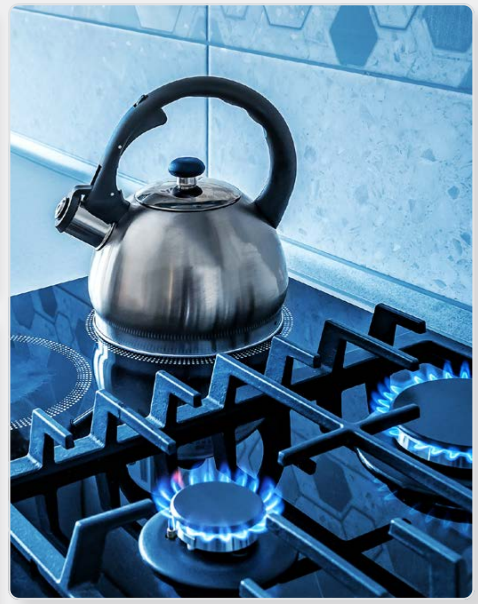
2023 FINANCIAL STATEMENTS AND MANAGEMENT DISCUSSION & ANALYSIS

AltaGas



MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") dated March 7, 2024 is provided to enable readers to assess the results of operations, liquidity, and capital resources of AltaGas Ltd. ("AltaGas", the "Company" or the "Corporation") as at and for the year ended December 31, 2023. This MD&A should be read in conjunction with the accompanying audited Consolidated Financial Statements and notes thereto of AltaGas as at and for the year ended December 31, 2023.

The Consolidated Financial Statements and comparative information have been prepared in accordance with United States ("U.S.") generally accepted accounting principles ("U.S. GAAP") and in Canadian dollars, unless otherwise indicated. Throughout this MD&A, references to GAAP refer to U.S. GAAP and dollars refer to Canadian dollars, unless otherwise indicated.

Abbreviations, acronyms and capitalized terms used in this MD&A without express definition shall have the same meanings given to those terms in the MD&A as at and for the year ended December 31, 2023 or the Annual Information Form for the year ended December 31, 2023.

This MD&A contains forward-looking information ("forward-looking statements"). Words such as "may", "can", "would", "could", "should", "will", "intend", "plan", "anticipate", "believe", "aim", "seek", "propose", "contemplate", "estimate", "focus", "strive", "forecast", "expect", "project", "target", "potential", "objective", "continue", "outlook", "vision", "opportunity" and similar expressions suggesting future events or future performance, as they relate to the Corporation or any affiliate of the Corporation, are intended to identify forward-looking statements. In particular, this MD&A contains forward-looking statements with respect to, among other things, business objectives, expected growth, results of operations, performance, business projects and opportunities and financial results. Specifically, such forward-looking statements included in this document include, but are not limited to, statements with respect to the following: AltaGas' belief in the role and importance of global resource exports; AltaGas' 2024 strategic priorities; AltaGas' belief in the role and importance of the Blythe Energy Center in meeting California's power needs and reliability on the power grid; expected 2024 annual consolidated normalized EBITDA of approximately $1.675 to $1.775 billion; anticipated 2024 normalized earnings per share of approximately $2.05 to $2.25; the expectation that the Utilities segment will contribute approximately 55 percent of normalized EBITDA for 2024; expected growth drivers of normalized EBITDA in the Utilities segment; the expectation that the Midstream segment will contribute approximately 45 percent of normalized EBITDA for 2024; drivers of expected growth in the Midstream segment; expected higher normalized EBITDA from the Corporate/Other segment in 2024; expected growth drivers of 2024 normalized earnings per share; AltaGas' expectation of an active 2024 hedging program and anticipated outcomes therefrom; the Company's ability to deliver on its 2024 guidance; the percentage of AltaGas' expected 2024 frac exposed volumes that are hedged; the percentage of AltaGas' expected 2024 global export volumes that are tolled or financially hedged; AltaGas' 2024 Midstream Hedge Program quarterly estimates; estimated impact of changes in commodity prices, exchange rates, and weather on normalized annual EBITDA; AltaGas' commitment to maintaining a disciplined, self-funded capital program; expected invested capital expenditures of approximately $1.2 billion in 2024; anticipated segment allocation and focus of capital expenditures in 2024; the expectation that the 2024 committed capital program will be funded through internally-generated cash flow, asset sales and normal course borrowings on existing committed credit facilities; the estimated cost, status and expected in-service dates for growth capital projects in the Midstream and Utilities businesses; anticipated annual average capital spending at SEMCO through 2025; AltaGas' pursuit of opportunities and its long-term objectives in the Utilities segment including, among other things, RNG and lower carbon investments, anticipated rate base growth and ensuring energy affordability for its customers; REEF reaching a positive FID, the timing thereof and AltaGas' responsibilities with respect to the construction and operation of REEF; anticipated benefits of the Pipestone Phase II expansion project and the Dimsdale expansion project; anticipated in-service date for MVP and completion date of MVP Southgate; expected timing and outcomes of the Harmattan carbon capture opportunity; AltaGas' pursuit of opportunities and its long-term objectives in the Midstream segment including, among other things, increasing export volumes and throughput, advancing ESG initiatives, goals and opportunities, and mitigating commodity, volume and counterparty risk; expected filing, procedure and decision dates for rate cases in the Utilities business; timing of material regulatory filings, proceedings and decisions in the Utilities business; Washington Gas' ARP *modernization programs and the expected benefits therefrom; proposed expenditures on waste reduction; penalties for breaching merger conditions associated with the WGL acquisition; objectives and expected results from AltaGas' commodity price contract strategies by segment; AltaGas' dividend policy and the dividend rate for 2024; future changes in accounting policies and adoption of new accounting standards; and the expected delivery and in-service date of the VLGCs and the anticipated benefits of the seven-year time charter including reduced shipping costs.*

These statements involve known and unknown risks, uncertainties and other factors that may cause actual results, events and achievements to differ materially from those expressed or implied by such statements. Such statements reflect AltaGas' current expectations, estimates, and projections based on certain material factors and assumptions at the time the statement was made. Material assumptions include: effective tax rate of approximately 21 percent, U.S./Canadian dollar exchange rates; inflation; interest rates, credit ratings, regulatory approvals and policies; expected commodity supply, demand and pricing; volumes and rates; propane price differentials; degree day variance from normal; pension discount rate; financing initiatives; the performance of the businesses underlying each sector; impacts of the hedging program; weather; frac spread; access to capital; future operating and capital costs; timing and receipt of regulatory approvals; seasonality; planned and unplanned plant outages; timing of in-service dates of new projects and acquisition and divestiture activities; taxes; operational expenses; returns on investments; dividend levels; and transaction costs.

AltaGas' forward-looking statements are subject to certain risks and uncertainties which could cause results or events to differ from current expectations, including, without limitation: health and safety risks; operating risks; infrastructure; natural gas supply risks; volume throughput; service interruptions; transportation of petroleum products; market risk; inflation; general economic conditions; cybersecurity, information, and control systems; climate-related risks; environmental regulation risks; regulatory risks; litigation; changes in law; Indigenous and treaty rights; dependence on certain partners; political uncertainty and civil unrest; risks related to conflict, including the conflicts in Eastern Europe and the Middle East; decommissioning, abandonment and reclamation costs; reputation risk; weather data; capital market and liquidity risks; interest rates; internal credit risk; foreign exchange risk; debt financing, refinancing, and debt service risk; counterparty and supplier risk; technical systems and processes incidents; growth strategy risk; construction and development; underinsured and uninsured losses; impact of competition in AltaGas' businesses; counterparty credit risk; composition risk; collateral; rep agreements; market value of the Common Shares and other securities; variability of dividends; potential sales of additional shares; labor relations; key personnel; risk management costs and limitations; commitments associated with regulatory approvals for the acquisition of WGL; cost of providing retirement plan benefits; failure of service providers; risks related to pandemics, epidemics or disease outbreaks; and the other factors discussed under the heading "Risk Factors" in the Corporation's Annual Information Form for the year ended December 31, 2023 ("AIF") and set out in AltaGas' other continuous disclosure documents.

Many factors could cause AltaGas' or any particular business segment's actual results, performance or achievements to vary from those described in this MD&A, including, without limitation, those listed above and the assumptions upon which they are based proving incorrect. These factors should not be construed as exhaustive. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this MD&A as intended, planned, anticipated, believed, sought, proposed, estimated, forecasted, expected, projected or targeted and such forward-looking statements included in this MD&A, should not be unduly relied upon. The impact of any one assumption, risk, uncertainty, or other factor on a particular forward-looking statement cannot be determined with certainty because they are interdependent and AltaGas' future decisions and actions will depend on Management's assessment of all information at the relevant time. Such statements speak only as of the date of this MD&A. AltaGas does not intend, and does not assume any obligation, to update these forward-looking statements except as required by law. The forward-looking statements contained in this MD&A are expressly qualified by these cautionary statements.

Financial outlook information contained in this MD&A about prospective financial performance, financial position, or cash flows is based on assumptions about future events, including economic conditions and proposed courses of action, based on AltaGas Management's assessment of the relevant information currently available. Readers are cautioned that such financial outlook information contained in this MD&A should not be used for purposes other than for which it is disclosed herein.

Additional information relating to AltaGas, including its quarterly and annual MD&A and Consolidated Financial Statements, Annual Information Form, and press releases are available through AltaGas' website at www.altagas.ca or through SEDAR+ at www.sedarplus.ca.

AltaGas Business Overview and Organization

AltaGas is a leading North American energy infrastructure company that connects customers and markets to affordable and reliable sources of energy. The Company operates a diversified, lower-risk, high-growth energy infrastructure business that is focused on delivering resilient and durable value for its stakeholders. AltaGas has three reporting segments - Utilities, Midstream, and Corporate/Other.

Utilities Segment

AltaGas' Utilities segment owns and operates franchised, cost-of-service, rate-regulated natural gas distribution and storage utilities that are focused on providing safe, reliable, and affordable energy to its customers. AltaGas' Utilities provided energy to approximately 1.6 million residential and commercial customers in 2023 with an average rate base of approximately US$5.1 billion.

The Utilities segment includes two utilities that operate across four major U.S. jurisdictions:

- Washington Gas Light Company ("Washington Gas"), which is the Company’s largest operating utility that serves approximately 1.2 million customers across Maryland, Virginia, and the District of Columbia; and
- SEMCO Energy, Inc. ("SEMCO Energy"), which delivers essential energy to approximately 328,000 customers in Southern Michigan and Michigan’s Upper Peninsula.

The Utilities business also includes other storage facilities and contracts for interstate natural gas transportation and storage services, as well as WGL Energy Services, an affiliated retail energy marketing business, which sells natural gas and electricity directly to residential, commercial, and industrial customers located in Maryland, Virginia, Delaware, Pennsylvania, Ohio, and the District of Columbia. AltaGas also previously owned ENSTAR Natural Gas Company and a 65 percent indirect interest in Cook Inlet Natural Gas Storage Alaska ("CINGSA") and other ancillary operations in Alaska, which were divested to TriSummit Utilities Inc. on March 1, 2023 (the "Alaska Utilities Disposition").

Midstream Segment

AltaGas’ Midstream segment is a leading North American platform that connects customers and markets. From wellhead to tidewater, the Company is focused on providing its customers with safe and reliable service and connectivity that facilitates the best outcomes for their businesses. This includes global market access for North American Liquified Petroleum Gases ("LPGs"), which provides North American producers and aggregators with attractive netbacks for propane and butane while delivering diversity of supply and supporting stronger energy security in Asia to AltaGas' downstream customers.

Throughout AltaGas’ Midstream operations, the Company is playing a vital role within the larger energy ecosystem that keeps the global economy moving forward in a safe, reliable, and affordable manner.

AltaGas’ Midstream platform is heavily focused on the Montney and Deep Basin resource plays and centers around global exports, which is where the Company believes the market is headed for Canadian resource development over the long-term. AltaGas also operates a broader set of midstream infrastructure assets across the Western Canadian Sedimentary Basin

("WCSB") and select regions in the U.S., which are all focused on connecting customers and markets in the most efficient manner possible.

There are three core pillars to AltaGas' Midstream platform that are integral to each other and facilitate the Company's wellhead to tidewater value chain. These include:

- Global Exports, which includes AltaGas' two operational LPG export terminals where the Company has capacity to export up to 150,000 Bbl/d of propane and butane to key markets in Asia;
- Natural Gas Gathering, Processing and Extraction, which includes 1.2 Bcf/d of extraction processing capacity and approximately 1.2 Bcf/d of raw field gas processing capacity, which is heavily focused on the Montney and Deep Basin; and
- Fractionation and Liquids Handling platform, which includes 85 MBbl/d of fractionation capacity and a sizable liquids handling footprint.

The Midstream segment also consists of natural gas and NGL marketing businesses, domestic logistics, trucking and rail terminals, and approximately 3.2 million barrels of liquid storage capability through a network of underground salt caverns through the Company's Strathcona Storage JV with ATCO Energy Solutions Ltd., 15 Bcf of natural gas storage through the recently acquired Dimsdale natural gas storage facility ("Dimsdale") in the Alberta Montney, as well as AltaGas' 10 percent interest in the Mountain Valley Pipeline ("MVP").

Corporate/Other Segment

AltaGas' Corporate/Other segment consists of the Company's corporate activities and a small portfolio of gas-fired power generation and distribution assets capable of generating 508 MW of power primarily in California.

Subsidiary Entities

The businesses of AltaGas are operated by the Company and a number of its subsidiaries including, without limitation, AltaGas Services (U.S.) Inc., AltaGas Utility Holdings (U.S.) Inc., WGL Holdings, Inc. ("WGL"), Wrangler 1 LLC, Wrangler SPE LLC, Washington Gas Resources Corp., WGL Energy Services, Inc. ("WGL Energy Services"), and SEMCO Holding Corporation; in regard to the Utilities business, Washington Gas Light Company, Hampshire Gas Company, and SEMCO Energy, Inc.; and in regard to the Midstream business, AltaGas Extraction and Transmission Limited Partnership, AltaGas Pipeline Partnership, AltaGas Processing Partnership, AltaGas Northwest Processing Limited Partnership, Harmattan Gas Processing Limited Partnership, Ridley Island LPG Export Limited Partnership, AltaGas Pacific Partnership, AltaGas LPG Limited Partnership, Petrogas Energy Corporation ("Petrogas"), Petrogas Holdings Partnership, and Petrogas, Inc. In the Corporate/Other segment the main subsidiary is AltaGas Power Holdings (U.S.) Inc. SEMCO Energy conducts its Michigan natural gas distribution business under the name SEMCO Energy Gas Company ("SEMCO").

Fourth Quarter and Full Year 2023 Highlights

(Normalized EBITDA, normalized funds from operations, normalized net income, and net debt are non-GAAP financial measures. Normalized funds from operations per share and normalized net income per share are non-GAAP ratios. Please see Non-GAAP Financial Measures section of this MD&A.)

Financial and Operational Highlights

- Normalized EBITDA was $502 million in the fourth quarter and $1,575 million for the full year of 2023, while income before income taxes was $161 million in the fourth quarter and $912 million for the full year of 2023. Full year normalized EBITDA was in the upper-half of the Company's 2023 guidance range of $1.5 billion to $1.6 billion and included strong performance across the Midstream platform and ongoing enterprise growth.
- Normalized net income per share was $0.76 in the fourth quarter and $1.90 for the full year of 2023, while GAAP net income per share was $0.40 in the fourth quarter and $2.27 for the full year of 2023. Full year normalized net income per share was slightly below the mid-point of the Company's 2023 net income per share guidance range of $1.85 to $2.05, principally due to higher interest costs weighing on strong operating performance across the business.
- Normalized funds from operation per share was $1.33 in the fourth quarter and $4.00 for the full year of 2023, while cash from operations per share was $0.54 in the fourth quarter and $3.98 for the full year of 2023. Normalized funds from operations per share for the quarter increased slightly year-over-year due to higher normalized EBITDA, partially offset by non-cash items included in normalized EBITDA, higher normalized current income tax expense, and higher interest expense.
- The Utilities segment reported normalized EBITDA of $311 million in the fourth quarter of 2023 compared to $294 million in the fourth quarter of 2022, while income before taxes was $207 million in the fourth quarter of 2023 compared to $80 million in the fourth quarter of 2022. The largest drivers of the fourth quarter year-over-year increase in normalized EBITDA were strong contributions from WGL's retail business, lower operating and administrative expenses, continued rate base growth, and the Virginia rate case. These positive factors were partially offset by the Alaska Utilities divestiture, lower asset optimization, and warmer weather in Michigan and the District of Columbia ("DC").
- The Midstream segment reported normalized EBITDA of $182 million in the fourth quarter of 2023 compared to $163 million in the fourth quarter of 2022, while income before taxes in the segment was $79 million in the fourth quarter of 2023 compared to $113 million in the fourth quarter of 2022. The largest drivers of the fourth quarter year-over-year increase in normalized EBITDA included strong performance from the global exports business, Allowance for Funds Used During Construction ("AFUDC") on the MVP project, and the absence of inventory write downs.
- On March 1, 2023, AltaGas closed the Alaska Utilities Disposition for consideration of approximately US$800 million (approximately CAD$1.1 billion) prior to closing adjustments, resulting in a pre-tax gain of approximately $304 million. Sale proceeds were used to reduce debt while providing AltaGas with the financial flexibility to advance its strong growth opportunities across the Midstream and Utilities platforms over the coming years.
- The global exports business shipped 90,996 Bbl/d of liquified petroleum gases ("LPGs") in the fourth quarter of 2023 and an average of 106,071 Bbls/d during 2023 from the Ridley Island Propane Export Terminal ("RIPET") and the Ferndale terminal ("Ferndale"). Although the fourth quarter is a seasonally low quarter for exports, volumes were below internal expectations this quarter due to delayed ship arrivals at both terminals during December 2023, which were loaded in the first quarter of 2024. Despite these timing effects, AltaGas continued to demonstrate the multi-year

growth trajectory since 2019 while connecting the Canadian upstream and Asian downstream markets and driving stronger Canadian industry netbacks.

- On December 22, 2023, AltaGas closed the previously announced acquisition of natural gas processing and storage infrastructure assets in the Pipestone area of the Alberta Montney (the "Pipestone Acquisition"), including the Pipestone natural gas processing facility Phase I ("Pipestone Phase I"), the Pipestone natural gas processing facility Phase II expansion project ("Pipestone Phase II"), the Dimsdale storage facility, and ancillary assets from Tidewater Midstream and Infrastructure Ltd. ("Tidewater"). AltaGas also declared a positive final investment decision ("FID") on Pipestone Phase II with 100 percent of the capacity contracted under long-term take-or-pay agreements.
- AltaGas continued to advance key activities on the Ridley Island Energy Export Facility ("REEF") during and subsequent to the fourth quarter of 2023. This included commencing site clearing work, including logging, clearing, and drainage work that will further solidify the project's readiness to reaching FID, which is expected during the second quarter of 2024.
- In December 2023, AltaGas commissioned the first of two new very large gas carriers ("VLGCs"), the Boreal Pioneer, which made its maiden voyage from Ferndale to Asia in early January 2024. The second VLGC, the Boreal Voyager, was commissioned in February 2024. These two seven-year time charters with optional extensions will reduce and de-risk shipping costs with materially all of AltaGas' expected Baltic freight exposure protected through time charters, financial hedges, and tolled volumes in 2024.
- On October 20, 2023, Washington Gas executed a definitive agreement with Opal Fuels Inc. ("Opal Fuels") to support a renewable natural gas ("RNG") project at the Prince William County Landfill in Virginia. As part of the agreement, Washington Gas will become an offtake customer for RNG production and purchase key interconnect infrastructure for approximately US$25 million and continue to advance long-term climate goals.
- On December 14, 2023, the Public Service Commission of Maryland ("PSC of MD") approved a US$10 million rate increase with a 9.5 percent return on equity and 52 percent equity thickness. The new rates became effective immediately.
- On December 22, 2023, the Public Service Commission of the District of Columbia ("PSC of DC") approved an increase of approximately US$20 million in revenues, net of approximately US$5 million of costs collected through Washington Gas' 40-year accelerated pipeline replacement program ("PROJECTpipes") surcharge. This included a 9.65 percent return on equity and 52 percent equity thickness. The new rates went into effect January 19, 2024.
- On December 5, 2023, AltaGas' Board of Directors approved a 6 percent increase to its annual common share dividends to $1.19 per common share annually ($0.2975 per common share quarterly). This change will be effective for the dividend that will be paid on March 29, 2024.
- On December 5, 2023, AltaGas released its 2023 ESG Report, highlighting 2022 data for key topics and outlining progress towards the Company's sustainability goals within the areas of climate, diversity and inclusion, and safety.
- AltaGas is pleased with the construction progress on MVP. The pipeline is now 99 percent complete and expected to be placed into service in the second quarter of 2024, and will provide critical energy security to customers in the Eastern U.S.
- AltaGas had a series of financings during the fourth quarter, including:

  - On October 19, 2023, Washington Gas issued US$200 million in private placement notes, which includes US$150 million of notes with a 6.06 percent interest rate, maturing on October 14, 2033, and US$50 million of notes at a 6.43 percent interest rate, maturing on October 15, 2053.
  - On November 10, 2023, AltaGas issued $200 million of hybrid 8.90 percent Fixed-to-Fixed Rate Subordinated Notes, Series 3, due November 10, 2083. On December 31, 2023, AltaGas used the proceeds of the hybrid issuance to redeem all of its issued and outstanding Series E Preferred Shares for $25 per Series E Share, together with all accrued and unpaid dividends.
- AltaGas is reiterating the Company's 2024 full year guidance, including normalized EBITDA of $1,675 million to $1,775 million, and normalized net income per share of $2.05 to $2.25.

Highlights Subsequent to 2023 Year End

- On January 8, 2024, AltaGas issued $400 million of senior unsecured medium-term notes with a 4.67 percent coupon, due on January 8, 2029. The net proceeds were used to pay down existing indebtedness under AltaGas' credit facilities (part of which was incurred to fund the debt portion of the Pipestone Acquisition), to fund working capital, and for general corporate purposes.

2024 Outlook

In 2024, AltaGas expects to achieve normalized EBITDA of approximately $1.675 to $1.775 billion, compared to actual normalized EBITDA of $1.58 billion in 2023, and normalized earnings per share of approximately $2.05 to $2.25 compared to actual normalized earnings per share and GAAP net income per share of $1.90 and $2.27 in 2023. For the year ended December 31, 2023, income before income taxes and net income applicable to common shares were $912 million and $641 million, respectively.

The Utilities segment is expected to contribute approximately 55 percent of normalized EBITDA in 2024, with year-over-year growth driven primarily by positive contribution from the continued rate base growth through ongoing capital investments in asset modernization programs on behalf of AltaGas' customers, the DC rate case, normal 2024 weather, and new customer growth, partially offset by the lost contribution from the Alaskan utilities due to the Alaska Utilities Disposition in the first quarter of 2023, and higher operating and administrative expenses associated with a higher inflationary and cost environment. The Midstream segment is expected to contribute approximately 45 percent of normalized EBITDA, with year-over-year expected growth driven primarily by contributions from the Pipestone Acquisition, strong expected global export volumes and margins, higher utilization at the Company's Northeastern B.C. facilities, and the absence of wildfire impacts, partially offset by the absence of the resolution of certain commercial disputes in 2023, and lower co-generation revenue at the Harmattan gas processing facility and extraction plant ("Harmattan"). Normalized EBITDA from the Corporate/Other segment, which includes AltaGas' remaining power assets, is expected to be higher in 2024 mainly due to the impact of higher expected financial performance at Blythe.

The expected variance in normalized earnings per share from $1.90 in 2023 to approximately $2.05 to $2.25 in 2024 is expected to be primarily due to the same factors impacting normalized EBITDA and lower expected preferred share dividends, partially offset by higher expected interest expense, higher depreciation and amortization expense, and higher income tax expense.

The forecasted normalized EBITDA and earnings per share include assumptions around the Canadian/U.S. dollar exchange rate. Within each segment, the performance of the underlying businesses has the potential to vary. Any variance from AltaGas' current assumptions could impact the forecasted normalized EBITDA and normalized earnings per share. For further discussion of the risks impacting AltaGas please refer to the *Risk Factors* section of AltaGas' 2023 Annual Information Form, which is available on SEDAR+ at www.sedarplus.ca.

AltaGas continues to focus on de-risking its business and managing direct commodity price exposure to drive predictable and durable results. While the Company does have exposure, it plans to maintain an active hedging program that proactively hedges commodity price and spread risk to mitigate the impact of fluctuations in margins and cash flows. For 2024, AltaGas has hedged:

- Approximately 90 percent of AltaGas' 2024 expected global export volumes through a combination of tolls and financial hedges with an average FEI to North American financial hedge price of approximately US$18/Bbl for non-tolled propane and butane volumes.
- Approximately 80 percent of its 2024 expected frac exposed volumes hedged at approximately US$27/Bbl, prior to transportation costs.
- Materially all of AltaGas' expected Baltic freight exposure is protected through time charters, financial hedges, and tolled volumes in 2024.

2024 Midstream Hedge Program	Q1 2024	Q2 2024	Q3 2024	Q4 2024	Full Year 2024
Global Exports volumes hedged (%) (1)	99	88	90	84	90
Average propane/butane FEI to North America average hedge (US$/Bbl) (2)	18.47	17.37	16.54	19.24	17.88
Fractionation volume hedged (%) (3)	75	91	91	66	80
Frac spread hedge rate (US$/Bbl) (3)	28.13	27.51	27.51	25.06	27.04

(1) Approximate expected volume hedged. Includes contracted tolling volumes and financial hedges. Based on AltaGas' internally assumed export volumes. AltaGas is hedged at a higher percentage for firmly committed volumes.

(2) Approximate average for the period. Does not include physical differential to FSK for C3 volumes. Butane is hedged as a percentage of WTI.

(3) Approximate average for the period.

Sensitivity Analysis

AltaGas' financial performance is affected by factors such as changes in commodity prices, exchange rates, and weather. The following table illustrates the approximate effect of these key variables on AltaGas' expected normalized EBITDA for 2024:

Factor	Increase or decrease	Approximate impact on normalized annual EBITDA *($ millions)*
Degree day variance from normal - Utilities (1)	5 percent	8
Change in Canadian dollar per U.S. dollar exchange rate (2)	0.05	6
Propane and butane Far East Index to Mont Belvieu spread (3)	US$1/Bbl	23
Pension discount rate	1 percent	2

(1) Degree days – Utilities relate to SEMCO and District of Columbia service areas. Degree days are a measure of coldness determined daily as the numbers of degrees the average temperature during the day in question is below 65 degrees Fahrenheit. Degree days for a particular period are the average of degree days during the prior 15 years for SEMCO and during the prior 30 years for Washington Gas.

(2) The sensitivity is net of hedges on U.S. denominated earnings currently in place. Refer to the *Risk Management* section of this MD&A for more details.

(3) The sensitivity is net of hedges currently in place. The impact on normalized EBITDA due to changes in the spread will vary and is being managed through an active hedging program.

Growth Capital

AltaGas is maintaining a disciplined, equity self-funded capital program, and currently expects to deploy approximately $1.2 billion of invested capital in 2024, compared to actual invested capital of $946 million in 2023. The Utilities segment is expected to account for approximately 58 percent of total 2024 capital expenditures, while the Midstream segment is expected to account for approximately 36 percent, and the Corporate/Other segment will account for the balance. In 2024, AltaGas' capital expenditures for the Utilities segment are expected to focus primarily on maintenance, safety, and reliability programs including system betterment, asset modernization and pipeline replacement programs, and new customer additions. In the Midstream segment, capital expenditures are anticipated to primarily relate to new project development, maintenance and administrative capital, optimization of existing assets, and environmental initiatives. The Corporation continues to focus on capital efficient organic growth and disciplined capital allocation while improving balance sheet strength and flexibility.

AltaGas' 2024 committed capital program is expected to be funded through internally-generated cash flow, opportunistic asset sales, and normal course borrowings on existing committed credit facilities.

Please refer to the *Net Invested Capital* and *Non-GAAP Financial Measures* sections of this MD&A for additional information on the components of AltaGas' invested capital.

Growth Capital Project Updates

The following table summarizes the status of AltaGas' significant growth projects:

Project	AltaGas' Ownership Interest	Estimated Cost [(1)]	Expenditures to Date [(2)]	Project Description and Status	Expected In-Service Date
Midstream Projects					
Pipestone Phase II	100%	$425 million - $450 million	$107 million [(3)]	Pipestone Phase II is a 100 MMcf/d sour deep-cut natural gas processing facility with 20,000 Bbls/d of liquids handling capabilities. The project reached a positive FID in December 2023 and is 100 percent contracted under long-term take-or-pay agreements. The project will be adjacent to Pipestone Phase I, which AltaGas acquired in December 2022, and will be constructed on a fixed price turnkey basis for the majority of the capital costs. The project will begin construction in 2024 and when complete, will deliver critical gas processing and liquids handling capacity in the Pipestone region of Alberta, which is one of the fastest growing liquids-rich natural gas developments in Canada.	2025 Year-end
REEF	50%	Currently undergoing FEED and detailed cost estimations.	$33 million (net of partner recoveries)	REEF is a proposed large-scale LPG and bulk liquids export terminal with supporting marine infrastructure that is planned to be constructed on Ridley Island, British Columbia. The project is being developed by AltaGas and Vopak Development Canada Holdings Inc. ("Vopak") and is planned to be located adjacent to the partners' existing RIPET facility. Should REEF reach a positive FID, the project is planned to be developed and brought online in phases. This approach will provide the most capital efficient build out of the project, match energy export supply with throughput capacity, mitigate the challenges that a large development project can have on the local community, and provide local construction and employment opportunities that would extend over longer time horizons. AltaGas will hold a 50 percent working interest in REEF and will be the project operator with Vopak holding the other 50 percent interest. If a positive FID is made, Phase 1 is anticipated to begin construction in 2024 and will include construction of a new deep water marine jetty with significant capacity for potential future phases. During the fourth quarter of 2023, site clearing work including logging, clearing, and draining activities commenced, that will further solidify the project's readiness to reaching FID, which is expected during the second quarter of 2024.	Site clearing work is underway and FID is expected in the second quarter of 2024.

Project	AltaGas' Ownership Interest	Estimated Cost [(1)]	Expenditures to Date [(2)]	Project Description and Status	Expected In-Service Date
Midstream Projects, continued					
Harmattan Acid Gas Injection Well	100%	$49 million	$46 million	AltaGas is nearing the completion of the Harmattan Acid Gas Injection Well, which is a project that will be capable of capturing up to 60,000 tonnes/year of carbon emissions at AltaGas' Harmattan facility. The project involves decommissioning Harmattan's existing sulfur plant, which significantly reduces the facility's operational complexity and extends the facility's turnaround cycle from 4 years to 5 years, which is expected to result in ongoing cost savings. The acid gas injection well was placed in service in January 2024.	Placed in service in January 2024.
Rolling Hills Carbon Sequestration Hub	50%	Currently undergoing evaluation work	N/A	Rolling Hills is a prospective open-access carbon hub being evaluated by AltaGas and Whitecap Resources Inc. ("Whitecap"). Rolling Hills would be strategically located near AltaGas' Harmattan gas plant and is surrounded by Whitecap's extensive production and geological leadership in Central Alberta. The project is designed to include CO_2 injection wells, carbon storage in underground reservoirs, and various intra-hub pipelines. AltaGas would have a 50 percent interest in the project with Whitecap holding the other 50 percent interest. The project has been awarded carbon sequestration hub evaluation rights with evaluation work progressing.	In-service date to be determined
MVP	10%	US$352 million	US$352 million	MVP is an interstate natural gas pipeline system that spans more than 300 miles from northwestern West Virginia to southern Virginia. The project is owned by a consortium with AltaGas owning a 10 percent equity stake. The project is expected to provide up to 2 Bcf/day of firm transmission capacity to markets in the Mid- and South Atlantic regions of the United States. MVP has a targeted in-service date in the second quarter of 2024. The total project costs are estimated to be US$7.6 billion. AltaGas' exposure is contractually capped to the original estimated contributions of approximately US$352 million.	Second quarter of 2024.

Project	AltaGas' Ownership Interest	Estimated Cost (1)	Expenditures to Date (2)	Project Description and Status	Expected In-Service Date
Midstream Projects, continued					
MVP Southgate Project	5%	US$19 million	US$4 million	The MVP Southgate Project is an interstate natural gas pipeline that will extend MVP by approximately 75 miles from southern Virginia into central North Carolina. The project is owned by a consortium with AltaGas owning a 5 percent equity stake. In December 2023, MVP announced it entered into precedent agreements with two counterparties to collectively provide 550,000 Dth per day of firm capacity commitments for 20-year terms with two potential five-year extensions. The precedent agreements contemplate a redesigned project, which would extend 31-miles from the terminus of MVP in Pittsylvania County, Virginia to planned new delivery points in Rockingham County, North Carolina using a 30-inch diameter pipe, substantially fewer water crossings, and would not require a new compressor station. MVP expects to finalize the redesigned project scope after it conducts an open season and executes any additional agreements for firm capacity. The redesigned MVP Southgate Project is expected to cost approximately US$370 million, of which approximately US$19 million will be AltaGas' portion. In the fourth quarter of 2021, AltaGas impaired its equity investment in the MVP Southgate project to a carrying value of $nil as a result of legal and regulatory challenges the project has encountered.	June 2028 with majority of the spend expected in 2027.
Utilities Projects					
Accelerated Utility Pipe Replacement Programs – ***Washington Gas - District of Columbia***	100%	Estimated US$150 million over the three year period from January 2021 to December 2023 and an additional US$50 million for the 12-month period ending February 2025, plus additional expenditures for subsequent phases upon approval.	US$149 million (4)	The second phase of Washington Gas' accelerated pipe replacement program ("ARP") modernization in D.C. ended in December 2023. On December 22, 2022, Washington Gas filed an application with the PSC of DC for PROJECT*pipes* 3, seeking approval of approximately US$672 million for the five-year period from January 1, 2024 to December 31, 2028. On November 6, 2023, Washington Gas filed a request to extend PROJECT*pipes* 2 through December 31, 2024, while the PSC of DC continues to evaluate the PROJECT*pipes* 3 application. The Office of the People's Counsel for the District of Columbia ("DC OPC") opposed the request, and Washington Gas responded. On December 20, 2023, the PSC of DC held Washington Gas' extension request in abeyance and directed the filing of additional information to justify the extension. On January 4, 2024, Washington Gas filed the requested information. Other parties subsequently filed comments responding to Washington Gas' submission. On February 23, 2024, the PSC of DC granted Washington Gas' request to extend PROJECT*pipes* 2 and the surcharge for 12 months, through February 2025, with a surcharge spending limit of US$50 million. Washington Gas must also file a project list for the extension period within 15 days of the date of the Order. Washington Gas continues to view ARP modernization programs as critical initiatives to ensure the long-term safety and reliability of the network.	Individual assets are placed into service throughout the program and are captured in rate base through rate riders.

Project	AltaGas' Ownership Interest	Estimated Cost (1)	Expenditures to Date (2)	Project Description and Status	Expected In-Service Date
Utilities Projects, continued					
Accelerated Utility Pipe Replacement Programs – ***Washington Gas - Maryland***	100%	Estimated US$350 million over the five year period from January 2019 to December 2023, plus additional expenditures for subsequent phases upon approval.	US$350 million (4)	The second phase of Washington Gas' ARP modernization program in Maryland ("STRIDE 2.0") ended in December 2023. Beginning in March 2022, the PSC of MD has issued orders reducing the Strategic Infrastructure Development Enhancement Plan (STRIDE) surcharge for 2022 and 2023 by 14.7 percent each year. Recovery of STRIDE expenditures not included in this surcharge will be requested through the normal rate-making process. On June 16, 2023, Washington Gas filed an application with the PSC of MD for the third phase of its ARP modernization program ("STRIDE 3"), seeking approval for approximately US$495 million of modernization investments on behalf of customers over the five-year period from January 1, 2024 to December 31, 2028. On October 25, 2023, a public law judge issued a proposed order to approve the STRIDE 3 plan, subject to a reduced number of replacement projects equal to a reduction to the five-year budget by at least one third. On November 13, 2023, Washington Gas notified the PSC of MD that it accepts the order. Two other parties [Maryland Office of People's Counsel ("MD OPC") and Sierra Club] appealed, with Sierra Club arguing for a smaller ARP program. On December 13, 2023, the PSC of MD affirmed the public law judge's proposed order in part, and directed Washington Gas to negotiate the terms of a notice to be sent to impacted customers. On January 10, 2024, the PSC of MD issued a memorandum explaining its December 13, 2023 decision. On February 9, 2024, the MD OPC filed a motion for rehearing with the PSC of MD. Washington Gas filed a response on February 22, 2024 and a PSC of MD decision for rehearing is pending.	Individual assets are placed into service throughout the program and are captured in rate base through rate riders.
Accelerated Utility Pipe Replacement Programs – ***Washington Gas - Virginia***	100%	Estimated US$878 million over the five year period from January 2023 to December 2027, plus additional expenditures for subsequent phases upon approval.	US$150 million (4)	On May 26, 2022, the Commonwealth of Virginia State Corporation Commission ("SCC of VA") approved the proposed amendment for the 2023 to 2027 SAVE Plan with a total five-year spending cap of approximately US$878 million, which may be exceeded by up to 5 percent.	Individual assets are placed into service throughout the program and are captured in rate base through rate riders.

Project	AltaGas' Ownership Interest	Estimated Cost (1)	Expenditures to Date (2)	Project Description and Status	Expected In-Service Date
Utilities Projects, continued					
Accelerated Mains Replacement and Infrastructure Reliability Improvement Programs – ***SEMCO ENERGY - Michigan***	100%	Estimated US$115 million over five year period from 2021 to 2025, plus additional expenditures for subsequent phases upon approval.	US$67 million (4)	A Main Replacement Program ("MRP") was agreed to in SEMCO's last rate case settled in December 2019. The five-year MRP program began in 2021 with a total spend of approximately US$60 million. In addition to the MRP program, SEMCO was also granted an Infrastructure Reliability Improvement Program ("IRIP"), which is also a five-year program with a total spend of approximately US$55 million beginning in 2021.	Individual assets are placed into service throughout the program and are captured in rate base through rate riders.

(1) These amounts are estimates and are subject to change based on various factors. Where appropriate, the amounts reflect AltaGas' share of the various projects.
(2) Expenditures to date reflect total cumulative capital expenditures incurred from inception of the projects to December 31, 2023.
(3) Includes expenditures made prior to acquisition and incurred after the close of the Pipestone Acquisition on December 22, 2023.
(4) The utility accelerated replacement programs are long-term projects with multiple phases for which expenditures are approved by the regulators and managed in multi-year increments. Expenditures to date only include amounts for the current programs described above, and exclude any expenditures made under prior increments of the programs. Actual regulatory filings may differ from reported amounts.

Utilities

Description of Assets

AltaGas owns and operates utilities assets that store and deliver natural gas to residential, commercial, and industrial end-users in Virginia, Maryland, Michigan, and the District of Columbia. Subsequent to the Alaska Utilities Disposition on March 1, 2023, AltaGas' Utilities provide energy to approximately 1.6 million customers with an average rate base of approximately US$5.1 billion.

The Utilities are underpinned by regulated returns and regulatory regimes that generally provide AltaGas with stable earnings and cash flows. The Utilities segment enhances the diversification of AltaGas' portfolio of energy infrastructure assets and strengthens the Corporation's business profile, thus allowing the Corporation to meet its objective of operating a diversified lower-risk, high-growth energy infrastructure business that is focused on delivering resilient and durable value for its stakeholders with long-life assets.

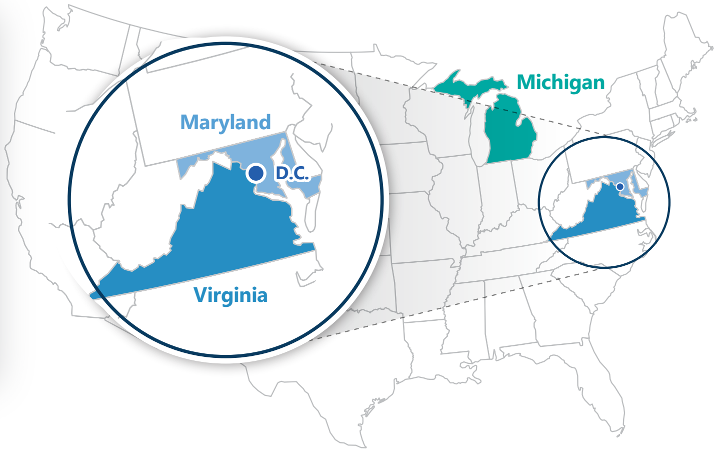
The Utilities segment includes:

- **Washington Gas**, which is a regulated gas utility that operates in Virginia, Maryland, and the District of Columbia;
- **Hampshire Gas**, which provides regulated interstate natural gas storage to Washington Gas;
- **SEMCO**, which is a regulated gas utility that operates in Michigan; and
- **WGL's Retail Marketing** business, which is an unregulated energy platform that sells power and natural gas directly to residential, commercial, and industrial customers in Maryland, Virginia, Delaware, Pennsylvania, Ohio, and the District of Columbia.

AltaGas Utilities

Breakdown		Customers[1]	Rate Base (US$MM)	Allowed ROE
Washington Gas	Maryland	515,000	1,569	9.50%
	Virginia	553,000	1,860	9.65%
	D.C.	165,000	777	9.65%
SEMCO ENERGY	Michigan	328,000	894	9.87%

1) Numbers are rounded/approximate.



All of AltaGas' regulated Utilities are allowed the opportunity to earn regulated returns. This return on rate base is composed of regulator-allowed financing costs and return on equity ("ROE"). If actual costs are different from those recoverable through approved rates, the utility bears the risk of this difference other than for certain costs that are subject to deferral treatment.

Earnings in the Utilities segment are seasonal, as revenues are primarily based on the demand for space heating in the winter months, mainly from November to March. Costs, on the other hand, are generally incurred more uniformly over the year. This typically results in stronger first and fourth quarters and weaker second and third quarters. In Michigan and the District of Columbia, earnings can be impacted by variations from normal weather resulting in delivered gas volumes being different than anticipated. Increases in the number of customers or changes in customer usage are other factors that might typically affect delivered volumes, and hence actual earned returns for the Utilities segment. In Virginia and Maryland, Washington Gas has billing mechanisms in place which are designed to eliminate or mitigate the effects of variance in customer usage caused by weather and other factors such as conservation.

Washington Gas

Washington Gas is a regulated gas utility that distributes natural gas to end users in Virginia, Maryland, and the District of Columbia. At the end of 2023, Washington Gas had approximately 1.2 million customers, of which approximately 94 percent were residential and the balance were commercial and industrial. The number of customers at Washington Gas increased approximately 1 percent in 2023. The average rate base for the year ended December 31, 2023 was approximately US$4.2 billion. At the end of 2023, the approved regulated ROE for Washington Gas in its various jurisdictions ranged from 9.3 - 9.7 percent based on an equity ratio ranging from 52.0 - 52.5 percent.

Washington Gas is regulated by the PSC of DC, the PSC of MD, and the SCC of VA, which approve its terms of service and the billing rates that it charges to customers. The rates charged to Utilities customers are designed to recover Washington Gas' operating expenses and natural gas commodity costs and to provide a return on its investment in the net assets used in its firm gas sales and delivery service.

Washington Gas utilizes ARP modernization programs across all three of its operating jurisdictions. These programs are focused on reducing risk and further enhancing the safety and reliability of the networks. Each regulatory commission with jurisdiction over Washington Gas' customer rates has ARPs with an associated surcharge mechanism to recover the cost, including providing a return on those capital investments. In contrast to the traditional rate-making approach to capital investments, these ARP programs ensure that Washington Gas is receiving recovery for these investments as the programs are executed against over three to five-year approved increments.

Washington Gas’ customers are eligible to purchase their natural gas from unregulated third-party marketers through natural gas unbundling. As at December 31, 2023, approximately 13 percent of its customers have chosen to purchase gas from marketers. This does not negatively impact Washington Gas’ earnings as the Corporation does not earn a margin on the sale of natural gas to firm customers, rather only from the delivery and distribution of the gas.

Washington Gas obtains natural gas supplies that originate from multiple regions throughout the United States. At December 31, 2023, it had service agreements with four pipeline companies that provided firm transportation and storage services with contract expiration dates ranging from 2024 to 2044. Washington Gas has also contracted with various interstate pipeline and storage companies to add to its storage and transportation capacity. Washington Gas, under its asset optimization program, makes use of storage and transportation capacity resources available, when those assets are not required to serve utility customers. The objective of this program is to derive a profit from excess storage and transportation capacity that is shared with its utility customers. These profits are earned by entering into commodity-related physical and financial contracts with third parties and the profits help reduce overall utility costs for Washington Gas' customers.

Hampshire Gas

Hampshire owns underground natural gas storage facilities, including pipeline delivery facilities located in and around Hampshire County, West Virginia, and operates these facilities to serve Washington Gas. Hampshire is regulated by the Federal Energy Regulatory Commission ("FERC"). Washington Gas purchases all of the storage services of Hampshire, and includes the cost of the services in the commodity cost of its regulated energy bills to customers. Hampshire operates under a “pass-through” cost-of-service based tariff approved by FERC.

SEMCO

SEMCO is a regulated gas utility that distributes natural gas to end users in Michigan's southern half of the Lower Peninsula and in the central, eastern, and western parts of the state's Upper Peninsula. At the end of 2023, SEMCO had approximately 320,000 regulated customers, of which approximately 92 percent were residential, and the balance were commercial and industrial. In 2023, SEMCO experienced customer growth of approximately 1 percent reflecting growth in the franchise areas and customer conversions with the favourable price of natural gas compared to other heating sources. The average 2023 rate base was approximately US$894 million. In 2023, the approved regulated ROE for SEMCO was 9.87 percent with an approved capital structure based on 45.86 percent equity, inclusive of the impact of deferred income tax.

SEMCO is regulated by the Michigan Public Service Commission ("MPSC"). It operates under cost-of-service regulation and utilizes actual results from the most recently completed fiscal year along with known and measurable changes in its application for new rates.

SEMCO has an Accelerated MRP surcharge to recover a stated amount of accelerated main replacement capital expenditures in excess of what is authorized in its current base rates. For the years 2021 to 2025, the anticipated annual average capital spending is approximately US$12 million. Any MRP revenue associated with unspent capital will be placed into a regulatory liability account to be addressed in the next general rate base case. Additionally, an IRIP was approved in the 2019 rate case, pursuant to which SEMCO will complete certain projects totaling US$55 million to improve the reliability of infrastructure. Similar to the MRP, any unspent IRIP capital is placed into a regulatory liability account to be addressed in the next general rate base case. At December 31, 2023, there was less than $1 million of underspent IRIP capital.

Retail Energy Marketing

The U.S. retail gas marketing business sells natural gas directly to residential, commercial, and industrial customers in Maryland, Virginia, Delaware, Pennsylvania, and the District of Columbia.

The U.S. retail power marketing business sells power to end users in Maryland, Delaware, Pennsylvania, Ohio, and the District of Columbia. This area is served by the PJM Interconnection ("PJM"), a regional transmission organization that regulates and coordinates generation supply and the wholesale delivery of electricity in these states and jurisdictions.

