounts, and

(ii) if the Company intends either to settle on a net basis or to realize the assets and settle the liabilities simultaneously.

Derecognition of financial instruments

Financial assets are derecognized:

(i) when the right to receive cash flows from the financial assets has expired or been transferred, and

(ii) the Company has transferred substantially all the risks and rewards of ownership.

Financial liabilities are derecognized when the obligation is discharged, cancelled, or expired.

Fair value hierarchy

The Company uses quoted market prices when available to estimate fair value. Models incorporating observable market data, along with transaction specific factors, are also used to estimate fair value. Financial assets and liabilities are classified in the fair value hierarchy according to the lowest level of input that is significant to the fair value measurement. Management's judgment as to the significance of a particular input may affect placement within the fair value hierarchy levels.

The hierarchy is as follows:

- Level 1: quoted prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2: inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e., as prices) or indirectly (i.e., derived from prices).
- Level 3: inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The Company applies settlement date accounting to the purchases and sales of financial assets. Settlement date accounting means recognizing an asset on the day it is received by the Company and recognizing the disposal of an asset on the day it is delivered by the Company. Any gain or loss on disposal is also recognized on that day.

IMPAIRMENT OF FINANCIAL INSTRUMENTS

At each reporting date, the Company assesses whether there is evidence that a financial asset or group of financial assets is impaired. If such evidence exists, an impairment loss is recognized in earnings.

Impairment losses on financial assets carried at amortized cost are calculated as the difference between the amortized cost and the present value of estimated future cash flows discounted at the financial asset's original effective interest rate. Impairment losses on financial assets carried at amortized cost may be reversed in whole or in part if there is evidence that a change in the estimated recoverable amount is warranted. The revised recoverable amount cannot exceed the carrying amount that would have been determined had no impairment charge been recognized in previous periods.

The Company applies the expected credit loss allowance matrix based on historical credit loss experience, aging of financial assets, default probabilities, forward-looking information specific to the counterparty, and industry-specific economic outlooks.

For accounts receivable and contract assets and finance lease receivables, the Company estimates credit loss allowances at initial recognition and throughout the life of the receivable. For receivable under service concession arrangement, the Company estimates credit loss allowances from possible default events within the twelve months after the balance sheet date.

DERIVATIVE FINANCIAL INSTRUMENTS

Contracts settled net in cash or in another financial asset are classified as derivatives, unless they meet the Company's own use requirements.

All derivative financial instruments are measured at fair value. The gain or loss that results from changes in fair value of the derivative is recognized in earnings immediately, unless the derivative is designated and effective as a hedging instrument, in which case the timing of recognition in earnings depends on the hedging relationship.

Where the Company elects to apply hedge accounting, the Company documents the relationship between the derivative and the hedged item at inception of the hedge, based on the Company's risk management policies. A qualitative assessment of the effectiveness of the hedging relationship is performed at each reporting period if both the critical terms of the hedging relationship and the economic relationship between the hedged item and hedging instrument continue to remain the same or similar. If the mismatch in terms is significant, a quantitative assessment may be required. Ineffectiveness, if any, is measured at the end of each reporting period.

If the risk management hedge ratio used to form the economic relationship of the hedged item and hedging instrument changes, rebalancing of the hedging relationship is required. Under this circumstance, an adjustment to the quantities of the hedged item or hedging instrument would be allowed to realign the hedging relationship in accordance with the appropriate risk management hedge ratio. The Company can only discontinue hedge accounting prospectively if there is no longer an economic relationship between the hedged item and hedging instrument, the risk management objective changes, the derivative no longer is designated as a hedging instrument, or the underlying hedged item is derecognized.

Cash flow hedges

The Company enters into interest rate swaps, foreign currency forward contracts and natural gas and forward power purchase and sale contracts to offset the risk of volatility in the variable cash flows arising from a recognized asset or liability, a highly probable forecast transaction or a firm commitment in a foreign currency transaction. The effective portion of changes in fair value of the derivative is recognized in OCI, whereas the ineffective portion is recognized in earnings immediately. Sources of hedge ineffectiveness can occur as a result of credit risk, change in hedge ratio, changes in the timing of payment, and forecast adjustments leading to over-hedging. The cumulative gain or loss in AOCI is transferred to earnings when the hedged item affects earnings. If a forecast transaction results in the recognition of a non-financial asset or liability, the amount in AOCI is added to the initial cost of the non-financial asset or liability.