Natural gas and electricity are purchased with the objective of earning a profit through competitively priced sales contracts with end users. Requirements to serve retail customers is closely matched with commitments for deliveries, and thus, a secured supply arrangement expiring in March 2026 has been entered into with Shell Energy North America (US), L.P, which reduces credit requirements.

Capitalize on Opportunities

AltaGas expects to grow its existing utility infrastructure through continued investment and capital improvements in franchise areas, which will result in rate base growth and continued customer growth including the conversion of users of alternative energy sources to natural gas. AltaGas' utilities have had annual rate base growth averaging approximately 9 percent over the past three years after adjusting for the impact of foreign exchange translation and excluding the impact of asset sales. The growth in rate base is a result of prudent investments in current areas of operations and the addition of new customers. Customer growth rates for AltaGas' utilities are moderate, as is typical with mature utilities, with growth rates generally tied closely to the economic growth of the respective franchise regions.

Midstream

Description of Assets

AltaGas' Midstream segment is a leading North American platform that connects customers and markets. From wellhead to tidewater, the Company is focused on providing its customers with safe and reliable service and connectivity that facilitates the best outcomes for their businesses. This includes global market access for North American LPGs, which provides North American producers and aggregators with attractive netbacks for propane and butane while delivering diversity of supply and supporting stronger energy security in Asia to AltaGas' downstream customers.

Throughout AltaGas' Midstream operations, the Company is playing a vital role within the larger energy ecosystem that keeps the global economy moving forward in a safe, reliable, and affordable manner.

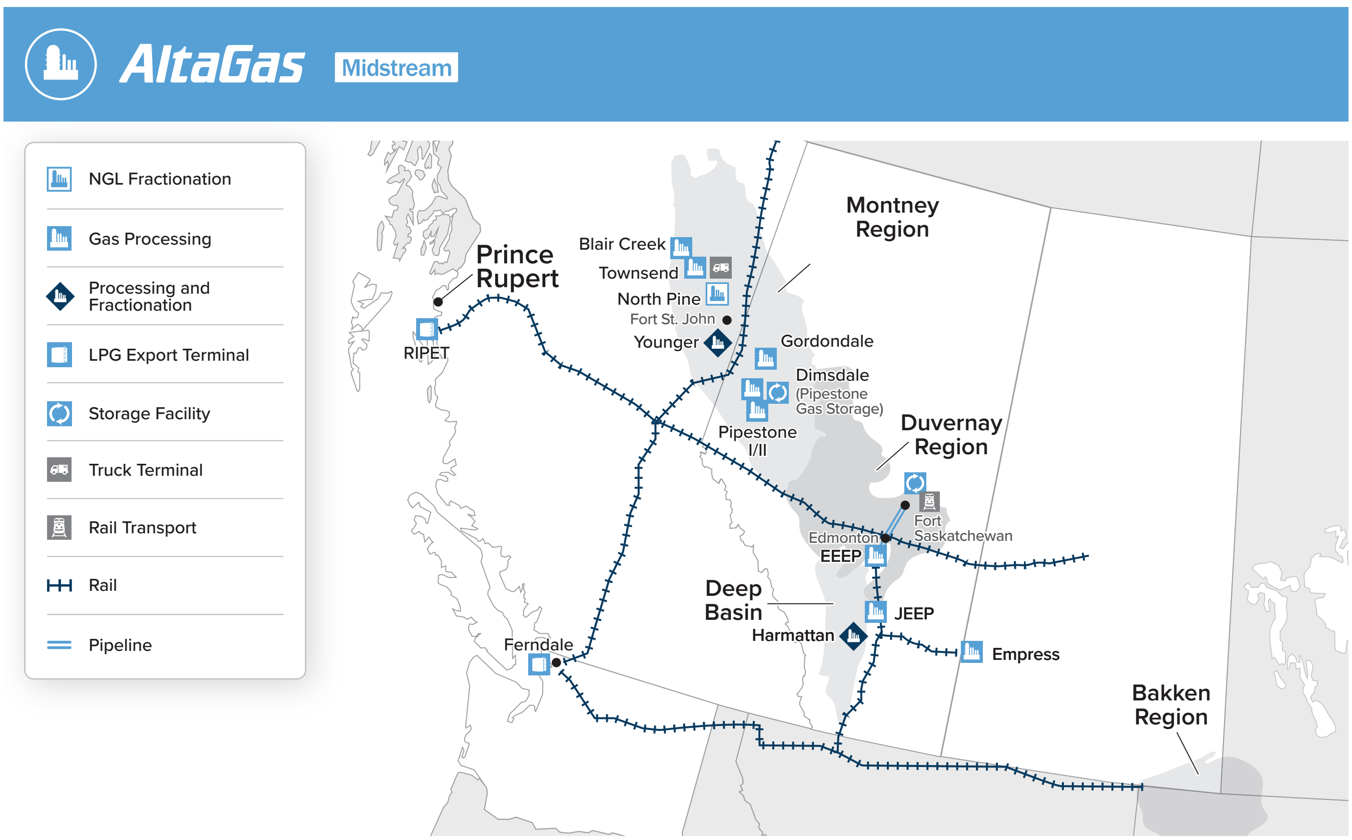
AltaGas' Midstream platform is heavily focused on the Montney and Deep Basin resource plays and centers around global exports, which is where the Company believes the market is headed for Canadian resource development over the long-term. AltaGas also operates a broader set of midstream infrastructure assets across the WCSB and select regions in the U.S., which are all focused on connecting customers and markets in the most efficient manner possible.

There are three core pillars to AltaGas' Midstream platform that are integral to each other and facilitate the Company's wellhead to tidewater value chain. These include:

- **Global Exports**, which includes AltaGas' two operational LPG export terminals where the Company has capacity to export up to 150,000 Bbl/d of propane and butane to key markets in Asia;
- **Natural Gas Gathering, Processing and Extraction**, which includes 1.2 Bcf/d of extraction processing capacity and approximately 1.2 Bcf/d of raw field gas processing capacity, which is heavily focused on the Montney and Deep Basin; and
- **Fractionation and Liquids Handling**, which includes 85 MBbl/d of fractionation capacity and a sizable liquids handling footprint.

The Midstream segment also consists of natural gas and NGL marketing business, domestic logistics, trucking and rail terminals, and approximately 3.2 million barrels of liquid storage capability though a network of underground salt caverns through the Company's Strathcona Storage Joint Venture with ATCO Energy Solutions Ltd, 15 Bcf of natural gas storage through the recently acquired Dimsdale facility, as well as AltaGas' 10 percent interest in MVP, which is nearing completion.

The Midstream segment includes expansion projects under development or construction, as discussed under the *Growth Capital* section of this MD&A.



Global Exports

AltaGas' global export business provides market connectivity for north American LPGs to reach global downstream markets and realize the strongest pricing. The business owns and operates two large-scale operational export terminals and has one proposed new export terminal that is currently undergoing FEED evaluation with expectations of reaching an FID in the second quarter of 2024.

The operational terminals include RIPET, which is located on Ridley Island in Northern B.C. and exclusively exports propane, and the Ferndale terminal, which is located in Washington State and exports propane and butane to key downstream markets. The two facilities have the combined capacity to export up to 150,000 Bbls/d of LPGs and are supported by 1.4 million barrels of onsite LPG storage capacity. Both of these facilities are capable of loading VLGCs, which provide the strongest economies of scale and are the most efficient, safest, and lowest-carbon solution to transporting across the Pacific Ocean. VLGCs are also the most in demand vessels from a destination perspective in key import markets, like Japan and South Korea.

REEF is a proposed large-scale LPG and bulk liquids export terminal with supporting marine infrastructure that is planned to be constructed on Ridley Island in Northern B.C. and will be adjacent to the current RIPET terminal. The project is being developed by AltaGas and Vopak and is proposed to have the capability to export propane and butane in the first phase of development, with bulk liquids, ethane and other products as potential next phases of development. Should REEF reach a positive FID, the project is planned to be developed and brought online in phases. This approach will provide the most capital efficient build out of the project, match energy export supply with throughput capacity, mitigate the challenges that a large development project can have on the local community, and provide local construction and employment opportunities that would extend over longer time horizons. If a positive FID is made, Phase 1 is anticipated to begin construction in 2024 and will include construction of a new deep water marine jetty with significant capacity for potential future phases. During the fourth quarter of 2023, site clearing work, including logging, clearing, and draining activities commenced, which further solidifies the project's readiness to advance the project.

Natural Gas Gathering, Processing and Extraction

Gas gathering and processing activities are comprised of gathering systems that move raw natural gas and NGLs from producing wells to processing facilities, where impurities and certain hydrocarbon components are removed, and the product moves down the energy value chain. The gas is then compressed to meet downstream pipelines' operating specifications for transportation to North American natural gas markets. All of AltaGas' processing facilities are capable of extracting NGLs and converting the throughput into usable products. The facilities provide revenues based on take-or-pay contracts and fee-for-service arrangements with its customers, with the latter based on volumes processed. A significant portion of AltaGas' Midstream contracts flow the Company's operating costs through to the producers. AltaGas' gas gathering, processing, and extraction facilities are as follows:

Natural Gas Gathering, Processing, and Extraction Facilities				
Facility	Location	Interest (%)	Operated / Non-Operated	2023 Licensed Capacity Gas Processing - Net (Mmcf/d)
Townsend	North of Fort St. John, BC	100 %	Operated	550
Pipestone Phase I	Grand Prairie, AB	100 %	Operated	110
Gordondale	Bonanza, AB	100 %	Operated	150
Blair Creek	North of Fort St. John, BC	100 %	Operated	120
JEEP	Joffre, AB	100 %	Operated	250
EEEP	Edmonton, AB	100 %	Operated	390
Empress Pembina ("PEEP")	Empress, AB	11 %	Non-Operated	135
Harmattan	Sundre, AB	100 %	Operated	490
Younger	Taylor, BC	28 %	Non-Operated	213
Total				2,408

AltaGas also owns and operates the Pipestone II facility, for which a positive FID has been made. Pipestone Phase II is a fully permitted, shovel-ready expansion project that will provide an additional 100 MMcf/d of sour deep-cut natural gas processing capacity and an additional 20,000 Bbls/d of liquids handling capabilities.

Fractionation and Liquids Handling

Fractionation production is a function of NGL mix volumes processed, liquids composition, recovery efficiency of the plants, and plant on-line time. Due to the integration and inter-connectivity of AltaGas' Midstream assets, the fractionation and liquids handling activities provide integral services to the other Midstream businesses and customers by providing access to high value NGL products with access to North American and global markets through rail networks, pipelines, RIPET, and Ferndale.

AltaGas' liquids handling infrastructure consists of NGL pipelines, treating, storage, truck, and rail terminal infrastructure centered around AltaGas' key Midstream operating assets at RIPET, Ferndale, Harmattan and, in Northeast British Columbia ("NEBC"), Townsend and North Pine. AltaGas' fractionation and liquids handling business also includes terminals, wellsite fluids and fuels, and trucking.

AltaGas' fractionation and liquids handling facilities are as follows:

Fractionation and Liquids Handling Facilities				
Facility	Location	Interest (%)	Operated / Non-Operated	2023 Licensed Capacity NGL Fractionation - Net (Bbls/d)
Harmattan	Sundre, AB	100 %	Operated	35,000
Younger	Taylor, BC	50 %	Non-Operated	9,750
North Pine	Fort St. John, BC	100 %	Operated	20,000
Pipestone Phase I	Grand Prairie, AB	100 %	Operated	20,000
Total				84,750

Other fractionation and liquids handling infrastructure includes:

- A network of NGL pipelines in the NEBC area that connects upstream gas plant producers to the AltaGas North Pine facility. The NEBC NGL pipelines consist of three liquids egress lines. The third line, which connects the Townsend facility to the Townsend truck terminal on the Alaska Highway (30 km) and AltaGas' North Pine facility (70 km), was commissioned in the third quarter of 2020;

- NGL and spec propane lines that connect the Townsend complex in the North, to the Aitken Creek facilities through the 60 km Aitken Connector NGL pipeline, Canadian Natural Resources Limited's Nig plant through a lateral, and to the Tourmaline Gundy facility in the West through a 15 km spec propane line, were commissioned in the first half of 2020;
- A rail logistics network consisting of more than 4,000 rail cars that AltaGas manages to support LPG and NGL handling.

Terminals and Storage

AltaGas' terminals and storage business provides support to the LPG exports and distribution business by providing the ability to source, transport, process, store, and deliver products through strategically located fixed assets throughout North America. In addition, the business provides various storage and handling services to third-party customers through take-or-pay and fee-for-service agreements, which provide earnings stability through volatile commodity price environments.

The terminals and storage business consists of strategically located crude, NGL, and natural gas assets which provide storage, blending, rail, and truck logistical support and waterborne LPG export capabilities. Significant infrastructure includes:

Terminals

Facility	Location	Interest (%)	Operated / Non-Operated	Operational Capacity LPG/ NGL/Crude - Gross (Bbls/d)	2023 Storage Capacity - Gross (Bbls)
Griffith LPG Terminal	Griffith, IN	100 %	Operated	12,000	700,000
Fort Sask. NGL Terminal	Fort Saskatchewan, AB	100 %	Operated	25,000	180,000
Strathcona Storage JV	Fort Saskatchewan, AB	40 %	Non-Operated	—	3,215,500
Crude Blending Terminals	Various	100 %	Operated	25,700	20,000
Total				62,700	4,115,500

Natural Gas Storage Facilities

Facility	Location	Interest (%)	Operated / Non-Operated	2023 Storage Capacity - Gross (Bcf)
Sarnia Gas Storage	Sarnia, ON	50 %	Non-Operated	5.9
Dimsdale Natural Gas Storage	Grand Prairie, AB	100 %	Operated	15.0

Other terminals and storage infrastructure includes:

- Sarnia Storage and Crude Oil Terminal JV agreement, which provides up to 2.1 million barrels of crude oil and refined product storage capacity with outbound throughput supported by 10,000 Bbls/d of rail loading capacity. The right to access the terminal assets under the joint venture arrangement have been recorded as a lease by AltaGas;
- Three primary trucking entities which AltaGas operates, providing transportation related services within the WCSB and the Pacific Northwest in the U.S. by hauling frac fluid, produced water, crude oil, and NGLs between producers, terminals, customers and end users; and
- Enerchem International Inc., a wholly owned subsidiary of AltaGas, is a Canadian corporation which focuses on the production of drilling and wellsite fluids and consumer fuels. Enerchem operates two primary facilities located in Sundre and Slave Lake, Alberta, which are capable of processing over 1.5 million barrels of finished products per year. These plants are supported by various ancillary storage and distribution facilities located across the WCSB, providing over 150,000 barrels of storage capacity, strategically placed within the vicinity of active drilling regions.

Energy Services

In addition to supporting the other Midstream activities within AltaGas, the logistics business identifies opportunities to buy and resell NGLs for producers, and exchange, reallocate or resell pipeline and storage capacity to earn a profit. Net revenues from these activities are derived from low risk opportunities based on transportation cost differentials between pipeline systems and differences in commodity prices from one period to another. Margins are earned by locking in buy and sell transactions in compliance with AltaGas’ credit and commodity risk policies. AltaGas also provides energy procurement services for utilities gas users and manages the third-party pipeline transportation requirements for many of its gas marketing customers.

AltaGas' marketing business is focused on the purchase, sale, exchange, and distribution of NGLs and crude oil, primarily in proximity to its strategically owned and leased asset base. By leveraging AltaGas' fully integrated infrastructure base and extensive logistical capabilities, the marketing team is able to source competitively priced supply at the key hubs and across various hydrocarbon basins in order to capture arbitrage opportunities derived through regional pricing differentials. Marketing efforts are driven by two primary focuses: 1) domestic NGL and crude oil wholesale, and 2) LPG waterborne exports. AltaGas supports its distribution efforts by maintaining an extensive leased rail fleet. Leases are on a full-service basis and are established on a staggered maturity schedule with multiple lessors to ensure railcar integrity and up-to-date DOT classification.

Pipeline Investments

AltaGas has a 10 percent equity interest in the MVP, which is an interstate natural gas pipeline system that spans more than 300 miles from northwestern West Virginia to southern Virginia. The project is owned by a consortium with AltaGas owning a 10 percent equity stake. The project is expected to provide up to 2.0 Bcf/d of firm transmission capacity to markets in the Mid- and South Atlantic regions of the United States and has throughput expansion opportunities. AltaGas also owns a 5 percent equity stake in the MVP Southgate Project, which is an interstate natural gas pipeline that will extend MVP by approximately 75 miles from Southern Virginia into central North Carolina. The targeted in-service date for MVP is the second quarter of 2024, and the completion date for MVP Southgate is June 2028. Please refer to the Growth Capital section of the MD&A for additional details on MVP and MVP Southgate.

Harmattan Acid Gas Injection Well and Rolling Hills Carbon Capture Project

AltaGas is nearing the completion of the Harmattan Acid Gas Injection well, which is a project that will be capable of capturing up to 60,000 tonnes/year of carbon emissions at the Company’s Harmattan gas plant. The project involves decommissioning Harmattan’s existing sulfur plant, which significantly reduces the facility’s operational complexity and extends the facility’s turnaround cycle from 4 years to 5 years, which is expected to result in ongoing cost savings. The acid gas injection well was placed in service in January 2024.

Rolling Hills is a prospective open-access carbon hub being evaluated by AltaGas and Whitecap and would be strategically located near AltaGas’ Harmattan gas plant and is surrounded by Whitecap’s extensive production and geological leadership in Central Alberta. The project is designed to include CO_2 injection wells, carbon storage in underground reservoirs, and various intra-hub pipelines. AltaGas would have a 50 percent interest in the project with Whitecap Resources holding the other 50 percent interest. The project has been awarded carbon sequestration hub evaluation rights with evaluation work progressing.

Capitalize on Opportunities

To take advantage of opportunities, including the continued Montney LPG growth and the increasing Asian demand for LPG, AltaGas plans to grow its Midstream business by expanding and optimizing strategically-located assets as well as its global export platform. New infrastructure consists of larger scale facilities supporting the vast reserves in North America and growing the footprint and integration of AltaGas' existing assets. While providing safe and reliable service, AltaGas pursues opportunities in the Midstream segment to deliver value to its customers while enhancing long-term shareholder value.

Corporate/Other

Description of Assets

AltaGas' Corporate/Other activities includes all non-operating activities that support AltaGas and are not specifically attributable to the Utilities and Midstream segments. This includes the last remaining assets of AltaGas' former Power segment, including the Blythe Energy Center, a natural gas-fired plant in California with 507 MW of generating capacity (the "Blythe Energy Center" or "Blythe").

Blythe Energy Center is a gas-fired power generation asset that serves the transmission grid operated by the California Independent System Operator ("CAISO") to cover periods of high demand primarily driven by the Los Angeles region. The facility is directly connected to an El Paso Gas Company natural gas pipeline for its primary gas supply and a Southern California Gas Company pipeline as a secondary supply source, and interconnects to Southern California Edison ("SCE") and CAISO via a 67-mile transmission line also owned by Blythe Energy Inc., an indirect wholly-owned subsidiary of AltaGas. In February 2023, AltaGas reached an agreement with SCE for the purchase of resource adequacy attributes from Blythe for the period from January 1, 2024 through December 31, 2027. AltaGas believes this facility is an important asset for California to meet its ongoing power needs and ensuring the reliability of the power grid during peak demand periods.

Consolidated Financial Review

	Three Months Ended December 31		Year Ended December 31	
($ millions, except where noted)	**2023**	2022	**2023**	2022
Revenue	**3,288**	3,898	**12,997**	14,087
Normalized EBITDA (1)	**502**	454	**1,575**	1,537
Income before income taxes	**161**	78	**912**	716
Net income applicable to common shares	**113**	54	**641**	399
Normalized net income (1)(2)	**214**	189	**536**	544
Total assets	**23,471**	23,965	**23,471**	23,965
Total long-term liabilities	**12,195**	12,940	**12,195**	12,940
Invested capital (1)(3)	**290**	326	**946**	948
Cash flows used in investing activities	**(594)**	(336)	**(199)**	(997)
Dividends declared (4)	**79**	75	**316**	298
Cash from (used by) operations	**154**	(289)	**1,121**	539
Normalized funds from operations (1)	**376**	371	**1,128**	1,204
Normalized effective income tax rate (%) (1)(2)	**21.1**	21.5	**20.9**	20.4
Effective income tax rate (%)	**20.5**	15.4	**24.5**	20.0

	Three Months Ended December 31		Year Ended December 31	
($ per share, except shares outstanding)	**2023**	2022	**2023**	2022
Net income per common share - basic	**0.40**	0.19	**2.27**	1.42
Net income per common share - diluted	**0.40**	0.19	**2.26**	1.41
Normalized net income - basic (1)(2)	**0.76**	0.67	**1.90**	1.94
Normalized net income - diluted (1)(2)	**0.75**	0.67	**1.89**	1.92
Dividends declared (4)	**0.28**	0.27	**1.12**	1.06
Cash from (used by) operations	**0.54**	(1.02)	**3.98**	1.92
Normalized funds from operations (1)	**1.33**	1.32	**4.00**	4.28
Shares outstanding - basic (millions)				
During the period (5)	**283**	282	**282**	281
End of period	**295**	282	**295**	282

(1) Non-GAAP financial measure; see discussion in the *Non-GAAP Financial Measures* section of this MD&A.

(2) In the fourth quarter of 2023, AltaGas changed its non-GAAP policy to exclude the impact of unrealized foreign exchange losses (gains) on intercompany balances between Canadian and U.S. entities. Prior periods have been restated to reflect this change. Please refer to the *Non-GAAP Financial Measures* section of this MD&A for additional details.

(3) In the fourth quarter of 2023, AltaGas changed its non-GAAP policy to exclude cash paid for business acquisitions and for the purchase of remaining non-controlling interest in a subsidiary from invested capital. Prior periods have been restated to reflect this change.

(4) Dividends declared per common share per quarter: $0.265 per share beginning March 2022, increased to $0.28 per share beginning March 31, 2023, increased to $0.2975 per share beginning March 31, 2024.

(5) Weighted average.

Three Months Ended December 31

Normalized EBITDA for the fourth quarter of 2023 was $502 million, compared to $454 million for the same quarter in 2022. The largest positive impact was from the Midstream segment, followed by the Utilities and Corporate/Other segments.

In the Midstream segment, normalized EBITDA was positively impacted by higher profitability from the global exports business, including hedging gains, AFUDC at MVP as a result of the resumption of construction activities in June 2023, stronger marketing profitability due to the absence of the 2022 write down of natural gas storage inventory to its net realizable value, and lower operating and administrative expenses in the quarter. These factors were partially offset by the absence of the favourable resolution of certain acquisition related commercial disputes and contingencies in the fourth quarter of 2022, lower profitability at the extraction facilities driven by lower frac spreads, third party pipeline restrictions, and lower power revenue at Harmattan primarily driven by lower power prices.

In the Utilities segment, factors positively impacting normalized EBITDA included higher contribution from WGL's retail marketing business, customer growth, higher rate base from ongoing ARP modernization investments, foreign exchange hedge gains, contribution from Washington Gas' 2022 Virginia rate case, and lower operating and administrative expenses. These factors were partially offset by the impact of the Alaska Utilities Disposition, decreased asset optimization activities at Washington Gas relative to the larger-than-normal contribution in the fourth quarter of 2022, and warmer weather in Michigan and the District of Columbia where the Utilities do not have weather normalization and decoupled rate structures.

In the Corporate/Other segment, normalized EBITDA was positively impacted by lower personnel-related expenses and lower corporate operating and administrative expenses.

For the three months ended December 31, 2023, the average Canadian/U.S. dollar exchange rate increased to 1.362 from an average of 1.358 in the same quarter of 2022, resulting in an increase in normalized EBITDA of less than $1 million.

Income before income taxes for the fourth quarter of 2023 was $161 million, compared to $78 million for the same quarter in 2022. The increase was mainly due to lower unrealized losses on risk management contracts, the same previously referenced factors impacting normalized EBITDA, and the absence of provisions on assets, partially offset by higher foreign exchange losses and costs related to the CEO transition and other restructuring initiatives that took place in 2023. Net income applicable to common shares for the fourth quarter of 2023 was $113 million ($0.40 per share), compared to $54 million ($0.19 per share) for the same quarter in 2022. The increase was primarily due to the same previously referenced factors impacting income before income taxes, partially offset by higher income tax expense and the loss on the redemption of the Series E Preferred Shares on December 31, 2023.

Normalized funds from operations for the fourth quarter of 2023 was $376 million ($1.33 per share), compared to $371 million ($1.32 per share) for the same quarter in 2022. The increase was mainly due to the same previously referenced factors impacting normalized EBITDA, partially offset by the impact of non-cash items included in normalized EBITDA, higher normalized current income tax expense, and higher interest expense.

Cash from operations for the fourth quarter of 2023 was $154 million ($0.54 per share), compared to cash used by operations of $289 million ($1.02 per share) for the same quarter in 2022. The increase was mainly due to favourable variances in the net change in operating assets and liabilities, primarily as a result of fluctuations in commodity prices and sales volumes, partially offset by lower net income after taxes (after adjusting for non-cash items). Please refer to the *Liquidity* section of this MD&A for further details on the variance in cash from operations.

In the fourth quarter of 2022, AltaGas recorded pre-tax provisions on assets of approximately $6 million ($5 million after-tax) primarily related to the abandoned Alton natural gas storage projects as a result of updated reclamation cost estimates.

Operating and administrative expense for the fourth quarter of 2023 was $427 million, compared to $396 million for the same quarter in 2022. The increase was mainly due to the absence of acquisition related contingencies, partially offset by the impact of the Alaska Utilities Disposition. Depreciation and amortization expense for the fourth quarter of 2023 was $110 million, compared to $112 million for the same quarter in 2022. The decrease was due to the impact of the Alaska Utilities Disposition, partially offset by the impact of new assets placed in-service. Interest expense for the fourth quarter of 2023 was $101 million, compared to $99 million for the same quarter in 2022. The increase was due to $3 million of incremental hybrid interest costs compared to the same quarter in 2022 due to hybrid notes replacing preferred shares. Excluding the impact of shifting the financing costs between preferred shares and hybrid notes, interest costs were relatively comparable. For the three months ended December 31, 2023, AltaGas recorded total interest expense of $11 million on the subordinated hybrid notes, which previously would have been captured in preferred share dividends.

AltaGas recorded income tax expense of $33 million for the fourth quarter of 2023 compared to $12 million in the same quarter in 2022. The increase in income tax expense was mainly due to an increase in income before income taxes in the fourth quarter of 2023 compared to the same quarter in 2022.

Normalized net income was $214 million ($0.76 per share) for the fourth quarter of 2023, compared to $189 million ($0.67 per share) reported for the same quarter in 2022. The increase was mainly due to the same factors impacting normalized EBITDA, partially offset by higher foreign exchange losses and higher normalized income tax expense. Normalizing items in the fourth quarter of 2023 increased normalized net income by $101 million and included after-tax amounts related to unrealized losses on risk management contracts, CEO transition and other restructuring costs, transaction costs related to acquisitions and dispositions, unrealized foreign exchange losses on intercompany balances, and loss on redemption of preferred shares. Normalizing items in the fourth quarter of 2022 increased normalized net income by $135 million and included after-tax amounts related to transaction costs related to acquisitions and dispositions, provisions on assets, unrealized foreign exchange losses on intercompany balances, and unrealized losses on risk management contracts. Please refer to the *Non-GAAP Financial Measures* section of this MD&A for further details on normalization adjustments.

Year Ended December 31

Normalized EBITDA for the year ended December 31, 2023 was $1,575 million, compared to $1,537 million in 2022, with the largest positive impact coming from the Midstream segment.

In the Midstream segment, normalized EBITDA was positively impacted by higher earnings from the export facilities, AFUDC at MVP, the absence of the 2022 write down of natural gas storage inventory to its net realizable value, the favourable resolution of certain acquisition related commercial disputes and contingencies, and other smaller factors. These were partially offset by the absence of turnaround recoveries in the third quarter of 2022, the impact of the sale of AltaGas' interest in the Aitken Creek processing facilities in the second quarter of 2022, lower inventory withdrawals, lower earnings at the extraction facilities driven by lower frac spreads, higher operating costs within the global export business, downtime from turnarounds at the extraction facilities in the third quarter of 2023, and lower marketing contribution.

In the Utilities segment, factors positively impacting normalized EBITDA included the impact of a higher average Canadian/U.S. dollar exchange rate, contribution from the 2022 Virginia rate case, higher revenue from ARP modernization investment, the gain resulting from the partial debt defeasance associated with the Alaska Utilities Disposition in the first quarter of 2023 (please refer to Note 15 of the Consolidated Financial Statements as at and for the year ended December 31, 2023 for further details), customer growth, and foreign exchange hedge gains. These factors were more than offset by the impact of the Alaska Utilities Disposition, decreased asset optimization activities at Washington Gas relative to the larger-than-normal contribution in 2022, warmer weather in Michigan and the District of Columbia where the utilities do not have weather normalization and rate decoupling, higher operating and administrative expenses, and lower contributions from WGL's retail marketing business.

Factors that positively impacted the Corporate/Other segment normalized EBITDA included lower corporate operating and administrative expenses and lower personnel related expenses, partially offset by lower contributions from Blythe.

For the year ended December 31, 2023, the average Canadian/U.S. dollar exchange rate increased to 1.35 from an average of 1.30 in 2022, resulting in an increase in normalized EBITDA of approximately $34 million.

Income before income taxes for the year ended December 31, 2023 was $912 million, compared to $716 million in 2022. The increase was mainly due to higher pre-tax gains on dispositions of assets, including the gain on the Alaska Utilities Disposition and additional proceeds received due to contract contingencies on the sale of the Goleta energy storage development in Goleta, California ("Goleta") that was divested in the first quarter of 2022, as well as the same previously referenced factors impacting normalized EBITDA, and the absence of provisions on assets, partially offset by higher interest expense, higher transaction costs related to acquisitions and dispositions, higher unrealized losses on risk management contracts, CEO transition and other restructuring costs incurred in 2023, and higher foreign exchange losses. Net income applicable to common shares for the year ended December 31, 2023 was $641 million ($2.27 per share), compared to $399 million ($1.42 per share) in 2022. The increase was mainly due to the same previously referenced factors impacting income before income taxes, lower loss on the redemption of preferred shares, lower net income applicable to non-controlling interests, and lower preferred share dividends, partially offset by higher income tax expense.

Normalized funds from operations for the year ended December 31, 2023 was $1,128 million ($4.00 per share), compared to $1,204 million ($4.28 per share) in 2022. The decrease was mainly due to higher interest expense and the impact of non-cash items included in normalized EBITDA, partially offset by the same factors impacting normalized EBITDA and lower normalized current income tax expense.

Cash from operations for the year ended December 31, 2023 was $1,121 million ($3.98 per share), compared to $539 million ($1.92 per share) in 2022. The increase was mainly due to favourable variances in the net change in operating assets and liabilities, primarily as a result of fluctuations in commodity prices and sales volumes, partially offset by lower net income after taxes after adjusting for non-cash items. Please refer to the *Liquidity* section of this MD&A for further details on the variance in cash from operations.

In 2023, AltaGas recorded pre-tax gains on dispositions of assets of approximately $319 million which was primarily comprised of the gain on the Alaska Utilities Disposition. Additional proceeds included the favourable settlement of contract contingencies related to the sale of Goleta, and the cash proceeds received from an escrow account related to the 2019 disposition of AltaGas' interest in the Central Penn pipeline ("Central Penn"). In 2022, AltaGas recorded a pre-tax gain on disposition of assets of approximately $3 million.

Operating and administrative expense for the year ended December 31, 2023 was $1,579 million, compared to $1,568 million in 2022. The increase was due to a number of factors, including higher operating and administrative expense at the Utilities, the impact of the higher average Canadian/U.S. dollar exchange rate, and higher operating costs within the global exports business, partially offset by the impact of the Alaska Utilities Disposition, lower operating costs at the extraction facilities and trucking business, the favourable resolution of select commercial disputes and contingencies, lower corporate operating and administrative expenses, and lower expenses related to employee incentive plans. Depreciation and amortization expense for the year ended December 31, 2023 was $441 million, compared to $439 million in 2022. The increase was mainly due to new assets placed in-service, partially offset by the impact of the Alaska Utilities Disposition. Interest expense for the year ended December 31, 2023 was $394 million, compared to $330 million in 2022. The increase was due to higher average interest rates, higher average debt balances, $15 million of incremental hybrid interest costs due to hybrid notes replacing preferred shares, and a higher average Canadian/U.S. dollar exchange rate. For the year ended December 31, 2023, AltaGas recorded total interest expense of $37 million on the subordinated hybrid notes, which previously would have been captured in preferred share dividends.

AltaGas recorded income tax expense of $223 million for the year ended December 31, 2023 compared to $143 million in 2022. The increase in tax expense was mainly due to higher income before income taxes and the tax impact of the Alaska Utilities Disposition. Current tax expense of $43 million was recorded for the year ended December 31, 2023, compared to current tax expense of $23 million in 2022. The increase in current tax expense was mainly due to the tax impact of the Alaska Utilities Disposition in the first quarter of 2023.

Normalized net income was $536 million ($1.90 per share) for the year ended December 31, 2023, compared to $544 million ($1.94 per share) in 2022. The decrease was mainly due to higher interest expense, higher foreign exchange losses, and higher accretion expense, partially offset by the same previously referenced factors impacting normalized EBITDA, lower net income applicable to non-controlling interests, lower preferred share dividends, and lower normalized income tax expense. Normalizing items in the year ended December 31, 2023 reduced normalized net income by $105 million and included after-tax amounts related to gains on the sale of assets, unrealized losses on risk management contracts, transaction costs related to acquisitions and dispositions, CEO transition and other restructuring costs, unrealized foreign exchange losses on intercompany balances, loss on the redemption of preferred shares, and wind-up of the Canadian defined benefit pension plan. Normalizing items in the year ended December 31, 2022 increased normalized net income by $145 million and included after-tax amounts related to gains on sale of assets, transaction costs related to acquisitions and dispositions, loss on redemption of preferred shares, provisions on assets, reversal of provisions on investments accounted for by the equity method, non-controlling interest portion of non-GAAP adjustments, unrealized foreign exchange losses on intercompany balances, and unrealized losses on risk management contracts.

Non-GAAP Financial Measures

This MD&A contains references to certain financial measures used by AltaGas that do not have a standardized meaning prescribed by GAAP and may not be comparable to similar measures presented by other entities. Readers are cautioned that these non-GAAP measures should not be construed as alternatives to other measures of financial performance calculated in accordance with GAAP. The non-GAAP measures and their reconciliation to GAAP financial measures are shown below. These non-GAAP measures provide additional information that management of AltaGas ("Management") believes is meaningful in describing AltaGas' operational performance, liquidity and capacity to fund dividends, capital expenditures, and other investing activities. The specific rationale for, and incremental information associated with, each non-GAAP measure is discussed below.

References to normalized EBITDA, normalized net income, normalized funds from operations, normalized income tax expense, normalized effective income tax rate, net debt, net debt to total capitalization, invested capital, and net invested capital throughout this MD&A have the meanings as set out in this section.

Change in Composition of Non-GAAP Measures

In the fourth quarter of 2023, Management has changed the composition of certain of AltaGas' non-GAAP measures such that normalized net income now excludes the impact of unrealized intercompany foreign exchange gains (losses) resulting from intercompany balances between a U.S. subsidiary and a Canadian entity, where the foreign exchange impact in the U.S. subsidiary is recorded through gain (loss) on foreign currency translation in the Consolidated Statements of Comprehensive Income and the Canadian entity revaluation is recorded through the foreign exchange gain (loss) line item on the Consolidated Statements of Income. This change was made as a result of Management's assessment that excluding these intercompany foreign exchange impacts from normalized net income is more representative of the Company's ongoing financial performance. Prior period calculations of the relevant non-GAAP measures have been restated to reflect this change. The following table summarizes the impact of this change on the periods presented in this MD&A:

Increase (decrease) as result of change	Three Months Ended December 31		Year Ended December 31	
($ millions, except where noted)	**2023**	2022	**2023**	2022
Normalized net income (1)	**$ 6**	$ 11	**$ 7**	$ 14
Normalized income tax expense	**$ 2**	$ 3	**$ 2**	$ 5
Normalized effective tax rate (%)	**0.1 %**	— %	**— %**	0.2 %

(1) Corresponding per share amounts have also been adjusted.

Normalized EBITDA

		Three Months Ended December 31				Year Ended December 31		
($ millions)		**2023**		2022		**2023**		2022
Income before income taxes (GAAP financial measure)	**$**	**161**	$	78	**$**	**912**	$	716
Add:								
Depreciation and amortization		**110**		112		**441**		439
Interest expense		**101**		99		**394**		330
EBITDA	**$**	**372**	$	289	**$**	**1,747**	$	1,485
Add (deduct):								
Transaction costs related to acquisitions and dispositions [1]		**6**		2		**36**		6
Unrealized losses on risk management contracts [2]		**94**		156		**70**		49
Gains on sale of assets [3]		**—**		—		**(319)**		(3)
CEO transition and other restructuring costs [4]		**15**		—		**22**		—
Wind-up of pension plan [5]		**—**		—		**2**		—
Provisions on assets		**—**		6		**—**		6
Reversal of provisions on investments accounted for by the equity method [6]		**—**		—		**—**		(3)
Accretion expenses		**3**		2		**11**		7
Foreign exchange losses (gains)		**12**		(1)		**6**		(10)
Normalized EBITDA	**$**	**502**	$	454	**$**	**1,575**	$	1,537

(1) Comprised of transaction costs related to acquisitions and dispositions of assets and/or equity investments in the period. These costs are included in the "cost of sales" and "operating and administrative" line items on the Consolidated Statements of Income. Transaction costs include expenses, such as legal fees, which are directly attributable to the acquisition or disposition. Please refer to Notes 3 and 4 of the 2023 Annual Consolidated Financial Statements for further details regarding AltaGas' acquisition and disposition of assets in the period.

(2) Included in the "revenue" and "cost of sales" line items on the Consolidated Statements of Income. Please refer to Note 23 of the 2023 Annual Consolidated Financial Statements for further details regarding AltaGas' risk management activities.

(3) Included in the "other income" line item on the Consolidated Statements of Income. Please refer to Note 4 of the 2023 Annual Consolidated Financial Statements for further details regarding AltaGas' disposition of assets in the period.

(4) Comprised of costs related to the transition of AltaGas' CEO and other restructuring costs. These costs are included in the "operating and administrative" line item on the Consolidated Statements of Income.

(5) Relates to the completion of the wind-up of the Canadian defined benefit pension plan in the second quarter of 2023. The settlement charge is included in the "other income" line on the Consolidated Statements of Income. Please refer to Note 28 of the 2023 Annual Consolidated Financial Statements for further details regarding the wind-up of the pension plan.

(6) Relates to the return of certain costs associated with the Constitution pipeline project as a result of its cancellation in February 2020. The provisions are included in the "income from equity investments" line item on the Consolidated Statements of Income.

EBITDA is a measure of AltaGas' operating profitability prior to how business activities are financed, assets are amortized, or earnings are taxed. EBITDA is calculated from the Consolidated Statements of Income using income before income taxes adjusted for pre-tax depreciation and amortization, and interest expense.

AltaGas presents normalized EBITDA as a supplemental measure. Normalized EBITDA is used by Management to enhance the understanding of AltaGas' earnings over periods, as well as for budgeting and compensation related purposes. The metric is frequently used by analysts and investors in the evaluation of entities within the industry as it excludes items that can vary substantially between entities depending on the accounting policies chosen, the book value of assets, and the capital structure.

Normalized Net Income

($ millions)		Three Months Ended December 31 2023		2022		Year Ended December 31 2023		2022
Net income applicable to common shares (GAAP financial measure)	**$**	**113**	$	54	**$**	**641**	$	399
Add (deduct) after-tax:								
Transaction costs related to acquisitions and dispositions (1)		**5**		1		**27**		4
Unrealized losses on risk management contracts (2)		**74**		118		**54**		39
Gains on sale of assets (3)		**—**		—		**(217)**		(4)
Non-controlling interest portion of non-GAAP adjustments (4)		**—**		—		**—**		5
CEO transition and other restructuring costs (5)		**11**		—		**17**		—
Loss on redemption of preferred shares, including foreign exchange impact (6)		**5**		—		**5**		84
Wind-up of pension plan (7)		**—**		—		**2**		—
Provisions on assets		**—**		5		**—**		5
Reversal of provisions on investments accounted for by the equity method (8)		**—**		—		**—**		(2)
Unrealized foreign exchange losses on intercompany balances (9)		**6**		11		**7**		14
Normalized net income	**$**	**214**	$	189	**$**	**536**	$	544

(1) Comprised of transaction costs related to acquisitions and dispositions of assets and/or equity investments in the period. The pre-tax costs are included in the "cost of sales" and "operating and administrative" line items on the Consolidated Statements of Income. Transaction costs include expenses, such as legal fees, which are directly attributable to the acquisition or disposition. Please refer to Notes 3 and 4 of the 2023 Annual Consolidated Financial Statements for further details regarding AltaGas' acquisition and disposition of assets in the period.

(2) The pre-tax amounts are included in the "revenue" and “cost of sales” line items on the Consolidated Statements of Income. Please refer to Note 23 of the 2023 Annual Consolidated Financial Statements for further details regarding AltaGas' risk management activities.

(3) The pre-tax amounts are included in the "other income" line item on the Consolidated Statements of Income. Please refer to Note 4 of the 2023 Annual Consolidated Financial Statements for further details regarding AltaGas' disposition of assets in the period.

(4) The portion of non-GAAP adjustments applicable to non-controlling interests are excluded in the computation of normalized net income to ensure consistency of normalizations applied to controlling and non-controlling interests. These amounts are included in the “net income applicable to non-controlling interests" line item on the Consolidated Statements of Income.

(5) Comprised of costs related to the transition of AltaGas' CEO and other restructuring costs. The pre-tax costs are included in the “operating and administrative” line item on the Consolidated Statements of Income.

(6) Comprised of losses on the redemption of Series K Preferred Shares on March 31, 2022, the redemption of U.S. dollar denominated Series C Preferred Shares on September 30, 2022 including an associated foreign exchange loss of approximately $69 million, and the redemption of Series E Preferred Shares on December 31, 2023. The loss on redemption of preferred shares is recorded on the "loss of redemption of preferred shares" line on the Consolidated Statements of Income.

(7) Relates to the completion of the wind-up of the Canadian defined benefit pension plan in the second quarter of 2023. The settlement charge is included in the "other income" line on the Consolidated Statements of Income. Please refer to Note 28 of the 2023 Annual Consolidated Financial Statements for further details regarding the wind-up of the pension plan.

(8) Relates to the return of certain costs associated with the Constitution pipeline project as a result of its cancellation in February 2020. The pre-tax provisions are included in the “income from equity investments” line item on the Consolidated Statements of Income.

(9) Relates to unrealized foreign exchange losses (gains) on intercompany accounts receivable and accounts payable balances between a U.S. subsidiary and a Canadian entity, where the impact to the U.S. subsidiary is recorded through accumulated other comprehensive income as a gain (loss) on foreign currency translation, and the impact to the Canadian entity is recorded through the "foreign exchange gains (losses)" line item on the Consolidated Statements of Income. As noted previously in this MD&A, in the fourth quarter of 2023, AltaGas changed its non-GAAP policy to exclude the impact of unrealized foreign exchange losses (gains) on intercompany balances between Canadian and U.S. entities. The amounts presented in this table reflect the restated figures to align with the revised policy.

Normalized net income and normalized net income per share are used by Management to enhance the comparability of AltaGas’ earnings, as it reflects the underlying performance of AltaGas’ business activities.

Normalized Funds From Operations

($ millions)	Three Months Ended December 31 2023	2022	Year Ended December 31 2023	2022
Cash from (used by) operations (GAAP financial measure)	**$ 154**	$ (289)	**$ 1,121**	$ 539
Add (deduct):				
Net change in operating assets and liabilities	**198**	653	**(100)**	650
Asset retirement obligations settled	**3**	5	**15**	10
Funds from operations	**$ 355**	$ 369	**$ 1,036**	$ 1,199
Add (deduct):				
Transaction costs related to acquisitions and dispositions (1)	**6**	2	**36**	6
Current tax expense (recovery) on asset sales (2)	**—**	—	**34**	(1)
CEO transition and other restructuring costs (3)	**15**	—	**22**	—
Normalized funds from operations	**$ 376**	$ 371	**$ 1,128**	$ 1,204

(1) Comprised of transaction costs related to acquisitions and dispositions of assets and/or equity investments in the period. These costs exclude non-cash amounts and are included in the "cost of sales" and "operating and administrative" line items on the Consolidated Statements of Income. Transaction costs include expenses, such as legal fees, which are directly attributable to the acquisition or disposition. Please refer to Notes 3 and 4 of the 2023 Annual Consolidated Financial Statements for further details regarding AltaGas' acquisition and disposition of assets in the period.

(2) Included in the "current income tax expense" line item on the Consolidated Statements of Income.

(3) Comprised of costs related to the transition of AltaGas' CEO and other restructuring costs. These costs are included in the "operating and administrative" line item on the Consolidated Statements of Income.

Normalized funds from operations and funds from operations are used to assist Management and investors in analyzing the liquidity of the Corporation. Management uses these measures to understand the ability to generate funds for capital investments, debt repayment, dividend payments, and other investing activities.

Funds from operations and normalized funds from operations as presented should not be viewed as an alternative to cash from (used by) operations or other cash flow measures calculated in accordance with GAAP.

Normalized Income Tax Expense

($ millions)	Three Months Ended December 31 2023	2022	Year Ended December 31 2023	2022
Income tax expense (GAAP financial measure)	**$ 33**	$ 12	**$ 223**	$ 143
Add (deduct) tax impact of:				
Transaction costs related to acquisitions and dispositions	**1**	1	**9**	2
Unrealized losses on risk management contracts	**20**	38	**16**	10
Gains on sale of assets	**—**	—	**(102)**	1
CEO transition and other restructuring costs	**4**	—	**5**	—
Provisions on assets	**—**	1	**—**	1
Reversal of provisions on investments accounted for by the equity method	**—**	—	**—**	(1)
Unrealized foreign exchange losses on intercompany balances (1)	**2**	3	**2**	5
Normalized income tax expense	**$ 60**	$ 55	**$ 153**	$ 161

(1) As noted previously in this MD&A, in the fourth quarter of 2023, AltaGas changed its non-GAAP policy to exclude the impact of unrealized foreign exchange losses (gains) on intercompany balances between Canadian and U.S. entities. The amounts presented in this table reflect the restated figures to align with the revised policy.

The above table provides a reconciliation of normalized income tax expense from the GAAP financial measure, income tax expense. The reconciling items are comprised of the income tax impacts of normalizing items present in the calculation of normalized net income. For more information on the individual normalizing items, please refer to the normalized net income reconciliation above.

Normalized income tax expense is used by Management to enhance the comparability of the impact of income tax on AltaGas' earnings, as it reflects the underlying performance of AltaGas' business activities, and is presented to provide this perspective to analysts and investors.