If the Company discontinues hedge accounting, the cumulative gain or loss in AOCI is transferred to earnings at the same time as the hedged item affects earnings.

The amount in AOCI is immediately transferred to earnings if the hedged item is derecognized or it is probable that a forecast transaction will not occur in the originally specified time frame.

RETIREMENT BENEFITS

The Company accrues for its obligations under defined benefit pension and OPEB plans.

Pension plan assets at the balance sheet date are reported at fair value. Accrued benefit obligations at the balance sheet date are determined using a discount rate that reflects market interest rates. The rates are equivalent to those on high quality corporate bonds that match the timing and amount of expected benefit payments.

The cost for defined benefit plans includes net interest expense. This expense is calculated by applying the discount rate to the net defined benefit asset or liability at the beginning of the year plus projected contributions and benefit payments during the year.

Gains and losses resulting from experience adjustments and changes in assumptions used to measure the accrued benefit obligations are recognized in OCI in the period in which they occur. Those gains and losses are then transferred directly to retained earnings.

Employer contributions to the defined contribution pension plans are expensed as employees render service.

For defined benefit pension plans and OPEB plans, service cost is recognized as an expense in salaries, wages and benefits, and net interest expense is recognized in interest expense. The cost of defined contribution pension plans is recognized as an expense in salaries, wages and benefits. Past service costs are recognized immediately in earnings in the period of a plan amendment or curtailment. The change in the present value of the defined benefit pension plans resulting from a curtailment is accounted for as a past service cost. When retirement benefit costs for employee services are incurred in constructing an asset and meet asset recognition criteria, they are included in the related property, plant and equipment or intangible asset.

SHARE-BASED COMPENSATION PLANS

The Company expenses stock options. The Company determines the fair value of the options on the date of grant. The fair value is recognized over the vesting period of the options granted by applying graded vesting, adjusted for estimated forfeitures. The fair value of the options is recorded in salaries, wages and benefits expense and contributed surplus. Contributed surplus is reduced as the options are exercised, and the amount initially recorded in contributed surplus is credited to Class A and Class B share capital.

SARs are cash-settled and are measured at fair value. The fair value is recognized over the vesting period of the SARs granted by applying graded vesting, adjusted for estimated forfeitures. The fair value of SARs is recorded in salaries, wages and benefits expense and accounts payable and accrued liabilities and other non-current liabilities. The liabilities are re-measured at each reporting period.

The MTIP awards are equity-settled with shares purchased on the secondary market. They are measured at fair value based on the purchase price of the Company's Class A non-voting shares at the date of grant. The awards are held by a trust until the shares are vested, at which time they are transferred to the employee. The fair value of the MTIP awards is recognized in salaries, wages and benefits expense over the vesting period, with a corresponding charge to contributed surplus.

RELATED PARTY TRANSACTIONS

Transactions with related parties in the normal course of business are measured at the exchange amount. Transfers of assets or business combinations between entities under common control are measured at the carrying amount.

FOREIGN CURRENCY TRANSLATION

Foreign currency transactions

Transactions denominated in foreign currencies are translated at the exchange rate on the date of the transaction. Monetary assets and liabilities and non-monetary assets and liabilities measured at fair value denominated in a foreign currency are adjusted to reflect the exchange rate at the balance sheet date. Gains or losses on translation of these monetary and non-monetary items are recognized in earnings. Non-monetary items not measured at fair value are not retranslated after they are first recognized.

Foreign operations

The assets and liabilities of subsidiaries whose functional currencies are other than Canadian dollars are translated into Canadian dollars at the exchange rate at the balance sheet date. Revenues and expenses are translated at the average monthly exchange rates during the period, which approximates the foreign exchange rates on the dates of the transactions. Gains or losses on translation are included in OCI.

If the Company disposes of its entire interest in a foreign operation, or loses control, joint control, or significant influence over a foreign operation, the accumulated foreign currency translation gains or losses related to the foreign operation are recognized in earnings.

The exchange rates for the major currencies used in the preparation of the consolidated financial statements were as follows:

	Exchange Rates as at December 31		Average Exchange Rates for Year Ended December 31	
	2021	**2020**	**2021**	**2020**
U.S. dollar	**1.2656**	1.2838	**1.2793**	1.3415
Australian dollar	**0.9200**	0.9726	**0.9164**	0.9247

ACCOUNTING STANDARDS AND INTERPRETATIONS NOT YET ADOPTED

At December 31, 2021, there are no new or amended standards and interpretations that need to be adopted in future periods and will have a significant impact on the Company.

CONSOLIDATED ANNUAL RESULTS [1]

YEAR ENDED DECEMBER 31, 2021

(Millions of Canadian dollars, except as indicated)	**2021**	2020	2019	2018	2017
EARNINGS STATEMENT					
Revenues	**3,515**	3,233	3,905	4,377	4,085
Earnings attributable to equity owners of the Company	**393**	427	951	634	514
Adjusted earnings [2]					
Utilities	**635**	584	575	525	593
Energy Infrastructure	**28**	28	110	156	77
Corporate & Other and eliminations	**(77)**	(77)	(77)	(74)	(68)
Adjusted earnings	**586**	535	608	607	602
BALANCE SHEET					
Cash [3]	**750**	778	977	599	418
Total assets	**21,075**	20,296	20,044	21,819	20,839
Capitalization					
Bank indebtedness	**3**	3	–	–	7
Short-term debt	**206**	–	–	175	–
Long-term debt	**9,308**	9,053	8,966	8,904	8,499
Non-recourse long-term debt	–	–	–	1,401	1,416
Non-controlling interests	**187**	187	187	187	187
Equity attributable to equity owners of the Company	**6,635**	6,621	6,734	6,375	6,153
Capitalization	**16,339**	15,864	15,887	17,042	16,262
CASH FLOW STATEMENT					
Cash flows from operating activities	**1,718**	1,631	1,358	870	1,312
Capital expenditures					
Electricity	**350**	366	389	467	438
Natural Gas	**747**	510	646	622	761
Utilities	**1,097**	876	1,035	1,090	1,199
Energy Infrastructure	**120**	19	88	51	32
Corporate & Other and eliminations	**10**	8	6	16	3
Capital expenditures	**1,227**	903	1,129	1,156	1,234
PER SHARE DATA					
Earnings per share ($)	**1.21**	1.32	3.24	2.08	1.66
Adjusted earnings per share ($) [2]	**2.17**	1.96	2.23	2.24	2.23
Dividends paid per share ($)	**1.76**	1.74	1.69	1.57	1.43
Equity per share ($)	**18.80**	18.83	19.22	17.91	17.23
Class A non-voting closing share price ($)	**36.69**	31.09	39.17	31.32	37.41
Class B common closing share price ($)	**36.61**	31.08	39.00	31.25	37.22

Full disclosure of all financial information is available on the SEDAR website - www.sedar.com.

(1) Financial results have been prepared in accordance with International Financial Reporting Standards (IFRS).

(2) Adjusted earnings are earnings attributable to equity owners of the Company after adjusting for the timing of revenues and expenses associated with rate-regulated activities, dividends on equity preferred shares of the Company, and unrealized gains or losses on mark-to-market forward and swap commodity contracts. Adjusted earnings also exclude one-time gains and losses, impairments and items that are not in the normal course of business or a result of day-to-day operations. The most directly comparable measure to “adjusted earnings” that is reported in accordance with IFRS is “earnings attributable to equity owners of the company”. For additional information regarding these total of segment measures, see “Other Financial and Non-GAAP Measures” and “Reconciliation of Adjusted Earnings to Earnings Attributable to Equity Owners of the Company” in Management’s Discussion and Analysis for the year-ended December 31, 2021, which is available at www.canadianutilities.com, and incorporated by reference herein.