Net Debt and Net Debt to Total Capitalization

Net debt and net debt to total capitalization are used by the Corporation to monitor its capital structure and financing requirements. It is also used as a measure of the Corporation's overall financial strength and is presented to provide this perspective to analysts and investors. Net debt is defined as short-term debt, plus current and long-term portions of long-term debt, and subordinated hybrid notes, less cash and cash equivalents. Total capitalization is defined as net debt plus shareholders' equity and non-controlling interests. Additional information regarding these non-GAAP measures can be found under the *Capital Resources* section of this MD&A.

Invested Capital and Net Invested Capital

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2023**	2022	**2023**	2022
Cash used in investing activities (GAAP financial measure)	**$ 594**	$ 336	**$ 199**	$ 997
Add (deduct):				
Net change in non-cash capital expenditures (1)	**26**	(7)	**3**	(6)
AFUDC (2)	**(3)**	(3)	**(3)**	(3)
Net invested capital	**$ 617**	$ 326	**$ 199**	$ 988
Business acquisition (3)	**(327)**	—	**(327)**	—
Purchase of remaining non-controlling interest in a subsidiary	**—**	—	**—**	(285)
Asset dispositions	**—**	—	**1,073**	245
Disposals of equity investments (4)	**—**	—	**1**	—
Invested capital (5)	**$ 290**	$ 326	**$ 946**	$ 948

(1) Comprised of non-cash capital expenditures included in the "accounts payable and accrued liabilities" line item on the Consolidated Balance Sheets. Please refer to Note 31 of the 2023 Annual Consolidated Financial Statements for further details.

(2) AFUDC is the amount that a rate-regulated enterprise is allowed to recover for its cost of financing assets under construction and is included in the "property, plant and equipment" line item on the Consolidated Balance Sheets.

(3) Includes only the cash portion of the total consideration paid for the Pipestone Acquisition, net of cash acquired.

(4) Relates to escrow account proceeds received from AltaGas' previous investment in Central Penn. Upon close of the sale in 2019, various escrow accounts were established to provide the purchaser a form of recourse for the settlement of indemnification obligations.

(5) In the fourth quarter of 2023, AltaGas changed its non-GAAP policy to exclude cash paid for business acquisitions and for the purchase of remaining non-controlling interest in a subsidiary from invested capital. Prior periods have been restated to reflect this change.

Invested capital is a measure of AltaGas' use of funds for capital expenditure activities. It includes expenditures relating to property, plant, and equipment and intangible assets, capital contributed to long term investments, and contributions from non-controlling interests. Net invested capital is invested capital presented net of cash paid for business acquisitions, cash paid for the purchase of remaining non-controlling interest in a subsidiary, and proceeds from disposals of assets and equity investments in the period. Net invested capital is calculated based on the investing activities section in the Consolidated Statements of Cash Flows, adjusted for items such as non-cash capital expenditures, AFUDC, and contributions from non-controlling interests. Invested capital and net invested capital are used by Management, investors, and analysts to enhance the understanding of AltaGas' capital expenditures from period to period and provide additional detail on the Company's use of capital.

Supplemental Calculations

Reconciliation of Normalized EBITDA to Normalized Net Income

The below table provides a supplemental reconciliation of normalized EBITDA to normalized net income. Both of these non-GAAP measures have been previously reconciled to the relevant GAAP financial measures in the section above. This supplemental information is provided as additional information to assist analysts and investors in comparing normalized EBITDA to normalized net income and is not intended as a substitute for the reconciliations to the nearest comparable GAAP measures. Readers should not place undue reliance on this supplemental reconciliation.

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2023**	2022	**2023**	2022
Normalized EBITDA (1)	**$ 502**	$ 454	**$ 1,575**	$ 1,537
Add (deduct):				
Depreciation and amortization	**(110)**	(112)	**(441)**	(439)
Interest expense	**(101)**	(99)	**(394)**	(330)
Income tax expense	**(33)**	(12)	**(223)**	(143)
Normalizing items impacting income taxes (1)	**(27)**	(43)	**70**	(18)
Accretion expenses	**(3)**	(2)	**(11)**	(7)
Foreign exchange gains (losses)	**(12)**	1	**(6)**	10
Unrealized foreign exchange losses on intercompany balances (2)	**8**	14	**9**	19
Non-controlling interest portion of non-GAAP adjustments (3)	**—**	—	**—**	5
Net income applicable to non-controlling interests	**(3)**	(5)	**(16)**	(50)
Preferred share dividends	**(7)**	(7)	**(27)**	(40)
Normalized net income (1) (2)	**$ 214**	$ 189	**$ 536**	$ 544

(1) Represents the income tax expense related to the normalizing items included in the calculation of normalized EBITDA.

(2) As noted previously in this MD&A, in the fourth quarter of 2023, AltaGas changed its non-GAAP policy to exclude the impact of unrealized foreign exchange losses (gains) on intercompany balances between Canadian and U.S. entities. The amounts presented in this table reflect the restated figures to align with the revised policy.

(3) The portion of non-GAAP adjustments applicable to non-controlling interests are excluded in the computation of normalized net income to ensure consistency of normalizations applied to controlling and non-controlling interests. These amounts are included in the “net income applicable to non-controlling interests" line item on the Consolidated Statements of Income.

Calculation of Normalized Effective Income Tax Rate

The below table provides a calculation of normalized effective income tax rate from normalized net income and normalized income tax expense. Both of these non-GAAP measures have been previously reconciled to the relevant GAAP measures in the section above. This supplemental calculation is provided as additional information to assist analysts and investors in comparing normalized income tax expense to normalized net income and is not intended as a substitute for the reconciliations to the nearest comparable GAAP measures. Readers should not place undue reliance on this supplemental calculation.

($ millions, except where noted)		Three Months Ended December 31 2023		2022		Year Ended December 31 2023		2022
Normalized net income [1]	**$**	**214**	$	189	**$**	**536**	$	544
Add (deduct):								
Normalized income tax expense [1][2]		**60**		55		**153**		161
Net income applicable to non-controlling interests		**3**		5		**16**		50
Non-controlling interest portion of non-GAAP adjustments [3]		**—**		—		**—**		(5)
Preferred share dividends		**7**		7		**27**		40
Normalized net income before taxes [1]	**$**	**284**	$	256	**$**	**732**	$	790
Normalized effective income tax rate (%) [1][4]		**21.1**		21.5		**20.9**		20.4

(1) As noted previously in this MD&A, in the fourth quarter of 2023, AltaGas changed its non-GAAP policy to exclude the impact of unrealized foreign exchange losses (gains) on intercompany balances between Canadian and U.S. entities. The amounts presented in this table reflect the restated figures to align with the revised policy.
(2) Calculated in the section above.
(3) The portion of non-GAAP adjustments applicable to non-controlling interests are excluded in the computation of normalized net income to ensure consistency of normalizations applied to controlling and non-controlling interests. These amounts are included in the "net income applicable to non-controlling interests" line item on the Consolidated Statements of Income.
(4) Calculated as normalized income tax expense divided by normalized net income before taxes.

Results of Operations by Reporting Segment

Normalized EBITDA [1] ($ millions)		Three Months Ended December 31 2023		2022		Year Ended December 31 2023		2022
Utilities	**$**	**311**	$	294	**$**	**886**	$	933
Midstream		**182**		163		**684**		607
Sub-total: Operating Segments	**$**	**493**	$	457	**$**	**1,570**	$	1,540
Corporate/Other		**9**		(3)		**5**		(3)
	$	**502**	$	454	**$**	**1,575**	$	1,537

(1) Non-GAAP financial measure; See discussion in the *Non-GAAP Financial Measures* section of this MD&A.

Income (Loss) Before Income Taxes ($ millions)		Three Months Ended December 31 2023		2022		Year Ended December 31 2023		2022
Utilities	**$**	**207**	$	80	**$**	**886**	$	548
Midstream		**79**		113		**460**		526
Sub-total: Operating Segments	**$**	**286**	$	193	**$**	**1,346**	$	1,074
Corporate/Other		**(125)**		(115)		**(434)**		(358)
	$	**161**	$	78	**$**	**912**	$	716

Revenue ($ millions)		Three Months Ended December 31 2023		2022		Year Ended December 31 2023		2022
Utilities	**$**	**1,288**	$	1,725	**$**	**4,827**	$	4,980
Midstream		**1,971**		2,145		**8,069**		9,010
Sub-total: Operating Segments	**$**	**3,259**	$	3,870	**$**	**12,896**	$	13,990
Corporate/Other		**29**		28		**101**		97
	$	**3,288**	$	3,898	**$**	**12,997**	$	14,087

Utilities

Operating Statistics

	Three Months Ended December 31		Year Ended December 31	
	2023	2022	**2023**	2022
Natural gas deliveries - end-use (Bcf) [1]	**48.3**	54.3	**133.5**	164.6
Natural gas deliveries - transportation (Bcf) [1]	**30.5**	34.0	**108.0**	126.9
Service sites (thousands) [2]	**1,560**	1,704	**1,560**	1,704
Degree day variance from normal - SEMCO (%) [3]	**(9.8)**	(1.7)	**(10.6)**	1.2
Degree day variance from normal - ENSTAR (%) [3]	**n/a**	8.7	**(4.9)**	(2.2)
Degree day variance from normal - Washington Gas (%) [3] [4]	**(9.2)**	9.2	**(17.9)**	4.5
Retail energy marketing - gas sales volumes (Mmcf)	**16,863**	18,064	**56,438**	59,302
Retail energy marketing - electricity sales volumes (GWh)	**3,518**	3,328	**14,339**	13,217

(1) Bcf is one billion cubic feet.
(2) Service sites reflect all of the service sites of the utilities, including transportation and non-regulated business lines.
(3) A degree day is a measure of coldness determined daily as the number of degrees the average temperature during the day in question is below 65 degrees Fahrenheit. Degree days for a particular period are determined by adding the degree days incurred during each day of the period. Normal degree days for a particular period are the average of degree days during the prior 15 years for SEMCO, during the prior 10 years for ENSTAR, and during the prior 30 years for Washington Gas. The degree day variance from normal for ENSTAR is for the period prior to the close of the Alaska Utilities Disposition on March 1, 2023.
(4) In certain of Washington Gas' jurisdictions (Virginia and Maryland) there are billing mechanisms in place that are designed to eliminate the effects of variance in customer usage caused by weather and other factors such as conservation. In the District of Columbia, there is no weather normalization billing mechanism nor does Washington Gas hedge to offset the effects of weather. As a result, colder or warmer weather will result in variances to financial results.

Regulatory Metrics

	Year Ended December 31	
	2023	2022
Approved ROE (%) [1]	**9.6**	9.6
Approved return on debt (%) [1]	**4.5**	4.7
Rate base *($ millions)* [2] [3] [4]	**5,100**	5,211

(1) Weighted average of all the regulated utilities.
(2) Rate base is indicative of the earning potential of each utility over time. Approved revenue requirement for each utility is typically based on the rate base as approved by the regulator for the respective rate application, but may differ from the rate base indicated above.
(3) In U.S. dollars.
(4) 2023 rate base excludes ENSTAR and SEMCO Energy's 65 percent interest in CINGSA, which were sold on March 1, 2023 pursuant to the Alaska Utilities Disposition.

During the fourth quarter of 2023, AltaGas' Utilities segment experienced warmer weather at SEMCO and warmer weather at Washington Gas compared to the same quarter of 2022.

For the year ended December 31, 2023, AltaGas' Utilities segment experienced warmer weather at SEMCO, warmer weather at ENSTAR prior to the close of the Alaska Utilities Disposition, and warmer weather at Washington Gas compared to 2022.

Service sites at December 31, 2023 decreased by approximately 144,000 sites compared to December 31, 2022 due to the impact of the close of the Alaska Utilities Disposition on March 1, 2023, which was partially offset by continued customer additions across the remaining jurisdictions.

In the fourth quarter of 2023, U.S. retail gas sales volumes were 16,863 Mmcf, compared to 18,064 Mmcf in the same quarter of 2022. The decrease was primarily due to a decrease in commercial customers served by the business and warmer weather in the fourth quarter of 2023 compared to the same quarter of 2022. In the fourth quarter of 2023, U.S. retail electricity sales volumes were 3,518 GWh compared to 3,328 GWh in the same quarter of 2022. The increase was primarily due to an increase in commercial customers served by the business, partially offset by warmer weather in the fourth quarter of 2023 compared to the same quarter of 2022.

For the year ended December 31, 2023, U.S. retail gas sales volumes were 56,438 Mmcf, compared to 59,302 Mmcf in the same period in 2022. The decrease was primarily due to significantly warmer weather in the year ended December 31, 2023 compared to 2022. For the year ended December 31, 2023, U.S. retail electricity sales volumes were 14,339 GWh compared to 13,217 GWh in the same period in 2022. The slight increase was primarily due to an increase in commercial customers served by the business.

Three Months Ended December 31

The Utilities segment reported normalized EBITDA of $311 million in the fourth quarter of 2023, compared to $294 million in the same quarter in 2022. The increase in normalized EBITDA was mainly due to higher gas and power margins from WGL's retail marketing business, customer growth, higher revenue from accelerated pipe replacement program spend, foreign exchange hedge gains, the impact of Washington Gas' Virginia rate case, and lower operating and administrative expenses. These factors were partially offset by the impact of the Alaska Utilities Disposition in the first quarter of 2023, decreased asset optimization activities at Washington Gas relative to the larger-than-normal contribution in the fourth quarter of 2022, and warmer weather in Michigan and the District of Columbia where the Utilities do not have weather normalization.

The Utilities segment income before income taxes was $207 million in the fourth quarter of 2023, compared to $80 million in the same quarter in 2022. The increase was mainly due to lower unrealized losses on risk management contracts, the same previously referenced factors impacting normalized EBITDA, and lower depreciation expense, partially offset by costs related to restructuring initiatives.

Year Ended December 31

The Utilities segment reported normalized EBITDA of $886 million in the year ended December 31, 2023, compared to $933 million in 2022. The decrease in normalized EBITDA was mainly due to the impact of the Alaska Utilities Disposition, decreased asset optimization activities at Washington Gas as a result of lower margins relative to larger-than-normal contributions in 2022, warmer weather in Michigan and the District of Columbia where the Utilities do not have weather normalization, higher operating and administrative expenses, and lower contributions from WGL's retail marketing business. These factors were partially offset by an impact of approximately $35 million due to the change in foreign exchange rates, the impact of Washington Gas' 2022 Virginia rate case, higher revenue from accelerated pipe replacement program spend, the gain resulting in the partial debt defeasance associated with the Alaska Utilities Disposition in the first quarter of 2023, customer growth, and foreign exchange hedge gains.

The Utilities segment income before income taxes was $886 million in the year ended December 31, 2023, compared to $548 million in 2022. The increase was mainly due to the to the gain on the Alaska Utilities Disposition and higher unrealized gains on risk management contracts, partially offset by the same previously referenced factors impacting normalized EBITDA, higher transaction costs related to acquisitions and dispositions, and costs related to restructuring initiatives.

In 2023, the Utilities segment recognized a pre-tax gain on disposition of assets of approximately $304 million due to the gain on the Alaska Utilities Disposition.

Rate Case Updates

Utility/ Jurisdiction	Date Filed	Request	Status	Expected Timing of Decision
Washington Gas - Maryland	May 2023	US$49 million increase in base rates, including US$21 million currently collected through the STRIDE surcharge for system upgrades. Therefore, the incremental amount of the base rate increase requested was approximately US$28 million.	On May 18, 2023, Washington Gas filed an application for authority to increase charges for gas service in Maryland. On December 14, 2023, the PSC of MD approved a US$10 million rate increase with a 9.5 percent return on equity and 52 percent equity thickness. The amount comprised of approximately US$12 million for costs currently recovered through the STRIDE plan surcharge and a US$2 million decrease in base rates, including a reduction in the allowed ROE. Two parties, the PSC of MD Staff and the General Service Administration, filed motions for clarification. The PSC of MD Staff motion for clarification recommended that the PSC of MD amend its finding to adopt a revised revenue increase of approximately US$8 million to address inconsistencies it believes exist in the order. Washington Gas was the only party to file a petition for rehearing, on January 16, 2024. The MD OPC, the Apartment and Office Building Association of Greater Washington, and the Chesapeake Climate Action Network filed responses to the Washington Gas petition for rehearing. PSC of MD action on the motions is pending. The new rates went into effect December 14, 2023.	Final order received on December 14, 2023.
Washington Gas - District of Columbia	April 2022	US$53 million increase in base rates, including US$5 million currently collected through the PROJECT*pipes* surcharge. Therefore, the incremental amount of the base rate increase requested was approximately US$48 million.	On April 4, 2022, Washington Gas filed an application for authority to increase charges for gas service in the District of Columbia. On December 22, 2023, the PSC of DC approved a revenue increase of approximately US$25 million, of which approximately US$5 million is currently collected through the PROJECT*pipes* 2 surcharge (net revenue increase of approximately US$20 million), based on 9.65 percent return on equity and 52 percent equity thickness. The new rates went into effect January 19, 2024. Requests for reconsideration of certain limited findings in the Commission's decision were filed by certain parties. On February 22, 2024, the PSC of DC issued an Order with parameters for an affiliate cost of service study ("ACOSS"), which would include the allocation and assignment of costs for services Washington Gas has provided to affiliated entities and has received payment for such services. Parties in the case have 20 days from the date of the order to file any additional information they believe should be included in the ACOSS. Washington Gas must file its ACOSS 90 days before filing its next base rate case. The Order denied other requests for reconsideration.	Final order received on December 22, 2023.

Utility/ Jurisdiction	Date Filed	Request	Status	Expected Timing of Decision
Washington Gas - Virginia	June 2022	US$48 million increase in base rates, plus the request to transfer an additional US$39 million currently collected in SAVE surcharge into base rates, for a total increase of approximately US$87 million.	On June 29, 2022, Washington Gas filed an application for authority to increase rates in the Commonwealth of Virginia. On July 17, 2023, the Hearing Examiner report was issued and recommended the SCC of VA approve the proposed stipulation with certain recommendations. On August 29, 2023, the SCC of VA adopted the Hearing Examiner's report, approving approximately US$41 million of incremental base rates plus approximately US$32 million of SAVE surcharges for a total rate increase of approximately US$73 million. Amounts refundable to customers were paid with interest by December 15, 2023, per the extension granted by the SCC of VA.	Final order received August 29, 2023.
Washington Gas - Maryland	August 2020	US$27 million increase in base rates, including US$6 million currently collected through STRIDE surcharges for system upgrades. Therefore, the incremental amount of the base rate increase requested was approximately US$21 million.	On April 9, 2021, a final order was received from the PSC of MD related to this rate increase application, authorizing Washington Gas to increase its Maryland natural gas distribution rates by approximately US$13 million (including US$6 million currently collected through the STRIDE surcharge), reflecting a return on equity of 9.70 percent. The revenue increase became effective on March 26, 2021. On May 14, 2021, the MD OPC filed a petition for re-hearing of the PSC of MD's finding on merger synergy savings and certain rate base additions. On May 31, 2022, the Circuit Court of Baltimore City Circuit Court granted the PSC of MD and Washington Gas' joint motion, determining that the PSC of MD properly permitted Washington Gas' recovery of corporate costs and relieving the PSC of MD of the obligation to rule on merger synergy savings on remand. On June 30, 2022, the MD OPC appealed the Circuit Court's new order on merger synergy savings to the Appellate Court of Maryland (formerly the Maryland Court of Special Appeals). On August 11, 2023, the Supreme Court of Maryland granted OPC's petition. On February 23, 2024, the Supreme Court of Maryland issued a decision upholding the PSC of MD's decision in the rate case regarding merger synergy savings.	Final order issued April 2021. Decision by Court of Special Appeals received February 2024.

Other Regulatory Updates

Merger Commitments - District of Columbia

On August 9, 2023, the PSC of DC determined that AltaGas had failed to fulfill Term No. 5 Commitment of the PSC of DC's merger approval order related to the June 2018 merger of AltaGas, WGL, and Washington Gas. On reconsideration, the PSC of DC confirmed, in relevant part, that it had credited AltaGas with causing the development of 2.4 MW of Tier one renewable resources by the July 6, 2023 deadline, and that the Company had breached its Term No. 5 Commitment only for the remaining 7.6 MW. As directed by the PSC of DC, AltaGas, the District of Columbia Government ("DCG"), and the District of Columbia Office of People's Counsel ("DC OPC") conducted negotiations in good faith to reach agreement on a penalty. On November 14, 2023, DCG reported that DCG and AltaGas believed that further negotiations would be fruitless. In a November 21, 2023 motion, AltaGas confirmed that it will specifically perform its Term No. 5 obligations by continuing to cause the development of the remaining 7.6 MW of solar renewable energy. AltaGas also proposed a penalty of approximately US$0.5 million if the Company fulfills the balance of its renewable development obligation before the end of 2024, or US$0.6 million if the balance is not completed until after the end of 2024. On December 19, 2023, DCG proposed that AltaGas pay a penalty of approximately US$8 million. OPC proposed a penalty not less than DCG's proposed penalty, to be paid before September 30, 2024. Management believes that the likelihood of a civil penalty is probable however, is unable to estimate the maximum possible penalty.

Prince William County Biogas Pipeline

On December 4, 2023, Washington Gas filed an application with the SCC of VA seeking approval for a biogas supply investment plan and rate adjustment clause. Washington Gas seeks approval to purchase, own, operate, and maintain an eight-mile pipeline, associated interconnection facilities and other necessary equipment to transport RNG from a biogas production facility located at the Prince William County Landfill. Washington Gas also proposes to purchase a portion of the facilities output, a subset of which will be accompanied by marketable environmental attributes. Washington Gas is seeking recovery of the project costs and RNG costs through a RNG rider. Evidentiary hearing is set for March 19, 2024 and a decision is expected around early June 2024.

SEMCO Energy Waste Reduction Program ("EWRP")

On June 30, 2023, SEMCO submitted its 2024-2025 EWRP seeking approval to spend approximately US$35 million on energy waste reduction over 2024 and 2025. SEMCO reached an in-principle settlement agreement with the MPSC staff and the Michigan Department of Attorney General. The MPSC formally approved the settlement agreement on December 21, 2023.

EmPOWER Maryland Plan

Effective January 1, 2024, the PSC of MD approved Washington Gas' three-year plan modifying and expanding the existing portfolio of programs for residential, commercial, industrial, and low-income customers with a total three-year budget of approximately US$64 million. The approved EmPOWER Plan also includes a new Demand Response program for eligible residential customers and a pilot to test and monitor Energy Management Systems for commercial buildings with centralized boiler heating systems.

Midstream

Operating Statistics

	Three Months Ended December 31		Year Ended December 31	
	2023	2022	**2023**	2022
LPG export volumes (Bbls/d) (1)	**90,996**	97,152	**106,071**	101,654
Total inlet gas processed (Mmcf/d) (1)	**1,312**	1,274	**1,303**	1,268
Extracted ethane volumes (Bbls/d) (1)	**23,879**	21,947	**25,533**	23,816
Extracted NGL volumes (Bbls/d) (1) (2)	**36,138**	34,782	**34,369**	32,853
Fractionation volumes (Bbls/d) (1) (3)	**38,150**	36,658	**38,745**	33,602
Frac spread - realized ($/Bbl) (1) (4)	**23.13**	25.14	**24.15**	26.07
Frac spread - average spot price ($/Bbl) (1) (5)	**20.55**	23.14	**22.37**	32.02
Propane Far East Index ("FEI") to Mont Belvieu spread (US$/Bbl) (1) (6)	**26.44**	18.95	**20.68**	13.81
Butane FEI to Mont Belvieu spread (US$/Bbl) (1) (7)	**27.74**	18.59	**21.73**	13.31

(1) Average for the period.
(2) NGL volumes refer to propane, butane, and condensate.
(3) Fractionation volumes include NGL mix volumes processed.
(4) Realized frac spread or NGL margin, expressed in dollars per barrel of NGL, is derived from sales recorded by the segment during the period for frac spread exposed volumes plus the settlement value of frac hedges settled in the period less extraction premiums, divided by the total frac exposed volumes produced during the period.
(5) Average spot frac spread or NGL margin, expressed in dollars per barrel of NGL, is indicative of the average sales price that AltaGas receives for propane, butane and condensate less extraction premiums, before accounting for hedges, divided by the respective frac spread exposed volumes for the period.
(6) Average propane price spread between FEI and Mont Belvieu TET commercial index.
(7) Average butane price spread between FEI and Mont Belvieu TET commercial index.

LPG volumes exported to Asia from RIPET and Ferndale for the three months ended December 31, 2023 averaged 90,996 Bbls/d compared to 97,152 Bbls/d for the same period in 2022. There were 15 full shipments and 1 partial shipment in the fourth quarter of 2023, compared to 16 full shipments in the same period in 2022. Lower export volumes were primarily the result of logistical constraints and the timing of ship loadings around quarter end, partially offset by higher available supply.

LPG volumes exported to Asia from RIPET and Ferndale for the year ended December 31, 2023 averaged 106,071 Bbls/d compared to 101,654 Bbls/d for the same period in 2022. There were 71 full shipments and 1 partial shipment during the year ended December 31, 2023 compared to 68 shipments in the same period of 2022. The partially loaded vessels are a function of revenue recognition taking place at the point of ship loading and select loadings taking place over quarter-ends. Higher export volumes and shipments were primarily the result of increased offtake demand, higher available supply, and improved logistics.

Inlet gas processing volumes for the fourth quarter of 2023 increased by 38 Mmcf/d compared to the same quarter in 2022. Higher inlet gas processing volumes in the fourth quarter of 2023 were primarily the result of higher producer volumes at the Townsend complex and higher volumes at the Harmattan raw gas and co-stream facilities, partially offset by lower volumes at the Edmonton ethane extraction plant ("EEEP") due to the September turnaround, which extended into the fourth quarter of 2023 and third party pipeline restrictions, as well as lower volumes at the Younger extraction plant ("Younger") due to the extension of a plant turnaround in the area.

Inlet gas processing volumes for the year ended December 31, 2023 increased by 35 Mmcf/d compared to the same period in 2022. Higher inlet gas processing volumes in the year ended December 31, 2023 were primarily the result of higher producer volumes at the Townsend complex, higher volumes at the Harmattan raw gas and co-stream facilities, and higher frac exposed volumes, partially offset by the impact of the Aitken Creek sale in the second quarter of 2022, and lower volumes at EEEP due to the turnaround in September 2023 which extended into the fourth quarter of 2023, and third party pipeline restrictions.

Average ethane volumes for the fourth quarter of 2023 increased by 1,932 Bbls/d, while average NGL production volumes increased by 1,356 Bbls/d compared to the same quarter in 2022. Higher ethane volumes were primarily a result of higher co-stream inlet volumes and higher raw gas production at Harmattan, partially offset by lower volumes at EEEP due to the extension of the plant turnaround and lower volumes at PEEP due to higher reinjection rates. Higher extracted NGL volumes were due to higher raw gas inlet volumes at the Townsend facilities due to higher demand from third party customers.

Average ethane volumes for the year ended December 31, 2023 increased by 1,717 Bbls/d compared to 2022, while average extracted NGL volumes increased by 1,516 Bbls/d compared to the same period in 2022. Higher ethane volumes were a result of higher co-stream inlet volumes and higher raw gas production at Harmattan, as well as higher volumes at the Joffre ethane extraction plant ("JEEP") due to the absence of a turnaround in the third quarter of 2022, partially offset by lower volumes at EEEP due to the turnaround in September 2023 and higher reinjection rates at PEEP. Higher extracted NGL volumes were a result of increased production at the Townsend facilities due to higher demand from third party customers and higher production at Harmattan due to the absence of a turnaround in the second quarter of 2022, partially offset by a third party pipeline outage which resulted in the re-injection of NGL volumes at Gordondale in the first quarter of 2023.

Fractionation volumes for the fourth quarter of 2023 increased by 1,492 compared to the same quarter in 2022. The increase was due to higher Harmattan trucked-in NGL mix and raw gas volumes as a result of plant turnarounds in the area increasing spot volumes and additional volumes resulting from increased customer production, higher fractionation volumes at the Younger facility due to additional volumes sold during the turnaround extension, and higher North Pine volumes and utilization.

Fractionation volumes for the year ended December 31, 2023 increased by 5,143 Bbls/d compared to the same period in 2022. Higher fractionation volumes were a result of higher North Pine volumes and utilization, higher Harmattan trucked-in NGL mix and raw gas volumes as a result of plant turnarounds in the area increasing spot volumes and additional volumes resulting from increased customer production, and higher fractionation volumes at the Younger facility due to additional volumes sold during the turnaround extension, partially offset by the impact of the wildfires at the NEBC facilities in the second quarter of 2023.

Three Months Ended December 31

The Midstream segment reported normalized EBITDA of $182 million in the fourth quarter of 2023, compared to $163 million in the same quarter in 2022. The increase in normalized EBITDA in the fourth quarter of 2023 was mainly due to strong performance from the global exports business as a result of higher LPG margins (inclusive of hedges), partially offset by lower merchant volumes, as well as AFUDC at MVP as a result of the resumption of construction activities in June 2023, higher marketing volumes and margins due to the absence of the 2022 write down of natural gas storage inventory to its net realizable value, and lower operating expenses at the processing and trucking facilities. The increase in normalized EBITDA was partially offset by the absence of the favourable resolution of certain acquisition related commercial disputes and contingencies in the fourth quarter of 2022, lower earnings at the extraction facilities driven by lower frac spreads and volumes due to third party pipeline restrictions, lower power revenue at Harmattan primarily driven by lower power prices, and lower crude marketing margins.

Income before income taxes in the Midstream segment was $79 million in the fourth quarter of 2023, compared to $113 million in the same quarter in 2022. The decrease was mainly due to higher unrealized losses on risk management contracts and higher depreciation expense, partially offset by the same previously referenced factors impacting normalized EBITDA and the absence of provisions on assets.

In the fourth quarter of 2022, the Midstream segment recognized a pre-tax provision on assets of approximately $6 million ($5 million after-tax) primarily related to the abandoned Alton natural gas storage project.

Year Ended December 31

The Midstream segment reported normalized EBITDA of $684 million in the year ended December 31, 2023, compared to $607 million in 2022. There were several positive and negative contributors underpinning the year-over-year variance. Positive factors included strong performance from the global exports business as a result of higher LPG margins (inclusive of hedges) and tolling volume growth, as well as AFUDC at MVP as a result of the resumption of construction activities in June 2023, the absence of the 2022 write down of natural gas inventory to its net realizable value, resolution of certain commercial disputes and contingencies, stronger performance at Harmattan, and cost management across a number of businesses. These were partially offset by the absence of turnaround recoveries in the third quarter of 2022, the impact of the sale of AltaGas' interest in the Aitken Creek processing facilities in the second quarter of 2022, lower inventory withdrawals, lower earnings at the extraction facilities driven by lower frac spreads, lower marketing performance, and lower power revenue at Harmattan primarily due to lower power prices. Other factors negatively impacting normalized EBITDA include the impact of the turnarounds at the extraction facilities in the third quarter of 2023 and the wildfires at NEBC facilities in the second quarter of 2023, the latter of which included a 12.5 day force majeure.

Income before income taxes in the Midstream segment was $460 million in the year ended December 31, 2023, compared to $526 million in 2022. The decrease was mainly due to higher unrealized losses on risk management contracts, higher depreciation expense, and higher transaction costs related to acquisitions and dispositions, partially offset by the same previously referenced factors impacting normalized EBITDA and the absence of provision on assets.

Midstream Hedges

	Three Months Ended December 31		Year Ended December 31	
	2023	2022	**2023**	2022
Frac exposed volumes (Bbls/d)	**10,597**	10,927	**10,062**	10,440
NGL volumes hedged (Bbls/d)	**8,000**	8,000	**7,496**	8,204
Average price of NGL volumes hedged ($/Bbl) (1)	**36**	34	**36**	34
Average export volumes hedged (Bbls/d) (2)	**60,418**	55,953	**63,254**	54,721
Average FEI to North American NGL price spread for volumes hedged (US$/Bbl)	**15**	11	**14**	16

(1) Excludes basis differential.

(2) Represents volumes hedged using financial contracts excluding tolling and take or pay volumes.

Corporate/Other

Three Months Ended December 31

In the Corporate/Other segment, normalized EBITDA for the fourth quarter of 2023 was $9 million, compared to a loss of $3 million in the same quarter in 2022. The increase in normalized EBITDA was mainly due to lower expenses related to employee incentive plans and lower corporate operating and administrative expenses.

Loss before income taxes in the Corporate/Other segment was $125 million in the fourth quarter of 2023, compared to $115 million in the same quarter in 2022. The higher loss was mainly due to higher foreign exchange losses and costs related to the CEO transition and other restructuring initiatives, partially offset by the same previously referenced factors impacting normalized EBITDA and lower unrealized losses on risk management contracts.

Year Ended December 31

In the Corporate/Other segment, normalized EBITDA for the year ended December 31, 2023 was $5 million, compared to a loss of $3 million in 2022. The increase in normalized EBITDA was mainly due to lower corporate operating and administrative expenses and lower expenses related to employee incentive plans, partially offset by a lower contribution from Blythe.

Loss before income taxes in the Corporate/Other segment was $434 million in the year ended December 31, 2023, compared to $358 million in 2022. The higher loss was mainly due to higher interest expense, costs related to the CEO transition and other restructuring initiatives, higher foreign exchange losses, and higher transaction costs on acquisitions and dispositions, partially offset by higher unrealized gains on risk management contracts, the same factors impacting normalized EBITDA, and additional proceeds received due to contract contingencies on the sale of Goleta in the first quarter of 2022.

In 2023, the Corporate/Other segment recognized an additional pre-tax gain of approximately $11 million on the sale of Goleta in 2022 as a result of a payment received in the first quarter of 2023 for the favourable settlement of outstanding contingencies based on contract outcomes. In 2022, the Corporate/Other segment recognized a pre-tax gain on disposition of assets of approximately $5 million which was comprised of a pre-tax gain of $7 million on the previously mentioned sale of Goleta, partially offset by a pre-tax loss of $2 million on the sale of a power plant in Brush, Colorado.

Net Invested Capital

Net invested capital is a non-GAAP financial measure. Please refer to the *Non-GAAP Financial Measures* section of this MD&A for further discussion.

							Three Months Ended December 31, 2023
($ millions)		**Utilities**		**Midstream**		**Corporate/ Other**	**Total**
Invested capital:							
Property, plant and equipment	**$**	**192**	**$**	**89**	**$**	**4**	**$ 285**
Intangible assets		**—**		**4**		**1**	**5**
Invested capital	**$**	**192**	**$**	**93**	**$**	**5**	**$ 290**
Acquisitions and dispositions:							
Business acquisition [1]		**—**		**327**		**—**	**327**
Net invested capital	**$**	**192**	**$**	**420**	**$**	**5**	**$ 617**

(1) Includes only the cash portion of the total consideration paid for the Pipestone Acquisition, net of cash acquired.

							Three Months Ended December 31, 2022
($ millions)		Utilities		Midstream		Corporate/ Other	Total
Invested capital:							
Property, plant and equipment	$	271	$	49	$	1	$ 321
Intangible assets		1		3		—	4
Long-term investments		—		1		—	1
Invested capital and net invested capital	$	272	$	53	$	1	$ 326

During the fourth quarter of 2023, AltaGas' invested capital was $290 million, compared to $326 million in the same quarter in 2022. The decrease in invested capital was primarily due to lower additions to property, plant, and equipment as a result of lower spend primarily on system betterment, new business, and general plant programs at Washington Gas, partially offset by higher maintenance capital in the Midstream segment. In the fourth quarter of 2023, acquisitions related to the cash paid for the Pipestone Acquisition.

The invested capital in the fourth quarter of 2023 included maintenance capital of $31 million (2022 - $18 million) in the Midstream segment and $1 million (2022 - less than $1 million) related to remaining power assets in the Corporate/Other segment. The increase in Midstream maintenance capital in the fourth quarter of 2023 primarily related to routine maintenance expenditures at the Younger, Harmattan, and Sarnia facilities, as well as turnaround expenditures at the EEEP and Ferndale facilities.

During the fourth quarter of 2023, AltaGas' cash flow from investing activities was an outflow of $594 million, compared to $336 million in the same quarter in 2022. Please refer to the *Non-GAAP Financial Measures* and *Liquidity* sections of this MD&A for further information on AltaGas' cash flow from investing activities.

				Year Ended December 31, 2023
($ millions)	**Utilities**	**Midstream**	**Corporate/ Other**	**Total**
Invested capital:				
Property, plant and equipment	**$ 745**	**$ 180**	**$ 8**	**$ 933**
Intangible assets	**—**	**8**	**1**	**9**
Long-term investments	**—**	**4**	**—**	**4**
Invested capital	**$ 745**	**$ 192**	**$ 9**	**$ 946**
Acquisitions and dispositions:				
Business acquisition [(1)]	**—**	**327**	**—**	**327**
Asset dispositions	**(1,059)**	**(3)**	**(11)**	**(1,073)**
Disposals of equity method investments [(2)]	**—**	**(1)**	**—**	**(1)**
Net invested capital	**$ (314)**	**$ 515**	**$ (2)**	**$ 199**

(1) Includes only the cash portion of the total consideration paid for the Pipestone Acquisition, net of cash acquired.

(2) Relates to escrow account proceeds received from AltaGas' previous investment in Central Penn. Upon close of the sale in 2019, various escrow accounts were established to provide the purchaser a form of recourse for the settlement of indemnification obligations.

				Year Ended December 31, 2022
($ millions)	Utilities	Midstream	Corporate/ Other	Total
Invested capital:				
Property, plant and equipment	$ 822	$ 108	$ 10	$ 940
Intangible assets	2	6	1	9
Long-term investments	—	(1)	—	(1)
Invested capital [(1)]	$ 824	$ 113	$ 11	$ 948
Acquisitions and dispositions:				
Purchase of remaining non-controlling interest in a subsidiary	—	285	—	285
Asset dispositions	—	(225)	(20)	(245)
Net invested capital	$ 824	$ 173	$ (9)	$ 988

(1) In the fourth quarter of 2023, AltaGas changed its non-GAAP policy to exclude cash paid for business acquisitions and for the purchase of remaining non-controlling interest in a subsidiary from invested capital. Prior periods have been restated to reflect this change.

During the year ended December 31, 2023, AltaGas' invested capital was $946 million, compared to $948 million in 2022. The slight decrease in invested capital was primarily due to the lower spend on system betterment and new business programs in the Utility segment, the impact of the Alaska Utilities Disposition, and lower maintenance capital in both the Midstream and Corporate/Other segments. The decrease was partially offset by higher spend on accelerated pipe replacement programs at Washington Gas, the impact of the higher average Canadian/U.S. dollar exchange rate, higher spend on the Harmattan acid gas injection well, and higher growth capital spend in the Midstream segment primarily related to Pipestone Phase II, new business development, and various optimization projects.

In 2023, acquisitions related to the cash paid for the Pipestone Acquisition, while asset dispositions primarily related to the Alaska Utilities Disposition and additional proceeds received for the favourable settlement of outstanding contingencies on the sale of Goleta in the first quarter of 2022. In 2022, acquisitions related to cash paid to purchase the remaining equity ownership of Petrogas, while asset dispositions primarily related to proceeds received from the sale of AltaGas' interest in the Aitken Creek processing facilities, a power plant in Brush, Colorado, and the previously mentioned sale of Goleta.

The invested capital for the year ended December 31, 2023 included maintenance capital of $53 million (2022 - $66 million) in the Midstream segment and $4 million (2022 - $8 million) related to remaining power assets in the Corporate/Other segment. The decrease in maintenance capital for the Midstream segment was primarily due to lower turnaround spend while the decrease in maintenance capital for the Corporate/Other segment was primarily due to lower maintenance costs at Blythe.

During the year ended December 31, 2023, AltaGas' cash flow from investing activities was an outflow of $199 million, compared to $997 million in 2022. Please refer to the *Non-GAAP Financial Measures* and *Liquidity* sections of this MD&A for further information on AltaGas' cash flow from investing activities.

Risk Management

AltaGas is subject to a variety of risks which could have a material impact on the financial results and operations of the Company. Shareholders and prospective investors should carefully evaluate risk factors noted by the Company before investing in the Company's securities, as each of these risks may negatively affect the trading price of the Company's securities, the amount of dividends paid to shareholders and the ability of the Company to fund its debt obligations, including debt obligations under its outstanding notes and any other debt securities that the Company may issue from time to time. For discussion of the risks and trends that could materially affect the Company's performance please refer to AltaGas' 2023 Annual Information Form, which is available on SEDAR+ at www.sedarplus.ca.

Risk Management Contracts

AltaGas is exposed to various market risks in the normal course of operations that could impact earnings and cash flows. AltaGas enters into physical and financial derivative contracts to manage exposure to fluctuations in commodity prices and foreign exchange rates, as well as to optimize certain owned and managed natural gas assets. These contracts do not eliminate AltaGas' exposure to risk associated with fluctuations in commodity prices or foreign exchange rates. The Board of Directors of AltaGas has established a risk management policy for the Corporation establishing AltaGas' risk management control framework. Derivative instruments are governed under, and subject to, this policy. As at December 31, 2023 and December 31, 2022, the fair values of the Corporation's derivatives were as follows:

($ millions)	**December 31, 2023**	December 31, 2022
Natural gas	**$ (46)**	$ (203)
Energy exports	**(4)**	27
NGL frac spread	**1**	(3)
Power	**(75)**	(78)
Crude oil and NGLs	**4**	4
Foreign exchange	**19**	—
Net derivative liability	**$ (101)**	$ (253)

AltaGas strives to continuously and systematically de-risk the business in order to drive predictable and durable returns and maximize long-term value for stakeholders. For Midstream, this includes striving to match financial hedges with physical volumes, and for Utilities, this includes purchasing physical gas throughout the year to help shield customers from major cost spikes during peak winter demand. AltaGas may also enter into foreign exchange forward derivatives to manage the risk associated with variations in foreign exchange rates.

Commodity Price Contracts

The Corporation executes natural gas, power, LPG, crude oil, ocean freight, and other physical and financial commodity contracts to serve its customers as well as manage and optimize its asset portfolio. A portion of these physical contracts are not recorded at fair value because they are either: 1) designated as "normal purchases and normal sales"; 2) do not qualify as derivative instruments due to the significance of their notional amount relative to the applicable liquid markets; or 3) are weather derivatives, which are not exchanged or traded and the underlying variables relate to a climactic, geological, or other physical variable. The fair value of commodity contracts that qualify as derivatives was calculated using estimated forward prices based on published sources for the relevant period. For AltaGas' Midstream segment, changes in the fair value of these derivative contracts are recorded in the Consolidated Statements of Income in the period in which the change occurs. For the Utilities segment, changes in the fair value of derivative instruments recoverable or refundable to customers are recorded to regulatory assets or regulatory liabilities on the Consolidated Balance Sheets, while changes in the fair value of derivative instruments not affected by rate regulation are recorded in the Consolidated Statements of Income in the period in which the change occurs. The Midstream segment also executes fixed-for-floating NGL frac spread swaps to manage exposure to frac spreads as the financial results of several extraction plants are affected by fluctuations in NGL frac spreads.

- The average indicative spot NGL frac spread for the year ended December 31, 2023 was approximately $22/Bbl (2022 – $32/Bbl), inclusive of basis differentials. The average NGL frac spread realized by AltaGas (based on average spot price and realized hedge price inclusive of basis differentials) for the year ended December 31, 2023 was approximately $24/Bbl inclusive of basis differentials (2022 - $26/Bbl).

AltaGas continues to focus on de-risking its business and managing direct commodity price exposure to drive predictable and durable results. While the Company does have exposure, it plans to maintain an active hedging program that proactively hedges commodity price and spread risk to mitigate the impact of fluctuations in margins and cash flows. For 2024, AltaGas has hedged:

- Approximately 90 percent of AltaGas' 2024 expected global export volumes through a combination of tolls and financial hedges with an average FEI to North American financial hedge price of approximately US$18/Bbl for non-tolled propane and butane volumes.
- Approximately 80 percent of its 2024 expected frac exposed volumes hedged at approximately US$27/Bbl, prior to transportation costs.
- Materially all of AltaGas' expected Baltic freight exposure is protected through time charters, financial hedges, and tolled volumes in 2024.

Additionally, AltaGas uses physical and financial derivatives for the purchase and sale of natural gas in order to optimize owned storage and transportation capacity as well as manage transportation and storage assets on behalf of third parties.

The Utilities segment enters into hedging contracts and other contracts that may qualify as derivative instruments related to the purchase of natural gas to manage price risk for its ratepayers. Additionally, Washington Gas executes commodity-related physical and financial contracts in the form of forward, futures, and option contracts as part of an asset optimization program.

Under this program, Washington Gas realizes value from its long-term natural gas transportation and storage capacity resources when they are not being fully used to serve utility customers. To serve retail customers, WGL Energy Services enters into both physical and financial contracts for the purchase and sale of electricity and natural gas. Beginning in 2023, WGL Energy Services also began purchasing natural gas indexed to NYMEX Henry Hub to be sold to third party customers. WGL Energy Services' risk management objective and strategy is to protect earnings against the risk of price fluctuations associated with forecasted NYMEX Henry Hub purchases through the use of the NYMEX Henry Hub financial swaps.

The Corporate/Other segment has various fixed-for-floating power purchase and sale contracts in the Alberta market, which are expected to be settled over the next year.

Foreign Exchange Contracts

AltaGas is exposed to foreign exchange risk as changes in foreign exchange rates may affect the fair value or future cash flows of the Corporation’s financial instruments. AltaGas has foreign operations whereby the functional currency is the U.S. dollar. As a result, the Corporation’s earnings, cash flows, and other comprehensive income are exposed to fluctuations resulting from changes in foreign exchange rates. This risk is partially mitigated to the extent that AltaGas has U.S. dollar-denominated debt outstanding. AltaGas may also enter into foreign exchange forward derivatives to manage the risk of fluctuating cash flows and earnings due to variations in foreign exchange rates as well as to benefit from favorable movements in the rates. Any hedges transacted are subject to risk limits and guidelines and are actively monitored and managed by AltaGas’ risk management team to ensure they align with AltaGas’ overall financial strategy.

- As at December 31, 2023, Management has designated US$715 million of outstanding loans as a net investment hedge to hedge against the currency translation effect of its foreign investments (December 31, 2022 - US$281 million).

- For the year ended December 31, 2023, a $25 million after-tax unrealized gain on the net investment hedge was recorded in other comprehensive income (2022 - after-tax unrealized loss $15 million).

As at December 31, 2022, AltaGas did not have any outstanding foreign exchange forward contracts. The following foreign exchange forward contracts are outstanding as at December 31, 2023:

Foreign exchange forward contract	Duration	Fair Value *($ millions)*
Forward USD sales (deliverable)	Less than 1 month	less than $1 million
Forward USD sales (non-deliverable)	Less than 1 year	$ 10
Forward USD sales (non-deliverable)	1 - 2 years	$ 9

For the year ended December 31, 2023, AltaGas had pre-tax gains on foreign exchange contracts of $25 million. Of this, an unrealized gain of less than $1 million, as well as a realized gain of less than $1 million related to foreign exchange contracts entered into for the purpose of risk associated with cash management, was recorded in the Consolidated Statements of Income under the line item "foreign exchange gains" (year ended December 31, 2022 - $nil). Additionally, an unrealized gain of $19 million, as well as a realized gain of $6 million related to foreign exchange contracts entered into for the purpose of managing income statement risk, was recorded in the Consolidated Statements of Income under the line item "revenue" (year ended December 31, 2022 - $nil).

Interest Rate Contracts

AltaGas is exposed to interest rate risk as changes in interest rates may impact future cash flows and the fair value of its financial instruments. The Corporation manages its interest rate risk by holding a mix of both fixed and floating interest rate debt.

From time to time, AltaGas may concurrently draw on its credit facility in U.S. dollars and enter into cross currency basis swaps whereby, on final settlement, AltaGas receives U.S. dollars from the counterparty and pays Canadian dollars to the counterparty.

Weather Instruments

WGL Energy Services utilizes heating degree day ("HDD") instruments from time to time to manage weather and price risks related to its natural gas and electricity sales during the winter heating season. WGL Energy Services also utilizes cooling degree day ("CDD") instruments and other instruments to manage weather and price risks related to its electricity sales during the summer cooling season. These instruments cover a portion of estimated revenue or energy-related cost exposure to variations in HDDs or CDDs. For the year ended December 31, 2023, a pre-tax loss of $8 million (2022 - pre-tax loss of less than $1 million) was recorded related to HDD and CDD instruments.

The Effects of Derivative Instruments on the Consolidated Statements of Income

The following table presents the unrealized gains (losses) on derivative instruments as recorded in the Corporation's Consolidated Statements of Income:

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2023**	2022	**2023**	2022
Natural gas	**$ (29)**	$ (98)	**$ (12)**	$ (57)
Energy exports	**(50)**	(12)	**(78)**	21
Crude oil and NGLs	**(16)**	(4)	**(5)**	2
NGL frac spread	**1**	(5)	**4**	16
Power	**(20)**	(37)	**2**	(31)
Foreign exchange	**20**	—	**19**	—
	$ (94)	$ (156)	**$ (70)**	$ (49)

Please refer to Note 23 of the 2023 Annual Consolidated Financial Statements for further details regarding AltaGas' risk management activities.

Liquidity

As a result of certain commitments made to the PSC of DC, the PSC of MD, and the SCC of VA in respect of the acquisition of WGL Holdings, Inc. (the "WGL Acquisition"), Washington Gas is subject to certain restrictions when paying dividends to AltaGas. However, AltaGas does not expect that this will have an impact on AltaGas' ability to meet its obligations.

In addition, Wrangler SPE LLC and Washington Gas made certain ring fencing commitments to the PSC of DC, the PSC of MD, and the SCC of VA with the intention of removing Washington Gas from the bankruptcy estate of AltaGas and its affiliates, other than Washington Gas and Wrangler SPE LLC (together, the "Ring Fenced Entities"). Because of these ring fencing measures, none of the assets of the Ring Fenced Entities would be available to satisfy the debt or contractual obligations of

AltaGas or any non-Ring Fenced Entity Affiliate, including any indebtedness or other contractual obligations of AltaGas, and the Ring Fenced Entities do not bear any liability for indebtedness or other contractual obligations of any non-Ring Fenced Entity, and vice versa.

		Year Ended December 31
($ millions)	**2023**	2022
Cash from operations	**$ 1,121**	$ 539
Investing activities	**(199)**	(997)
Financing activities	**(882)**	435
Increase (decrease) in cash, cash equivalents, and restricted cash	**$ 40**	$ (23)

Cash From Operations

Cash from operations increased by $582 million for the year ended December 31, 2023 compared to 2022, primarily due to favourable variances in the net change in operating assets and liabilities, partly offset by lower net income after taxes (after adjusting for non-cash items). The majority of the variance in net change in operating assets and liabilities was due to increased cash flow from accounts receivable due to fluctuations in commodity prices, sales volumes, and weather, and higher cash flows from inventory as a result of increased volumes held, partially offset by lower cash flow from accounts payable and accrued liabilities due to fluctuations in commodity prices, and lower cash flows from regulatory liabilities primarily due to overall warmer weather experienced by the Utilities segment.

Working Capital

($ millions, except working capital ratio)	**December 31, 2023**	December 31, 2022
Current assets	**$ 3,045**	$ 4,638
Current liabilities	**3,413**	3,407
Working capital (deficiency)	**$ (368)**	$ 1,231
Working capital ratio [(1)]	**0.89**	1.36

(1) Calculated as current assets divided by current liabilities.

The decrease in the working capital ratio was primarily due to decreases in assets held for sale related to the Alaska Utilities Disposition, accounts receivable, inventory, and risk management assets, as well as an increase in current portion of long-term debt. This was partially offset by decreases in liabilities associated with assets held for sale, accounts payable and accrued liabilities, short-term debt, regulatory liabilities, and risk management liabilities. AltaGas' working capital will fluctuate in the normal course of business. The working capital deficiency is expected to be funded using cash flow from operations and available credit facilities as required.

Investing Activities

Cash used in investing activities for the year ended December 31, 2023 was $199 million, compared to $997 million in 2022. Investing activities for the year ended December 31, 2023 primarily included proceeds of approximately $1.1 billion from the disposition of assets primarily related to the Alaska Utilities Disposition and additional proceeds received for the favourable settlement of outstanding contingencies on the sale of Goleta, partially offset by expenditures of approximately $943 million for property, plant, and equipment and intangible assets, the cash payment, net of cash acquired, of $327 million for the Pipestone Acquisition, and approximately $4 million of net contributions to equity investments. Investing activities for the year ended December 31, 2022 included expenditures of approximately $958 million for property, plant, and equipment and intangible assets, and a cash payment of approximately $285 million for the purchase of the remaining non-controlling interest of Petrogas, partially offset by proceeds of $245 million from the disposition of assets primarily related to the disposition of the interest in the Aitken Creek processing facilities, a 60 MW stand-alone energy development project in Goleta, California, and a power plant in Brush, Colorado, as well as approximately $1 million of contributions to equity investments.

Financing Activities

Cash used in financing activities for the year ended December 31, 2023 was $882 million, compared to cash from financing activities of $435 million in 2022. Financing activities for the year ended December 31, 2023 were primarily comprised of net repayments under credit facilities of $678 million, repayments of long-term debt of $338 million, dividends of $343 million, redemption of preferred shares of $200 million, purchase of marketable securities in connection with debt defeasance of $193 million, and distributions to non-controlling interests of $18 million, partially offset by long-term debt issuances of $673 million, issuance of subordinated hybrid notes, net of issuance costs of $198 million, and net proceeds from common shares issued on the exercise of options granted pursuant to AltaGas' share option plan ("Share Options") of $17 million. Financing activities for the year ended December 31, 2022 were primarily comprised of long-term debt issuances of $718 million, net issuances under credit facilities of $466 million, issuance of subordinated hybrid notes, net of debt issuance costs of $544 million, issuances of short-term debt of $128 million, and net proceeds from common shares issued on the exercise of Share Options of $25 million, partially offset by repayments of long-term debt of $513 million, dividends of $338 million, redemption of preferred shares of $574 million, and distributions to non-controlling interests of $21 million.

Capital Resources

AltaGas' objective for managing capital is to maintain its investment grade credit ratings, ensure adequate liquidity, optimize the profitability of its existing assets, and grow its energy infrastructure to create long-term value and enhance returns for its investors. AltaGas' capital structure is comprised of shareholders' equity (including non-controlling interests), short-term and long-term debt (including the current portion and debt classified as held for sale), and subordinated hybrid notes, less cash and cash equivalents.

The use of debt or equity funding is based on AltaGas’ capital structure, which is determined by considering the norms and risks associated with operations and cash flow stability and sustainability.

($ millions)		December 31, 2023		December 31, 2022
Short-term debt	**$**	**129**	$	293
Current portion of long-term debt (1)		**999**		327
Current portion of finance lease liabilities		**11**		7
Long-term debt (2)		**7,528**		8,679
Subordinated hybrid notes (3) (4)		**742**		544
Finance lease liabilities		**120**		15
Debt classified as held for sale		**—**		60
Finance lease liabilities classified as held for sale		**—**		3
Total debt		**9,529**		9,928
Less: cash and cash equivalents		**(95)**		(53)
Net debt	**$**	**9,434**	$	9,875
Shareholders' equity		**7,713**		7,456
Non-controlling interests		**150**		162
Total capitalization	**$**	**17,297**	$	17,493
Net debt-to-total capitalization (%)		**55**		56

(1) Net of debt issuance costs of less than $1 million as at December 31, 2023 (December 31, 2022 - less than $1 million).

(2) Net of debt issuance costs of $38 million as at December 31, 2023 (December 31, 2022 - $41 million).

(3) The $300 million subordinated hybrid notes, Series 1 have a coupon rate of 5.25 percent, and are due on January 11, 2082. The $250 million subordinated hybrid notes, Series 2 have a coupon rate of 7.35 percent and are due on August 17, 2082. The $200 million subordinated hybrid notes, Series 3, have a coupon rate of 8.90% and are due on November 10, 2083. These notes were offered under AltaGas' short form base shelf prospectus dated March 31, 2023, as supplemented by a prospectus supplement dated November 7, 2023.

(4) Net of debt issuance costs of $8 million as at December 31, 2023 (December 31, 2022 - $6 million).

As at December 31, 2023, AltaGas’ total debt primarily consisted of outstanding medium-term notes ("MTNs") of $3.9 billion (December 31, 2022 - $3.8 billion), WGL and Washington Gas long-term debt of $3.0 billion (December 31, 2022 - $2.8 billion), reflecting fair value adjustments on acquisition, SEMCO long-term debt of $393 million (December 31, 2022 - $670 million, of which $63 million was classified as held for sale), $1.0 billion drawn under the bank credit facilities (December 31, 2022 - $1.5 billion), $750 million of subordinated hybrid notes (December 31, 2022 - $550 million), and short-term debt of $129 million (December 31, 2022 - $293 million). In addition, AltaGas had $252 million of letters of credit outstanding (December 31, 2022 - $198 million).

As at December 31, 2023, AltaGas’ total market capitalization was approximately $8.2 billion based on approximately 295 million common shares outstanding and a closing trading price on December 31, 2023 of $27.82 per common share.

AltaGas' earnings interest coverage for the rolling twelve months ended December 31, 2023 was 3.0 times (twelve months ended December 31, 2022 – 2.4 times).

Credit Facilities *($ millions)*	Borrowing capacity	**Drawn at December 31, 2023**	Drawn at December 31, 2022
AltaGas demand credit facilities [1] [2]	$ 70	**$ —**	$ —
AltaGas revolving credit facilities [1] [2]	2,300	**484**	861
AltaGas term credit facility [1][3]	450	**450**	450
SEMCO Energy US$150 million credit facilities [1] [2]	198	**86**	189
WGL US$300 million revolving credit facility [1] [2] [4]	397	**199**	250
Washington Gas US$450 million revolving credit facility [1] [2] [4]	595	**261**	429
	$ 4,010	**$ 1,480**	$ 2,179

(1) Amount drawn at December 31, 2023 converted at the month-end rate of 1 U.S. dollar = 1.3226 Canadian dollar (December 31, 2022 - 1 U.S. dollar = 1.3544 Canadian dollar).
(2) All US$ borrowing capacity was converted at the December 31, 2023 U.S./Canadian dollar month-end exchange rate.
(3) Draws on the facility can be by way of prime loans, U.S. base-rate loans, SOFR loans, or banker's acceptances where interest is prepaid and netted against the face value repayable at maturity. As at December 31, 2023 the net amount outstanding on the facility is $449 million.
(4) Amounts drawn include commercial paper that is supported by the long term facilities. WGL and Washington Gas have the right to request additional borrowings of up to US$100 million with the bank's approval, for a total of US$400 million and US$550 million on their respective facilities.

In addition to the facilities listed above, AltaGas has demand Letter of Credit facilities of $451 million (December 31, 2022 - $461 million). At December 31, 2023, there were letters of credit for $252 million (December 31, 2022 - $198 million) issued on these facilities and an additional less than $1 million (December 31, 2022 - less than $1 million) issued on the Company's revolving credit facilities.

WGL and Washington Gas use short-term debt in the form of commercial paper or unsecured short-term bank loans to fund seasonal cash requirements. Revolving committed credit facilities are maintained in an amount equal to or greater than the expected maximum commercial paper position. As at December 31, 2023, commercial paper outstanding totaled $461 million for WGL and Washington Gas (December 31, 2022 – $679 million).

All of the borrowing facilities have covenants customary for these types of facilities, which must be met at each quarter end. AltaGas and its subsidiaries have been in compliance with all financial covenants each quarter since the establishment of the facilities. AltaGas and its subsidiaries are also in compliance with trust indenture requirements for its MTNs as at December 31, 2023 and December 31, 2022.

The following table summarizes the Corporation's primary financial covenants as defined by the credit facility agreements:

Ratios	Debt covenant requirements	**As at December 31, 2023**
Bank debt-to-capitalization [1] [2]	not greater than 65%	less than 52%
Bank EBITDA-to-interest expense [1] [2]	not less than 2.5x	greater than 3.8x
Bank debt-to-capitalization (SEMCO) [2] [3]	not greater than 60%	less than 43%
Bank EBITDA-to-interest expense (SEMCO) [2] [3]	not less than 2.25x	greater than 6.5x
Bank debt-to-capitalization (WGL) [2] [4]	not greater than 65%	less than 49%
Bank debt-to-capitalization (Washington Gas) [2] [4]	not greater than 65%	less than 50%

(1) Calculated in accordance with the Corporation's $2.3 billion credit facility agreement, which is available on SEDAR+ at www.sedarplus.ca. The covenants are equivalent and applicable to all the Corporation's committed credit facilities.
(2) Estimated, subject to final adjustments.
(3) Bank EBITDA-to-interest expense (SEMCO) and bank debt-to-capitalization (SEMCO) are calculated based on SEMCO's consolidated financial statements and are calculated similarly to bank debt-to-capitalization and bank EBITDA-to-interest expense.
(4) WGL's bank debt-to-capitalization ratio is calculated based on WGL's consolidated financial statements.

On March 31, 2023, a short form base shelf prospectus for the issuance of certain types of future public debt and/or equity issuances was filed to replace the short form base shelf prospectus dated February 22, 2021. This enables AltaGas to access the Canadian capital markets on a timely basis during the 25-month period that the short form base shelf prospectus remains effective.

Contractual Obligations

December 31, 2023					
($ millions)	**Total**	Less than 1 year	1 - 3 years	4 - 5 years	After 5 years
Short-term debt	**$ 129**	$ 129	$ —	$ —	$ —
Long-term debt [(1)]	**8,492**	999	2,092	1,548	3,853
Subordinated hybrid notes [(2)]	**750**	—	—	—	750
Operating and finance leases [(3)]	**969**	145	252	186	386
Purchase obligations	**17,548**	2,849	4,222	2,975	7,502
Capital project commitments	**23**	23	—	—	—
Pension plan and retiree benefits [(4)]	**14**	14	—	—	—
Merger commitments [(5)]	**5**	2	3	—	—
Environmental commitments	**12**	6	2	1	3
Other liabilities [(6)]	**43**	43	—	—	—
Total contractual obligations [(7)]	**$ 27,985**	$ 4,210	$ 6,571	$ 4,710	$ 12,494

(1) Excludes deferred financing costs, discounts, and the fair value adjustment on the WGL Acquisition.
(2) Excludes deferred financing costs.
(3) Payments are presented on an undiscounted cash basis.
(4) Assumes only required payments will be made into the pension plans in 2024. Contributions are made in accordance with independent actuarial valuations.
(5) Relates to merger commitments arising from the WGL Acquisition. Represents the estimated future payments of merger commitments that have been accrued but not paid. Among other things, these commitments include rate credits distributable to both residential and non-residential customers to partially offset rate increases resulting from gas expansion, extension of natural gas service over a 10-year period and other programs, various public interest commitments, and safety programs. As at December 31, 2023, the cumulative amount of merger commitments that have been expensed but not yet paid is approximately US$3 million. Additionally, there are a number of operational commitments with various timeframes, including the funding of leak mitigation and reducing leak backlogs, the funding of damage prevention efforts, developing projects to extend natural gas service, maintaining pre-merger quality of service standards including odor call response times, increasing supplier diversity, achieving synergy savings benefits, as well as reporting and tracking related to certain commitments, and causing the development of 15 MW of either electric grid energy storage or tier one renewable resources within five years of the WGL Acquisition, comprised of 10 MW in the District of Columbia and 5 MW in Maryland. Several of these commitments ended in the second quarter of 2023, or five years after the WGL Acquisition. Please refer to Note 29 of the 2023 Annual Consolidated Financial Statements for further discussion of the commitment to develop renewable energy resources in the District of Columbia.
(6) Excludes non-financial liabilities.
(7) U.S. dollar commitments have been converted to Canadian dollars using the December 31, 2023 exchange rate.

AltaGas expects to fund its obligations through internally-generated cash flow, asset sales, and normal course borrowings on existing committed credit facilities.

Related Party Transactions

In the normal course of business, AltaGas transacts with its subsidiaries, affiliates and joint ventures. Refer to Note 30 of the 2023 Annual Consolidated Financial Statements for the amounts due to or from related parties on the Consolidated Balance Sheets and the classification of revenue, income, and expenses in the Consolidated Statements of Income.

Credit Ratings

The below table summarizes the most recent credit ratings for AltaGas and subsidiaries:

Entity	Rating Agency	Debt Rated	Most Recent Rating	Comments
AltaGas	Standard & Poor's ("S&P")	Issuer rating	BBB-	Last reviewed June 23, 2023.
		Senior unsecured	BBB-	Last reviewed June 23, 2023.
		Preferred shares and Junior Subordinated	P-3 / BB	Last reviewed November 9, 2023. Junior Subordinated added on January 5 and August 3, 2022, and November 9, 2023.
	Fitch Ratings ("Fitch")	Issuer	BBB	Last reviewed on June 30, 2023.
		Senior unsecured	BBB	Last reviewed on January 4, 2024.
		Preferred shares and Junior Subordinated	BB+	Last reviewed on November 7, 2023. Junior Subordinated added on January 5 and August 3, 2022, and November 7, 2023.
Washington Gas	S&P	Unsecured debt	A-	Last reviewed June 28, 2023.
		Commercial paper	A-2	Last reviewed June 28, 2023.
	Fitch	Unsecured debt	A	Last reviewed June 30, 2023.
WGL	S&P	Issuer	BBB-	Last reviewed June 28, 2023.
		Senior unsecured	BB+	Last reviewed June 28, 2023.
		Commercial paper	A-3	Last reviewed June 28, 2023.
	Fitch	Issuer	BBB	Last reviewed June 30, 2023.
SEMCO	Moody's	Long-term issuer	A3	Last reviewed May 26, 2023.
		Senior secured notes	A1	Last reviewed May 26, 2023.
	S&P	Long-term issuer	BBB	Last reviewed September 28, 2023.
		Senior secured notes	A-	Last reviewed September 28, 2023.

Please refer to the S&P, Moody's, and Fitch websites for additional details on their ranking systems.

Share Information

	As at March 1, 2024
Issued and outstanding	
Common shares	295,327,138
Preferred Shares	
Series A	6,746,679
Series B	1,253,321
Series G	6,885,823
Series H	1,114,177
Issued	
Share options	5,122,890
Share options exercisable	5,120,729

Dividends

AltaGas declares and pays a quarterly dividend to its common shareholders. Dividends on preferred shares are also paid quarterly. Dividends are at the discretion of the Board of Directors and dividend levels are reviewed periodically, giving consideration to the ongoing sustainable cash flow from operating activities, maintenance and growth capital expenditures, and debt repayment requirements of AltaGas.

The following table summarizes AltaGas' dividend declaration history:

Common Share Dividends

Year Ended December 31				
($ per common share)		**2023**		2022
First quarter	**$**	**0.280000**	$	0.265000
Second quarter		**0.280000**		0.265000
Third quarter		**0.280000**		0.265000
Fourth quarter		**0.280000**		0.265000
Total	**$**	**1.120000**	$	1.060000

Series A Preferred Share Dividends

Year Ended December 31				
($ per preferred share)		**2023**		2022
First quarter	**$**	**0.191250**	$	0.191250
Second quarter		**0.191250**		0.191250
Third quarter		**0.191250**		0.191250
Fourth quarter		**0.191250**		0.191250
Total	**$**	**0.765000**	$	0.765000

Series B Preferred Share Dividends

Year Ended December 31				
($ per preferred share)		**2023**		2022
First quarter	**$**	**0.418750**	$	0.171920
Second quarter		**0.450260**		0.198020
Third quarter		**0.455150**		0.260690
Fourth quarter		**0.492580**		0.376700
Total	**$**	**1.816740**	$	1.007330

Series C Preferred Share Dividends (1)

Year Ended December 31				
(US$ per preferred share)		**2023**		2022
First quarter	**$**	**—**	$	0.330625
Second quarter		**—**		0.330625
Third quarter		**—**		0.330625
Total	**$**	**—**	$	0.991875

(1) On September 30, 2022, AltaGas redeemed all of its outstanding Series C Preferred Shares.

Series E Preferred Share Dividends [1]

Year Ended December 31		
($ per preferred share)	**2023**	2022
First quarter	**$ 0.337063**	$ 0.337063
Second quarter	**0.337063**	0.337063
Third quarter	**0.337063**	0.337063
Fourth quarter	**0.337063**	0.337063
Total	**$ 1.348252**	$ 1.348252

(1) On December 31, 2023, AltaGas redeemed all of its outstanding Series E Preferred Shares.

Series G Preferred Share Dividends

Year Ended December 31		
($ per preferred share)	**2023**	2022
First quarter	**$ 0.265125**	$ 0.265125
Second quarter	**0.265125**	0.265125
Third quarter	**0.265125**	0.265125
Fourth quarter	**0.265125**	0.265125
Total	**$ 1.060500**	$ 1.060500

Series H Preferred Share Dividends

Year ended December 31		
($ per preferred share)	**2023**	2022
First quarter	**$ 0.443404**	$ 0.196582
Second quarter	**0.475190**	0.222950
Third quarter	**0.480350**	0.285890
Fourth quarter	**0.517780**	0.401900
Total	**$ 1.916724**	$ 1.107322

Series K Preferred Share Dividends [1]

Year Ended December 31		
($ per preferred share)	**2023**	2022
First quarter	**$ —**	$ 0.312500
Total	**$ —**	$ 0.312500

(1) On March 31, 2022, AltaGas redeemed all of its outstanding Series K Preferred Shares.

Critical Accounting Estimates

Since a determination of the value of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of AltaGas' Consolidated Financial Statements requires the use of estimates and assumptions that have been made using careful judgment. AltaGas' significant accounting policies are contained in the notes to the 2023 Annual Consolidated Financial Statements. Certain of these policies involve critical accounting estimates as a result of the requirement to make particularly subjective or complex judgments about matters that are inherently uncertain, and because of the likelihood that materially different amounts could be reported under different conditions or using different assumptions.

Significant estimates and judgments made by Management in the preparation of the Consolidated Financial Statements are outlined below:

Regulatory Assets and Liabilities

SEMCO and Washington Gas engage in the delivery and sale of natural gas. SEMCO is regulated by the MPSC, and Washington Gas is regulated by the PSC of DC in the District of Columbia, the PSC of MD in Maryland, and the SCC of VA in Virginia.

The regulatory agencies exercise statutory authority over matters such as tariffs, rates, construction, operations, financing, returns and certain contracts with customers. In order to recognize the economic effects of the actions and decisions of the regulators, the timing of recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using U.S. GAAP for entities not subject to rate regulation.

Regulatory assets represent future revenues associated with certain costs incurred in the current period or in prior periods that are expected to be recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that are expected to be refunded to customers through the rate-setting process.

Asset Impairment

AltaGas reviews long-lived assets, regulatory assets, and intangible assets with indefinite and finite lives whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Recoverability is determined based on an estimate of undiscounted cash flows or other indicators of fair value, and measurement of an impairment loss is determined based on the fair value of the assets. The determination of fair value requires Management to make assumptions about future cash inflows and outflows over the life of an asset. Any changes to the assumptions used for the future cash flow could result in revisions to the evaluation of the recoverability of the long-lived assets or intangible assets and the recognition of an impairment loss in the Consolidated Financial Statements.

AltaGas also tests goodwill for impairment annually or more frequently if events or changes in circumstances indicate that it is more likely than not that the fair value of a reporting unit is less than its carrying value. The Corporation has the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment test. If the quantitative goodwill impairment test is performed, the fair value of the Corporation’s reporting units is compared to the carrying values. If the carrying value of a reporting unit, including allocated goodwill exceeds its fair value, goodwill impairment is measured as the excess of the carrying value amount of the reporting unit’s allocated goodwill over the implied fair value of the goodwill. Based on the valuation approach, the fair value used in the quantitative impairment test of goodwill requires determining appropriate market multiples of earnings or estimating future cash flows as well as appropriate discount rates. AltaGas has assessed goodwill for impairment as at December 31, 2023 and determined that no write-down was required.

Asset Retirement Obligations

AltaGas records liabilities relating to asset retirement obligations when there is a legal obligation. In estimating the obligations, Management is required to make assumptions regarding inflation and discount rates, ultimate amounts and timing of settlements, and expected changes in environmental laws and regulation. A change in any of these estimates could have a material impact on AltaGas' Consolidated Financial Statements.

Income Taxes

The Corporation is subject to the provisions of the *Income Tax Act* (Canada) for purposes of determining the amount of income that will be subject to tax in Canada and the *Internal Revenue Code* (U.S.) for the purposes of determining the amount of income that will be subject to tax in the United States. The determination of AltaGas' and its subsidiaries' provision for income taxes requires the application of these complex rules.

The recognition of deferred tax assets depends on the assumption that future earnings will be sufficient to realize the deferred benefit. A valuation allowance is recorded against deferred tax assets where all or a portion of that asset is not expected to be realized. The amount of the deferred tax asset or liability recorded is based on Management's best estimate of the timing of the realization of the assets or liabilities.

If Management's interpretation of tax legislation differs from that of tax authorities, or if timing of reversals is not as anticipated, the provision for income taxes could increase or decrease in future periods. See Note 20 of the 2023 Annual Consolidated Financial Statements.

Pension Plans and Post-Retirement Benefits

The determination of pension plan obligations and expense is based on a number of actuarial assumptions. Critical assumptions include the expected long-term rate-of-return on plan assets, the discount rate applied to pension plan obligations, the expected rate of compensation increase, and mortality rates. For post-retirement benefit plans, which provide for certain health care premiums and life insurance benefits for qualifying retired employees and which are not funded, critical assumptions in determining post-retirement obligations and expense are the discount rate and the assumed health care cost trend rates.

Depreciation and Amortization

Depreciation and amortization of property, plant, and equipment and intangible assets are based on Management's judgment of the estimated useful life of the assets. When it is determined that assigned asset lives do not reflect the estimated remaining period of benefit, prospective changes are made to the depreciable lives of those assets. For regulated entities, amortization rates are generally prescribed by the applicable regulatory authority. There are a number of uncertainties inherent in estimating the remaining useful life of certain assets and changes in assumptions could result in material adjustments to the amount of amortization that AltaGas recognizes from period to period.

Loss Contingencies

AltaGas and its subsidiaries are subject to various legal claims and actions arising in the normal course of business. Liabilities for loss contingencies are determined on a case-by-case basis and are accrued for when it is probable that a liability has been incurred and the amount can be reasonably estimated. Significant judgment is required to determine the probability of having incurred the liability and the estimated amount. Estimates are reviewed regularly and updated as new information is received. As at December 31, 2023, no material provisions on loss contingencies have been recorded by the Corporation. However, due to the inherent uncertainty of the litigation process, the resolution of any particular contingencies could have a material adverse effect on the Corporation's results of operations or financial position.

Fair Value of Financial Instruments

Fair value is defined as the amount of consideration that would be agreed upon in an arms-length transaction, other than a forced sale or liquidation, between knowledgeable, willing parties who are under no compulsion to act. The best evidence of fair value is a quoted bid or ask price, as appropriate, in an active market. Fair value based on unadjusted quoted prices in an active market requires minimal judgment by Management. Where bid or ask prices in an active market are not available, Management's judgment on valuation inputs is necessary to determine fair value. AltaGas enters into physical and financial derivative contracts to manage exposure to fluctuations in commodity prices and foreign exchange rates, as well as to optimize certain owned and managed natural gas assets. AltaGas estimates forward prices based on published sources adjusted for factors specific to the asset or liability, including basis and location differentials, discount rates, and currency exchange. The forward curves used to mark these derivative instruments to market are vetted against public sources. Where observable market data is not available, AltaGas uses valuation techniques which require significant judgment by Management. Changes in estimates and assumptions about these inputs could affect the reported fair value.

Adoption of New Accounting Standards

Effective January 1, 2023, AltaGas adopted the following Financial Accounting Standards Board ("FASB") issued Accounting Standards Updates ("ASU"):

- In October 2021, FASB issued ASU 2021-08 "Business Combinations (Topic 805): Accounting for Contract Assets and Contract Liabilities from Contracts with Customers". The amendments in this ASU require an entity to recognize and measure contract assets and liabilities acquired in a business combination in accordance with Topic 606. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements.

- In March 2022, FASB issued ASU No. 2022-01 "Derivatives and Hedging (Topic 815): Fair Value Hedging - Portfolio Layer Method". The amendments in this ASU will allow non-prepayable financial assets to be included in a closed portfolio hedged using the portfolio layer method and promote consistency in single and multiple hedged layers. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements.

- In March 2022, FASB issued ASU No. 2022-02 "Financial Instruments - Credit Losses (Topic 326): Troubled Debt Restructurings and Vintage Disclosures". The amendments in this ASU will eliminate the accounting guidance for troubled debt restructurings ("TDRs") by creditors while enhancing disclosure requirements for certain loan refinancings and restructurings by creditors when a borrower is experiencing financial difficulty, as well as require the disclosure of current-period write offs by year of origination for financing receivables and net investments in leases. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements.

- In September 2022, FASB issued ASU No. 2022-04 "Liabilities (Subtopic 405-50) - Supplier Finance Programs". The amendments in this ASU will require a buyer in a supplier finance program to disclose the key terms of the program, the amount outstanding at the end of the period, a roll forward of that obligation during the period, and where the obligation is presented on the balance sheet. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements.

Future Changes in Accounting Principles

In June 2022, FASB issued ASU No. 2022-03 "Fair Value Measurement (Topic 820): Fair Value Measurement of Equity Securities Subject to Contractual Sale Restrictions". The amendments in this ASU clarify that a contractual restriction on the sale of an equity security is not considered part of the unit of account of the equity security, and therefore, is not considered in measuring fair value. In addition, an entity cannot, as a separate unit of account, recognize a contractual sale restriction. Equity securities subject to contractual sale restrictions also require certain additional disclosures. The amendments in this ASU are effective for fiscal years beginning after December 15, 2023 and should be applied prospectively with adjustments as a result of adopting this ASU being recognized in earnings. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

In March 2023, FASB issued ASU No. 2023-01 "Leases (Topic 842): Common Control Arrangements". The relevant amendments in this ASU allow entities to amortize leasehold improvements under common control over the economic life of the leasehold improvements as long as the lessee controlled the use of the leased asset. The amendments in this ASU are effective for fiscal years beginning after December 15, 2023, including interim periods within those fiscal years and can be applied using one of the following three methods: 1) prospectively to all new leasehold improvements recognized on or after the date the entity applies the amendments, 2) prospectively to all new leasehold improvements recognized on or after the date the entity applies the amendments, with any remaining unamortized balance of existing leasehold improvements amortized over their remaining useful life to the common-control group determined at that date, or 3) retrospectively to the beginning of the period in which the entity first applied Topic 842, with any leasehold improvements that otherwise would not have been amortized or impaired recognized through a cumulative-effect adjustment to opening retained earnings at the beginning of the earliest period presented. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

In March 2023, FASB issued ASU No. 2023-02 "Investments - Equity Method and Joint Ventures (Topic 323) - Accounting for Investments in Tax Credit Structures Using the Proportional Amortization Method". The amendments in this ASU allow entities the option to elect to account for tax equity investments, regardless of the tax credit program from which the income tax credits are received, using the proportional amortization method if certain conditions are met. The amendments in this ASU are effective for public business entities for fiscal years beginning after December 15, 2023, including interim periods within those fiscal years and can applied on either a modified prospective or retrospective basis. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

In October 2023, FASB issued ASU No. 2023-06 "Disclosure Improvements". The amendments in this ASU modify the disclosure or presentation requirements of a variety of topics in the codification as a result of FASB's decision to incorporate disclosures referred to in SEC Release No. 33-10532, which sought to simplify SEC disclosure requirements. The amendments in this ASU allow users to more easily compare entities subject to the SEC's existing disclosures with those entities that were not previously subject to the SEC's requirements. This Update is only effective upon the removal of the related disclosure from SEC regulations with an expiration of June 30, 2027. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements at this time, but may have an impact in future periods as AltaGas is subject to the scope of this ASU.

In November 2023, FASB issued ASU No. 2023-07 "Segment Reporting (Topic 280)". This ASU requires all public entities required to report segment information in accordance with Topic 280 to provide: (1) annual and interim disclosure of significant segment expenses regularly provided to the chief operating decision maker ("CODM"), (2) annual and interim disclosure of other segment items, (3) annual disclosures about reportable segment profit or loss and assets currently required by Topic 280 in interim periods, (4) disclosure of additional measures used to measure a segments profit or loss outside of GAAP, (5) disclosure of the title and position of the CODM, and (6) a public entity that has a single reportable segment to provide all the disclosures required by this update and all existing segment disclosures in Topic 280. This update is effective for fiscal years beginning after December 31, 2023, and interim periods with fiscal years beginning after December 15, 2024. The adoption of this ASU will have an impact on AltaGas' segment disclosures.

In December 2023, FASB issued ASU No. 2023-09 "Income Taxes (Topic 740): Improvements to Income Tax Disclosures". The amendments in this ASU require that public business entities on an annual basis: (1) disclose additional categories about federal, state, and foreign income taxes in the rate reconciliation table and (2) provide additional information for reconciling items that meet a quantitative threshold. Additionally, entities are required to annually disclose disaggregated income from continuing operations, income tax expense, and income taxes paid (net of refunds received) by certain tax authorities and jurisdictions. This update is effective for annual periods beginning after December 15, 2024. The adoption of this ASU will have an impact on AltaGas' income tax disclosures.

Off-Balance Sheet Arrangements

AltaGas is not party to any contractual arrangements with unconsolidated entities that have, or are reasonably likely to have, a current or future material effect on the Corporation's financial performance or financial condition including liquidity and capital resources.

Disclosure Controls and Procedures ("DCP") and Internal Control Over Financial Reporting ("ICFR")

Management, including the Chief Executive Officer and Chief Financial Officer, are responsible for establishing and maintaining DCP and ICFR, as those terms are defined in National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings". The objective of this instrument is to improve the quality, reliability, and transparency of information that is filed or submitted under securities legislation.

Management, including the Chief Executive Officer and the Chief Financial Officer, have designed, or caused to be designed under their supervision, DCP and ICFR to provide reasonable assurance that information required to be disclosed by AltaGas in its annual filings, interim filings or other reports to be filed or submitted by it under securities legislation is made known to them, is reported on a timely basis, financial reporting is reliable, and financial statements prepared for external purposes are in accordance with U.S. GAAP.

The ICFR have been designed based on the framework established in the 2013 Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

Management has designed the existing framework to result in both a complete and accurate consolidation of related information. During the year ended December 31, 2023, there were no changes made to AltaGas' ICFR that materially affected, or are reasonably likely to materially affect, its ICFR or DCP.

The Chief Executive Officer and the Chief Financial Officer have evaluated, with the assistance of AltaGas' employees, the effectiveness of AltaGas' DCP and ICFR as at December 31, 2023 and concluded that as at December 31, 2023 AltaGas' DCP and ICFR were effective.

Limitation on Scope

In accordance with the provisions under National Instrument 52-109, the scope of the evaluation does not include ICFR related to the Pipestone Acquisition, which closed on December 22, 2023. These provisions allow an issuer to exclude a business which was acquired not more than 365 days before the issuer's financial year-end from the scope of its certifications. As such, the controls, policies, and procedures related to the Pipestone Acquisition were excluded from management's evaluation of the effectiveness of AltaGas' ICFR as at December 31, 2023. Summary financial information of the Pipestone Acquisition included in the audited Consolidated Financial Statements as at and for the year ended December 31, 2023, includes total assets of approximately $887 million and revenues of approximately $14 million.

It should be noted that a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues, including instances of fraud, if any, have been detected. The design of any system of controls is also based in part on certain assumptions about the likelihood of future events, and there can be no assurances that any design will succeed in achieving its stated goals under all potential conditions.

Summary of Consolidated Results for the Eight Most Recent Quarters [1]

($ millions)	**Q4-23**	Q3-23	Q2-23	Q1-23	Q4-22	Q3-22	Q2-22	Q1-22
Total revenue	**3,288**	3,030	2,631	4,048	3,898	3,056	3,241	3,892
Normalized EBITDA [2]	**502**	252	239	582	454	233	276	574
Net income (loss) applicable to common shares	**113**	(50)	133	445	54	(48)	35	357
($ per share)	**Q4-23**	Q3-23	Q2-23	Q1-23	Q4-22	Q3-22	Q2-22	Q1-22
Net income (loss) per common share								
Basic	**0.40**	(0.18)	0.47	1.58	0.19	(0.17)	0.12	1.27
Diluted	**0.40**	(0.18)	0.47	1.57	0.19	(0.17)	0.12	1.26
Dividends declared	**0.28**	0.28	0.28	0.28	0.27	0.27	0.27	0.27

(1) Amounts may not add due to rounding.
(2) Non-GAAP financial measure. Prior periods have been revised to reflect a change in the composition of normalized EBITDA made in the third quarter of 2022. See discussion in the *Non-GAAP Financial Measures* section of this MD&A.

AltaGas' quarter-over-quarter financial results are impacted by seasonality, fluctuations in commodity prices, weather, the U.S./Canadian dollar exchange rate, planned and unplanned plant outages, timing of in-service dates of new projects, and acquisition and divestiture activities.

Revenue for the Utilities is generally the highest in the first and fourth quarters of any given year as the majority of natural gas demand occurs during the winter heating season, which typically extends from November to March.

Other significant items that impacted quarter-over-quarter revenue during the periods noted include:

- The impact of the sale of AltaGas' interest in the Aitken Creek processing facilities in the second quarter of 2022;
- The impact of the Alaska Utilities Disposition in the first quarter of 2023; and
- The impact of the Pipestone Acquisition in the fourth quarter of 2023.

Net income (loss) applicable to common shares is also affected by non-cash items such as deferred income tax, depreciation and amortization expense, accretion expense, provisions on assets, gains or losses on long-term investments, and gains or losses on the sale of assets. In addition, net income (loss) applicable to common shares is also impacted by preferred share dividends and gains or losses on the redemption of preferred shares. For these reasons, net income (loss) may not necessarily reflect the same trends as revenue. Net income (loss) applicable to common shares during the periods noted was impacted by:

- After-tax transaction costs of approximately $27 million and $4 million incurred throughout 2023 and 2022, respectively, primarily due to asset sales and the Pipestone Acquisition;
- The gain on the sale of Goleta in the first quarter of 2022 as well as an additional gain recorded in the first quarter of 2023 a result of the favourable settlement of outstanding contingencies;
- The loss on the Series K Preferred Shares that were redeemed on March 31, 2022;
- Favourable resolution of certain acquisition related commercial disputes and contingencies in 2022 and in the first quarter of 2023;
- The loss on the redemption of the U.S. dollar denominated Series C Preferred Shares in September 2022, including the associated foreign exchange impact;
- The gain resulting from the partial defeasance of SEMCO's First Mortgage Bonds in the first quarter of 2023;
- The gain on the Alaska Utilities Disposition in the first quarter of 2023; and
- The loss on the Series E Preferred Shares that were redeemed on December 31, 2023.

SELECTED ANNUAL FINANCIAL INFORMATION

($ millions, except where noted)	**2023**	2022	2021
Revenue	**12,997**	14,087	10,573
Net income applicable to common shares	**641**	399	230
Net income per common share - basic	**2.27**	1.42	0.82
Net income per common share - diluted	**2.26**	1.41	0.82
Total assets	**23,471**	23,965	21,593
Total long-term liabilities	**12,195**	12,940	11,335
Weighted average number of common shares outstanding *(millions)*	**282**	281	280
Dividends declared per common share *($ per share)*	**1.120000**	1.060000	0.999600
Preferred share dividends declared *($ per share)*			
Series A	**0.765000**	0.765000	0.765000
Series B	**1.816740**	1.007330	0.694360
Series C *(US$)* (1)	**—**	0.991875	1.322500
Series E (2)	**1.348252**	1.348252	1.348252
Series G	**1.060500**	1.060500	1.060500
Series H	**1.916724**	1.107322	0.794372
Series K (2)	**—**	0.312500	1.250000

(1) Series C Preferred Shares were redeemed on September 30, 2022.
(2) Series E Preferred Shares were redeemed on December 31, 2023.
(3) Series K Preferred Shares were redeemed on March 31, 2022.

OTHER INFORMATION

DEFINITIONS

Bbls/d	barrels per day
Bcf	billion cubic feet
CBM	cubic meter
Dth	dekatherm
GJ	gigajoule
GWh	gigawatt-hour
Mmcf	million cubic feet
Mmcf/d	million cubic feet per day
MW	megawatt
MWh	megawatt-hour
US$	United States dollar

ABOUT ALTAGAS

AltaGas is a leading North American energy infrastructure Company that connects NGLs and natural gas to domestic and global markets. The Company operates a diversified, lower-risk, high-growth Utilities and Midstream business that is focused on delivering resilient and durable value for its stakeholders.

For more information visit www.altagas.ca or reach out to one of the following:

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MANAGEMENT'S REPORT

The Consolidated Financial Statements of AltaGas Ltd. ("AltaGas", the "Corporation", or the "Company") and other financial information included in this report are the responsibility of Management. The Consolidated Financial Statements have been prepared by Management in accordance with United States Generally Accepted Accounting Principles ("U.S. GAAP") and include amounts that are based on Management’s best estimates and judgments. It is Management's responsibility to ensure that judgments, estimates and accounting principles and methods used in the preparation of financial information are reasonable, appropriate, and applied consistently.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal controls over financial reporting for the Corporation (as defined in Rules 13a-15(f) of the Securities Exchange Act and under National Instrument 52-109).

Management has used the framework established in the 2013 Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") to evaluate the effectiveness of the Corporation's internal control over financial reporting. Based on this evaluation, Management, including the CEO and CFO, has concluded that the Corporation's internal control over financial reporting is effective as at December 31, 2023.

In accordance with the provisions under National Instrument 52-109, the scope of the evaluation does not include ICFR related to the Pipestone Acquisition, which closed on December 22, 2023. As such, the controls, policies, and procedures related to the Pipestone Acquisition were excluded from management's evaluation of the effectiveness of AltaGas' ICFR as at December 31, 2023. Summary financial information of the Pipestone Acquisition included in the audited Consolidated Financial Statements as at and for the year ended December 31, 2023, includes total assets of approximately $887 million and revenues of approximately $14 million.

Internal control over financial reporting may not prevent all misstatements due to its inherent limitations. In addition, the evaluation of internal control was made as of a specific date and continued effectiveness in future periods is subject to the risk that controls may become inadequate.

The Board of Directors is responsible for ensuring that Management fulfills its responsibilities for financial reporting and internal controls. The Board is assisted in carrying out its responsibilities principally through its Audit Committee which is composed of independent non-management directors. The Audit Committee meets with Management regularly and meets independently with internal and external auditors and as a group to review any significant accounting, internal controls, and auditing matters in accordance with the terms of the Charter of the Audit Committee, which is set out in the Annual Information Form.

The shareholders have appointed Ernst & Young LLP as independent external auditors to express an opinion as to whether the Consolidated Financial Statements present fairly, in all material respects, the Corporation’s consolidated financial position, results of operations, and cash flows in accordance with U.S. GAAP. Ernst & Young LLP is not required under securities law to express an opinion as to the effectiveness of the Corporation's internal control over financial reporting. The report of Ernst & Young LLP outlines the scope of its examination and its opinion on the Consolidated Financial Statements.

(signed) "Vern Yu"

VERN YU
President and
Chief Executive Officer of
AltaGas Ltd.

(signed) "James Harbilas"

JAMES HARBILAS
Executive Vice President and
Chief Financial Officer of
AltaGas Ltd.

March 7, 2024

INDEPENDENT AUDITOR'S REPORT

To the Shareholders and Directors of AltaGas Ltd.

Opinion

We have audited the consolidated financial statements of AltaGas Ltd. and its subsidiaries (the Group), which comprise the consolidated balance sheets as at December 31, 2023 and 2022, and the consolidated statements of income, consolidated statements of comprehensive income, consolidated statements of equity and consolidated statements of cash flows for the years then ended, and notes to the consolidated financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Group as at December 31, 2023 and 2022, and the consolidated results of its operations and its consolidated cash flows for the years then ended in accordance with United States generally accepted accounting principles ("US GAAP").

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 are independent of the Group in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key audit matters

Key audit matters are those matters that, in our professional judgment, were of most significance in the audit of the consolidated financial statements of the current period. These matters were addressed in the context of the audit of the consolidated financial statements as a whole, and in forming the auditor's opinion thereon, and we do not provide a separate opinion on these matters. For the matter below, our description of how our audit addressed the matter is provided in that context.

We have fulfilled the responsibilities described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report, including in relation to this matter. Accordingly, our audit included the performance of procedures designed to respond to our assessment of the risks of material misstatement of the consolidated financial statements. The results of our audit procedures, including the procedures performed to address the matter below, provide the basis for our audit opinion on the accompanying consolidated financial statements.

Fair Value Measurement of Level 3 Derivatives

Key audit matter

As described in note 23 to the consolidated financial statements, AltaGas Ltd. enters into commodity contracts that qualify as derivative instruments and are accounted for under ASC Topic 815, Derivatives and Hedging. The fair value measurements of certain of these contracts are considered Level 3 under the fair value hierarchy as they are determined using significant unobservable inputs. As of December 31, 2023, derivative assets of $82 million and derivative liabilities of $135 million were recorded based on Level 3 fair value measurements.

Auditing the fair value measurement of Level 3 derivative instruments was complex given the judgmental nature of the assumptions used as inputs into the valuation models. In particular, the valuation of Level 3 derivative instruments is sensitive to significant unobservable inputs used by the Group such as the assumed natural gas basis prices and implied volatilities of natural gas prices. These unobservable assumptions can be affected by future economic and market conditions.

How our audit addressed the key audit matter

To test the Group's valuation of Level 3 derivative instruments, our audit procedures included, among others:

- Evaluated the appropriateness of the underlying valuation methodologies used by the Group.
- For a sample of instruments, we independently determined the significant unobservable assumptions described above, calculated the resulting fair values and compared them to the Group's estimates.
- For a sample of instruments, we obtained forward prices from independent sources, including broker quotes, evaluated the Group's assumptions related to their forward curves and obtained external confirmation of key contract terms from counterparties.
- Performed sensitivity analyses using independent sources of market data to evaluate the change in fair value of Level 3 derivative instruments that would result from changes in underlying assumptions.
- Evaluated the adequacy of the Level 3 fair value measurement note disclosure in the consolidated financial statements related to the matter.