(3) Cash is defined as cash and cash equivalents less current bank indebtedness.

CONSOLIDATED OPERATING SUMMARY

YEAR ENDED DECEMBER 31, 2021

(Millions of Canadian dollars, except as indicated)	**2021**	2020	2019	2018	2017
Utilities					
Electricity distribution and transmission operations					
Capital expenditures	**350**	366	389	467	438
Power lines (thousands of kilometres)	**105**	75	75	75	75
Power lines owned (thousands of kilometres)	**71**	71	71	71	71
Electricity distributed (millions of kilowatt hours)	**12,491**	12,012	12,664	12,928	11,961
Average annual use per residential customer (kWh)	**7,535**	7,528	7,227	7,398	7,325
Average customers during the year (thousands)	**261**	261	260	258	256
Natural gas distribution operations					
Capital expenditures	**385**	307	353	383	464
Pipelines (thousands of kilometres)	**55**	55	55	55	55
Maximum daily demand (terajoules)	**2,476**	2,535	2,304	2,292	2,381
Natural gas distributed (petajoules)	**299**	300	311	304	287
Average annual use per residential customer (gigajoules) for ATCO Gas	**111**	113	112	111	116
Average annual use per residential customer (gigajoules) for ATCO Gas Australia	**14**	13	13	14	14
Average customers during the year (thousands)	**2,036**	2,014	1,989	1,964	1,936
Natural gas transmission operations					
Capital expenditures	**362**	203	293	239	297
Pipelines (thousands of kilometres)	**9**	9	9	9	9
Energy Infrastructure					
Electricity generation operations (1)					
Capital expenditures	**28**	2	59	30	16
Non-regulated generating capacity (megawatts)	**348**	347	344	3,922	3,887
Non-regulated generating capacity owned (megawatts)	**248**	247	244	2,517	2,482
Energy storage & industrial water operations					
Capital expenditures	**92**	17	29	21	16
Natural gas storage capacity (petajoules)	**101**	52	52	52	52
Salt cavern storage capacity (thousands of m^3)	**400**	400	400	400	200
Industrial water infrastructure intake capacity (thousands of m^3/day)	**85**	85	85	85	85

(1) In 2019, the Company closed a series of transactions related to the sale of its Canadian fossil fuel-based electricity generation business. A transaction with Heartland Generation Ltd., an affiliate of Energy Capital Partners, included the sale of 10 partly or fully owned natural gas-fired and coal-fired electricity generation assets located in Alberta and British Columbia. In two other separate transactions, the Company sold its 50 per cent ownership interest in the Cory Cogeneration Station to SaskPower International and its 50 per cent ownership interest in Brighton Beach Power to Ontario Power Generation.

GENERAL INFORMATION

INCORPORATION

Canadian Utilities Limited was incorporated under the laws of Canada on May 18, 1927.

AUDITORS

PricewaterhouseCoopers LLP
Calgary, AB

LEGAL COUNSEL

Bennett Jones LLP
Calgary, AB

STOCK EXCHANGE LISTINGS

Class A non-voting shares – Symbol CU
Class B common shares – Symbol CU.X
Cumulative Redeemable Second Preferred Shares
3.403% Series Y Symbol CU.PR.C
4.90% Series AA Symbol CU.PR.D
4.90% Series BB Symbol CU.PR.E
4.50% Series CC Symbol CU.PR.F
4.50% Series DD Symbol CU.PR.G
5.25% Series EE Symbol CU.PR.H
4.50% Series FF Symbol CU.PR.I
4.75% Series HH Symbol CU.PR.J
Listing: The Toronto Stock Exchange

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Canada T3E 8B4

REGISTRAR & TRANSFER AGENT

Class A non-voting and
Class B common shares and
Second Preferred (Series Y, AA, BB, CC, DD, and EE) Shares
TSX Trust Company
Calgary/Montreal/Toronto/Vancouver

Second Preferred (Series FF and HH) Shares
TSX Trust Company
Calgary/Toronto

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Monday–Friday

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