Other information

Management is responsible for the other information. The other information comprises:

- Management's Discussion and Analysis

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

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information 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.

We obtained Management's Discussion and Analysis prior to the date of this auditor's report. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact in this auditor's report. We have nothing to report in this regard.

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 US GAAP, 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 Group’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 Group or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Group’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 Group’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 Group’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 Group 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 Group to express an opinion on the consolidated financial statements. We are responsible for 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 Ann-Marie Brockett.

Ernst & Young LLP

Chartered Professional Accountants

Calgary, Canada
March 7, 2024

CONSOLIDATED BALANCE SHEETS

As at December 31		2023		2022
ASSETS				
Current assets				
Cash and cash equivalents *(note 31)*	**$**	**95**	$	53
Accounts receivable *(net of credit losses of $29 million) (notes 9 and 23)*		**1,844**		2,091
Inventory *(note 6)*		**847**		1,060
Regulatory assets *(note 21)*		**58**		38
Risk management assets *(note 23)*		**54**		140
Prepaid expenses and other current assets *(notes 28 and 31)*		**147**		169
Assets held for sale		**—**		1,087
		3,045		4,638
Property, plant and equipment *(note 7)*		**12,728**		11,686
Intangible assets *(note 8)*		**122**		120
Operating right-of-use assets *(note 9)*		**337**		281
Goodwill *(note 10)*		**5,270**		5,250
Regulatory assets *(note 21)*		**329**		448
Risk management assets *(note 23)*		**57**		77
Prepaid post-retirement benefits *(note 28)*		**626**		538
Long-term investments and other assets *(net of credit losses of $1 million) (notes 11, 28, and 31)*		**271**		273
Investments accounted for by the equity method *(note 13)*		**686**		654
	$	**23,471**	$	23,965
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities				
Accounts payable and accrued liabilities *(notes 17, 18, 23, and 28)*	**$**	**1,863**	$	1,902
Short-term debt *(notes 14 and 23)*		**129**		293
Current portion of long-term debt *(notes 15 and 23)*		**999**		327
Customer deposits		**92**		79
Regulatory liabilities *(note 21)*		**85**		183
Risk management liabilities *(note 23)*		**97**		172
Operating lease liabilities *(note 9)*		**92**		92
Current portion of finance lease liabilities *(note 9 and 23)*		**11**		7
Other current liabilities *(note 23)*		**45**		57
Liabilities associated with assets held for sale		**—**		295
		3,413		3,407
Long-term debt *(notes 15 and 23)*		**7,528**		8,679
Asset retirement obligations *(note 17)*		**448**		451
Unamortized investment tax credits *(note 20)*		**1**		2
Deferred income taxes *(note 20)*		**1,536**		1,369
Subordinated hybrid notes *(notes 16 and 23)*		**742**		544
Regulatory liabilities *(note 21)*		**1,274**		1,201
Risk management liabilities *(note 23)*		**115**		298
Operating lease liabilities *(note 9)*		**258**		215
Finance lease liabilities *(note 9 and 23)*		**120**		15
Other long-term liabilities *(notes 19 and 23)*		**124**		122
Future employee obligations *(note 28)*		**49**		44
	$	**15,608**	$	16,347

As at December 31		2023		2022
Shareholders' equity				
Common shares, no par values, unlimited shares authorized; 2023 - 294.9 million and 2022 - 281.5 million issued and outstanding *(note 25)*	**$**	**7,120**	$	6,761
Preferred shares *(note 25)*		**391**		586
Contributed surplus		**624**		625
Accumulated deficit		**(817)**		(1,142)
Accumulated other comprehensive income (AOCI) *(note 22)*		**395**		626
Total shareholders' equity		**7,713**		7,456
Non-controlling interests		**150**		162
Total equity	**$**	**7,863**	$	7,618
	$	**23,471**	$	23,965

Acquisitions (note 3)
Variable interest entities (note 12)
Commitments, guarantees and contingencies (note 29)
Related party transactions (note 30)
Segmented information (note 32)
Subsequent events (note 33)

See accompanying notes to the Consolidated Financial Statements.

Approved by the Board of Directors of AltaGas Ltd.

(signed) "Vern Yu"

VERN YU
Director

(signed) "Linda Sullivan"

LINDA SULLIVAN
Director

CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31		2023		2022
REVENUE *(note 24)*	**$**	**12,997**	$	14,087
EXPENSES				
Cost of sales, exclusive of items shown separately		**10,112**		11,138
Operating and administrative		**1,579**		1,568
Accretion expenses *(note 17)*		**11**		7
Depreciation and amortization *(notes 7 and 8)*		**441**		439
Provisions on assets *(note 5)*		**—**		6
		12,143		13,158
Income from equity investments *(note 13)*		**55**		13
Other income *(note 27)*		**403**		94
Foreign exchange gains (losses)		**(6)**		10
Interest expense		**(394)**		(330)
Income before income taxes		**912**		716
Income tax expense *(note 20)*				
Current		**43**		23
Deferred		**180**		120
Net income after taxes		**689**		573
Net income applicable to non-controlling interests		**16**		50
Net income applicable to controlling interests		**673**		523
Preferred share dividends		**(27)**		(40)
Loss on redemption of preferred shares *(note 25)*		**(5)**		(84)
Net income applicable to common shares	**$**	**641**	$	399
Net income per common share *(note 26)*				
Basic	**$**	**2.27**	$	1.42
Diluted	**$**	**2.26**	$	1.41
Weighted average number of common shares outstanding (millions) *(note 26)*				
Basic		**282.1**		281.0
Diluted		**283.7**		283.3

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31		2023		2022
Net income after taxes	**$**	**689**	$	573
Other comprehensive income (loss), net of taxes				
Gain (loss) on foreign currency translation		**(250)**		643
Unrealized gain (loss) on net investment hedge *(note 23)*		**25**		(15)
Actuarial gain on defined benefit pension and post-retirement benefit (PRB) plans *(note 28)*		**1**		3
Settlement of Canadian defined benefit pension plan *(note 28)*		**2**		—
Unrealized loss on cash flow hedges *(note 23)*		**(9)**		—
Total other comprehensive income (loss) (OCI), net of taxes	**$**	**(231)**	$	631
Comprehensive income attributable to controlling interests and non-controlling interests, net of taxes	**$**	**458**	$	1,204
Comprehensive income attributable to:				
Non-controlling interests	**$**	**16**	$	53
Controlling interests		**442**		1,151
	$	**458**	$	1,204

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF EQUITY

Year Ended December 31		2023		2022
Common shares *(note 25)*				
Balance, beginning of year	**$**	**6,761**	$	6,735
Shares issued for cash on exercise of options		**19**		28
Shares issued related to Pipestone Acquisition *(note 3)*		**340**		—
Deferred taxes on share issuance costs		**—**		(2)
Balance, end of year	**$**	**7,120**	$	6,761
Preferred shares *(note 25)*				
Balance, beginning of year		**586**		1,076
Redemption of preferred shares *(note 25)*		**(195)**		(490)
Balance, end of year	**$**	**391**	$	586
Contributed surplus				
Balance, beginning of year		**625**		388
Share options expense		**1**		3
Exercise of share options		**(2)**		(3)
Purchase of remaining non-controlling interest in a subsidiary		**—**		237
Balance, end of year	**$**	**624**	$	625
Accumulated deficit				
Balance, beginning of year		**(1,142)**		(1,243)
Net income applicable to controlling interests		**673**		523
Common share dividends		**(316)**		(298)
Preferred share dividends		**(27)**		(40)
Loss on redemption of preferred shares *(note 25)*		**(5)**		(84)
Balance, end of year	**$**	**(817)**	$	(1,142)
AOCI *(note 22)*				
Balance, beginning of year		**626**		(7)
Other comprehensive income (loss)		**(231)**		628
Purchase of remaining non-controlling interest in a subsidiary		**—**		5
Balance, end of year	**$**	**395**	$	626
Total shareholders' equity	**$**	**7,713**	$	7,456
Non-controlling interests				
Balance, beginning of year		**162**		652
Net income applicable to non-controlling interests		**16**		50
Foreign currency translation adjustments		**—**		3
Contributions from non-controlling interests to subsidiaries		**33**		—
Distributions by subsidiaries to non-controlling interests		**(18)**		(21)
Acquisition of remaining non-controlling interest in a subsidiary		**—**		(522)
Adjustment on disposition of assets *(note 4)*		**(43)**		—
Balance, end of year	**$**	**150**	$	162
Total equity	**$**	**7,863**	$	7,618

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31	2023	2022
Cash from operations		
Net income after taxes	**$ 689**	$ 573
Items not involving cash:		
Depreciation and amortization *(notes 7 and 8)*	**441**	439
Provisions on assets *(note 5)*	**—**	6
Accretion expenses *(note 17)*	**11**	7
Share-based compensation *(note 25)*	**1**	3
Deferred income tax expense *(note 20)*	**180**	120
Gains on sale of assets *(notes 4 and 27)*	**(319)**	(3)
Gain on debt defeasance *(note 15)*	**(14)**	—
Income from equity investments *(note 13)*	**(55)**	(13)
Unrealized losses on risk management contracts *(note 23)*	**70**	49
Amortization of deferred financing costs	**8**	6
Allowance for credit losses *(note 23)*	**24**	26
Change in pension and other post-retirement benefits *(note 28)*	**6**	(46)
Other	**(19)**	18
Asset retirement obligations settled *(note 17)*	**(15)**	(10)
Distributions from equity investments	**13**	14
Changes in operating assets and liabilities *(note 31)*	**100**	(650)
	$ 1,121	$ 539
Investing activities		
Business acquisitions, net of cash acquired *(note 3)*	**(327)**	—
Capital expenditures - property, plant and equipment	**(934)**	(945)
Capital expenditures - intangible assets	**(9)**	(13)
Distributions from (contributions to) equity investments	**(4)**	1
Proceeds from disposition of equity investments	**1**	—
Proceeds from disposition of assets, net of transaction costs *(note 4)*	**1,074**	245
Purchase of remaining non-controlling interest in a subsidiary	**—**	(285)
	$ (199)	$ (997)
Financing activities		
Net issuance of short-term debt	**—**	128
Issuance of long-term debt, net of debt issuance costs	**673**	718
Purchase of marketable securities in connection with debt defeasance *(note 15)*	**(193)**	—
Repayment of long-term debt and finance leases	**(338)**	(513)
Net borrowing (repayment) under credit facilities	**(678)**	466
Issuance of subordinated hybrid notes, net of debt issuance costs *(note 16)*	**198**	544
Dividends - common shares	**(316)**	(298)
Dividends - preferred shares	**(27)**	(40)
Distributions to non-controlling interests	**(18)**	(21)
Net proceeds from shares issued on exercise of options *(note 25)*	**17**	25
Redemption of preferred shares *(note 25)*	**(200)**	(574)
	$ (882)	$ 435
Change in cash, cash equivalents, and restricted cash	**40**	(23)
Effect of exchange rate changes on cash, cash equivalents, and restricted cash	**—**	4
Net change in cash classified within assets held for sale	**—**	(1)
Cash, cash equivalents, and restricted cash beginning of year	**64**	84
Cash, cash equivalents, and restricted cash end of year *(note 31)*	**$ 104**	$ 64

See accompanying notes to the Consolidated Financial Statements.

(Tabular amounts and amounts in footnotes to tables are in millions of Canadian dollars unless otherwise indicated.)

1. Organization and Overview of the Business

The businesses of AltaGas are operated by the Company and a number of its subsidiaries including, without limitation, AltaGas Services (U.S.) Inc., AltaGas Utility Holdings (U.S.) Inc., WGL Holdings, Inc. ("WGL"), Wrangler 1 LLC, Wrangler SPE LLC, Washington Gas Resources Corp., WGL Energy Services, Inc. ("WGL Energy Services"), and SEMCO Holding Corporation; in regard to the Utilities business, Washington Gas Light Company ("Washington Gas"), Hampshire Gas Company, and SEMCO Energy, Inc.; and in regard to the Midstream business, AltaGas Extraction and Transmission Limited Partnership, AltaGas Pipeline Partnership, AltaGas Processing Partnership, AltaGas Northwest Processing Limited Partnership, Harmattan Gas Processing Limited Partnership, Ridley Island LPG Export Limited Partnership, AltaGas Pacific Partnership, AltaGas LPG Limited Partnership, Petrogas Energy Corporation ("Petrogas"), Petrogas Holdings Partnership, and Petrogas, Inc. In the Corporate/Other segment the main subsidiary is AltaGas Power Holdings (U.S.) Inc. SEMCO Energy conducts its Michigan natural gas distribution business under the name SEMCO Energy Gas Company ("SEMCO").

AltaGas is a leading North American energy infrastructure company that connects customers and markets to affordable and reliable sources of energy. The Company operates a diversified, lower-risk, high-growth energy infrastructure business that is focused on delivering resilient and durable value for its stakeholders.

AltaGas' operating segments include the following:

- Utilities, which owns and operates franchised, cost-of-service, rate regulated natural gas distribution and storage utilities that focus on providing safe, reliable, and affordable energy to approximately 1.6 million residential and commercial customers. This includes operating two utilities that operate across four major U.S. jurisdictions with a rate base of approximately US$5.1 billion. The Utilities business also includes storage facilities and contracts for interstate natural gas transportation and storage services, as well as WGL Energy Services, an affiliated retail energy marketing business, which sells natural gas and electricity directly to residential, commercial, and industrial customers located in Maryland, Virginia, Delaware, Pennsylvania, Ohio, and the District of Columbia; and
- Midstream, which is a leading North American platform that connects customers and markets from wellhead to tidewater. The three pillars of the Midstream business include: 1) global exports, which includes AltaGas' two operational LPG export terminals and one prospective development terminal; 2) natural gas gathering, processing and extraction; and 3) fractionation and liquids handling. AltaGas' Midstream segment also includes its natural gas and NGL marketing business, domestic logistics, trucking and rail terminals, and liquid and natural gas storage capability.

The Corporate/Other segment consists of AltaGas' corporate activities and a small portfolio of gas-fired power generation and distribution assets capable of generating 508 MW of power primarily in the state of California.

2. Summary of Significant Accounting Policies

BASIS OF PRESENTATION

These Consolidated Financial Statements have been prepared by Management in accordance with United States Generally Accepted Accounting Principles ("U.S. GAAP").

Pursuant to National Instrument 52-107, "Acceptable Accounting Principles and Auditing Standards" ("NI 52-107"), U.S. GAAP reporting is generally permitted by Canadian securities laws for companies subject to reporting obligations under U.S. securities laws. On March 28, 2023, AltaGas filed Form 15 with the Securities and Exchange Commission ("SEC") and as such, is no longer an SEC issuer and can no longer rely on the provisions of NI 52-107. Therefore, AltaGas sought and obtained exemptive relief by the securities regulators in Alberta and Ontario to permit it to prepare its financial statements in accordance with U.S. GAAP. The Alberta Securities Commission exemption will terminate on or after the earlier of January 1, 2027, the date to which AltaGas ceases to have activities subject to rate regulation, or the first day of AltaGas' fiscal year that commences on or following the latter of: a) the effective date prescribed by the IASB for a mandatory rate regulated standard; or b) two years after the IASB publishes the final version of a mandatory rate regulated standard.

PRINCIPLES OF CONSOLIDATION

These Consolidated Financial Statements of AltaGas include the accounts of the Corporation, its subsidiaries, variable interest entities ("VIEs") for which the Corporation is the primary beneficiary, and its interest in various partnerships and joint ventures where AltaGas has an undivided interest in the assets and liabilities. Investments in unconsolidated companies that AltaGas has significant influence, but not control, over are accounted for using the equity method.

Hypothetical Liquidation at Book Value ("HLBV") methodology is used for AltaGas' investment in Mountain Valley Pipeline ("MVP") This methodology is used when the governing structuring agreement over the equity investment results in different liquidation rights and priorities than what is reflected by the underlying ownership interest percentage.

All intercompany balances and transactions are eliminated on consolidation. Where there is a party with a non-controlling interest in a subsidiary that AltaGas controls, that non-controlling interest is reflected as “non-controlling interests” in the Consolidated Financial Statements. The non-controlling interests in net income of consolidated subsidiaries are shown as an allocation of the consolidated net income and are presented separately in "net income applicable to non-controlling interests".

USE OF ESTIMATES AND MEASUREMENT UNCERTAINTY

The preparation of Consolidated Financial Statements in accordance with U.S. GAAP requires Management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenue and expenses during the period. Key areas where Management has made complex or subjective judgments, when matters are inherently uncertain, include but are not limited to: determining the nature and timing of satisfaction of performance obligations and determining the transaction price and amounts allocated to performance obligations for revenue recognition; depreciation and amortization rates; determination as to whether a contract is or contains a lease; determination of the classification, term, and discount rate for leases; fair value of asset retirement obligations; fair value of property, plant and equipment and goodwill for impairment assessments; fair value of financial instruments; measurement of credit losses; provisions for income taxes; assumptions used to measure employee future benefits; provisions for contingencies; purchase price allocations; and carrying value of regulatory assets and liabilities. Certain estimates are necessary for the regulatory environment in which AltaGas' subsidiaries or affiliates operate, which often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. By their nature, these estimates are subject to measurement uncertainty and may impact the Consolidated Financial Statements of future periods.

COMPARATIVE AMOUNTS

Certain prior year comparative figures in the Consolidated Balance Sheets and notes to the Consolidated Financial Statements have been reclassified to conform to the current period presentation.

SIGNIFICANT ACCOUNTING POLICIES

Rate-Regulated Operations

SEMCO, Washington Gas, Hampshire Gas, and, prior to the Alaska Utilities Disposition, ENSTAR (collectively "the Utilities") engage in the delivery, sale, and storage of natural gas. SEMCO is regulated by the Michigan Public Service Commission ("MPSC"). Washington Gas operates in the District of Columbia, Maryland, and Virginia, and is regulated in those jurisdictions by the Public Service Commission of the District of Columbia ("PSC of DC"), the Maryland Public Service Commission ("PSC of MD"), and the Commonwealth of Virginia State Corporation Commission ("SCC of VA"), respectively. Hampshire is regulated under a cost-of-service tariff by the Federal Energy Regulatory Commission ("FERC").

The MPSC, PSC of DC, PSC of MD, and SCC of VA exercise statutory authority over matters such as tariffs, rates, construction, operations, financing, returns, accounting, and certain contracts with customers. In order to recognize the economic effects of the actions and decisions of the MPSC, PSC of DC, PSC of MD, and SCC of VA, the timing of recognition of certain assets, liabilities, revenues, and expenses as a result of regulation may differ from that otherwise expected using U.S. GAAP for entities not subject to rate regulation.

Regulatory assets represent future revenues associated with certain costs incurred in the current period or in prior periods that are expected to be recovered from customers in future periods through the rate setting process. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that are expected to be refunded to customers through the rate setting process.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand, balances with banks, and investments in money market instruments with original maturities of less than three months.

Restricted Cash Holdings from Customers

Cash deposited, which is restricted and is not available for general use by AltaGas, is separately presented as restricted cash holdings in the Consolidated Balance Sheets. Pursuant to the acquisition of WGL Holdings, Inc. (the "WGL Acquisition"), rabbi trust funds were funded to satisfy certain Washington Gas executive and outside director retirement benefit plan obligations. The rabbi trust funds are invested in money market funds which are considered cash equivalents. These balances are included in "prepaid expenses and other current assets" and "long-term investments and other assets" in the Consolidated Balance Sheets.

Accounts Receivable

Receivables are recorded net of the allowance for credit losses in the Consolidated Balance Sheets. AltaGas regularly analyzes and evaluates the collectability of the accounts receivable based on a combination of factors. If circumstances related to the collectability change, the allowance for credit losses is further adjusted. Accounts are written off when collection efforts are complete and future recovery is unlikely.

Inventory

Inventory consists of materials, supplies, natural gas, natural gas liquids, crude oil and condensates, processed finished products, and emission compliance instruments which are valued at the lower of cost or net realizable value. Inventory also includes renewable energy credits which are valued using the specific identification method. Cost of inventory is assigned using a weighted average cost formula. In general, commodity costs and variable transportation costs are capitalized as gas in underground storage. Fixed costs, primarily pipeline demand charges and storage charges, are expensed as incurred through the cost of gas.

Property, Plant, and Equipment ("PP&E"), Depreciation and Amortization

Property, plant, and equipment are carried at cost. The Corporation depreciates the cost of capital assets, net of salvage value, on a straight-line basis over the estimated useful life of the assets, with the exception of rate-regulated utilities assets, for which depreciation is calculated on a straight-line basis or over the contract term of a specific agreement at rates as approved by the regulatory authorities.

The Utilities charge maintenance and repairs directly to operating expense and capitalize betterments and renewal costs. In accordance with regulatory requirements, depreciation expense includes an amount allowed for regulatory purposes to be collected in current rates for future removal and site restoration costs.

Interest costs are capitalized on major additions to property, plant, and equipment until the asset is ready for its intended use. The interest rate used for calculating the interest costs to be capitalized is based on AltaGas' prior quarter actual borrowing long-term interest rate.

The Utilities capitalize an imputed carrying cost on assets during construction as authorized by regulatory authorities and the amount so capitalized is an allowance for funds used during construction ("AFUDC"). AFUDC is the amount that a rate-regulated enterprise is allowed to recover for its cost of financing assets under construction. Capitalized overhead, administrative expenses, and AFUDC are included in the cost of the related assets and are recovered in rates charged to customers through depreciation expense, as allowed by the regulators.

The range of useful lives for AltaGas’ PP&E is as follows:

Utilities assets	4 to 69 years
Midstream assets	1 to 43 years
Corporate/Other assets	3 to 46 years

As required by the regulatory authority, net additions to SEMCO's utility assets are amortized for one half-year in the year in which they are brought into active service. Net additions to WGL’s assets are amortized in the month after they are brought into active service.

Generally, when a regulated asset is retired or disposed of, there is no gain or loss recorded in the Consolidated Statements of Income. Any difference between the cost and accumulated depreciation of the asset, net of salvage proceeds, is charged to accumulated depreciation or another regulatory asset or liability account. It is expected that any gain or loss that is charged to accumulated depreciation or another regulatory account will be reflected in future depreciation expense when it is refunded or collected in rates. When a non-regulated asset is retired or disposed of from PP&E, the original cost and related accumulated depreciation and amortization are derecognized and any gain or loss is recorded in the Consolidated Statements of Income.

Intangible Assets

Intangible assets are recorded at cost. Intangible assets which have a finite useful life are amortized on a straight-line basis over their term or estimated useful life. The range of useful lives for intangible assets with a finite life is as follows:

Energy services relationships	6 to 20 years
Software	3 to 20 years
Extraction and Transmission ("E&T") Contracts	25 years
Commodity contracts	7 to 13 years

Assets Held for Sale

The Corporation classifies assets as held for sale when the carrying amount will be principally recovered through a sale transaction rather than through continuing use. This condition is met when Management approves and commits to a formal plan to sell the assets, the assets are available for immediate sale in their present condition, and Management expects the sale to close within the next 12 months. Upon classifying an asset as held for sale, an asset is recorded at the lower of its carrying value or the estimated fair value less cost to sell. Assets held for sale are not depreciated or amortized.

Business Acquisitions

Business acquisitions are accounted for using the acquisition method. Under the acquisition method, assets and liabilities of the acquired entity are recorded at fair value at the date of acquisition. Acquisition-related costs are expensed as incurred. Goodwill represents the excess of purchase price over the fair value of the net assets acquired. Management applies its best estimates and assumptions to determine the fair value of net assets acquired; however, the estimates are subject to further refinement of assumptions over a measurement period, which may be up to one year from the acquisition date. During the measurement period, adjustments to assets acquired and liabilities assumed may be recorded, with a corresponding impact to goodwill.

Provisions on Assets

If facts and circumstances suggest that a long-lived asset or an intangible asset may be impaired, the carrying value is reviewed. If this review indicates that the value of the asset is not recoverable, as determined by the projected undiscounted cash flows related to the asset over its remaining life, then the carrying value of the asset is reduced to its estimated fair value and an impairment loss is recognized.

Goodwill is not subject to amortization, but assessed at least annually for impairment, or more often when events or changes in circumstances indicate that goodwill may be impaired. The annual assessment of goodwill is performed at the reporting unit level, which is an operating segment or one level below. The Corporation has the option to first assess qualitative factors to determine whether events or changes in circumstances indicate that the goodwill may be impaired. If a quantitative impairment test is performed, the fair value of the reporting unit will be compared to its carrying value (including goodwill). If the carrying value of the reporting unit exceeds the fair value, goodwill is reduced to its fair value and an impairment loss would be recorded in the Consolidated Statements of Income.

Investments Accounted for by the Equity Method

The equity method of accounting is used for investments in which AltaGas has the ability to exercise significant influence, but does not have a controlling interest. Equity investments are initially measured at cost and are adjusted for the Corporation's proportionate share of earnings or losses. Equity investments are increased for contributions made and decreased for distributions received. To the extent an investee undertakes activities necessary to commence its planned principal operations, the Corporation will capitalize interest costs associated with its investment during such period.

The HLBV methodology is used to allocate earnings or losses for certain WGL equity method investments when WGL's ownership interest percentage is different than distribution percentages. When applying HLBV accounting, the Corporation determines the amount that it would receive if an equity investment entity were to liquidate all of its assets at book value (as valued in accordance with U.S. GAAP) and distribute that cash to the investors based on the contractually defined liquidation priorities. The change in the Corporation's claim on the equity investment entity's book value at the beginning and end of the reporting period (adjusted for contributions and distributions) is the Corporation's share of the earnings or losses from the equity investment for the period.

An equity method investment is reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of the investment may not be recoverable. When such condition is deemed other than temporary, the carrying value of the investment is written down to its fair value, and an impairment charge is recorded in the Consolidated Statements of Income.

Financial Instruments

Cash inflows and outflows related to derivative instruments are classified as cash from operations in the Consolidated Statements of Cash Flows.

<u>Non-Utility Operations</u>

All financial instruments are initially recorded at fair value unless they qualify for, and are designated under, a normal purchase and normal sale ("NPNS") exemption. Subsequent measurement of the financial instruments is based on their classification. The financial assets are classified as "held-for-trading", "held-to-maturity", or "loans and receivables". Financial liabilities are classified as "held-for-trading" or other financial liabilities. Subsequent measurement is determined by classification.

A physical contract generally qualifies for the NPNS exemption if the transaction is reasonable in relation to AltaGas' business needs and AltaGas has the ability, and intent, to deliver or take delivery of the underlying item. AltaGas continually assesses the contracts designated under the NPNS exemption and will discontinue the treatment of these contracts under this exemption where the criteria are no longer met.

Held-for-trading instruments include non-derivative financial assets and financial assets and liabilities that may consist of swaps, options, forwards, and equity securities. These financial instruments are initially recorded at their fair value, with subsequent changes in fair value recorded in net income. Held-to-maturity, loans and receivables, and other financial liabilities are recognized at amortized cost using the effective interest method unless they are held-for-sale and recognized at the lower of cost or fair value less transaction fees.

Investments in equity instruments not accounted for under the equity method that do not have a quoted market price in an active market are measured at cost. Income earned from these investments is included in the Consolidated Statements of Income under "other income".

Derivatives embedded in other financial instruments or contracts (the host instrument) are recorded separately and are measured at fair value if the economic characteristics of the embedded derivative are not closely related to the host instrument, the terms of the embedded derivative are the same as those of a standalone derivative, and the entire contract is not held-for-trading or accounted for at fair value. Changes in fair value are included in earnings.

The fair values recorded on the Consolidated Balance Sheets reflect netting of the asset and liability positions where counterparty master netting arrangements contain provisions for net settlement.

Transaction costs related to the acquisition of held-for-trading financial assets and liabilities are expensed as incurred.

Transaction costs for obtaining debt financing other than line-of-credit arrangements are recognized as a direct deduction from the related debt liability on the Consolidated Balance Sheets. Transaction costs related to line-of-credit arrangements are capitalized and included under "long-term investments and other assets" on the Consolidated Balance Sheets. Premiums and discounts are netted against long-term debt on the Consolidated Balance Sheets. The deferred charges are amortized over the life of the related debt on an effective interest basis and included in “interest expense” on the Consolidated Statements of Income.

Regulated Utility Operations

All physical and financial derivative contracts are initially recorded at fair value. Changes in the fair value of derivative instruments that are recoverable or refunded to customers when they settle are recorded as regulatory assets or liabilities. Changes in the fair value of derivatives not affected by rate regulation are reflected in net income.

Transaction costs for obtaining debt financing and reacquired debt costs are recorded as regulatory assets or liabilities, or as a reduction of the debt liability on the Consolidated Balance Sheets.

Weather-Related Instruments

WGL purchases certain weather-related instruments, such as heating degree day ("HDD") derivatives and cooling degree day ("CDD") derivatives to manage weather and price risks related to its natural gas and electricity sales. These derivatives are accounted for in accordance with ASC 815-45, Derivatives and Hedging – Weather Derivatives. For HDD derivatives, gains or losses are recognized when the actual HDDs falls above or below the contractual HDDs for each instrument. For CDD derivatives, gains or losses are recognized when the average temperature exceeds or is below a contractually stated level during the contract period. Refer to Note 23 for further discussion on weather-related instruments.

Hedges

As part of its risk management strategy, AltaGas may use derivatives to reduce its exposure to commodity price, interest rate, and foreign exchange risk. AltaGas may designate certain outstanding loans to hedge against the currency translation effect of its foreign investments. In 2023, AltaGas began to designate certain commodity financial swaps as cash flow hedges in accordance with ASC Topic 815. For more information, please refer to Note 23.

Non-Utility Operations

The change in fair value of cash flow hedges is recognized in OCI. Gains or losses from cash flow hedges are reclassified to net income when the hedged transaction affects earnings, such as when the hedged forecasted transaction occurs.

Regulated Utility Operations

During planned issuances of debt securities, Washington Gas may utilize derivative instruments to manage the risk of interest-rate volatility. Gains and losses associated with these types of derivatives are recorded as regulatory liabilities or assets, and amortized in accordance with regulatory requirements, typically over the life of the related debt.

Credit Losses

AltaGas regularly analyzes and evaluates the collectability of the accounts receivable based on a combination of factors. If circumstances related to the collectability change, the allowance for credit losses is adjusted. Accounts are written off when collection efforts are complete and future recovery is unlikely. See below for a description of how expected credit loss estimates are developed.

Utilities Customer Receivables and Contract Assets

AltaGas is exposed to risk through the non-payment of utility bills by customers. To manage this customer credit risk, AltaGas' regulated utilities customers are offered budget billing options or high risk customers may be required to provide a cash deposit until the requirement for deposit refunds are met. AltaGas can recover a portion of non-payments from customers in future periods through the rate-setting process. For accounts receivable generated by the Utilities business, an allowance for credit losses is recognized using a loss-rate based on historical payment and collection experience. This rate may be adjusted based on Management’s expectations of unusual macroeconomic conditions and other factors. AltaGas regularly evaluates the reasonableness of the allowance based on a combination of factors, such as: the length of time receivables are past due, historical expected payment, collection experience, financial condition of customers, and other circumstances that could impact customers' ability or desire to make payments. For retail energy marketing customer receivables where AltaGas has enrolled in a regulatory utility purchase of receivable program, the associated utility discount rate is used to determine credit losses.

Midstream Customer Receivables and Contract Assets

AltaGas operates under an existing credit policy that is designed to mitigate credit risk. Credit limits are established for each counterparty and credit enhancements such as letters of credit, parent guarantees, and cash collateral may be required. The creditworthiness of all counterparties is continuously monitored. A credit loss reserve is recorded for receivables with customers and trading counterparties AltaGas considers to be below investment grade by applying an estimated loss rate. The estimated loss rate is based on the historical default rates published by external rating agencies. For accounts receivable, a one-year rate is used. For contract assets, historical loss rates associated with the estimated time frame that the contract asset will be billed to the customer is used. In the event a customer or trading counterparty no longer exhibits similar risk characteristics, the associated receivable is evaluated individually.

Other

For other long-term receivables, associated counterparties are evaluated and assigned internal credit ratings based on AltaGas' credit policy. An allowance for credit losses is recorded based on historical default rates published by external credit rating agencies and a rate commensurate with the period in which the receivables are expected to be collected.

Debt

AltaGas uses short-term debt in the form of commercial paper and advances under its syndicated bank credit facilities to fund seasonal cash requirements. Short-term obligations are excluded from current liabilities if AltaGas has the ability and the intent to refinance these obligations on a long-term basis. The ability to refinance is primarily demonstrated through the availability of long-term revolving committed credit facilities in an amount equal to or greater than the expected maximum short-term obligation.

Asset Retirement Obligations

AltaGas recognizes asset retirement obligations in the period in which the legal obligation is incurred and a reasonable estimate of fair value can be determined. The associated asset retirement costs are capitalized as part of the carrying amount of the asset and are depreciated over the estimated useful life of the asset. The liability is increased due to the passage of time over the estimated period until the settlement of the obligation, with a corresponding charge to accretion expense for asset retirement obligations.

There are timing differences between accretion and depreciation amounts being recorded pursuant to GAAP and the recognition of depreciation expense for legal asset removal costs that are recovered in rates, as allowed by the regulators. These timing differences are recorded as a reduction to “regulatory liabilities” in accordance with ASC 980.

Certain midstream and utility assets will have future legal obligations on retirement, but an asset retirement obligation has not been recorded due to its indeterminate life and corresponding indeterminable timing and scope of these asset retirement obligations. The Utilities recognize asset retirement obligations for some interim retirements, as expected by their regulators.

Revenue Recognition

AltaGas has revenue from various sources, including rate-regulated revenue, commodity sales, midstream service contracts, gas sales and transportation services, and storage services. For a detailed description of the Corporation’s revenue recognition policy by major source of revenue, please refer to Note 24.

Foreign Currency Translation

Monetary assets and liabilities denominated in a foreign currency are converted to the functional currency using the exchange rate in effect at the balance sheet date. Adjustments resulting from the conversion are recorded in the Consolidated Statements of Income. Non-monetary assets and liabilities are converted at the historical exchange rate in effect at the transaction date. Revenues and expenses are converted at the exchange rate applicable at the transaction date.

For foreign entities with a functional currency other than Canadian dollars, AltaGas’ reporting currency, assets and liabilities are translated into Canadian dollars at the rate in effect at the reporting date. Revenues and expenses are translated at average exchange rates during the reporting period. All adjustments resulting from the translation of the foreign operations are recorded in OCI.

AltaGas may designate certain outstanding loans to hedge against the currency translation effect of its foreign investments. Accordingly, foreign exchange gains and losses, from the dates of designation, on the translation of these loans are included in OCI. Additionally, AltaGas may enter into foreign exchange forward derivatives to manage the risk of fluctuating cash flows and earnings due to variations in foreign exchange rates as well as to benefit from favorable movements in the rates. Any hedges transacted are subject to risk limits and guidelines and are actively monitored and managed by AltaGas’ risk management team to ensure they align with AltaGas’ overall financial strategy. Gains and losses arising from the settlements of the derivatives entered into for the purpose of managing income statement risk are included in the line item "revenue" on the Consolidated Statements of Income, while gains and losses arising from the settlements of the derivatives entered into for the purpose of cash management are included in the line item "foreign exchange gains (losses)" on the Consolidated Statements of Income. For more information, please refer to Note 23.

Share Options and Other Compensation Plans

Share Options granted are recorded using fair value. Compensation expense is measured at the date of the grant using the Black-Scholes-Merton model and is recognized over the vesting period of the options. Consideration received by AltaGas on exercise of the Share Options is credited to shareholders' equity.

AltaGas has a phantom unit plan ("Phantom Plan") for eligible employees, officers, and directors, which includes two types of awards: restricted units ("RUs") and performance units ("PUs"). AltaGas' RUs and PUs are valued based on the dividends declared during the vesting period and the weighted average share price of AltaGas' common shares multiplied by the units outstanding at the end of the vesting period. Upon vesting, the RUs and PUs are paid in cash. All PUs are also subject to a performance multiplier ranging from 0 to 2 dependent on the Corporation's performance relative to performance targets as approved by the Board of Directors. Compensation expense is recognized using the liability method and is recorded as operating and administrative expense over the vesting period. A change in value of the RUs or PUs is recognized in the period the change occurs. Forfeitures are recognized when they occur instead of estimating the number of awards that are expected to vest.

In addition, AltaGas has a deferred share unit plan ("DSUP") for directors, officers, and eligible employees as an additional form of long-term variable compensation incentive. Although the DSUP is available to directors, officers, and eligible employees, AltaGas currently only grants deferred share units ("DSUs") under the DSUP as a form of director compensation. The DSUs granted are fully vested upon being credited to a participant's account, the participant is entitled to payment upon retirement, and payment is not subject to satisfaction of any requirements as to any minimum period of membership or employment or other conditions. DSUs are accounted for at fair value. Compensation expense is determined based on the fair value of the DSUs on the date of the grant and fluctuations in fair value are recognized in the period the change occurs. Forfeitures are recognized when they occur instead of estimating the number of awards that are expected to vest.

Pension Plans and Post-Retirement Benefits

AltaGas maintains defined benefit pension plans, defined contribution plans, and other post-retirement benefit plans for eligible employees. Contributions made by the Corporation to the defined contribution plans are expensed in the period in which the contribution occurs.

The cost of defined benefit pension plans and post-retirement benefits is actuarially determined using the projected benefit method prorated based on service and Management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees, expected health care costs, and other actuarial factors including discount rates and mortality. Pension plan assets are measured at fair value. The expected return on plan assets is based on historical and projected rates of return for each asset class in the plan portfolio. The projected benefit obligation is discounted using the market interest rate on high-quality debt instruments with cash flows matching the timing and amount of benefit payments.

Unrecognized actuarial gains and losses in excess of 10 percent of the greater of the benefit obligation and the fair value of plan assets or the market-related value of assets along with any unamortized past service costs and credits are amortized on a straight-line basis over the expected average remaining service life of active employees.

AltaGas recognizes the overfunded or underfunded status of its pension and post-retirement benefit plans as either assets or liabilities in the Consolidated Balance Sheets. Unrecognized actuarial gains and losses and past service costs and credits that arise during the period are recognized in OCI or a regulatory asset or liability.

For certain regulated utilities, the Corporation expects to recover pension expense in future rates and therefore records unrecognized balances as either regulatory assets or liabilities. The regulatory assets or liabilities are amortized on a straight-line basis over the expected average remaining service life of active employees.

Income Taxes

Income taxes for the Corporation and its subsidiaries are calculated using the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are determined based on differences between the carrying value and the tax basis of assets and liabilities and are measured using the enacted tax rates and laws that are in effect in the periods in which the differences are expected to be settled or realized. Deferred income tax assets are routinely reviewed, and a valuation allowance is recorded to reduce the deferred tax assets if it is more likely than not that deferred tax assets will not be realized.

The financial statement effects of an uncertain tax position are recognized when it is more likely than not, based on technical merits, that the position will be sustained upon examination by a taxing authority. The current and deferred tax impact is equal to the largest amount, considering possible settlement outcomes, that is greater than 50 percent likely of being realized upon settlement with the taxing authorities.

Investment tax credits are recognized as reductions to income tax expense over the estimated service lives of the related properties.

The rate-regulated natural gas distribution subsidiaries recognize a separate regulatory asset or liability for the amount of deferred income taxes expected to be recovered from, or paid to, customers in the future. Any tax related interest and/or penalty incurred is included in interest expense.

Net Income per Share

Basic net income per common share is computed using the weighted average number of common shares outstanding during the period. Dilutive net income per common share is calculated using the weighted average number of common shares outstanding adjusted for dilutive common shares related to the Corporation’s share-based compensation awards.

The potentially dilutive impact of the share-based compensation awards is determined using the treasury stock method. Under the treasury stock method, awards are treated as if they had been exercised with any proceeds used to repurchase common stock at the average market price during the period. Any incremental difference between the assumed number of shares issued and purchased is included in the diluted share computation.

Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Any such accruals are adjusted thereafter as additional information becomes available or circumstances change.

Leases

The following are the Corporation’s significant accounting policies:

Leases – Lessee

AltaGas determines if an arrangement is a lease at inception. Operating leases are included in right-of-use ("ROU") assets, current operating lease liabilities, and long-term operating lease liabilities in the Consolidated Balance Sheets. Finance leases are included in property, plant and equipment and current portion of finance lease liabilities, and long-term finance lease liabilities in the Consolidated Balance Sheets.

ROU assets represent the right to use an underlying asset for the lease term and lease liabilities represent the obligation to make lease payments arising from the lease. Operating lease ROU assets and liabilities are recognized at commencement date based on the present value of lease payments over the lease term. AltaGas uses the rate implicit in the lease when readily determinable. When the implicit lease rate is not readily determinable, AltaGas uses its incremental borrowing rate to determine the present value of lease payments. AltaGas includes lessee options to renew or terminate the lease term in the determination of the ROU asset and lease liability when exercise is reasonably certain. The operating lease ROU asset is adjusted for lease payments made in advance of the commencement date, initial direct costs, and any lease incentives. Variable lease payments are based on a rate.

Operating lease expense is recognized on a straight-line basis over the lease term in "operating and administrative expense". Depreciation and interest expense are recorded on finance leases.

Leases – Lessor

AltaGas determines if an arrangement is a lease at inception. Lease payments under an operating lease are recognized on a straight-line basis over the term of the lease. Variable lease payments are recognized as revenue as the facts and circumstances on which the variable lease payment is based occur.

AltaGas does not include taxes assessed by governmental authorities, such as sales and related taxes, in the lease payments or variable lease payments.

ADOPTION OF NEW ACCOUNTING STANDARDS

Effective January 1, 2023, AltaGas adopted the following Financial Accounting Standards Board ("FASB") issued Accounting Standards Updates ("ASU"):

- In October 2021, FASB issued ASU 2021-08 "Business Combinations (Topic 805): Accounting for Contract Assets and Contract Liabilities from Contracts with Customers". The amendments in this ASU require an entity to recognize and measure contract assets and liabilities acquired in a business combination in accordance with Topic 606. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements.

- In March 2022, FASB issued ASU No. 2022-01 "Derivatives and Hedging (Topic 815): Fair Value Hedging - Portfolio Layer Method". The amendments in this ASU will allow non-prepayable financial assets to be included in a closed portfolio hedged using the portfolio layer method and promote consistency in single and multiple hedged layers. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements.

- In March 2022, FASB issued ASU No. 2022-02 "Financial Instruments - Credit Losses (Topic 326): Troubled Debt Restructurings and Vintage Disclosures". The amendments in this ASU will eliminate the accounting guidance for troubled debt restructurings ("TDRs") by creditors while enhancing disclosure requirements for certain loan refinancings and restructurings by creditors when a borrower is experiencing financial difficulty, as well as require the disclosure of current-period write offs by year of origination for financing receivables and net investments in leases. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements.

- In September 2022, FASB issued ASU No. 2022-04 "Liabilities (Subtopic 405-50) - Supplier Finance Programs". The amendments in this ASU will require a buyer in a supplier finance program to disclose the key terms of the program, the amount outstanding at the end of the period, a roll forward of that obligation during the period, and where the obligation is presented on the balance sheet. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements.

FUTURE CHANGES IN ACCOUNTING PRINCIPLES

In June 2022, FASB issued ASU No. 2022-03 "Fair Value Measurement (Topic 820): Fair Value Measurement of Equity Securities Subject to Contractual Sale Restrictions". The amendments in this ASU clarify that a contractual restriction on the sale of an equity security is not considered part of the unit of account of the equity security, and therefore, is not considered in measuring fair value. In addition, an entity cannot, as a separate unit of account, recognize a contractual sale restriction. Equity securities subject to contractual sale restrictions also require certain additional disclosures. The amendments in this ASU are effective for fiscal years beginning after December 15, 2023 and should be applied prospectively with adjustments as a result of adopting this ASU being recognized in earnings. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

In March 2023, FASB issued ASU No. 2023-01 "Leases (Topic 842): Common Control Arrangements". The relevant amendments in this ASU allow entities to amortize leasehold improvements under common control over the economic life of the leasehold improvements as long as the lessee controlled the use of the leased asset. The amendments in this ASU are effective for fiscal years beginning after December 15, 2023, including interim periods within those fiscal years and can be applied using one of the following three methods: 1) prospectively to all new leasehold improvements recognized on or after the date the entity applies the amendments, 2) prospectively to all new leasehold improvements recognized on or after the date the entity applies the amendments, with any remaining unamortized balance of existing leasehold improvements amortized over their remaining useful life to the common-control group determined at that date, or 3) retrospectively to the beginning of the period in which the entity first applied Topic 842, with any leasehold improvements that otherwise would not have been amortized or impaired recognized through a cumulative-effect adjustment to opening retained earnings at the beginning of the earliest period presented. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

In March 2023, FASB issued ASU No. 2023-02 "Investments - Equity Method and Joint Ventures (Topic 323) - Accounting for Investments in Tax Credit Structures Using the Proportional Amortization Method". The amendments in this ASU allow entities the option to elect to account for tax equity investments, regardless of the tax credit program from which the income tax credits are received, using the proportional amortization method if certain conditions are met. The amendments in this ASU are effective for public business entities for fiscal years beginning after December 15, 2023, including interim periods within those fiscal years and can applied on either a modified prospective or retrospective basis. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

In October 2023, FASB issued ASU No. 2023-06 "Disclosure Improvements". The amendments in this ASU modify the disclosure or presentation requirements of a variety of topics in the codification as a result of FASB's decision to incorporate disclosures referred to in SEC Release No. 33-10532, which sought to simplify SEC disclosure requirements. The amendments in this ASU allow users to more easily compare entities subject to the SEC's existing disclosures with those entities that were not previously subject to the SEC's requirements. This Update is only effective upon the removal of the related disclosure from SEC regulations with an expiration of June 30, 2027. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements at this time, but may have an impact in future periods as AltaGas is subject to the scope of this ASU.

In November 2023, FASB issued ASU No. 2023-07 "Segment Reporting (Topic 280)". This ASU requires all public entities required to report segment information in accordance with Topic 280 to provide: (1) annual and interim disclosure of significant segment expenses regularly provided to the chief operating decision maker ("CODM"), (2) annual and interim disclosure of other segment items, (3) annual disclosures about reportable segment profit or loss and assets currently required by Topic 280 in interim periods, (4) disclosure of additional measures used to measure a segments profit or loss outside of GAAP, (5) disclosure of the title and position of the CODM, and (6) a public entity that has a single reportable segment to provide all the disclosures required by this update and all existing segment disclosures in Topic 280. This update is effective for fiscal years beginning after December 31, 2023, and interim periods with fiscal years beginning after December 15, 2024. The adoption of this ASU will have an impact on AltaGas' segment disclosures.

In December 2023, FASB issued ASU No. 2023-09 "Income Taxes (Topic 740): Improvements to Income Tax Disclosures". The amendments in this ASU require that public business entities on an annual basis: (1) disclose additional categories about federal, state, and foreign income taxes in the rate reconciliation table and (2) provide additional information for reconciling items that meet a quantitative threshold. Additionally, entities are required to annually disclose disaggregated income from continuing operations, income tax expense, and income taxes paid (net of refunds received) by certain tax authorities and jurisdictions. This update is effective for annual periods beginning after December 15, 2024. The adoption of this ASU will have an impact on AltaGas' income tax disclosures.

3. Pipestone Acquisition

On December 22, 2023, AltaGas closed the previously announced acquisition of natural gas processing and storage infrastructure assets in the Pipestone area of the Alberta Montney (the "Pipestone Acquisition") with Tidewater Midstream and Infrastructure Ltd. ("Tidewater") for consideration upon close of $328 million in cash and approximately 12.5 million AltaGas common shares, inclusive of working capital and other adjustments. The Pipestone Acquisition includes the Pipestone natural gas processing facility Phase I, the Pipestone Phase II expansion project which is being developed, the Dimsdale natural gas storage facility, the Pipestone condensate truck-in/truck-out terminal, and the associated gathering pipeline systems required to operate these assets. Following the completion of key de-risking milestones in December 2023, AltaGas declared a positive final investment decision ("FID") on the Pipestone Phase II expansion project.

AltaGas accounted for the acquisition as a business combination using the acquisition method of accounting whereby the acquired assets and assumed liabilities are recorded at their estimated fair values at the date of acquisition. The excess of purchase price over estimated fair values of assets acquired and liabilities assumed is recognized as goodwill at the acquisition date.

The following table summarizes the preliminary purchase price allocation representing the consideration paid and the estimated fair value of the net assets acquired as at December 22, 2023. The purchase price allocation is preliminary and reflects Management's current best estimate of the fair value of the acquired assets and liabilities based on the analysis of information obtained to date. Management is continuing to obtain specific information to support the valuation of current assets, property, plant and equipment, intangible assets, long term investments and other assets, current liabilities, asset retirement obligations, deferred taxes, and contingencies. As additional information becomes available, the purchase price allocation may differ materially from the preliminary purchase price allocation below. The offset to any adjustments made to the aforementioned financial statement captions during the measurement period are expected to be recorded in goodwill. Any adjustments to the purchase price allocation will be made as soon as practicable but no later than one year from the date of acquisition.

Cash payment	**$**	**328**
Shares issued		**340**
Effective date and other adjustments		**8**
Total purchase consideration		**676**
Fair value assigned to net assets		
Current assets		**32**
Property, plant and equipment		**646**
Intangible assets		**30**
Operating right-of-use assets		**3**
Long-term investments and other assets		**5**
Current liabilities		**(52)**
Asset retirement obligations		**(5)**
Deferred income taxes		**(18)**
Operating lease liabilities		**(2)**
Finance lease liabilities		**(96)**
Fair value of net assets acquired	**$**	**543**
Goodwill	**$**	**133**

The preliminary purchase price allocation includes goodwill of approximately $133 million. The goodwill is primarily related to incremental growth opportunities in the Midstream business as a result of the acquisition and greater financial flexibility as a result of increased scale and earnings diversification. The goodwill recognized as part of this transaction is not deductible for income tax purposes, and as such, no deferred taxes have been recorded related to this goodwill.

Pre-tax acquisition expenses for the year ended December 31, 2023 of approximately $10 million were incurred and included in the "cost of sales" and "operating and administrative" line items on the Consolidated Statements of Income. For the period from close of the transaction through December 31, 2023, the Pipestone assets have generated approximately $14 million in revenues and less than $1 million in net income after taxes.

The following supplemental unaudited, pro forma consolidated financial information for the years ended December 31, 2023 and 2022 gives effect to the Pipestone Acquisition as if it had closed on January 1, 2022. This pro forma information is presented for information purposes only and does not purport to be indicative of the results that would have occurred had the Pipestone Acquisition taken place at the beginning of 2022, nor is it indicative of the results that may be expected in future periods.

	Year Ended December 31	
	2023	2022
Pro forma revenue	**$ 13,497**	$ 14,854
Pro forma net income after taxes	**$ 697**	$ 584

Pro forma net income after taxes excludes all non-recurring acquisition-related expenses incurred by AltaGas and Tidewater in relation to the Pipestone Acquisition. Proforma net income after taxes has also been adjusted for finance costs associated with credit facilities used to fund the acquisition and the related tax impacts. For the year ended December 31, 2023, the total after-tax pro forma adjustments decreased net income after taxes by $6 million (2022 – $9 million).

4. Dispositions

Alaskan Utilities

On March 1, 2023, AltaGas closed the sale of its 100 percent interest in ENSTAR and 65 percent indirect interest in CINGSA and other ancillary operations ("Alaska Utilities Disposition"), for consideration of approximately $1.1 billion (US$800 million), prior to closing adjustments. As a result, AltaGas recognized a pre-tax gain on disposition of approximately $304 million in the Consolidated Statements of Income under the line item "other income" for the year ended December 31, 2023.

Energy Storage Development Project

In the first quarter of 2022, AltaGas completed the sale of a 60 MW stand-alone energy storage development project in Goleta, California for total proceeds of $20 million (US$15 million), subject to certain contingencies. In February 2023, the parties reached an agreement on outstanding contingencies and as a result, the buyer paid AltaGas an additional payment of approximately $11 million (US$8 million) which was recognized as a pre-tax gain on disposition in the Consolidated Statements of Income under the line item "other income" for the year ended December 31, 2023.

Meade Escrow Proceeds

In 2019, AltaGas completed the disposition of its investment in Meade Pipeline Co. LLC ("Meade"), which held WGL Midstream's indirect, non-operating interest in the Central Penn pipeline. Upon close of the sale, various escrow accounts were established to provide the purchaser a form of recourse for the settlement of indemnification obligations. In the second quarter of 2023, AltaGas received approximately $1 million (US$1 million) of cash proceeds from the indemnity escrow account. As a result, AltaGas recognized a pre-tax gain on disposition of approximately $1 million in the Consolidated Statements of Income under the line item "other income" for the year ended December 31, 2023.

5. Provisions on Assets

Year Ended December 31	**2023**	2022
Midstream	**$ —**	$ 6
	$ —	$ 6

Midstream

In 2022, AltaGas recorded a pre-tax provision of $6 million related to the Alton Natural Gas Storage Project as a result of updated reclamation cost estimates. Since AltaGas has abandoned this project, the resulting property, plant and equipment associated with the estimated reclamation costs was impaired. The pre-tax provisions were primarily recorded against property, plant and equipment.

6. Inventory

As at December 31		2023		2022
Natural gas held in storage [(a)]	**$**	**282**	$	588
Natural gas liquids		**156**		197
Crude oil and condensate		**132**		152
Renewable energy credits and emission compliance instruments		**202**		127
Materials and supplies		**66**		76
Processed finished products		**9**		6
	$	**847**	$	1,146
Less: inventory reclassified to assets held for sale		**—**		(86)
	$	**847**	$	1,060

(a) As at December 31, 2023, $247 million of the natural gas held in storage was held by rate-regulated utilities (2022 - $520 million).

7. Property, Plant and Equipment

As at	December 31, 2023			December 31, 2022		
	Cost	**Accumulated amortization**	**Net book value**	Cost	Accumulated amortization	Net book value
Utilities	**$ 9,472**	**$ (595)**	**$ 8,877**	$ 9,806	$ (614)	$ 9,192
Midstream	**4,655**	**(997)**	**3,658**	3,810	(884)	2,926
Corporate/Other	**867**	**(674)**	**193**	879	(665)	214
Reclassified to assets held for sale	**—**	**—**	**—**	(1,124)	478	(646)
	$ 14,994	**$ (2,266)**	**$ 12,728**	$ 13,371	$ (1,685)	$ 11,686

Interest capitalized on long-term capital construction projects for the year ended December 31, 2023 was $2 million (2022 - less than $1 million).

As at December 31, 2023, the Corporation had approximately $822 million (December 31, 2022 - $571 million) of capital projects under construction that were not yet subject to depreciation.

Depreciation expense related to property, plant and equipment (including assets under capital leases) for the year ended December 31, 2023 was $394 million (2022 - $375 million).

8. Intangible Assets

As at	December 31, 2023			December 31, 2022		
	Cost	**Accumulated amortization**	**Net book value**	Cost	Accumulated amortization	Net book value
E&T contracts	**$ 27**	**$ (19)**	**$ 8**	$ 26	$ (18)	$ 8
Energy services relationships	**115**	**(94)**	**21**	96	(86)	10
Software	**309**	**(219)**	**90**	359	(255)	104
Land rights	**1**	**—**	**1**	1	—	1
Commodity contracts	**7**	**(5)**	**2**	8	(6)	2
Reclassified to assets held for sale	**—**	**—**	**—**	(30)	25	$ (5)
	$ 459	**$ (337)**	**$ 122**	$ 460	$ (340)	$ 120

Amortization expense related to intangible assets for the year ended December 31, 2023 was $47 million (2022 - $64 million).

As at December 31, 2023, the Corporation excluded $41 million (December 31, 2022 - $6 million) from the asset base subject to amortization. Items excluded relate to software assets under development, energy services relationships associated with projects under construction, and assets with an indefinite life.

The following table sets forth the estimated amortization expense of intangible assets, excluding any amortization of assets not yet subject to amortization as well as assets with an indefinite life, for the years ended December 31:

2024	**$ 34**
2025	**$ 25**
2026	**$ 11**
2027	**$ 1**
2028	**$ 1**
Thereafter	**$ 9**

9. Leases

Lessee

AltaGas has operating and finance leases for office space, office equipment, field equipment, rail cars, aquatic use, vehicles, power and gas facilities, transmission and distribution assets, and land.

The components of lease expense were as follows:

	Year Ended December 31, 2023	Year Ended December 31, 2022
Operating lease cost (includes variable lease payments)	**$ 105**	$ 100
Finance lease cost		
Amortization of right-of-use assets	**9**	7
Interest on lease liabilities	**1**	1
Total finance lease cost	**$ 10**	$ 8
Total lease cost	**$ 115**	$ 108

Supplemental cash flow information related to leases was as follows:

Year Ended December 31		2023		2022
Cash paid for amounts included in the measurement of lease liabilities:				
Operating cash flows from finance leases	**$**	**(1)**	$	—
Operating cash flows used by operating leases	**$**	**(104)**	$	(111)
Financing cash flows used by finance leases [(a)]	**$**	**(10)**	$	(8)
Right-of-use assets obtained in exchange for new lease liabilities				
Operating leases	**$**	**141**	$	56
Finance leases	**$**	**114**	$	14

(a) Included within repayment of long-term debt on the Consolidated Statements of Cash Flows.

Supplemental balance sheet information related to leases was as follows:

As at December 31		2023		2022
Operating Leases				
Operating lease right-of-use assets				
Long-term	**$**	**337**	$	281
Included in assets held for sale		**—**		1
Total operating lease right-of-use assets	**$**	**337**	$	282
Operating lease liabilities				
Current	**$**	**(92)**	$	(92)
Long-term		**(258)**		(215)
Included in liabilities associated with assets held for sale		**—**		(1)
Total operating lease liabilities	**$**	**(350)**	$	(308)
Finance Leases				
Property and equipment, gross	**$**	**163**	$	46
Accumulated depreciation		**(25)**		(21)
Total property and equipment, net	**$**	**138**	$	25
Less: finance lease property and equipment reclassified to assets held for sale		**—**		(3)
Property and equipment, net	**$**	**138**	$	22
Current portion of finance lease liabilities	**$**	**(11)**	$	(8)
Finance lease liabilities		**(120)**		(17)
Total finance lease liabilities	**$**	**(131)**	$	(25)
Less: finance lease liabilities reclassified to liabilities associated with assets held for sale		**—**		3
Finance lease liabilities	**$**	**(131)**	$	(22)

As at	December 31, 2023	December 31, 2022
Weighted average remaining lease term (years)		
Operating leases	**6.4**	6.4
Finance leases	**4.2**	4.5
Weighted average discount rate (%)		
Operating leases	**4.15**	2.91
Finance leases	**4.56**	3.29

Maturity analysis of lease liabilities was as follows:

	Operating Leases	Finance Leases
2024	$ 95	$ 18
2025	79	18
2026	66	17
2027	48	15
2028	30	12
Thereafter	91	127
Total lease payments	$ 409	$ 207
Less: imputed interest	(59)	(76)
Total	$ 350	$ 131

Lessor

Certain of AltaGas' revenues are obtained through power purchase agreements or take-or-pay contracts whereby AltaGas is the lessor in these operating lease arrangements. Minimum lease payments received are amortized over the term of the lease. Contingent rentals are recorded when the condition that created the present obligation to make such payments occurs such as when actual electricity is generated and delivered.

Maturity analysis of lease receivables was as follows:

	Operating Leases
2024	$ 47
2025	50
2026	50
2027	50
2028	2
Thereafter	74
Total	$ 273

The carrying value of property, plant, and equipment associated with these leases was approximately $193 million as at December 31, 2023.

AltaGas manages its risk associated with the residual value of its leased assets through strategically constructing leased facilities in key commercial regions and retaining the ability to sell commodities and ancillary services via the merchant market or through commodity sales agreements.

10. Goodwill

As at		December 31, 2023		December 31, 2022
Balance, beginning of year	**$**	**5,250**	$	5,153
Business acquisition *(note 3)*		**133**		—
Reclassified to assets held for sale		**—**		(226)
Foreign exchange translation		**(113)**		323
Balance, end of year	**$**	**5,270**	$	5,250

11. Long-Term Investments and Other Assets

As at		December 31, 2023		December 31, 2022
Deferred lease receivable	**$**	**15**	$	17
Debt issuance costs associated with credit facilities		**4**		7
Refundable deposits		**10**		10
Prepayment on long-term service agreements		**84**		79
Deferred information technology costs		**37**		24
Cash calls from joint venture partners		**19**		21
Contract asset *(net of credit losses of $1 million) (notes 23 and 24)*		**36**		37
Rabbi trust *(notes 28 and 31)*		**6**		8
Capitalized contract costs		**4**		5
Financial transmission rights		**26**		39
Other		**30**		27
	$	**271**	$	274
Less: long-term investments and other assets reclassified to assets held for sale		**—**		(1)
	$	**271**	$	273

12. Variable Interest Entities

Consolidated VIEs

AltaGas consolidates a variable interest entity ("VIE") where the Corporation is deemed the primary beneficiary. The primary beneficiary of a VIE has the power to direct the activities of the entity that most significantly impact its economic performance such as being the provider of construction, operating and marketing services to the entity. In addition, the primary beneficiary of a VIE also has the obligation to absorb losses of the entity or the right to receive benefits that could potentially be significant to the VIE. AltaGas determined that it is the primary beneficiary of the following VIEs:

Ridley Island LPG Export Limited Partnership

On May 5, 2017, AltaGas LPG Limited Partnership ("AltaGas LPG"), a wholly-owned subsidiary of AltaGas, and Vopak Development Canada Inc. ("Vopak"), a wholly-owned subsidiary of Koninklijke Vopak N.V. ("Royal Vopak"), a public company incorporated under the laws of the Netherlands, formed the Ridley Island LPG Export Limited Partnership ("RILE LP") to develop, own and operate the Ridley Island Propane Export Terminal ("RIPET"). AltaGas' subsidiaries hold a 70 percent interest while Vopak holds a 30 percent interest in RILE LP. The construction cost of RIPET was funded by AltaGas LPG and Vopak in proportion to their respective interests in RILE LP. As part of the arrangements, AltaGas entered into a long-term agreement for the capacity of RIPET with RILE LP, and AltaGas and certain of its subsidiaries provide operating services to RILE LP.

AltaGas has determined that RILE LP is a VIE in which it holds variable interests and is the primary beneficiary. In the determination that AltaGas is the primary beneficiary of the VIE, AltaGas noted that it has the power to direct the activities that most significantly impact the VIE's economic performance through the operating and marketing services provided to RILE LP. In addition, AltaGas has the obligation to absorb the losses and the right to receive the benefits that could potentially be significant to RILE LP through the long-term agreement for the capacity of RIPET. As such, AltaGas has consolidated RILE LP.

The assets of RILE LP are the property of RILE LP and are not available to AltaGas for any other purpose. RILE LP's asset balances can only be used to settle its own obligations. The liabilities of RILE LP do not represent additional claims against AltaGas' general assets. AltaGas' exposure to loss as a result of its interest as a limited partner is its net investment. AltaGas and Royal Vopak have provided limited guarantees for the obligations of their respective subsidiaries for the construction cost of RIPET. With the commencement of commercial operations at RIPET, the terms of the long-term capacity agreement between AltaGas LPG and RILE LP provide for a return on and of capital and reimbursement of RIPET's operating costs by AltaGas LPG in accordance with the terms set out in the agreement.

The following table represents amounts included in the Consolidated Balance Sheets attributable to AltaGas' consolidated VIE:

As at	**December 31, 2023**	December 31, 2022
Current assets	**$ 8**	$ 12
Property, plant and equipment	**349**	353
Long-term investments and other assets	**42**	45
Current liabilities	**(15)**	(16)
Asset retirement obligations	**(5)**	(4)
Net assets	**$ 379**	$ 390

Ridley Island Energy Export Facility

On April 4, 2023, AltaGas LPG and Vopak formed the Ridley Island Energy Export Facility Limited Partnership ("REEF LP") to develop, own, and operate the Ridley Island Energy Export Facility ("REEF"). AltaGas' subsidiaries and Vopak each hold a 50 percent interest in REEF LP. The construction cost of REEF is being funded by AltaGas LPG and Vopak in proportion to their respective interests in REEF LP. As part of the project definitive agreements, AltaGas entered into a long-term agreement for 100 percent of the capacity of REEF with REEF LP. Additionally, AltaGas and certain of its subsidiaries have been contracted to provide operating and project development services to REEF LP.

AltaGas has determined that REEF LP is a VIE in which it holds variable interests and is the primary beneficiary. In the determination that AltaGas is the primary beneficiary of the VIE, AltaGas noted that it has the power to direct the activities that most significantly impact the VIE's economic performance through its control of all operating and commercial aspects of the project. In addition, AltaGas has the obligation to absorb the losses and the right to receive the benefits that could potentially be significant to REEF LP through the long-term agreement for the capacity of REEF. As such, AltaGas has consolidated REEF LP.

The assets of REEF LP are the property of REEF LP and are not available to AltaGas for any purpose other than as described in the long-term capacity agreement. REEF LP's asset balances can only be used to settle its own obligations and the liabilities of REEF LP do not represent additional claims against AltaGas' general assets. AltaGas' exposure to loss as a result of its interest as a limited partner is its net investment. AltaGas and Royal Vopak have provided limited guarantees for the obligations of their respective subsidiaries for the construction cost of REEF. With the commencement of commercial operations at REEF, the terms of the long-term capacity agreement between AltaGas LPG and REEF LP provide for a return on and of capital and reimbursement of REEF's operating costs by AltaGas LPG in accordance with the terms set out in the agreement.

The following table represents amounts included in the Consolidated Balance Sheets attributable to REEF LP:

As at		December 31, 2023		December 31, 2022
Current assets	**$**	**7**	$	—
Property, plant and equipment		**65**		—
Net assets	**$**	**72**	$	—

<u>AltaGas Hybrid Trust</u>

On January 11, 2022, AltaGas closed its offering of $300 million of 5.25 percent Fixed-to-Fixed Rate Subordinated Notes, Series 1 (Note 16). In conjunction with the debt offering, AltaGas issued $300 million in Preferred Shares, Series 2022-A, to be held in the AltaGas Hybrid Trust with Computershare Trust Company of Canada acting as trustee. The Preferred Shares were issued to satisfy the obligations under the indenture governing the associated Series 1 Subordinated Notes. Following the occurrence of certain bankruptcy or insolvency events in respect of AltaGas, subject to certain exceptions, the Series 2022-A Preferred Shares would be delivered to the holders of the Series 1 Subordinated Notes. Upon delivery of the Series 2022-A Preferred Shares, the Series 1 Subordinated Notes would be immediately and automatically surrendered and cancelled and all rights of any Series 1 Subordinated Notes will automatically cease.

On August 17, 2022, AltaGas closed its offering of $250 million of 7.35 percent Fixed-to-Fixed Subordinated Notes, Series 2 (Note 16). In conjunction with the debt offering, AltaGas issued $250 million in Preferred Shares, Series 2022-B, to be held in the AltaGas Hybrid Trust with Computershare Trust Company of Canada acting as trustee. The Preferred Shares were issued to satisfy the obligations under the indenture governing the associated Series 2 Subordinated Notes. Following the occurrence of certain bankruptcy or insolvency events in respect of AltaGas, subject to certain exceptions, the Series 2022-B Preferred Shares would be delivered to the holders of the Series 2 Subordinated Notes. Upon delivery of the Series 2022-B Preferred Shares, the Series 2 Subordinated Notes would be immediately and automatically surrendered and cancelled and all rights of any Series 2 Subordinated Notes will automatically cease.

On November 10, 2023, AltaGas closed its offering of $200 million of 8.90 percent Fixed-to-Fixed Subordinated Notes, Series 3 (Note 16). In conjunction with the debt offering, AltaGas issued $200 million in Preferred Shares, Series 2023-A, to be held in the AltaGas Hybrid Trust with Computershare Trust Company of Canada acting as trustee. The Preferred Shares were issued to satisfy the obligations under the indenture governing the associated Series 3 Subordinated Notes. Following the occurrence of certain bankruptcy or insolvency events in respect of AltaGas, subject to certain exceptions, the Series 2023-A Preferred Shares would be delivered to the holders of the Series 3 Subordinated Notes. Upon delivery of the Series 2023-A Preferred Shares, the Series 3 Subordinated Notes would be immediately and automatically surrendered and cancelled and all rights of any Series 3 Subordinated Notes will automatically cease. The only assets held by the holding trust are the Series 2022-A, Series 2022-B and Series 2023-A Preferred Shares.

AltaGas has determined that AltaGas Hybrid Trust is a VIE in which it holds variable interests and is the primary beneficiary. In the determination that AltaGas is the primary beneficiary of the VIE, AltaGas noted that it has the power to direct the activities that most significantly impact the VIE's economic performance through its role as the sole administrative agent. In addition, AltaGas has the obligation to absorb the administrative expenses that are significant to the trust through the associated administrative agreement. As such, AltaGas has consolidated the AltaGas Hybrid Trust.

Unconsolidated VIE

Strathcona Storage Limited Partnership ("SSLP")

AltaGas owns an interest in SSLP, a partnership formed with ATCO Energy Solutions Ltd. to construct, operate, and maintain underground NGL storage caverns at Fort Saskatchewan, Alberta. The facility currently has five underground NGL storage salt caverns.

As at December 31, 2023, AltaGas held a 40 percent equity investment in SSLP with a carrying value of $130 million (2022 - $130 million). SSLP is not consolidated by AltaGas and instead is accounted for by the equity method of accounting. AltaGas is not the primary beneficiary of SSLP and it does not have the power to direct the activities most significant to the economic performance of SSLP. The maximum financial exposure to loss as a result of the involvement with this VIE is equal to AltaGas' net investment in SSLP.

13. Investments Accounted for by the Equity Method

			Carrying value as at December 31		Equity income (loss) for the year ended December 31	
Description	**Location**	**Ownership Percentage**	**2023**	2022	**2023**	2022
Constitution Pipeline, LLC ("Constitution")	United States	**10**	**$ —**	$ —	**$ —**	$ 3
Eaton Rapids Gas Storage System	United States	**50**	**28**	28	**3**	3
Mountain Valley Pipeline, LLC ("MVP") (a) (b)	United States	**10**	**511**	478	**45**	—
Sarnia Airport Storage Pool LP	Canada	**50**	**16**	17	**1**	1
Petrogas Terminals Penn LLC	United States	**50**	**1**	1	**—**	—
Strathcona Storage LP	Canada	**40**	**130**	130	**6**	6
			$ 686	$ 654	**$ 55**	$ 13

(a) The equity method is considered appropriate because MVP is an LLC with specific ownership accounts and ownership between five and fifty percent, resulting in AltaGas exercising a more than minor influence over the investee's operating and financing policies.

(b) Equity income for the year ended December 31, 2023 relates to allowance for funds used during construction ("AFUDC") as a result of the resumption of construction activities in June 2023.

The carrying amount of certain equity investments differs from the amount of the underlying equity in net assets. These basis differences include amounts related to purchase accounting adjustments, capitalized interest, and a contractual cap on contributions to MVP.

Summarized combined financial information, assuming a 100 percent ownership interest in AltaGas' equity investments listed above, is as follows:

Year Ended December 31		2023		2022
Revenues	**$**	**543**	$	50
Expenses		**(28)**		(26)
	$	**515**	$	24

As at December 31		2023		2022
Current assets	**$**	**476**	$	136
Property, plant and equipment	**$**	**11,633**	$	9,544
Long-term investments and other assets	**$**	**16**	$	12
Current liabilities	**$**	**(498)**	$	(166)
Other long-term liabilities	**$**	**(17)**	$	(14)

14. Short-term Debt

As at (a)		December 31, 2023		December 31, 2022
Commercial paper	**$**	**129**	$	293
	$	**129**	$	293

(a) As at December 31, 2023, AltaGas' weighted average interest rate on short-term borrowings outstanding was 5.7 percent (December 31, 2022 - 4.8 percent).

Credit Facilities

As at December 31, 2023, AltaGas held a $70 million (December 31, 2022 - $70 million) unsecured demand revolving operating credit facility with a Canadian chartered bank. Draws on the facility bear interest at the lender's prime rate or at the bankers' acceptance rate plus a stamping fee. As at December 31, 2023, there were no letters of credit outstanding under this facility (December 31, 2022 - $nil).

As at December 31, 2023, AltaGas held a US$322 million (December 31, 2022 - US$300 million) unsecured bilateral letter of credit demand facility, amended in November 2023, with a Canadian chartered bank. Borrowings on the facility incur fees and interest at rates relevant to the nature of the draws made. Letters of credit outstanding under this facility as at December 31, 2023 were $252 million (December 31, 2022 - $181 million).

WGL and Washington Gas use short-term debt in the form of commercial paper and advances under its syndicated bank credit facilities to fund seasonal cash requirements. Revolving committed credit facilities are maintained in an amount equal to or greater than the expected maximum commercial paper position. As at December 31, 2023, commercial paper outstanding classified as short-term debt totaled $129 million (December 31, 2022 - $293 million).

As at December 31, 2022, Petrogas held a $30 million unsecured bilateral letter of credit demand facility. Letters of credit outstanding under this facility as at December 31, 2022 were $16 million. The facility was terminated in November 2023.

As at December 31, 2023, Petrogas held a $25 million (December 31, 2022 - $25 million) unsecured bilateral letter of credit demand facility. As at December 31, 2023, there were no letters of credit outstanding under this facility (December 31, 2022 - $nil).

15. Long-Term Debt

As at	Maturity date	December 31, 2023	December 31, 2022
Credit facilities			
$2.3 billion unsecured extendible revolving facility [(a)]	20-May-2027	**$ 484**	$ 860
US$150 million unsecured extendible revolving facility	20-Dec-2026	**86**	188
Commercial paper [(b)]	Various	**332**	386
$450 million term loan	25-Aug-2024	**449**	450
AltaGas Ltd. medium-term notes ("MTNs")			
$300 million Senior unsecured - 3.57 percent	12-Jun-2023	**—**	300
$200 million Senior unsecured - 4.40 percent	15-Mar-2024	**200**	200
$350 million Senior unsecured - 1.23 percent	18-Mar-2024	**350**	350
$300 million Senior unsecured - 3.84 percent	15-Jan-2025	**300**	300
$500 million Senior unsecured - 2.16 percent	10-Jun-2025	**500**	500
$350 million Senior unsecured - 4.12 percent	7-Apr-2026	**350**	350
$400 million Senior unsecured - 4.64 percent	15-May-2026	**400**	—
$200 million Senior unsecured - 2.17 percent	16-Mar-2027	**200**	200
$200 million Senior unsecured - 3.98 percent	4-Oct-2027	**200**	200
$500 million Senior unsecured - 2.08 percent	30-May-2028	**500**	500
$200 million Senior unsecured - 2.48 percent	30-Nov-2030	**200**	200
$100 million Senior unsecured - 5.16 percent	13-Jan-2044	**100**	100
$300 million Senior unsecured - 4.50 percent	15-Aug-2044	**300**	300
$250 million Senior unsecured - 4.99 percent	4-Oct-2047	**250**	250
WGL and Washington Gas MTNs and private placement notes			
US$20 million Senior unsecured - 6.65 percent	20-Mar-2023	**—**	27
US$41 million Senior unsecured - 5.44 percent	11-Aug-2025	**54**	55
US$53 million Senior unsecured - 6.62 to 6.82 percent	Oct 2026	**70**	72
US$72 million Senior unsecured - 6.40 to 6.57 percent	Feb - Sep 2027	**95**	98
US$52 million Senior unsecured - 6.57 to 6.85 percent	Jan - Mar 2028	**69**	70
US$9 million Senior unsecured - 7.50 percent	1-Apr-2030	**11**	12
US$150 million Senior unsecured - 6.06 percent	14-Oct-2033	**199**	—
US$50 million Senior unsecured - 5.70 to 5.78 percent	Jan - Mar 2036	**66**	68
US$75 million Senior unsecured - 5.21 percent	3-Dec-2040	**99**	102
US$75 million Senior unsecured - 5.00 percent	15-Dec-2043	**99**	102
US$300 million Senior unsecured - 4.22 to 4.60 percent	Sep - Nov 2044	**397**	405
US$450 million Senior unsecured - 3.80 percent	15-Sep-2046	**595**	608
US$400 million Senior unsecured - 3.65 percent [(c)]	15-Sep-2049	**549**	563
US$200 million Senior unsecured - 2.98 percent	15-Dec-2051	**265**	271
US$25 million Senior unsecured - 5.25 percent	29-Dec-2042	**33**	34
US$175 million Senior unsecured - 5.33 percent	29-Dec-2052	**231**	237
US$50 million Senior unsecured - 6.43 percent	15-Oct-2053	**66**	—
SEMCO long-term debt			
US$82 million CINGSA Senior secured - 4.48 percent	n/a	**—**	60
US$225 million First Mortgage Bonds - 2.45 percent	21-Apr-2030	**95**	305
US$225 million First Mortgage Bonds - 3.15 percent	21-Apr-2050	**298**	305
Fair value adjustment on WGL acquisition		**74**	79
		$ 8,566	$ 9,107
Less: debt issuance costs		**(39)**	(41)
		$ 8,527	$ 9,066
Less: current portion		**(999)**	(327)
Less: liabilities associated with assets held for sale		**—**	(60)
		$ 7,528	$ 8,679

(a) Borrowings on the facility can be by way of prime loans, U.S. base-rate loans, SOFR loans, bankers' acceptances, or letters of credit. Borrowings on the facility have fees and interest at rates relevant to the nature of the draw made. This facility has a $2 billion four-year extendable committed revolving tranche and a $300 million two-year extendable side car revolving tranche.

(b) Commercial paper is supported by the availability of long-term committed credit facilities maturing in 2026. Commercial paper intended to be repaid within the next year is recorded as short-term debt (Note 14).

(c) The outstanding balance includes a US$15 million premium which is amortized as a reduction to interest expense over the term of the note.

Credit Facilities

As at December 31, 2023, AltaGas held $2.3 billion (December 31, 2022 - $2.5 billion) of unsecured revolving credit facilities. These facilities include a four-year extendable committed revolving tranche, and a two-year extendable side car revolving tranche. Draws on the facilities can be by way of prime loans, U.S. base-rate loans, SOFR loans, bankers' acceptances, or letters of credit. Outstanding bank loans under this facility as at December 31, 2023 were $484 million (December 31, 2022 - $860 million). In 2023, AltaGas terminated the $200 million revolving credit facility set to mature in 2025, which had previously been part of the overall unsecured revolving credit facilities.

As at December 31, 2023, AltaGas held a $450 million (December 31, 2022 - $450 million) unsecured two-year term credit facility. Draws on the facility can be by way of prime loans, U.S. base-rate loans, SOFR loans, bankers' acceptances, or letters of credit. Outstanding bank loans under this facility as at December 31, 2023 were $449 million (December 31, 2022 - $450 million).

As at December 31, 2023, WGL held a US$300 million (December 31, 2022 - US$300 million) unsecured revolving credit facility. Draws on the facility can be by way of prime loans, U.S. base-rate loans, LIBOR loans, bankers' acceptances, or letters of credit. There were no outstanding bank loans under this facility as at December 31, 2023 or December 31, 2022.

As at December 31, 2023, Washington Gas held a US$450 million (December 31, 2022 - US$450 million) unsecured revolving credit facility. Draws on the facility can be by way of prime loans, U.S. base-rate loans, LIBOR loans, bankers' acceptances, or letters of credit. There were no outstanding bank loans under this facility as at December 31, 2023 or December 31, 2022.

WGL and Washington Gas use short-term debt in the form of commercial paper and advances under its syndicated bank credit facilities to fund seasonal cash requirements. Revolving committed credit facilities are maintained in an amount equal to or greater than the expected maximum commercial paper position. As at December 31, 2023, outstanding commercial paper classified as long-term debt totaled $332 million (December 31, 2022 - $386 million).

As at December 31, 2023, SEMCO held a US$150 million (December 31, 2022 - US$150 million) unsecured extendible revolving facility. Draws on the facility can be by way of letters of credit, Alternate Base Rate or Eurodollar loans. There were US$65 million outstanding bank loans under this facility as at December 31, 2023 (December 31, 2022 - US$140 million).

SEMCO Debt Defeasance

In the first quarter of 2023, SEMCO executed a partial legal defeasance transaction to derecognize US$153 million of its previously issued 2.45 percent First Mortgage Bonds, Series 2020A-1, due April 21, 2030 (the "Defeased Bonds") in the aggregate principal amount of US$225 million. In satisfaction of the discharge requirements outlined in the indenture, certain assets were transferred to the indenture trustee to be held in trust to satisfy the remaining principal and interest obligations of the Defeased Bonds. As a result, SEMCO has been legally released from being the primary obligor of the Defeased Bonds. At transaction close AltaGas recognized a pre-tax gain of $14 million on the derecognition of the Defeased Bonds under the line item "other income" for the year ended December 31, 2023.

16. Subordinated Hybrid Notes

As at	Maturity date		**December 31, 2023**		December 31, 2022
$300 million subordinated notes, Series 1	11-Jan-2082	**$**	**300**	$	300
$250 million subordinated notes, Series 2	17-Aug-2082		**250**		250
$200 million subordinated notes, Series 3	10-Nov-2083		**200**		—
		$	**750**	$	550
Less: debt issuance costs			**(8)**		(6)
		$	**742**	$	544

On November 10, 2023, AltaGas closed its offering of $200 million of 8.90 percent Fixed-to-Fixed Rate Subordinated Notes, Series 3, due November 10, 2083. The subordinated notes were offered under AltaGas' short form base shelf prospectus dated March 31, 2023, as supplemented by a prospectus supplement dated November 7, 2023.

For the year ended December 31, 2023, AltaGas recorded interest expense of $37 million on the subordinated hybrid notes (2022 - $22 million).

17. Asset Retirement Obligations

As at December 31		**2023**		2022
Balance, beginning of year	**$**	**451**	$	429
Obligations acquired *(note 3)*		**5**		—
New obligations		**—**		3
Obligations settled [(a)]		**(15)**		(10)
Disposals		**—**		(1)
Revision in estimated cash flow		**(3)**		(2)
Accretion expense [(b)]		**26**		20
Foreign exchange translation		**(9)**		23
Reclassified to liabilities associated with assets held for sale		**—**		(4)
Total	**$**	**455**	$	458
Less: current portion (included in accounts payable and accrued liabilities)		**(7)**		(7)
Balance, end of year	**$**	**448**	$	451

(a) During the year ended December 31, 2023, approximately $7 million of asset retirement obligations included in accounts payable and accrued liabilities were settled (December 31, 2022 - $7 million).

(b) Certain amounts relating to Utility asset retirement obligations are recorded through regulatory assets or liabilities on the Consolidated Balance Sheets due to regulatory treatment. The remaining portion is recorded through the Consolidated Statements of Income.

The majority of the asset retirement obligations are associated with distribution and transmission systems in the Utilities segment.

AltaGas estimates the undiscounted cash required to settle the asset retirement obligations, excluding growth for inflation, at December 31, 2023 was $759 million (December 31, 2022 - $877 million).

The asset retirement obligations have been recorded in the Consolidated Financial Statements at estimated values discounted at rates between 2.0 and 8.4 percent (December 31, 2022 - between 2.0 to 8.4 percent) and are expected to be incurred between 2024 and 2141 (December 31, 2022 - between 2023 and 2140). No assets have been legally restricted for settlement of the estimated liability.

18. Environmental Matters

AltaGas is subject to federal, provincial, state and local laws and regulations related to environmental matters. These laws and regulations may require expenditures over a long time frame to control environmental effects. Almost all of the environmental liabilities AltaGas has recorded are for costs expected to be incurred to remediate sites where AltaGas or a predecessor affiliate operated manufactured gas plants ("MGPs"). Estimates of liabilities for environmental response costs are difficult to determine with precision because of the various factors that can affect their ultimate level. These factors include, but are not limited to, the following:

- the complexity of the site;
- changes in environmental laws and regulations at the federal, state, and local levels;
- the number of regulatory agencies or other parties involved;
- new technology that renders previous technology obsolete or experience with existing technology that proves ineffective;
- the level of remediation required; and
- variations between the estimated and actual period of time that must be dedicated to respond to an environmentally-contaminated site.

AltaGas has identified up to twelve sites where it or its predecessors may have operated MGPs. In connection with these operations, AltaGas is aware that coal tar and certain other by-products of the gas manufacturing process are present at or near some former sites and may be present at others.

As at December 31, 2023, a liability of $12 million has been recorded on an undiscounted basis related to future environmental response costs (December 31, 2022 - $13 million) in the Consolidated Balance Sheets under the line items “accounts payable and accrued liabilities and other long-term liabilities”. These estimates principally include the minimum liabilities associated with a range of environmental response costs expected to be incurred. As at December 31, 2023, AltaGas estimated the maximum liability associated with all of its sites to be approximately $54 million (December 31, 2022 - $50 million). The estimates were determined by AltaGas’ environmental experts, based on experience in remediating MGP sites and advice from legal counsel and environmental consultants. The variation between the recorded and estimated maximum liability primarily results from differences in the number of years that will be required to perform environmental response processes and the extent of remediation that may be required.

As at December 31, 2023, AltaGas reported a regulatory asset of $16 million (December 31, 2022 - $15 million) for the portion of environmental response costs that are expected to be recoverable in future rates (Note 21).

In 2023, AltaGas received a Directive Letter from the Department of Energy and Environment ("DOEE") related to a MGP that was formerly owned by Washington Gas known as the “West Station Gas Works.” The Directive Letter requests certain information and a site investigation. AltaGas is unable to estimate the total amount of potential costs or timing associated with a site investigation at this time. AltaGas has accrued an amount for estimated information request response costs based on a potential range of estimates.

19. Other Long-term Liabilities

As at		December 31, 2023		December 31, 2022
Deferred revenue	**$**	**16**	$	11
Customer advances for construction		**13**		69
Merger commitments		**3**		5
Non-retirement employee benefits [(a)]		**51**		51
Uncertain tax positions *(note 20)*		**20**		20
Other		**21**		19
	$	**124**	$	175
Less: liabilities associated with assets held for sale		**—**		(53)
	$	**124**	$	122

(a) Consists of long-term portion of liabilities relating to employee incentive plans and other non-retirement related employee benefits.

20. Income Taxes

Year Ended December 31		2023		2022
Income before income taxes - consolidated	**$**	**912**	$	716
Statutory income tax rate (%)		**23.0**		23.0
Expected taxes at statutory rates	**$**	**210**	$	165
Add (deduct) the tax effect of:				
Permanent differences	**$**	**—**	$	2
Statutory and other rate differences		**(1)**		1
Deferred income tax recovery on regulated assets		**(16)**		(21)
Tax differences on divestitures and transactions		**37**		(3)
Other		**(7)**		(1)
	$	**223**	$	143
Income tax provision				
Current	**$**	**43**	$	23
Deferred		**180**		120
	$	**223**	$	143
Effective income tax rate (%)		**24.5**		20.0

Net deferred income tax liabilities were composed of the following:

As at		December 31, 2023		December 31, 2022
PP&E and intangible assets	**$**	**1,969**	$	1,862
Regulatory assets		**(166)**		(187)
Tax pools, deferred financing, and compensation		**(179)**		(238)
Other		**(90)**		(69)
Valuation allowance		**2**		1
	$	**1,536**	$	1,369

The amount shown on the Consolidated Balance Sheets as deferred income tax liabilities represents the net differences between the tax basis and book carrying values on the Corporation's balance sheets at enacted tax rates.

As at December 31, 2023, the Corporation had tax-effected non-capital losses of approximately $282 million, which will be available to offset future taxable income. If not used, these losses will expire between 2028 and 2043.

Uncertain Tax Positions

The Corporation recognizes the benefit of an uncertain tax position only when it is more likely than not that such a position will be sustained by the taxing authorities based on the technical merits of the position. The current and deferred tax impact is equal to the largest amount, considering possible settlement outcomes, that has greater than 50 percent likelihood of being realized upon settlement with the taxing authorities.

On an annual basis, the Corporation and its subsidiaries file tax returns in Canada and various foreign jurisdictions. In Canada, AltaGas' federal and provincial tax returns for the years 2014 to 2022 remain subject to examination by taxation authorities. In the United States, both the federal and state tax returns for the years 2019 to 2022 remain subject to examination by the taxation authorities.

Management determined that the following provision was required for uncertainty on income taxes during the year:

Year ended December 31		**2023**		2022
Balance, beginning of year	**$**	**20**	$	20
Balance, end of year	**$**	**20**	$	20

21. Regulatory Assets and Liabilities

AltaGas accounts for certain transactions in accordance with ASC 980, Regulated Operations. AltaGas refers to this accounting guidance for regulated entities as “regulatory accounting”. Under regulatory accounting, utilities are permitted to defer expenses and income as regulatory assets and liabilities, respectively, in the Consolidated Balance Sheets when it is probable that those expenses and income will be allowed in the rate-setting process in a period different from the period in which they would have been reflected in the Consolidated Statements of Income by a non-rate-regulated entity. These deferred regulatory assets and liabilities are included in the Consolidated Statements of Income in future periods when the amounts are reflected in customer rates. If an application is filed to modify customer rates with certain regulatory commissions, AltaGas is permitted to charge customers new rates, subject to refund, until the regulatory commission renders a final decision. During this interim period, a provision is recorded for a rate refund regulatory liability based on the difference between the amount collected in rates and the amount expected to be recovered from a final regulatory decision.

Management’s assessment of the probability of recovery or pass-through of regulatory assets and liabilities requires judgment and interpretation of laws and regulatory agency orders, rules, and rate-making conventions. The relevant regulatory bodies are the MPSC, PSC of DC, PSC of MD, and SCC of VA.

If, for any reason, the Corporation ceases to meet the criteria for application of regulatory accounting for all or part of its operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be de-recognized from the Consolidated Balance Sheets and included in the Consolidated Statements of Income for the period in which the discontinuance of regulatory accounting occurs. Criteria that give rise to the discontinuance of regulatory accounting include: (i) increasing competition that restricts the ability of the Corporation to charge prices sufficient to recover specific costs, and (ii) a significant change in the manner in which rates are set by regulatory agencies from cost-based regulation to another form of regulation. The Corporation’s review of these criteria currently supports the continued application of regulatory accounting for all its utilities.

The following table summarizes the regulatory assets and liabilities recorded in the Consolidated Balance Sheets, as well as the remaining period, as at December 31, 2023 and 2022, over which the Corporation expects to realize or settle the assets or liabilities:

As at December 31		2023		2022	Recovery Period
Regulatory assets - current					
Deferred cost of gas [(a)]	**$**	**11**	$	15	Less than one year
Accelerated replacement recovery mechanisms [(b)]		**22**		11	Less than one year
Interruptible sharing [(c)]		**1**		—	Less than one year
Energy optimization costs		**4**		4	Less than one year
Virginia and Maryland revenue normalization [(c)]		**20**		8	Less than one year
	$	**58**	$	38	
Regulatory assets - non-current					
Deferred regulatory costs [(c) (d)]	**$**	**74**	$	254	1 - 52 years
Future recovery of pension and other retirement benefits [(c)]		**1**		1	Various
Future recovery of non-retirement employee benefits [(c) (e)]		**4**		16	Various
Deferred environmental costs [(c) (f)]		**16**		15	Various
Deferred loss on debt transactions and derivative instruments [(c) (g)]		**84**		91	Various
Deferred future income taxes [(c) (h)]		**97**		42	Various
Energy efficiency program - Maryland [(i)]		**39**		31	Various
COVID-19 costs [(j)]		**2**		4	Various
District of Columbia rate case [(k)]		**6**		4	Various
Other		**6**		4	Various
	$	**329**	$	462	
Less: non-current regulatory assets reclassified to assets held for sale		**—**		(14)	
	$	**329**	$	448	
Regulatory liabilities - current					
Deferred cost of gas [(a)]	**$**	**67**	$	164	Less than one year
Federal income tax rate change [(l)]		**1**		1	Less than one year
Virginia rate refund [(m)]		**—**		5	Less than one year
Interruptible sharing [(c)]		**2**		3	Less than one year
Virginia and Maryland revenue normalization [(a)]		**3**		2	Less than one year
Other		**12**		8	Less than one year
	$	**85**	$	183	
Regulatory liabilities - non-current					
Future expense of pension and other retirement benefits [(c)]	**$**	**283**	$	235	Various
Future removal and site restoration costs [(n)]		**409**		490	Various
Deferred gain on debt transactions and derivative instruments [(c) (g)]		**1**		1	Various
Federal income tax rate change [(l)]		**571**		568	Various
Other		**10**		3	Various
	$	**1,274**	$	1,297	
Less: non-current regulatory liabilities associated with assets held for sale		**—**		(96)	
	$	**1,274**	$	1,201	

(a) Washington Gas is not entitled to a rate of return on these assets. Washington Gas is allowed to recover and required to pay, using short-term interest rates, the carrying costs related to billed gas costs due from and to its customers in the District of Columbia and Virginia jurisdictions.

(b) Represents amounts for deferred over or under collections of surcharges associated with Washington Gas' accelerated pipeline recovery programs in the District of Columbia, Maryland, and Virginia.

(c) Washington Gas is not entitled to a rate of return on these assets.

(d) Includes deferred gas costs and fair value of derivatives, which are not included in customer bills until settled.

(e) Represents the timing difference between the recognition of workers compensation and short-term disability costs in accordance with generally accepted accounting principles and the way these costs are recovered through rates.

(f) This balance represents allowed environmental remediation expenditures at SEMCO and Washington Gas sites to be recovered through rates. The recovery period is over several years.

(g) The losses or gains on the issuance and extinguishment of debt and interest-rate derivative instruments include unamortized balances from transactions executed in prior years. These transactions create gains and losses that are amortized over the remaining life of the debt as prescribed by regulatory accounting requirements. As at December 31, 2023, this also includes a fair value adjustment of $70 million (December 31, 2022 - $74 million) recorded on the WGL Acquisition in 2018.

(h) This balance represents amounts due from customers for deferred tax assets and liabilities related to tax benefits/expenses on deductions flowed directly to customers prior to the adoption of income tax normalizations for ratemaking purposes and to tax rate changes.
(i) Represents amounts for deferred credits associated with Washington Gas' participation in the energy conservation and efficiency program EmPower in Maryland that are recovered from customers over time.
(j) Regulatory assets established to capture and track incremental COVID-19 related costs.
(k) This balance represents costs incurred in association with District of Columbia rate cases.
(l) The *Tax Cuts and Jobs Act* ("TCJA") was enacted on December 22, 2017, and required the Corporation to revalue its U.S. deferred tax assets and liabilities in 2018 to the lower federal corporate tax rate of 21 percent, resulting in excess accumulated deferred income taxes. The tax rate reduction created a reduction in deferred tax liability, which SEMCO and Washington Gas are required to refund to ratepayers. For the year ended December 31, 2023, $59 million was reclassified from a regulatory liability to a regulatory asset to be consistent with the normalization provision of the TCJA requiring cost of removal to be accounted for separately from deferred income taxes related to the depreciation of property, plant and equipment.
(m) This amount represents estimated refunds related to customers billed at a higher rate during the interim period as part of the 2022 Virginia rate case.
(n) This amount and timing of draw down is dependent upon the cost of removal of the underlying utility property, plant, and equipment and its useful life.

22. Accumulated Other Comprehensive Income (Loss)

($ millions)		Cash Flow Hedges		Defined benefit pension and PRB plans		Hedge net investments		Translation foreign operations		Total
Opening balance, January 1, 2023	**$**	**—**	**$**	**(5)**	**$**	**(173)**	**$**	**804**	**$**	**626**
OCI before reclassification		**(10)**		**2**		**28**		**(250)**		**(230)**
Settlement of Canadian defined benefit pension plan *(note 28)*		**—**		**2**		**—**		**—**		**2**
Amounts reclassified from OCI		**1**		**—**		**—**		**—**		**1**
Current period OCI (pre-tax)	**$**	**(9)**	**$**	**4**	**$**	**28**	**$**	**(250)**	**$**	**(227)**
Income tax on amounts retained in AOCI		**—**		**(1)**		**(3)**		**—**		**(4)**
Net current period OCI	**$**	**(9)**	**$**	**3**	**$**	**25**	**$**	**(250)**	**$**	**(231)**
Ending balance, December 31, 2023	**$**	**(9)**	**$**	**(2)**	**$**	**(148)**	**$**	**554**	**$**	**395**
Opening balance, January 1, 2022	$	—	$	(8)	$	(158)	$	159	$	(7)
OCI before reclassification		—		4		(17)		640		627
Current period OCI (pre-tax)	$	—	$	4	$	(17)	$	640	$	627
Income tax on amounts retained in AOCI		—		(1)		2		—		1
Net current period OCI	$	—	$	3	$	(15)	$	640	$	628
Purchase of remaining non-controlling interest in subsidiaries		—		—		—		5		5
Ending balance, December 31, 2022	$	—	$	(5)	$	(173)	$	804	$	626

Reclassification From Accumulated Other Comprehensive Income (Loss)

AOCI components reclassified	Income statement line item		Year Ended December 31, 2023		Year Ended December 31, 2022
Defined benefit pension and PRB plans [(a)]	Other income	**$**	**2**	$	—
Cash flow hedges	Cost of sales	**$**	**1**	$	—
		$	**3**	$	—

(a) Reclassification from AOCI for the year ended December 31, 2023 relates to the settlement of the Canadian defined benefit pension plan. Refer to Note 28 for more details.

23. Financial Instruments and Financial Risk Management

The Corporation's financial instruments consist of cash and cash equivalents, accounts receivable, risk management contracts, certain long-term investments and other assets, accounts payable and accrued liabilities, dividends payable, short-term and long-term debt, and certain other current and long-term liabilities.

Fair Value Hierarchy

AltaGas categorizes its financial assets and financial liabilities into one of three levels based on fair value measurements and inputs used to determine the fair value.

Level 1 - fair values are based on unadjusted quoted prices in active markets for identical assets or liabilities. Fair values are based on direct observations of transactions involving the same assets or liabilities and no assumptions are used. Included in this category are publicly traded shares valued at the closing price as at the balance sheet date.

Level 2 - fair values are determined based on valuation models and techniques where inputs other than quoted prices included within Level 1 are observable for the asset or liability either directly or indirectly. AltaGas enters into derivative instruments in the futures, over-the-counter and retail markets to manage fluctuations in commodity prices and foreign exchange rates. The fair values of power, natural gas, NGL, LPG, ocean freight, and crude oil derivative contracts were calculated using forward prices based on published sources for the relevant period, adjusted for factors specific to the asset or liability, including basis and location differentials, discount rates, and currency exchange. The fair value of foreign exchange derivative contracts was calculated using quoted market rates.

Level 3 - fair values are based on inputs for the asset or liability that are not based on observable market data. AltaGas uses valuation techniques when observable market data is not available. Level 3 derivatives include physical contracts at illiquid market locations with no observable market data, long-dated positions where observable pricing is not available over the life of the contract, contracts valued using historical spot price volatility assumptions, and valuations using indicative broker quotes for inactive market locations. A significant change to any one of these inputs in isolation could result in a significant upward or downward fluctuation in the fair value measurement.

The following methods and assumptions were used to estimate the fair value of each significant class of financial instruments:

Other current liabilities - the carrying amounts approximate fair value because of the short maturity of these instruments.

Current portion of long-term debt, long-term debt (including debt classified as held for sale), subordinated hybrid notes, and other long-term liabilities - the fair value of these liabilities was estimated based on discounted future interest and principal payments using the current market interest rates of instruments with similar terms.

Risk management assets and liabilities - the fair values of power, natural gas, NGL, and crude oil derivative contracts were calculated using forward prices from published sources for the relevant period. The fair value of foreign exchange derivative contracts was calculated using quoted market rates. The fair value of Level 3 derivative contracts was calculated using internally developed valuation inputs and pricing models.

Loans and receivables – the fair value of these assets was estimated based on discounted future interest and principal payments using the current market interest rates of instruments with similar terms.

As at	December 31, 2023				
	Carrying Amount	Level 1	Level 2	Level 3	Total Fair Value
Financial assets					
Fair value through net income [(a)(b)]					
Risk management assets - current	$ 49	$ —	$ 17	$ 32	$ 49
Risk management assets - non-current	37	—	12	25	37
Fair value through regulatory assets [(a)]					
Risk management assets - current	5	—	—	5	5
Risk management assets - non-current	20	—	—	20	20
	$ 111	$ —	$ 29	$ 82	$ 111
Financial liabilities					
Fair value through net income [(a)]					
Risk management liabilities - current	$ 85	$ —	$ 51	$ 34	$ 85
Risk management liabilities - non-current	70	—	25	45	70
Fair value through regulatory liabilities [(a)]					
Risk management liabilities - current	12	—	1	11	12
Risk management liabilities - non-current	45	—	—	45	45
Amortized cost					
Current portion of long-term debt	999	—	999	—	999
Current portion of finance lease liabilities	11	—	11	—	11
Long-term debt	7,528	—	6,812	—	6,812
Finance lease liabilities	120	—	120	—	120
Subordinated hybrid notes	742	—	700	—	700
Other current liabilities [(c)]	43	—	43	—	43
	$ 9,655	$ —	$ 8,762	$ 135	$ 8,897

(a) To manage price risk associated with acquiring natural gas supply for Maryland, Virginia, and District of Columbia utility customers, Washington Gas, a subsidiary of the Corporation, enters into physical and financial derivative transactions. Any gains and losses associated with these derivatives are recorded as regulatory liabilities or assets, respectively, to reflect the rate treatment for these economic hedging activities. Additionally, as part of its asset optimization program, Washington Gas enters into derivatives with the primary objective of securing operating margins that Washington Gas will ultimately realize. Regulatory sharing mechanisms provide for the annual realized profit from these transactions to be shared between Washington Gas' shareholder and customers; therefore, changes in fair value are recorded through earnings, or as regulatory assets or liabilities to the extent that it is probable that realized gains and losses associated with these derivative transactions will be included in the rates charged to customers when they are realized.

(b) Includes the fair value of designated hedging instruments classified as level 2 totaling $9 million. The change in fair value of these instruments is recorded to AOCI. Refer to the *Cash Flow Hedges* section below for more details.

(c) Excludes non-financial liabilities.

As at	December 31, 2022				
	Carrying Amount	Level 1	Level 2	Level 3	Total Fair Value
Financial assets					
Fair value through net income [(a)]					
Risk management assets - current	$ 132	$ —	$ 96	$ 36	$ 132
Risk management assets - non-current	77	—	52	25	77
Fair value through regulatory assets [(a)]					
Risk management assets - current	8	—	6	2	8
	$ 217	$ —	$ 154	$ 63	$ 217
Financial liabilities					
Fair value through net income [(a)]					
Risk management liabilities - current	$ 133	$ —	$ 11	$ 122	$ 133
Risk management liabilities - non-current	170	—	4	166	170
Fair value through regulatory liabilities [(a)]					
Risk management liabilities - current	39	—	—	39	39
Risk management liabilities - non-current	128	—	—	128	128
Amortized cost					
Current portion of long-term debt	327	—	327	—	327
Current portion of finance lease liabilities	7	—	7	—	7
Long-term debt	8,679	—	7,706	—	7,706
Finance lease liabilities	15	—	15	—	15
Subordinated hybrid notes	544	—	480	—	480
Debt classified as held for sale	63	—	60	—	60
Other current liabilities [(b)]	52	—	52	—	52
	$ 10,157	$ —	$ 8,662	$ 455	$ 9,117

(a) To manage price risk associated with acquiring natural gas supply for Maryland, Virginia, and District of Columbia utility customers, Washington Gas, a subsidiary of the Corporation, enters into physical and financial derivative transactions. Any gains and losses associated with these derivatives are recorded as regulatory liabilities or assets, respectively, to reflect the rate treatment for these economic hedging activities. Additionally, as part of its asset optimization program, Washington Gas enters into derivatives with the primary objective of securing operating margins that Washington Gas will ultimately realize. Regulatory sharing mechanisms provide for the annual realized profit from these transactions to be shared between Washington Gas' shareholder and customers; therefore, changes in fair value are recorded through earnings, or as regulatory assets or liabilities to the extent that it is probable that realized gains and losses associated with these derivative transactions will be included in the rates charged to customers when they are realized.

(b) Excludes non-financial liabilities.

Financial assets and liabilities not included in the fair value hierarchy table include money market funds, short-term debt, and commercial paper. The carrying value of these financial instruments approximate their fair value, which reflects the short-term maturity and/or normal credit terms of these financial instruments.

The following table includes quantitative information about the significant unobservable inputs used in the fair value measurement of Level 3 financial instruments as at December 31, 2023:

	Net Fair Value	Valuation Technique	Unobservable Inputs	Range	Weighted Average [(a)]
Natural gas	$ (29)	Discounted Cash Flow	Natural Gas Basis Price (per Dth)	$ (2.61) - $ 5.91	$ (0.03)
Natural gas	$ (1)	Option Model	Natural Gas Basis Price (per Dth)	$ (1.79) - $ 4.40	$ 0.42
			Annualized Volatility of Spot Market Natural Gas	11 % - 282 %	40 %
Electricity	$ (23)	Discounted Cash Flow	Electricity Congestion Price (per MWh)	$ (9.81) - $111.35	$ 13.09

(a) Unobservable inputs were weighted by transaction volume.

The following tables provide a reconciliation of changes in net fair value of derivative assets and liabilities classified as Level 3 in the fair value hierarchy:

For the year ended December 31	2023			2022		
	Natural Gas	**Electricity**	**Total**	Natural Gas	Electricity	Total
Balance, beginning of year	**$ (226)**	**$ (166)**	**$ (392)**	$ (107)	$ (48)	$ (155)
Net realized and unrealized gains (losses):						
Recorded in income	**72**	**168**	**240**	(43)	(213)	(256)
Recorded in regulatory assets	**104**	**—**	**104**	(100)	—	(100)
Transfers out of Level 3	**(6)**	**(5)**	**(11)**	2	(30)	(28)
Purchases	**—**	**(3)**	**(3)**	—	16	16
Settlements	**24**	**(18)**	**6**	35	118	153
Foreign exchange translation	**2**	**1**	**3**	(13)	(9)	(22)
Balance, end of year	**$ (30)**	**$ (23)**	**$ (53)**	$ (226)	$ (166)	$ (392)

Transfers between different levels of the fair value hierarchy may occur based on fluctuations in the valuation and on the level of observable inputs used to value the instruments from period to period. Transfers into and out of the different levels of the fair value hierarchy are presented at the fair value as of the beginning of the period. Transfers out of Level 3 during the year ended December 31, 2023 were due to an increase in valuations using observable market inputs.

Realized and Unrealized Gains (Losses) Recorded to Income for Level 3 Measurements

Year Ended December 31	2023	2022
Recorded to revenue	**$ 172**	$ (258)
Recorded to cost of sales	**68**	2
	$ 240	$ (256)

Summary of Unrealized Gains (Losses) on Risk Management Contracts Recognized in Net Income

Year Ended December 31	2023	2022
Natural gas	**$ (12)**	$ (57)
Energy exports	**(78)**	21
Crude oil and NGLs	**(5)**	2
NGL frac spread	**4**	16
Power	**2**	(31)
Foreign exchange	**19**	—
	$ (70)	$ (49)

Offsetting of Derivative Assets and Derivative Liabilities

Certain of AltaGas' risk management contracts are subject to master netting arrangements that create a legally enforceable right for a counterparty to offset the related financial assets and financial liabilities. As part of these master netting agreements, cash, letters of credit and parental guarantees may be required to be posted or obtained from counterparties in order to mitigate credit risk related to both derivative and non-derivative positions. Collateral balances are also offset against the related counterparties' derivative positions to the extent the application would not result in the over-collateralization of those derivative positions on the balance sheet.

As at	December 31, 2023				
	Derivative instruments not designated as hedging instruments		Derivative instruments designated as hedging instruments		
	Gross amounts of recognized assets/liabilities	Gross amounts offset in balance sheet	Gross amounts of recognized assets/liabilities	Netting of collateral	Net amounts presented in balance sheet
Risk management assets [(a)]					
Natural gas	$ 96	$ (44)	$ —	$ —	$ 52
Energy exports	34	(31)	—	—	3
Crude oil and NGLs	4	(6)	—	6	4
NGL frac spread	8	(7)	—	—	1
Power	72	(40)	—	—	32
Foreign exchange	19	—	—	—	19
	$ 233	$ (128)	$ —	$ 6	$ 111
Risk management liabilities [(b)]					
Natural gas	$ 164	$ (44)	$ 9	$ (31)	$ 98
Energy exports	119	(31)	—	(81)	7
Crude oil and NGLs	6	(6)	—	—	—
NGL frac spread	7	(7)	—	—	—
Power	147	(40)	—	—	107
	$ 443	$ (128)	$ 9	$ (112)	$ 212

(a) Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $54 million and risk management assets (non-current) balance of $57 million.

(b) Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $97 million and risk management liabilities (non-current) balance of $115 million.

As at	December 31, 2022			
	Gross amounts of recognized assets/liabilities	Gross amounts offset in balance sheet	Netting of collateral	Net amounts presented in balance sheet
Risk management assets [(a)]				
Natural gas	$ 174	$ (80)	$ (17)	$ 77
Energy exports	105	(112)	34	27
Crude oil and NGLs	6	(4)	2	4
NGL frac spread	6	(6)	—	—
Power	153	(44)	—	109
	$ 444	$ (246)	$ 19	$ 217
Risk management liabilities [(b)]				
Natural gas	$ 360	$ (80)	$ —	$ 280
Energy exports	112	(112)	—	—
Crude oil and NGLs	4	(4)	—	—
NGL frac spread	9	(6)	—	3
Power	231	(44)	—	187
	$ 716	$ (246)	$ —	$ 470

(a) Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $140 million and risk management assets (non-current) balance of $77 million.

(b) Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $172 million and risk management liabilities (non-current) balance of $298 million.

Cash Collateral

The following table presents collateral not offset against risk management assets and liabilities:

As at		December 31, 2023		December 31, 2022
Collateral posted with counterparties	$	12	$	2
Cash collateral held representing an obligation	$	—	$	4

Any collateral posted that is not offset against risk management assets and liabilities is included in line item "prepaid expenses and other current assets" in the Consolidated Balance Sheets. Collateral received and not offset against risk management assets and liabilities is included in line item "customer deposits" in the Consolidated Balance Sheets.

Certain derivative instruments contain contract provisions that require collateral to be posted if the credit rating of AltaGas or certain of its subsidiaries falls below certain levels. At December 31, 2023 and December 31, 2022, AltaGas has not posted any collateral related to its derivative liabilities that contained credit-related contingent features. The following table shows the aggregate fair value of all derivative instruments with credit-related contingent features that are in a liability position, as well as the maximum amount of collateral that would be required if specific credit-risk-related contingent features underlying these agreements were triggered:

As at		December 31, 2023		December 31, 2022
Risk management liabilities with credit-risk-contingent features	$	158	$	145
Maximum potential collateral requirements	$	111	$	68

Risks Associated with Financial Instruments

AltaGas is exposed to various financial risks in the normal course of operations such as market risks resulting from fluctuations in commodity prices, currency exchange rates and interest rates as well as credit risk and liquidity risk.

Commodity Price Risk

AltaGas enters into financial derivative contracts to manage exposure to fluctuations in commodity prices. The use of derivative instruments is governed under formal risk management policies and is subject to parameters set out by AltaGas' Risk Management Committee and Board of Directors.

Natural Gas

In the normal course of business, AltaGas purchases and sells natural gas to support its infrastructure business. The fixed price and market price contracts for both the purchase and sale of natural gas extend to 2034. In addition, AltaGas may enter into financial derivative contracts as part of WGL's asset optimization program. WGL optimized the value of its long-term natural gas transportation and storage capacity resources during periods when these resources are not being used to physically serve utility customers.

AltaGas had the following contracts outstanding as at December 31, 2023 and 2022:

December 31, 2023	**Fixed price (per GJ)**	**Period (months)**	**Notional volume (GJ)**		***Fair Value ($ millions)***
Sales	**0.80 to 9.38**	**1-118**	**233,499,133**	**$**	**(27)**
Purchases	**0.55 to 9.54**	**1-119**	**629,298,784**	**$**	**(4)**
Swaps [(a)]	**1.77 to 9.38**	**1-62**	**127,829,390**	**$**	**(15)**

(a) Includes approximately 15,765,174 GJ of natural gas swaps designated as hedging instruments that have terms extending until 2029.

December 31, 2022	Fixed price (per GJ)	Period (months)	Notional volume (GJ)		*Fair Value ($ millions)*
Sales	1.75 to 20.38	1-130	244,060,786	$	(54)
Purchases [(a)]	1.75 to 20.38	1-98	521,045,852	$	(169)
Swaps	3.28 to 17.02	1-57	147,565,012	$	20

(a) Excludes approximately 191,071,366 GJ of natural gas purchases through 2023 that are contingent on the in-service date of MVP.

Crude Oil and NGLs

In the normal course of business, AltaGas utilizes commodity swaps to manage the impact of timing between when product is purchased and sold in addition to differing indices on purchase and sales. AltaGas had the following contracts outstanding as at December 31, 2023 and 2022:

December 31, 2023	**Fixed price (per Bbl)**	**Period (months)**	**Notional volume (Bbl)**		***Fair Value ($ millions)***
Swaps	**33.87 to 106.53**	**1-8**	**2,399,972**	**$**	**4**

December 31, 2022	Fixed price (per Bbl)	Period (months)	Notional volume (Bbl)		*Fair Value ($ millions)*
Swaps	44.19 to 120.45	1-12	1,597,173	$	4

Energy Exports

In the normal course of business, AltaGas enters into swaps to lock in a portion of the volumes exposed to the propane and butane price differentials between North American Indices and the Far East Index for contracts not under tolling arrangements at RIPET and Ferndale. AltaGas had the following contracts outstanding as at December 31, 2023 and 2022:

December 31, 2023	**Fixed price (per Bbl)**	**Period (months)**	**Notional volume (Bbl)**		***Fair Value ($ millions)***
Purchases	**14.70 to 22.75**	**1-51**	**4,017,118**	**$**	**(1)**
Propane and butane swaps	**7.45 to 147.70**	**1-15**	**76,931,889**	**$**	**(3)**

December 31, 2022	Fixed price (per Bbl)	Period (months)	Notional volume (Bbl)		*Fair Value ($ millions)*
Purchases	9.45	1-3	90,646	Less than $1 million	
Propane and butane swaps	4.8 to 118.69	1-12	89,433,941	$	27

NGL Frac Spread

In the normal course of business, AltaGas enters into swaps to lock in a portion of the volumes exposed to NGL frac spread. AltaGas had the following contracts outstanding as at December 31, 2023 and 2022:

December 31, 2023	**Fixed price**	**Period (months)**	**Notional volume**		**Fair Value *($ millions)***
Propane swaps	**34.38 to 51.50/Bbl**	**1-12**	**1,040,595**	**Bbl $**	**5**
Crude oil swaps	**93.37 to 111.74/Bbl**	**1-12**	**194,513**	**Bbl $**	**1**
Natural gas swaps	**1.28 to 3.55/GJ**	**1-12**	**7,513,045**	**GJ $**	**(5)**

December 31, 2022	Fixed price	Period (months)	Notional volume		Fair Value *($ millions)*
Propane swaps	48.94 to 50.79/Bbl	1-12	1,075,194	Bbl $	5
Crude oil swaps	108.65 to 113.88/Bbl	1-12	214,255	Bbl $	1
Natural gas swaps	4.5 to 4.98/GJ	1-12	6,139,191	GJ $	(9)

Power

AltaGas sells power to the Alberta Electric System Operator at market prices, as well as through its WGL Energy Services affiliate, to commercial, industrial and mass market users within the PJM Regional Transmission Organization at fixed and market prices. AltaGas' strategy is to mitigate the cash flow risk to power prices to provide predictable earnings. Therefore, AltaGas uses third-party swaps and purchase contracts to fix the prices over time on a portion of the volumes to mitigate financial exposure associated with the sale contracts. These power purchase and sale contracts extend to 2027. As at December 31, 2023, AltaGas had no intention to terminate any contracts prior to maturity. AltaGas had the following contracts outstanding as at December 31, 2023 and 2022:

December 31, 2023	**Fixed price (per MWh)**	**Period (months)**	**Notional volume (MWh)**		**Fair Value *($ millions)***
Power sales	**26.98 to 102.04**	**1-42**	**5,256,989**	**$**	**35**
Power purchases	**26.98 to 102.04**	**1-42**	**6,157,474**	**$**	**(43)**
Swap purchases	**(9.81) to 133**	**1-41**	**26,220,739**	**$**	**(67)**

December 31, 2022	Fixed price (per MWh)	Period (months)	Notional volume (MWh)		Fair Value *($ millions)*
Power sales	37.18 to 167.07	1-42	5,276,832	$	(96)
Power purchases	37.18 to 167.07	1-42	6,341,582	$	99
Swap purchases	(10.86) to 185.54	1-41	23,888,348	$	(81)

The table below provides the potential impact on pre-tax income due to changes in the fair value of risk management contracts in place as at December 31, 2023:

Factor	Increase or decrease to forward prices	Increase or decrease to income before tax *($ millions)*
PJM power price	US$1/MWh	37
NYMEX natural gas price	US$0.50/GJ	136
Energy Exports:		
Propane Far East Index to domestic supply	$1/Bbl	(3)
Baltic LPG Freight	$1/Bbl	3
NGL frac spread:		
Propane	$1/Bbl	(1)
Natural gas	$0.50/GJ	4

Foreign Exchange Risk

AltaGas is exposed to foreign exchange risk as changes in foreign exchange rates may affect the fair value or future cash flows of the Corporation's financial instruments. AltaGas has foreign operations whereby the functional currency is the U.S. dollar. As a result, the Corporation's earnings, cash flows, and OCI are exposed to fluctuations resulting from changes in foreign exchange rates. This risk is partially mitigated to the extent that AltaGas has U.S. dollar-denominated debt outstanding. AltaGas may also enter into foreign exchange forward derivatives to manage the risk of fluctuating cash flows and earnings due to variations in foreign exchange rates as well as to benefit from favorable movements in the rates. Any hedges transacted are subject to risk limits and guidelines and are actively monitored and managed by AltaGas' risk management team to ensure they align with AltaGas' overall financial strategy.

AltaGas may designate its external U.S. dollar-denominated debt or certain U.S. dollar-denominated loans that may give rise to a foreign currency transaction gain or loss as a net investment hedge of its U.S. subsidiaries. As at December 31, 2023, AltaGas has designated US$715 million of outstanding loans as a net investment hedge (December 31, 2022 - US$281 million). For the year ended December 31, 2023, a $25 million after-tax unrealized gain on the net investment hedge was recorded in OCI (2022 - after-tax unrealized loss of $15 million).

As at December 31, 2022, AltaGas did not have any outstanding foreign exchange forward contracts. The following foreign exchange forward contracts were outstanding as at December 31, 2023:

Foreign exchange forward contract	Duration		Fair Value
Forward USD sales (deliverable)	Less than 1 month		less than $1 million
Forward USD sales (non-deliverable)	Less than 1 year	$	10
Forward USD sales (non-deliverable)	1 - 2 years	$	9

For the year ended December 31, 2023, AltaGas had pre-tax gains on foreign exchange contracts of $25 million. Of this, an unrealized gain of less than $1 million, as well as a realized gain of less than $1 million related to foreign exchange contracts entered into for the purpose of risk associated with cash management, was recorded in the Consolidated Statements of Income under the line item "foreign exchange gains" (year ended December 31, 2022 - $nil). Additionally, an unrealized gain of $19 million, as well as a realized gain of $6 million related to foreign exchange contracts entered into for the purpose of managing income statement risk, was recorded in the Consolidated Statements of Income under the line item "revenue" (year ended December 31, 2022 - $nil).

Cash Flow Hedges

In the normal course of business, WGL Energy Services purchases natural gas indexed to NYMEX Henry Hub to be sold to third party customers. WGL Energy Services' risk management objective and strategy is to protect earnings against the risk of price fluctuations associated with forecasted NYMEX Henry Hub purchases through the use of the NYMEX Henry Hub financial swaps. Beginning April 1, 2023, WGL Energy Services began prospectively designating its NYMEX Henry Hub financial swaps as cash flow hedges in accordance with ASC Topic 815 as it expects that the hedging relationship will be highly effective at achieving offsetting changes in cash flows attributable to the risk being hedged.

For hedging relationships that qualify as highly effective, the change in fair value of the hedging instrument will be recorded to AOCI. Amounts in AOCI will be reclassified into earnings in the same period the hedged forecasted transactions affect earnings, or when non-regulated cost of energy-related sales is recorded. For swaps that settle the month ahead of the physical transaction, the swap impact will be reclassified into earnings in the subsequent month when the associated hedged transaction is recorded into earnings. For storage inventory purchases, such reclassification into earnings will be based on WGL Energy Services' inventory turnover schedules for finished goods in which the hedged natural gas purchases are used. When applicable, the ineffective portion of a cash flow hedge will immediately be recognized in earnings.

For the year ended December 31, 2023, an after-tax unrealized loss on outstanding cash flow hedges of $9 million was recorded in OCI (year ended December 31, 2022 - $nil). For the year ended December 31, 2023, a loss of $1 million was reclassified from AOCI to the income statement during the period under the line item "cost of sales".

Interest Rate Risk

AltaGas is exposed to interest rate risk as changes in interest rates may impact future cash flows and the fair value of its financial instruments. The Corporation manages its interest rate risk by holding a mix of both fixed and floating interest rate debt. As at December 31, 2023, approximately 84 percent of AltaGas’ total outstanding short-term and long-term debt was at fixed rates (December 31, 2022 - 78 percent). In addition, from time to time, AltaGas may enter into interest rate swap agreements to fix the interest rate on a portion of its banker’s acceptances issued under its credit facilities. There were no outstanding interest rate swaps as at December 31, 2023.

Credit Risk

Credit risk results from the possibility that a counterparty to a financial instrument fails to fulfill its obligations in accordance with the terms of the contract.

AltaGas' credit policy details the parameters used to grant, measure, monitor and report on credit provided to counterparties. AltaGas minimizes counterparty risk by conducting credit reviews on counterparties in order to establish specific credit limits, both prior to providing products or services and on a recurring basis. In addition, most contracts include credit mitigation clauses that allow AltaGas to obtain financial or performance assurances from counterparties under certain circumstances. AltaGas maintains an allowance for doubtful accounts in the normal course of its business.

AltaGas' maximum credit exposure consists primarily of the carrying value of the non-derivative financial assets and the fair value of derivative financial assets. As at December 31, 2023, AltaGas had no concentration of credit risk with a single counterparty.

Weather Related Instruments

WGL Energy Services utilizes heating degree day ("HDD") instruments from time to time to manage weather and price risks related to its natural gas and electricity sales during the winter heating season. WGL Energy Services also utilizes cooling degree day ("CDD") instruments and other instruments to manage weather and price risks related to its electricity sales during the summer cooling season. These instruments cover a portion of estimated revenue or energy-related cost exposure to variations in HDDs or CDDs. For the year ended December 31, 2023, a pre-tax loss of less than $8 million was recorded related to these instruments (2022 - pre-tax loss of less than $1 million).

Accounts Receivable Past Due or Impaired

With the exception of accounts receivable which are due in one year or less as summarized in the following table, AltaGas does not have any past due or impaired accounts receivable ("AR") as at December 31, 2023:

As at December 31, 2023	Total	AR accruals	Receivables impaired	Less than 30 days	31 to 60 days	61 to 90 days	Over 90 days
Trade receivable	$ 1,742	$ 609	$ 29	$ 944	$ 58	$ 19	$ 83
Other	131	—	—	131	—	—	—
Allowance for credit losses	(29)	—	(29)	—	—	—	—
	$ 1,844	$ 609	$ —	$ 1,075	$ 58	$ 19	$ 83

As at December 31, 2022	Total	AR accruals	Receivables impaired	Less than 30 days	31 to 60 days	61 to 90 days	Over 90 days
Trade receivable	$ 2,067	$ 1,078	$ 41	$ 751	$ 87	$ 26	$ 84
Other	65	—	—	65	—	—	—
Allowance for credit losses	(41)	—	(41)	—	—	—	—
	$ 2,091	$ 1,078	$ —	$ 816	$ 87	$ 26	$ 84

The following table provides a summary of changes to the allowance for credit losses by segment and major type:

	Year Ended December 31, 2023		
	Accounts Receivable	Contract Assets [(a)]	Total
Utilities			
Balance, beginning of period	$ 40	$ —	$ 40
Foreign exchange translation	(2)	—	$ (2)
Adjustments to allowance	24	—	24
Written off	(38)	—	(38)
Recoveries collected	4	—	4
Balance, end of period	$ 28	$ —	$ 28
Midstream			
Balance, beginning of period	$ 1	$ 1	$ 2
Balance, end of period	$ 1	$ 1	$ 2
Total	$ 29	$ 1	$ 30

(a) An allowance for credit loss is assessed quarterly and is recorded based on historical default rates published by external credit rating agencies and a rate associated with the estimated time frame that the contract asset will be billed to the customer.

	Year Ended December 31, 2022		
	Accounts Receivable	Contract Assets [a]	Total
Utilities			
Balance, beginning of period	$ 38	$ —	$ 38
Foreign exchange translation	2	—	2
Adjustments to allowance [b]	26	—	26
Written off	(29)	—	(29)
Recoveries collected	4	—	4
Reclassified to assets held for sale *(note 5)*	(1)	—	(1)
Balance, end of period	$ 40	$ —	$ 40
Midstream			
Balance, beginning of period	$ 1	$ 1	$ 2
Balance, end of period	$ 1	$ 1	$ 2
Total	$ 41	$ 1	$ 42

(a) An allowance for credit loss is assessed quarterly and is recorded based on historical default rates published by external credit rating agencies and a rate associated with the estimated time frame that the contract asset will be billed to the customer.

(b) Includes $2 million recorded to a regulatory asset relating to the impact of COVID-19 on uncollectible accounts.

Liquidity Risk

Liquidity risk is the risk that AltaGas will not be able to meet its financial obligations as they come due. AltaGas manages this risk through its extensive budgeting and monitoring process to ensure it has sufficient cash and credit facilities to meet its obligations. AltaGas' objective is to maintain its investment-grade ratings to ensure it has access to debt and equity funding as required.

AltaGas had the following contractual maturities with respect to financial liabilities:

	Contractual maturities by period [a]				
As at December 31, 2023	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**After 5 years**
Accounts payable and accrued liabilities	**$ 1,863**	**$ 1,863**	**$ —**	**$ —**	**$ —**
Short-term debt	**129**	**129**	**—**	**—**	**—**
Other current liabilities [b]	**43**	**43**	**—**	**—**	**—**
Risk management contract liabilities	**212**	**97**	**91**	**22**	**2**
Current portion of long-term debt [c]	**999**	**999**	**—**	**—**	**—**
Long-term debt [c]	**7,493**	**—**	**2,092**	**1,548**	**3,853**
Subordinated hybrid notes	**750**	**—**	**—**	**—**	**750**
	$ 11,489	**$ 3,131**	**$ 2,183**	**$ 1,570**	**$ 4,605**

(a) Refer to Note 9 for contractual maturities relating to operating and finance leases.

(b) Excludes non-financial liabilities.

(c) Excludes deferred financing costs, discounts, and the fair value adjustment on the WGL Acquisition.

		Contractual maturities by period [a]				
As at December 31, 2022		Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Accounts payable and accrued liabilities	$	1,902	$ 1,902	$ —	$ —	$ —
Short-term debt		293	293	—	—	—
Other current liabilities [b]		52	52	—	—	—
Risk management contract liabilities		470	172	183	57	58
Current portion of long-term debt [c]		327	327	—	—	—
Long-term debt [c]		8,641	—	2,241	1,968	4,432
Debt classified as held for sale		(60)	(7)	(12)	(12)	(29)
Subordinated hybrid notes		550	—	—	—	550
	$	12,175	$ 2,739	$ 2,412	$ 2,013	$ 5,011

(a) Refer to Note 9 for contractual maturities relating to operating and finance leases.
(b) Excludes non-financial liabilities.
(c) Excludes deferred financing costs, discounts, the fair value adjustment on the WGL Acquisition, and debt classified as held for sale.

24. Revenue

The following tables disaggregate revenue by major sources for the year:

	Year Ended December 31, 2023			
	Utilities	**Midstream**	**Corporate/ Other**	**Total**
Revenue from contracts with customers				
Commodity sales contracts	**$ 1,971**	**$ 6,347**	**$ —**	**$ 8,318**
Midstream service contracts	**—**	**1,541**	**—**	**1,541**
Gas sales and transportation services	**2,506**	**8**	**—**	**2,514**
Storage services [a]	**4**	**—**	**—**	**4**
Other	**11**	**9**	**—**	**20**
Total revenue from contracts with customers	**$ 4,492**	**$ 7,905**	**$ —**	**$ 12,397**
Other sources of revenue				
Revenue from alternative revenue programs [b]	**$ 167**	**$ —**	**$ —**	**$ 167**
Leasing revenue [c]	**—**	**221**	**99**	**320**
Risk management and trading activities [d]	**173**	**(97)**	**2**	**78**
Other	**(5)**	**40**	**—**	**35**
Total revenue from other sources	**$ 335**	**$ 164**	**$ 101**	**$ 600**
Total revenue	**$ 4,827**	**$ 8,069**	**$ 101**	**$ 12,997**

(a) Relates to revenue earned for the period prior to the close of the Alaska Utilities Disposition on March 1, 2023.
(b) A large portion of revenue generated from the Utilities segment is subject to rate regulation and accordingly there are circumstances where the revenue recognized is mandated by the applicable regulators in accordance with ASC 980.
(c) Revenue generated from certain of AltaGas' gas facilities is accounted for as operating leases. For the Corporate/Other segment, a significant amount of revenue earned is through power purchase agreements which are accounted for as operating leases.
(d) Risk management activities involve the use of derivative instruments such as physical and financial swaps, and commodity and foreign exchange forward contracts. Certain of these derivatives are accounted for under ASC 815 and ASC 825. A portion of revenue generated by the Utilities segment is from the physical sale and delivery of natural gas and power to end users.

		Year Ended December 31, 2022		
	Utilities	Midstream	Corporate/ Other	Total
Revenue from contracts with customers				
Commodity sales contracts	$ 1,715	$ 6,260	$ —	$ 7,975
Midstream service contracts	—	2,411	—	2,411
Gas sales and transportation services	3,179	—	—	3,179
Storage services	24	—	—	24
Other	9	—	1	10
Total revenue from contracts with customers	$ 4,927	$ 8,671	$ 1	$ 13,599
Other sources of revenue				
Revenue from alternative revenue programs [a]	$ 94	$ —	$ —	$ 94
Leasing revenue [b]	—	232	99	331
Risk management and trading activities [c]	(28)	76	(3)	45
Other	(13)	31	—	18
Total revenue from other sources	$ 53	$ 339	$ 96	$ 488
Total revenue	$ 4,980	$ 9,010	$ 97	$ 14,087

(a) A large portion of revenue generated from the Utilities segment is subject to rate regulation and accordingly there are circumstances where the revenue recognized is mandated by the applicable regulators in accordance with ASC 980.

(b) Revenue generated from certain of AltaGas' gas facilities is accounted for as operating leases. For the Corporate/Other segment, a significant amount of revenue earned is through power purchase agreements which are accounted for as operating leases.

(c) Risk management activities involve the use of derivative instruments such as physical and financial swaps, forward contracts, and options. These derivatives are accounted for under ASC 815 and ASC 825. A portion of revenue generated by the Utilities segment is from the physical sale and delivery of natural gas and power to end users.

Revenue Recognition

The following is a description of the Corporation's revenue recognition policy by segment and by major source of revenue from contracts with customers.

Utilities Segment

Gas Sales and Transportation Services

Customers are billed monthly based on regular meter readings. Customer billings are based on two main components: (i) a fixed service fee and (ii) a variable fee based on usage. Revenue is recognized over time when the gas has been delivered or as the service has been performed. As meter readings are performed on a cycle basis, AltaGas recognizes accrued revenue for any services rendered to its customers but not billed at month-end. The vast majority of these contracts are "at-will" as customers may cancel their service at any time, however, there are certain contracts that have terms of one year or longer. For these long-term contracts, there is generally a contract demand specified in the contract whereby the customer has to pay regardless of whether or not gas has been delivered. These contracts generally do not contain any make up rights and revenue is recognized on a monthly basis as service has been performed.

Commodity Sales

Commodity sales also include gas sales to residential, commercial, and industrial customers in certain states where WGL Energy Services is authorized as a competitive service provider. These commodity sales contracts have varying terms that generally range from one to five years. Customers are billed monthly based on the amount of gas delivered to the customer. Revenue is recognized based on the amount the Corporation is entitled to invoice the customer.

Midstream Segment

Commodity Sales

A portion of the NGL production from AltaGas' extraction facilities is subject to frac spread between NGLs extracted and the natural gas purchased to make up the heating value of the NGLs extracted. For commodity sales contracts that do not meet the definition of a derivative or for contracts whereby AltaGas has elected to apply the normal purchase normal sales scope exception, the sales contract is accounted for under ASC 606. These commodity sales contracts have varying terms but the majority of the contracts have a one-year term which coincides with the NGL year. AltaGas recognizes revenue for commodity sales contracts at a point in time based on the actual volumes of the commodity sold at the delivery point, which corresponds to the customer's monthly invoice amount.

Commodity sales contracts at RIPET and Ferndale generate revenue from the sale and delivery of LPGs to customers in Asia shipped from offshore export terminals. Revenue is recognized when LPGs are loaded onto transport vessels, which is the delivery point. AltaGas has the right to consideration in an amount that directly corresponds to the volumes of LPGs loaded on a vessel. AltaGas' commodity sales also include the sale of upgraded crude oil, processed finished products, and various fuels. Delivery takes place when there is a sales contract in place, specifying delivery volumes and sales prices. The consideration received under these contracts is variable based on commodity prices.

Midstream Service Contracts

AltaGas earns revenue from its field gathering and processing facilities, extraction facilities, storage facilities, truck hauling services, rail and truck loading and unloading terminalling, and transmission systems through a variety of contractual arrangements. For arrangements that do not contain a lease, the revenue is accounted for under ASC 606 as follows:

Fee-for-service – The customer is charged a fee for the service provided on a per unit volume basis. Contract terms generally range from one month to up to the life of the reserves. Revenue under this type of arrangement is recognized over time as the service is provided, which corresponds to the customer's monthly invoice amount.

Take-or-pay – The customer has agreed to a minimum volume commitment whereby the customer must have AltaGas process or deliver a specified volume at a rate per unit that is specified in the contract. Quantities that the customer is unable to deliver are considered deficiency quantities. Certain of AltaGas' take-or-pay contracts contain provisions whereby the customer can make up deficiency quantities in subsequent periods. Under this type of arrangement, any consideration received relating to the deficiency quantities that will be made up in a future period will be deferred until either: (i) the customer makes up the volumes or (ii) the likelihood that the customer will make up the volumes before the make up period expires becomes remote. If AltaGas does not expect the customer to make up the deficiency quantities (also referred to as breakage amount), AltaGas may recognize the expected breakage amount as revenue before the make up period expires. Significant judgment is required in estimating the breakage amount. For contracts where the customer has no make up rights, revenue is recognized on a monthly basis based on the higher of (i) the actual quantity delivered times the per unit rate or (ii) the contracted minimum amount.

Storage fees are typically recognized in revenue ratably over the term of the contract and rail and truck loading and unloading fees are recognized when the volumes are delivered or received.

Corporate/Other Segment

For the Corporate/Other segment, the majority of revenue relates to remaining power assets, from which revenue is primarily earned through power purchase agreements which are accounted for as operating leases. In instances where power generation is not sold under a power purchase agreement, the commodity is sold via a merchant market, or via commodity sales agreements which are accounted for as financial instruments. For commodity sales contracts that do not meet the definition of a lease, derivative or for contracts whereby AltaGas has elected to apply the normal purchase normal sales scope exception, the sales contract is accounted for under ASC 606.

Contract Balances

As at December 31, 2023, a contract asset of $40 million (December 31, 2022 - $41 million) has been recorded on the Consolidated balance Sheets, of which $37 million ($36 million net of credit losses) is included within long-term investments and other assets (December 31, 2022 – $37 million net of credit losses) and $4 million within prepaid expenses and other current assets (December 31, 2022 - $4 million). This contract asset represents the difference in revenue recognized under new rates in blend-and-extend contract modifications with customers. Revenue from these contract modifications was recognized at the pre-modification rate until the effective date of the contract modification on the original contracts, with the excess revenue recorded as a contract asset. The contract asset is now being drawn down over the remaining term of the modified contracts.

Contract Assets

As at	**December 31, 2023**	December 31, 2022
Balance, beginning of year	**$ 41**	$ 54
Additions	**3**	1
Amortization [(a)]	**(4)**	(4)
Transfers to accounts receivable [(b)]	**—**	(10)
Balance, end of year	**$ 40**	$ 41

(a) Represents the drawdown of a contract asset under a blend-and-extend contract modification.

(b) Amounts included in contract assets are transferred to accounts receivable when AltaGas' right to consideration becomes unconditional.

Transaction Price Allocated to the Remaining Obligations

The following table includes estimated revenue expected to be recognized in the future related to performance obligations that are unsatisfied as of December 31, 2023:

	2024	2025	2026	2027	2028	2029 & beyond	**Total**
Midstream service contracts	$ 157	$ 141	$ 138	$ 134	$ 123	$ 795	**$ 1,488**
Other	1	1	1	1	—	4	**8**
	$ 158	$ 142	$ 139	$ 135	$ 123	$ 799	**$ 1,496**

AltaGas applies the practical expedient available under ASC 606 and does not disclose information about the remaining performance obligations for (i) contracts with an original expected length of one year or less, (ii) contracts for which revenue is recognized at the amount to which AltaGas has the right to invoice for performance completed, and (iii) contracts with variable consideration that is allocated entirely to a wholly unsatisfied performance obligation or to a wholly unsatisfied promise to transfer a distinct good or service that forms part of a single performance obligation. In addition, the table above does not include any estimated amounts of variable consideration that are constrained. The majority of midstream service contracts, gas sales and transportation service contracts, and storage service contracts contain variable consideration whereby uncertainty related to the associated variable consideration will be resolved (usually on a daily basis) as volumes are processed, gas is delivered or as service is provided.

25. Shareholders' Equity

Authorization

AltaGas is authorized to issue an unlimited number of voting common shares. AltaGas is also authorized to issue such number of preferred shares in series at any time as have aggregate voting rights either directly or on conversion or exchange that in the aggregate represent less than 50 percent of the voting rights attaching to the then issued and outstanding common shares.

Common Shares Issued and Outstanding [(a)]	Number of shares		Amount
January 1, 2022	280,269,038	$	6,735
Shares issued for cash on exercise of options	1,262,795		28
Deferred taxes on share issuance cost	—		(2)
December 31, 2022	281,531,833	$	6,761
Shares issued for cash on exercise of options	905,493		19
Shares issued related to Pipestone Acquisition *(note 3)*	12,466,437		340
Issued and outstanding at December 31, 2023	**294,903,763**	**$**	**7,120**

(a) Dividends declared per common share for the year ended December 31, 2023 was $1.12 (December 31, 2022 - $1.06).

Preferred Shares

As at	**December 31, 2023**			December 31, 2022		
Issued and Outstanding [(a) (b) (c)]	**Number of shares**		**Amount**	Number of shares		Amount
Series A	**6,746,679**	**$**	**169**	6,746,679	$	169
Series B	**1,253,321**		**31**	1,253,321		31
Series E [(d)]	**—**		—	8,000,000		200
Series G	**6,885,823**		**172**	6,885,823		172
Series H	**1,114,177**		**28**	1,114,177		28
Share issuance costs, net of taxes			**(9)**			(14)
	16,000,000	**$**	**391**	24,000,000	$	586

(a) On January 11, 2022, in connection with the offering of the Subordinated Notes, Series 1, AltaGas issued $300 million in Preferred Shares, Series 2022-A, to be held in the AltaGas Hybrid Trust with Computershare Trust Company of Canada acting as a trustee. Refer to Notes 12 and 16 for more details.

(b) On August 17, 2022, in connection with the offering of the Subordinated Notes, Series 2, AltaGas issued $250 million in Preferred Shares, Series 2022-B, to be held in the AltaGas Hybrid Trust with Computershare Trust Company of Canada acting as a trustee. Refer to Notes 12 and 16 for more details.

(c) On November 10, 2023, in connection with the offering of the Subordinated Notes, Series 3, AltaGas issued $200 million in Preferred Shares, Series 2023-A, to be held in the AltaGas Hybrid Trust with Computershare Trust Company of Canada acting as a trustee. Refer to Notes 12 and 16 for more details.

(d) On December 31, 2023, AltaGas redeemed all of its outstanding Series E Preferred Shares. A loss of approximately $5 million was recognized upon redemption related to share issuance costs for the preferred shares.

The following table outlines the characteristics of the cumulative redeemable preferred shares [(a) (h) (i) (j)]:

	Current yield	Annual dividend per share[(b)]	Redemption price per share [(g)]	Redemption and conversion option date[(c)(g)]	Right to convert into[(d)]
Series A [(e)]	3.060 %	$0.76500	$25	September 30, 2025	Series B
Series B [(f) (g)]	Floating	Floating	$25	September 30, 2025	Series A
Series G [(e)]	4.242 %	$1.06050	$25	September 30, 2024	Series H
Series H [(f) (g)]	Floating	Floating	$25	September 30, 2024	Series G

(a) The Corporation is authorized to issue up to 8,000,000 of Series F Shares, subject to certain conditions, upon conversion by the holders of the applicable currently issued and outstanding series of preferred shares noted opposite such series in the table on the applicable conversion option date. If issued upon the conversion of the applicable series of preferred shares, Series F Shares are also redeemable for $25.50 on any date after the applicable conversion option date, plus all accrued but unpaid dividends to, but excluding, the date fixed for redemption.

(b) The holders of Series A Shares and Series G Shares are entitled to receive a cumulative quarterly fixed dividend as and when declared by the Board of Directors. The holders of Series B Shares and Series H Shares are entitled to receive a quarterly floating dividend as and when declared by the Board of Directors. If issued upon the conversion of the applicable series of preferred shares, the holders of Series F Shares will be entitled to receive a quarterly floating dividend as and when declared by the Board of Directors.

(c) AltaGas may, at its option, redeem all or a portion of the outstanding shares for the redemption price per share, plus all accrued and unpaid dividends on the applicable redemption option date and on every fifth anniversary thereafter.

(d) The holder will have the right, subject to certain conditions, to convert their preferred shares of a specified series into preferred shares of that other specified series as noted in this column of the table on the applicable conversion option date and every fifth anniversary thereafter.

(e) Holders of Series A Shares and Series G Shares will be entitled to receive cumulative quarterly fixed dividends, which will reset on the redemption and conversion option date and every fifth year thereafter, at a rate equal to the sum of the then five-year Government of Canada bond yield plus 2.66 percent (Series A Shares) and 3.06 percent (Series G Shares).

(f) Holders of Series B Shares and Series H Shares will be entitled to receive cumulative quarterly floating dividends, which will reset each quarter thereafter at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill rate plus 2.66 percent (Series B Shares) and 3.06 percent (Series H Shares). Each quarterly dividend is calculated as the annualized amount multiplied by the number of days in the quarter, divided by the number of days in the year. Commencing December 31, 2023, the floating quarterly dividend rate is $0.47874 per share for Series B Shares and $0.50361 per share for Series H Shares for the period starting December 31, 2023 to, but excluding, March 31, 2024.

(g) Series B Shares can be redeemed for $25.50 per share on any date after September 30, 2015 that is not a Series B conversion date, plus all accrued and unpaid dividends to, but excluding, the date fixed for redemption. Series H Shares can be redeemed for $25.50 per share on any date after September 30, 2019 that is not a Series H conversion date, plus all accrued and unpaid dividends to, but excluding, the date fixed for redemption.

(h) The Series 2022-A Shares were issued to Computershare Trust Company of Canada to be held in trust to satisfy AltaGas' obligations under the Series 1 Indenture, in connection with the issuance of the Subordinated Notes, Series 1. Holders of the Series 2022-A Shares shall not be entitled to receive any dividends, nor shall any dividends accumulate or accrue, on the Series 2022-A Shares prior to delivery to the holders of the Subordinated Notes, Series 1 following the occurrence of certain bankruptcy or insolvency events in respect of AltaGas. If at any time, AltaGas redeems, purchases for cancellation or repays the Subordinated Notes, Series 1 such number of Series 2022-A Shares with an aggregate issue price equal to the principal amount of Subordinated Notes, Series 1 redeemed, purchased for cancellation or repaid by AltaGas will be redeemed in accordance with the terms of the Series 2022-A Shares.

(i) The Series 2022-B Shares were issued to Computershare Trust Company of Canada to be held in trust to satisfy AltaGas' obligations under the Series 2 Indenture, in connection with the issuance of the Subordinated Notes, Series 2. Holders of the Series 2022-B Shares shall not be entitled to receive any dividends, nor shall any dividends accumulate or accrue, on the Series 2022-B Shares prior to delivery to the holders of the Subordinated Notes, Series 2 following the occurrence of certain bankruptcy or insolvency events in respect of AltaGas. If at any time, AltaGas redeems, purchases for cancellation or repays the Subordinated Notes, Series 2 such number of Series 2022-B Shares with an aggregate issue price equal to the principal amount of Subordinated Notes, Series 2 redeemed, purchased for cancellation or repaid by AltaGas will be redeemed in accordance with the terms of the Series 2022-B Shares.

(j) The Series 2023-A Shares were issued to Computershare Trust Company of Canada to be held in trust to satisfy AltaGas' obligations under the Series 3 Indenture, in connection with the issuance of the Subordinated Notes, Series 3. Holders of the Series 2023-A Shares shall not be entitled to receive any dividends, nor shall any dividends accumulate or accrue, on the Series 2023-A Shares prior to delivery to the holders of the Subordinated Notes, Series 3 following the occurrence of certain bankruptcy or insolvency events in respect of AltaGas. If at any time, AltaGas redeems, purchases for cancellation or repays the Subordinated Notes, Series 3 such number of Series 2023-A Shares with an aggregate issue price equal to the principal amount of Subordinated Notes, Series 3 redeemed, purchased for cancellation or repaid by AltaGas will be redeemed in accordance with the terms of the Series 2023-A Shares.

Share Option Plan

AltaGas has an employee share option plan under which officers, employees, and service providers (as defined by the TSX) are eligible to receive grants. As at December 31, 2023, 10,807,874 shares were reserved for issuance under the plan.

As at December 31, 2023, Share Options granted under the plan have a term of six years until expiry and vest no longer than over a four-year period.

As at December 31, 2023, the unexpensed fair value of share option compensation cost associated with future periods was less than one million (December 31, 2022 - $1 million).

The following table summarizes information about the Corporation's Share Options:

As at	**December 31, 2023** **Options outstanding**		December 31, 2022 Options outstanding	
	Number of options	**Exercise price** [a]	Number of options	Exercise price [a]
Share options outstanding, beginning of year	**6,958,139**	**$ 19.28**	8,679,508	$ 19.98
Exercised	**(905,493)**	**18.22**	(1,262,795)	19.94
Forfeited	**(83,257)**	**21.90**	(107,799)	26.24
Expired	**(422,001)**	**31.53**	(350,775)	32.19
Share options outstanding, end of year	**5,547,388**	**$ 18.48**	6,958,139	$ 19.28
Share options exercisable, end of year	**4,990,946**	**$ 18.45**	4,960,341	$ 19.38

(a) Weighted average.

As at December 31, 2023, the aggregate intrinsic value of the total Share Options exercisable was $47 million (December 31, 2022 - $24 million), the total intrinsic value of Share Options outstanding was $52 million (December 31, 2022 - $33 million) and the total intrinsic value of Share Options exercised was $8 million (December 31, 2022 - $11 million).

The following table summarizes the employee share option plan as at December 31, 2023:

	Options outstanding			**Options exercisable**		
	Number outstanding	Weighted average exercise price	Weighted average remaining contractual life (years)	Number exercisable	Weighted average exercise price	Weighted average remaining contractual life (years)
$14.52 to $18.00	1,477,888	$ 15.54	1.06	1,477,888	$ 15.54	1.06
$18.01 to $25.08	3,909,998	19.27	2.25	3,354,494	19.36	2.13
$25.09 to $26.31	159,502	26.31	0.55	158,564	26.31	0.53
	5,547,388	**$ 18.48**	**1.89**	**4,990,946**	**$ 18.45**	**1.76**

Phantom Unit Plan ("Phantom Plan") and Deferred Share Unit Plan ("DSUP")

AltaGas has a Phantom Plan for employees, executive officers, and directors, which includes restricted units ("RUs") and performance units ("PUs") with vesting periods of 36 months from the grant date. In addition, AltaGas has a DSUP, pursuant to which directors and certain executives receive deferred share units ("DSUs"). DSUs granted under the DSUP vest immediately but settlement of the DSUs occur when the individual ceases to be a director.

PUs, RUs, and DSUs *(number of units)*	**2023**	2022
Balance, beginning of year	**4,332,062**	3,877,843
Granted	**2,281,596**	1,413,790
Vested and paid out	**(2,047,793)**	(1,784,293)
Forfeited	**(551,390)**	(140,150)
Units in lieu of dividends	**210,332**	172,563
Additional units added by performance factor	**828,111**	792,309
Outstanding, end of year	**5,052,918**	4,332,062

For the year ended December 31, 2023, the compensation expense recorded for the Phantom Plan and DSUP was $69 million (2022 – $50 million). As at December 31, 2023, the unrecognized compensation expense relating to the remaining vesting period for the Phantom Plan was $33 million (December 31, 2022 - $14 million) and is expected to be recognized over the vesting period.

26. Net Income Per Common Share

The following table summarizes the computation of net income per common share:

	Year Ended December 31	
	2023	2022
Numerator:		
Net income applicable to controlling interests	**$ 673**	$ 523
Less: Preferred share dividends	**(27)**	(40)
Loss on redemption of preferred shares	**(5)**	(84)
Net income applicable to common shares	**$ 641**	$ 399
Denominator:		
(millions of shares)		
Weighted average number of common shares outstanding	**282.1**	281.0
Dilutive equity instruments [(a)]	**1.6**	2.3
Weighted average number of common shares outstanding - diluted	**283.7**	283.3
Basic net income per common share	**$ 2.27**	$ 1.42
Diluted net income per common share	**$ 2.26**	$ 1.41

(a) Determined using the treasury stock method.

For the year ended December 31, 2023, less than a million Share Options (2022 – less than a million) were excluded from the diluted net income per common share calculation as their effects were anti-dilutive.

27. Other Income

Year Ended December 31	**2023**	2022
Gains on asset sales *(note 4)*	**$ 319**	$ 3
Other components of net benefit cost *(note 28)*	**57**	74
Gain on debt defeasance *(note 15)*	**14**	—
Interest income and other revenue	**13**	17
Total	**$ 403**	$ 94

28. Pension Plans and Retiree Benefits

The costs of the defined benefit and post-retirement benefit plans are based on Management's estimate of the future rate of return on the fair value of pension plan assets, salary escalations, mortality rates and other factors affecting the payment of future benefits.

Defined Contribution Plan

AltaGas has a defined contribution ("DC") pension plan for substantially all employees. The pension cost recorded for the DC plan and DC Supplemental Executive Retirement Plan ("SERP") was $26 million for the year ended December 31, 2023 (2022 - $25 million).

Defined Benefit Plans

AltaGas has three defined benefit pension plans for unionized and non-unionized employees in the United States. These include a qualified, trusteed, non-contributory defined benefit pension plan. Actuarial valuations for funding purposes are required annually for AltaGas' U.S. defined benefit plans. The defined benefit plans are fully funded.

In 2021, AltaGas made the decision to wind-up the Canadian defined benefit pension plan effective March 31, 2022. In October 2022, approval of the wind-up was received from the Alberta Superintendent of Pensions. On June 1, 2023, the wind-up of the Canadian defined benefit pension plan was completed and as a result a settlement charge of $2 million was recorded under the line item "other income" for the year ended December 31, 2023.

SERP

AltaGas has non-registered defined benefit plans that provide defined benefit pension benefits to eligible executives based on average earnings, years of service and age at retirement. The SERP benefits will be paid from the general revenue of the Corporation as payments come due or from the Rabbi Trusts funded as part of the WGL acquisition. Security will be provided for the SERP benefits through a letter of credit within a retirement compensation arrangement trust account.

Several executive officers of Washington Gas participate in a separate non-funded defined benefit SERP (a non-qualified pension plan) and a non-funded defined benefit restoration SERP. The defined benefit SERP was closed to new entrants beginning January 1, 2010 and the defined benefit restoration SERP was closed to new entrants in 2020.

In 2023, AltaGas closed the Canadian SERP to new entrants and launched a new a defined contribution SERP effective July 1, 2023, for eligible executives who join the Executive Committee on or after that date.

Post-Retirement Benefit Plans

AltaGas has several post-retirement benefit plans for unionized and non-unionized employees, including one in Canada and four in the United States. The post-retirement benefit plan in Canada is limited to the payment of life insurance and an annual allocation to a Healthcare Spending Account ("HSA"). This benefit plan is not funded.

Post-retirement benefit plans in the United States provide certain medical, prescription drug, dental, and life insurance benefits to eligible retired employees, their spouses and covered dependents. Benefits are based on a combination of the retiree's age and years of service at retirement. For eligible Washington Gas retirees and dependents not yet receiving Medicare benefits, Washington Gas provides medical, prescription drug, and dental benefits through Preferred Provider Organization ("PPO") or Health Maintenance Organization ("HMO") plans, through the Washington Gas Light Company Retiree Health and Welfare Plan. For Medicare-eligible retirees age 65 and older and their dependents, eligible retirees and dependents participate in a tax-free Health Reimbursement Account ("HRA") Plan. The HRA plan provides an annual subsidy to help purchase supplemental medical, prescription drug and dental coverage in the marketplace. Three of these plans are fully funded, and one is not funded.

Rabbi Trusts

Rabbi trusts of $9 million as at December 31, 2023 have been funded to satisfy the employee benefit obligations associated with WGL's various pension plans (December 31, 2022 - $11 million). These balances are included in the "prepaid expenses and other current assets" and "long-term investments and other assets" line items on the Consolidated Balance Sheets.

The following table summarizes the details of the defined benefit plans, including the SERP and post-retirement plans in Canada and the United States:

Year Ended December 31, 2023		Canada			United States			Total	
		Defined Benefit		Post-Retirement Benefits		Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Projected benefit obligation [(a)]									
Balance, beginning of year	$	28	$	2	$	1,268 $	332 $	1,296 $	334
Actuarial loss (gain)		2		(1)		35	(9)	37	(10)
Current service cost		6		—		12	6	18	6
Member contributions		—		—		—	2	—	2
Interest cost		1		—		69	18	70	18
Benefits paid		(3)		—		(83)	(20)	(86)	(20)
Settlements		(11)		—		—	—	(11)	—
Foreign exchange translation		—		—		(29)	(7)	(29)	(7)
Balance, end of year	$	23	$	1	$	1,272 $	322 $	1,295 $	323
Plan assets									
Fair value, beginning of year	$	13	$	—	$	1,266 $	842 $	1,279 $	842
Actual return on plan assets		—		—		113	116	113	116
Employer contributions		3		—		4	—	7	—
Member contributions		—		—		—	2	—	2
Benefits paid		(3)		—		(83)	(21)	(86)	(21)
Settlements		(11)		—		—	—	(11)	—
Other		—		—		1	—	1	—
Foreign exchange translation		—		—		(30)	(21)	(30)	(21)
Fair value, end of year	$	2	$	—	$	1,271 $	918 $	1,273 $	918
Funded status	$	(21)	$	(1)	$	(1) $	596 $	(22) $	595

(a) For post-retirement benefit plans, the projected benefit obligation represents the accumulated benefit obligation.

Year Ended December 31, 2022	Canada		United States		Total	
	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Projected benefit obligation [(a)]						
Balance, beginning of year	$ 34	$ 2	$ 1,743	$ 430	$ 1,777	$ 432
Actuarial gain	(6)	—	(473)	(118)	(479)	(118)
Current service cost	3	—	22	10	25	10
Member contributions	—	—	—	3	—	3
Interest cost	1	—	52	13	53	13
Benefits paid	(4)	—	(83)	(23)	(87)	(23)
Expenses paid	—	—	(1)	—	(1)	—
Settlements	—	—	(5)	—	(5)	—
Other	—	—	—	1	—	1
Foreign exchange translation	—	—	98	25	98	25
	$ 28	$ 2	$ 1,353	$ 341	$ 1,381	$ 343
Less: projected benefit obligation reclassified to liabilities associated with assets held for sale	—	—	(85)	(9)	(85)	(9)
Balance, end of year	$ 28	$ 2	$ 1,268	$ 332	$ 1,296	$ 334
Plan assets						
Fair value, beginning of year	$ 16	$ —	$ 1,715	$ 1,058	$ 1,731	$ 1,058
Actual return on plan assets	(3)	—	(374)	(254)	(377)	(254)
Employer contributions	4	—	8	—	12	—
Member contributions	—	—	—	3	—	3
Benefits paid	(4)	—	(83)	(23)	(87)	(23)
Expenses paid	—	—	(1)	—	(1)	—
Settlements	—	—	(5)	—	(5)	—
Other	—	—	—	1	—	1
Foreign exchange translation	—	—	99	60	99	60
	$ 13	$ —	$ 1,359	$ 845	$ 1,372	$ 845
Less: plan assets reclassified to assets held for sale	—	—	(93)	(3)	(93)	(3)
Fair value, end of year	$ 13	$ —	$ 1,266	$ 842	$ 1,279	$ 842
Funded status [(b)]	$ (15)	$ (2)	$ 6	$ 504	$ (9)	$ 502

(a) For post-retirement benefit plans, the projected benefit obligation represents the accumulated benefit obligation.

(b) Calculation includes plan assets and liabilities that were classified as held for sale on December 31, 2022.

For the year ended December 31, 2023, AltaGas' defined benefit pension plans incurred actuarial losses primarily due to the decrease in discount rates, which were the result of a decrease in high-quality corporate bond yield curves in the Canadian and U.S. markets, while AltaGas' post-retirement benefits plans incurred actuarial gains primarily due to updated census data and assumptions related to the HRA, partially offset by the decrease in discount rates. For the year ended December 31, 2022, AltaGas' defined benefit and post-retirement benefit pension plans incurred actuarial gains primarily due to the increase in discount rates, which were the result of an increase in high-quality corporate bond yield curves in the Canadian and U.S. markets.

The following amounts were included in the Consolidated Balance Sheets:

	December 31, 2023			December 31, 2022		
	Defined Benefit	**Post-Retirement Benefits**	**Total**	Defined Benefit	Post-Retirement Benefits	Total
Prepaid post-retirement benefits	**$ 29**	**$ 597**	**$ 626**	$ 28	$ 510	$ 538
Assets held for sale	**—**	**—**	**—**	8	—	8
Accounts payable and accrued liabilities [(a)]	**(4)**	**—**	**(4)**	(3)	—	(3)
Future employee obligations	**(47)**	**(2)**	**(49)**	(42)	(2)	(44)
Liabilities associated with assets held for sale	**—**	**—**	**—**	—	(6)	(6)
	$ (22)	**$ 595**	**$ 573**	$ (9)	$ 502	$ 493

(a) Account balances on the Consolidated Balance Sheets also include certain non-pension related amounts.

The accumulated benefit obligation for all defined benefit plans were:

As at	December 31, 2023		December 31, 2022	
	Canada	**United States**	Canada	United States
Accumulated benefit obligation [(a)]	**$ 21**	**$ 1,222**	$ 27	$ 1,307

(a) Accumulated benefit obligation differs from projected benefit obligation in that it does not include an assumption with respect to future compensation levels.

For those pension plans where the projected benefit obligation exceeded the fair value of plan assets as at December 31, 2023, the cumulative obligation and asset balances were:

As at	December 31, 2023		December 31, 2022	
	Defined Benefit	**Post-Retirement Benefits**	Defined Benefit	Post-Retirement Benefits
Projected benefit obligation	**$ 52**	**$ 2**	$ 49	$ 11
Plan assets	**$ 2**	**$ —**	$ 3	$ 3

For those pension plans where the accumulated benefit obligation exceeded the fair value of plan assets as at December 31, 2023, the cumulative obligation and asset balances were:

As at	December 31, 2023		December 31, 2022	
	Defined Benefit	**Post-Retirement Benefits**	Defined Benefit	Post-Retirement Benefits
Accumulated benefit obligation	**$ 50**	**$ 2**	$ 48	$ 11
Plan assets	**$ 2**	**$ —**	$ 3	$ 3

The following amounts were recorded in other comprehensive income (loss) and have not yet been recognized in net periodic benefit cost:

Year Ended December 31, 2023		Canada		United States		Total	
		Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Past service cost	$	— $	— $	— $	(1) $	— $	(1)
Net actuarial gain (loss)		—	—	1	(3)	1	(3)
Recognized in AOCI pre-tax	$	— $	— $	1 $	(4) $	1 $	(4)
Increase by the amount included in deferred tax liabilities		—	—	—	1	—	1
Net amount in AOCI after-tax	$	— $	— $	1 $	(3) $	1 $	(3)

Year Ended December 31, 2022		Canada		United States		Total	
		Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Past service cost	$	— $	— $	— $	(1) $	— $	(1)
Net actuarial loss		(2)	—	—	(3)	(2)	(3)
Recognized in AOCI pre-tax	$	(2) $	— $	— $	(4) $	(2) $	(4)
Increase by the amount included in deferred tax liabilities		—	—	—	1	—	1
Net amount in AOCI after-tax	$	(2) $	— $	— $	(3) $	(2) $	(3)

The following amounts were recorded in a regulatory asset (liability) and have not yet been recognized in net periodic benefit cost:

Year Ended December 31, 2023		Canada		United States		Total	
		Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Past service credit	$	— $	— $	— $	(44) $	— $	(44)
Net actuarial gain		—	—	(50)	(188)	(50)	(188)
Recognized in regulatory liability	$	— $	— $	(50) $	(232) $	(50) $	(232)

Year Ended December 31, 2022		Canada		United States		Total	
		Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Past service credit	$	— $	— $	— $	(64) $	— $	(64)
Net actuarial gain		—	—	(47)	(123)	(47)	(123)
	$	— $	— $	(47) $	(187) $	(47) $	(187)
Less: regulatory asset (liability) reclassified to assets (liabilities associated with assets) held for sale		—	—	(3)	3	(3)	3
Recognized in regulatory liability	$	— $	— $	(50) $	(184) $	(50) $	(184)

The costs of the defined benefit and post-retirement benefit plans are based on Management's estimate of the future rate of return on the fair value of pension plan assets, salary escalations, mortality rates and other factors affecting the payment of future benefits.

The net pension expense by plan was as follows:

	Year Ended December 31, 2023					
	Canada		United States		Total	
	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Current service cost [(a)]	$ 6	$ —	$ 12	$ 6	$ 18	$ 6
Interest cost [(b)]	1	—	69	18	70	18
Expected return on plan assets [(b)]	—	—	(78)	(48)	(78)	(48)
Amortization of past service credit [(b)]	—	—	—	(19)	—	(19)
Amortization of net actuarial gain [(b)]	—	—	—	(4)	—	(4)
Plan settlements [(b)]	2	—	4	(2)	6	(2)
Net benefit cost (income) recognized	$ 9	$ —	$ 7	$ (49)	$ 16	$ (49)

(a) Recorded under the line item “operating and administrative” expenses on the Consolidated Statements of Income.
(b) Recorded under the line item “other income” on the Consolidated Statements of Income.

	Year Ended December 31, 2022					
	Canada		United States		Total	
	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Current service cost [(a)]	$ 3	$ —	$ 22	$ 10	$ 25	$ 10
Interest cost [(b)]	1	—	52	13	53	13
Expected return on plan assets [(b)]	—	—	(79)	(38)	(79)	(38)
Amortization of past service credit [(b)]	—	—	—	(18)	—	(18)
Amortization of net actuarial loss (gain) [(b)]	—	—	2	(7)	2	(7)
Net benefit cost (income) recognized	$ 4	$ —	$ (3)	$ (40)	$ 1	$ (40)

(a) Recorded under the line item “operating and administrative” expenses on the Consolidated Statements of Income.
(b) Recorded under the line item “other income” on the Consolidated Statements of Income.

The objective for fund returns for the pension plans in the United States, over three to five-year periods, is the sum of two components - a passive component, which is the benchmark index market returns for the asset mix in effect, plus the added value expected from active management, if applicable to the fund. It is the Corporation’s belief that the potential additional returns justify the additional risk associated with active management. The risk inherent in the investment strategy over a market cycle (a three-to five-year period) is two-fold. There is a risk that the market returns, as measured by the benchmark returns, will not be in line with expectations. The other risk is that the expected added value of active management over passive management will not be realized over the time period prescribed in each fund manager's mandate. There is also the risk of annual volatility in returns, which means that in any one year the actual return may be very different from the expected return.

Cash and money market investments may be held from time to time as short-term investment decisions at the discretion of the fund manager(s) within the constraints prescribed by their mandate(s).

Upon wind-up of the Canadian defined benefit plan, the remaining assets in Canada consist of cash and cash equivalents attributable to the Canadian SERP and will continue to be held as such. The target asset mix for SEMCO plans is 33 percent fixed income assets, for WGL plans is 50 percent to 70 percent fixed income assets. These objectives have taken into account the nature of the liabilities and the risk-reward tolerance of the Corporation.

The collective investment mixes for the defined benefit plans are as follows as at December 31, 2023 and December 31, 2022:

Canada		Fair value		Level 1		Level 2	Percentage of Plan Assets (%)
December 31, 2023							
Cash and short-term equivalents	**$**	**2**	$	2	$	—	100
	$	**2**	$	2	$	—	100
December 31, 2022							
Cash and short-term equivalents	$	2	$	2	$	—	15
Fixed income							
Canadian bonds		11		11		—	85
	$	13	$	13	$	—	100

		Year Ended December 31, 2023					
United States		**Fair value**		Level 1		Level 2	Percentage of Plan Assets (%)
December 31, 2023							
Cash and short-term equivalents	**$**	**2**	$	2	$	—	—
Canadian equities		**3**		3		—	—
Foreign equities (a)		**203**		203		—	16
Fixed income							
Government debt		**407**		62		345	32
Corporate debt		**322**		23		299	25
Derivatives		**8**		—		8	1
Other (b)		**10**		—		10	1
Total investments in the fair value hierarchy	**$**	**955**	$	293	$	662	75
Investments measured at net asset value using the NAV practical expedient (c)							
Pooled separate accounts (d)	**$**	**39**					3
Collective trust funds (e)		**281**					22
Total fair value of plan investments	**$**	**1,275**					100
Net payable (f)		**(4)**					—
	$	**1,271**					100
December 31, 2022							
Cash and short-term equivalents	$	2	$	2	$	—	—
Canadian equities		2		2		—	—
Foreign equities (a)		247		247		—	20
Fixed income							
Government debt		413		80		333	33
Corporate debt		355		30		325	28
Derivatives		2		—		2	—
Other (b)		11		—		11	1
Total investments in the fair value hierarchy	$	1,032	$	361	$	671	82
Investments measured at net asset value using the NAV practical expedient (c)							
Pooled separate accounts (d)		43					3
Collective trust funds (e)		279					22
Total fair value of plan investments	$	1,354					107
Net receivable (f)		5					—
	$	1,359					107
Less: investments reclassified to assets held for sale		(93)					(7)
	$	1,266					100

(a) Consists of investments in foreign equities include U.S. and international securities.

(b) As at December 31, 2023 and December 31, 2022, these investments consisted primarily of non-U.S. government bonds and asset-backed securities.

(c) In accordance with ASC Topic 820, these investments are measured at fair value using net asset value (NAV) per share as a practical expedient and, therefore, have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliations of the fair value hierarchy to the statements of net assets available for plan benefits.

(d) As at December 31, 2023, investments in pooled separate accounts consisted of 100 percent income producing properties located in the United States (December 31, 2022 - 100 percent).

(e) As at December 31, 2023, investments in collective trust funds consisted primarily of 85 percent common stock of U.S. companies (December 31, 2022 - 79 percent), 13 percent income producing properties located in the United States (December 31, 2022 - 16 percent), and 2 percent of short-term money market investments (December 31, 2022 - 5 percent).

(f) As at December 31, 2023, this net payable primarily represents pending trades for investments purchased net of pending trades for investments sold and interest receivables. As at December 31, 2022, this net receivable primarily represents pending trades for investments sold and interest receivable net of pending trades for investments purchased.

The collective investment mixes for the post-retirement benefit plans are as follows as at December 31, 2023 and December 31, 2022:

United States	Fair value	Level 1	Level 2	Percentage of Plan Assets (%)
December 31, 2023				
Cash and short-term equivalents	**$ 8**	$ 8	$ —	1
Foreign equities [(a)]	**50**	50	—	5
Fixed income				
Government debt	**113**	22	91	12
Corporate debt	**91**	8	83	10
Other [(b)]	**5**	—	5	1
Total investments in the fair value hierarchy	**$ 267**	$ 88	$ 179	29
Investments measured at net asset value using the NAV practical expedient [(c)]				
Commingled funds [(d)]	**$ 651**			71
	$ 918			100
December 31, 2022				
Cash and short-term equivalents	$ 8	$ 8	$ —	1
Foreign equities [(a)]	50	50	—	6
Fixed income				
Government debt	101	21	80	12
Corporate debt	85	8	77	10
Other [(b)]	5	—	5	1
Total investments in the fair value hierarchy	$ 249	$ 87	$ 162	30
Investments measured at net asset value using the NAV practical expedient [(c)]				
Commingled funds [(d)]	$ 596			71
Total fair value of plan investments	$ 845			101
Less: investments reclassified to assets held for sale	(3)			(1)
	$ 842			100

(a) Consists of investments in foreign equities include U.S. and international securities.

(b) As at December 31, 2023 and December 31, 2022, these investments consisted primarily of non-U.S. government bonds.

(c) In accordance with ASC Topic 820, these investments are measured at fair value using net asset value (NAV) per share as a practical expedient and, therefore, have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliations of the fair value hierarchy to the statements of net assets available for plan benefits.

(d) As at December 31, 2023, investments in commingled funds consisted of approximately 50 percent common stock of large-cap U.S. companies (December 31, 2022 - 49 percent), 24 percent U.S. Government fixed income securities (December 31, 2022 - 23 percent), and 26 percent corporate bonds for WGL's post-retirement benefit plans (December 31, 2022 - 28 percent).

Year Ended December 31	2023		2022	
Significant actuarial assumptions used in measuring net benefit plan costs	**Defined Benefit**	**Post-Retirement Benefits**	Defined Benefit	Post-Retirement Benefits
Discount rate (%)	**4.60 - 5.60**	**5.30 - 5.70**	2.50 - 5.05	3.10
Expected long-term rate of return on plan assets (%) [(a)]	**6.45 - 6.75**	**4.50 - 6.45**	2.83 - 6.50	3.00 - 6.50
Rate of compensation increase (%)	**2.50 - 4.00**	**3.00**	2.50 - 4.00	3.00

(a) Only applicable for funded plans

As at December 31	2023		2022	
Significant actuarial assumptions used in measuring benefit obligations	**Defined Benefit**	**Post-Retirement Benefits**	Defined Benefit	Post-Retirement Benefits
Discount rate (%)	**4.60 - 5.40**	**4.65 - 5.40**	5.05 - 5.60	5.30 - 5.70
Rate of compensation increase (%)	**3.00 - 4.00**	**3.00**	2.50 - 4.00	3.00

The expected rate of return on assets is based on the current level of expected returns on risk free investments, the historical level of risk premium associated with other asset classes in which the portfolio is invested, and the expectations for future returns of each asset class. The expected return for each asset class was then weighted based on the target asset allocation to develop the expected rate of return on assets assumption for the portfolio.

The discount rate is based on yields available on high-quality long-term corporate bonds, with maturities matching the estimated timing and amount of expected benefit payments.

The estimates for health care benefits take into consideration increased health care benefits due to aging and cost increases in the future. The assumed health care cost trend rate used to measure the expected cost of benefits for the next year was between 4.2 and 6.5 percent. The health care cost trend rates were assumed to decline to between 2.5 and 5.0 percent by 2030.

The following table shows the expected cash flows for defined benefit pension and other post-retirement plans:

	Defined Benefit	Post-Retirement Benefits
Expected employer contributions:		
2024	$ 14	$ —
Expected benefit payments:		
2024	$ 87	$ 21
2025	$ 88	$ 21
2026	$ 89	$ 22
2027	$ 90	$ 22
2028	$ 91	$ 22
2029 - 2033	$ 462	$ 111

29. Commitments, Guarantees, and Contingencies

Commitments

AltaGas has long-term natural gas purchase and transportation arrangements, LPG purchase agreements, crude oil and condensate purchase agreements, electricity purchase arrangements, service agreements, pipeline and storage service contracts, capital commitments, environmental commitments, merger commitments, and operating leases for office space, office equipment, vehicles, rail cars, land, storage, aquatic surface use, and other equipment, all of which are transacted at market prices and in the normal course of business.

Future payments of these commitments as at December 31, 2023 are estimated as follows:

	2024	2025	2026	2027	2028	2029 & beyond	Total
Gas purchase [a] [b]	$ 643	$ 704	$ 685	$ 676	$ 610	$ 5,187	**$ 8,505**
Transportation and storage services [b] [c]	804	802	812	768	465	1,738	**5,389**
LPG purchase [d]	470	321	210	186	169	328	**1,684**
Electricity purchase [e]	863	442	150	33	7	9	**1,504**
Operating and finance leases [f]	145	133	119	103	83	386	**969**
Service agreements [g] [h] [i] [j]	59	54	42	32	29	240	**456**
Environmental [k]	6	1	1	1	—	3	**12**
Crude oil and condensate purchase [l]	10	—	—	—	—	—	**10**
Merger commitments [m]	2	2	1	—	—	—	**5**
Capital projects [n]	23	—	—	—	—	—	**23**
	$ 3,025	$ 2,459	$ 2,020	$ 1,799	$ 1,363	$ 7,891	**$ 18,557**

(a) AltaGas enters into contracts to purchase natural gas from various suppliers for its utilities. These contracts are used to ensure that there is an adequate supply of natural gas to meet the needs of customers and to minimize exposure to market price fluctuations. Gas purchase commitments are valued based on fixed prices and forward prices, which may fluctuate significantly from period to period.

(b) Includes $401 million of commitments as a result of the Pipestone Acquisition on December 22, 2023. Please refer to Note 3 for more details on the Pipestone Acquisition.

(c) Transportation and storage commitments include minimum payments for natural gas transportation, storage and peaking contracts that have expiration dates through 2044.

(d) AltaGas enters into contracts to purchase LPGs for its operations at RIPET and Ferndale. These contracts are used to ensure that there is an adequate supply of LPGs to meet shipment commitments and to minimize exposure to market price fluctuations. LPG purchase commitments are valued based on forward prices, which may fluctuate significantly from period to period.

(e) AltaGas enters into contracts to purchase electricity from various suppliers for its non-utility business. Electricity purchase commitments are based on existing fixed price and fixed volume contracts and include US$108 million of commitments related to renewable energy credits.

(f) Operating and finance leases include lease arrangements for office space, office equipment, field equipment, rail cars, aquatic use, vehicles, power and gas facilities, transmission and distribution assets, and land. Operating leases also include $240 million in future undiscounted cash flows associated with leasing arrangements for the use of three Very Large Gas Carriers ("VLGCs"), two of which are anticipated to commence in the first quarter of 2024, and one in the first half of 2026, as well as $47 million in future discounted cash flows associated with leasing arrangements for rail cars commencing in 2024 and 2025, and $66 million associated with a new office lease beginning in 2024.

(g) In 2014, AltaGas' Blythe facility entered into a Long-Term Service Agreement ("LTSA") with a service pro to complete various upgrade and maintenance services on the Combustion Turbines ("CT") at the Blythe facility over 124,000 equivalent operating hours per CT, or 25 years, whichever comes first. The LTSA has variable fees on a per equivalent operating hour basis. As at December 31, 2023, the total commitment was $149 million payable over the next 12 years, of which $59 million is expected to be paid over the next 5 years.

(h) In 2017, AltaGas entered into a 12-year service agreement commencing in 2019 for tug services to support the marine operations of RIPET.

(i) In 2015, AltaGas entered into a Project Agreement that contemplated the sublease of lands from Ridley Terminals Inc. ("RTI", now Trigon Pacific Terminals Ltd. ("Trigon")), provision of certain terminal services, and access to Trigon's terminal facilities to support RIPET's operations for an initial term of 20 years ending in 2039. In 2019, RILE LP and Trigon executed a Terminal Services Agreement that formalized the concepts outlined in the Project Agreement.

(j) Includes a commitment related to a service contract that involves a hosting arrangement.

(k) Environmental commitments include committed payments related to certain environmental response costs.

(l) AltaGas enters into contracts to purchase crude oil and condensates for marketing, sale, and distribution. These contracts are used to ensure that there is an adequate supply of crude oil and condensates to meet the needs of customers and to minimize exposure to market price fluctuations. Crude oil and condensate commitments are valued based on forward prices, which may fluctuate significantly from period to period.

(m) Represents the estimated future payments of WGL merger commitments that have been accrued but not paid. Among other things, these commitments include rate credits distributable to both residential and non-residential customers to partially offset rate increases resulting from gas expansion, extension of natural gas service over a 10-year period and other programs, various public interest commitments, and safety programs. As at December 31, 2023, the cumulative amount of merger commitments that have been expensed but not yet paid is approximately US$3 million. Additionally, there are a number of operational commitments with various timeframes, including the funding of leak mitigation and reducing leak backlogs, the funding of damage prevention efforts, developing projects to extend natural gas service, maintaining pre-merger quality of service standards including odor call response times, increasing supplier diversity, achieving synergy savings benefits, as well as reporting and tracking related to certain commitments, and causing the development of 15 MW of either electric grid energy storage or tier one renewable resources within five years of the WGL Acquisition, comprised of 10 MW in the District of Columbia and 5 MW in Maryland. Several of these commitments ended in the second quarter of 2023, or five years after the WGL Acquisition.

(n) Commitments for capital projects. Estimated amounts are subject to variability depending on the actual construction costs.

Guarantees

AltaGas has guaranteed payments primarily for certain commitments on behalf of some of its subsidiaries. As at December 31, 2023, AltaGas has no guarantees issued on behalf of external parties.

Contingencies

AltaGas and its subsidiaries are subject to various legal claims and actions arising in the normal course of business. While the final outcome of such legal claims and actions cannot be predicted with certainty, the Corporation does not believe that the resolution of such claims and actions will have a material impact on the Corporation's consolidated financial position or results of operations.

Merger Commitments - District of Columbia

On August 9, 2023, the PSC of DC determined that AltaGas had failed to fulfill Term No. 5 Commitment of the PSC of DC's merger approval order related to the June 2018 merger of AltaGas, WGL, and Washington Gas. On reconsideration, the PSC of DC confirmed, in relevant part, that it had credited AltaGas with causing the development of 2.4 MW of Tier one renewable resources by the July 6, 2023 deadline, and that the Company had breached its Term No. 5 Commitment only for the remaining 7.6 MW. As directed by the PSC of DC, AltaGas, the District of Columbia Government ("DCG"), and the District of Columbia Office of People's Counsel ("DC OPC") conducted negotiations in good faith to reach agreement on a penalty. On November 14, 2023, DCG reported that DCG and AltaGas believed that further negotiations would be fruitless. In a November 21, 2023 motion, AltaGas confirmed that it will specifically perform its Term No. 5 obligations by continuing to cause the development of the remaining 7.6 MW of solar renewable energy. AltaGas also proposed a penalty of approximately US$0.5 million if the Company fulfills the balance of its renewable development obligation before the end of 2024, or US$0.6 million if the balance is not completed until after the end of 2024. On December 19, 2023, DCG proposed that AltaGas pay a penalty of approximately US$8 million. OPC proposed a penalty not less than DCG's proposed penalty, to be paid before September 30, 2024. Management believes that the likelihood of a civil penalty is probable however, is unable to estimate the maximum possible penalty.

30. Related Party Transactions

In the normal course of business, AltaGas transacts with its subsidiaries, affiliates and joint ventures. Amounts due to or from related parties on the Consolidated Balance Sheets were measured at the exchange amount and were as follows:

As at	**December 31, 2023**	December 31, 2022
Due from related parties		
Accounts receivable [(a)]	**$ 1**	$ 1
Due to related parties		
Accounts payable [(b)]	**$ 1**	$ 1

(a) Receivables from affiliates.
(b) Payables to affiliates.

The following transactions with related parties have been recorded on the Consolidated Statements of Income for the years ended December 31, 2023 and 2022:

Year Ended December 31		2023		2022
Cost of sales [a]	**$**	**7**	$	7

(a) In the ordinary course of business, AltaGas obtained natural gas storage services from a joint venture.

31. Supplemental Cash Flow Information

The following table details the changes in operating assets and liabilities from operating activities:

		Year Ended December 31		
		2023		2022
Source (use) of cash:				
Accounts receivable	**$**	**271**	$	(691)
Inventory		**242**		(324)
Risk management assets - current		**(53)**		4
Prepaid expenses and other current assets		**(1)**		(1)
Regulatory assets - current		**(17)**		13
Accounts payable and accrued liabilities		**(178)**		377
Customer deposits		**11**		14
Regulatory liabilities - current		**(97)**		98
Risk management liabilities - current		**—**		(6)
Other current liabilities		**(11)**		(12)
Other operating assets and liabilities		**(67)**		(122)
Changes in operating assets and liabilities	**$**	**100**	$	(650)

The following table details the changes in non-cash investing and financing activities:

		Year Ended December 31		
		2023		2022
Decrease (increase) of balance:				
Exercise of stock options	**$**	**2**	$	3
Net right-of-use assets obtained in exchange for new operating lease liabilities	**$**	**(141)**	$	(56)
Net right-of-use assets obtained in exchange for new finance lease liabilities	**$**	**(114)**	$	(14)
Capital expenditures included in accounts payable and accrued liabilities	**$**	**(3)**	$	6

The following cash payments have been included in the determination of earnings:

		Year Ended December 31		
		2023		2022
Interest paid (net of capitalized interest)	**$**	**377**	$	304
Income taxes paid	**$**	**36**	$	17

The following table is a reconciliation of cash and restricted cash balances:

As at December 31		2023		2022
Cash and cash equivalents	$	**95**	$	53
Restricted cash included in prepaid expenses and other current assets [(a)]		**3**		3
Restricted cash included in long-term investments and other assets *(note 11)* [(a)]		**6**		8
Cash, cash equivalents, and restricted cash per Consolidated Statements of Cash Flows	$	**104**	$	64

(a) The restricted cash balances included in prepaid expenses and other current assets and long-term investments and other assets relate to Rabbi trusts associated with WGL's pension plans (see Note 28).

32. Segmented Information

AltaGas owns and operates a portfolio of assets and services used to move energy from the source to the end-user. The following describes the Corporation's reporting segments:

Utilities	▪ rate-regulated natural gas distribution assets in Michigan, the District of Columbia, Maryland, and Virginia. The sale of the Alaskan Utilities closed on March 1, 2023; ▪ rate-regulated natural gas storage in the United States, of which certain storage facilities in Alaska were sold on March 1, 2023, pursuant to the Alaska Utilities Disposition; and ▪ sale of natural gas and power to residential, commercial, and industrial customers in the District of Columbia, Maryland, Virginia, Delaware, Pennsylvania, and Ohio.
Midstream	▪ NGL processing and extraction plants; ▪ natural gas storage facilities; ▪ liquefied petroleum gas ("LPG") export terminals; ▪ transmission pipelines to transport natural gas and NGLs; ▪ natural gas gathering lines and field processing facilities; ▪ purchase and sale of natural gas; ▪ natural gas and NGL marketing; ▪ marketing, storage and distribution of wellsite fluids and fuels, crude oil and condensate diluents; and ▪ interest in a regulated pipeline in the Marcellus/Utica gas formation.
Corporate/ Other	▪ the cost of providing corporate services, financing and general corporate overhead, corporate assets, financing other segments, and the effects of changes in the fair value of certain risk management contracts; and ▪ a small portfolio of remaining power assets.

The following table provides a reconciliation of segment revenue to the disaggregated revenue table disclosed in Note 24:

		Year Ended December 31, 2023						
		Utilities		**Midstream**		**Corporate/ Other**		**Total**
External revenue *(note 24)*	**$**	**4,827**	**$**	**8,069**	**$**	**101**	**$**	**12,997**
Segment revenue	**$**	**4,827**	**$**	**8,069**	**$**	**101**	**$**	**12,997**

		Year Ended December 31, 2022						
		Utilities		Midstream		Corporate/ Other		Total
External revenue *(note 24)*	$	4,980	$	9,010	$	97	$	14,087
Segment revenue	$	4,980	$	9,010	$	97	$	14,087

Geographic Information

Year Ended December 31		2023		2022
Revenue [a]				
Canada	$	**8,137**	$	8,915
United States		**4,772**		5,155
Total	**$**	**12,909**	$	14,070

(a) Operating revenue from external customers, excluding unrealized gains and losses on risk management contracts.

As at December 31		2023		2022
Property, plant and equipment				
Canada	**$**	**3,664**	$	2,930
United States		**9,064**		8,756
Total	**$**	**12,728**	$	11,686
Operating right-of-use assets				
Canada	**$**	**276**	$	212
United States		**61**		69
Total	**$**	**337**	$	281

The following tables show the composition by segment:

	Year Ended December 31, 2023							
		Utilities		Midstream		Corporate/ Other		Total
Segment revenue *(note 24)*	**$**	**4,827**	**$**	**8,069**	**$**	**101**	**$**	**12,997**
Cost of sales		**(2,988)**		**(7,098)**		**(26)**		**(10,112)**
Operating and administrative		**(1,047)**		**(436)**		**(96)**		**(1,579)**
Accretion expenses		**(1)**		**(10)**		**—**		**(11)**
Depreciation and amortization		**(288)**		**(123)**		**(30)**		**(441)**
Income from equity investments		**3**		**52**		**—**		**55**
Other income		**380**		**6**		**17**		**403**
Foreign exchange losses		**—**		**—**		**(6)**		**(6)**
Interest expense		**—**		**—**		**(394)**		**(394)**
Income (loss) before income taxes	**$**	**886**	**$**	**460**	**$**	**(434)**	**$**	**912**
Net additions (reductions) to:								
Property, plant and equipment [a]	**$**	**(314)**	**$**	**177**	**$**	**(3)**	**$**	**(140)**
Intangible assets	**$**	**—**	**$**	**8**	**$**	**1**	**$**	**9**

(a) Net additions to property, plant, and equipment, and intangible assets may not agree to changes reflected in the Consolidated Statements of Cash Flows due to classification of business acquisition and foreign exchange changes on U.S. assets.

	Year Ended December 31, 2022			
	Utilities	Midstream	Corporate/ Other	Total
Segment revenue *(note 24)*	$ 4,980	$ 9,010	$ 97	$ 14,087
Cost of sales	(3,197)	(7,915)	(26)	(11,138)
Operating and administrative	(1,023)	(461)	(84)	(1,568)
Accretion expenses	(1)	(6)	—	(7)
Depreciation and amortization	(290)	(116)	(33)	(439)
Provision on assets *(note 5)*	—	(6)	—	(6)
Income from equity investments	2	11	—	13
Other income	77	9	8	94
Foreign exchange gains	—	—	10	10
Interest expense	—	—	(330)	(330)
Income (loss) before income taxes	$ 548	$ 526	$ (358)	$ 716
Net additions (reductions) to:				
Property, plant and equipment [(a)]	$ 822	$ (117)	$ (10)	$ 695
Intangible assets	$ 2	$ 6	$ 1	$ 9

(a) Net additions to property, plant, and equipment, and intangible assets may not agree to changes reflected in the Consolidated Statements of Cash Flows due to classification of business acquisition and foreign exchange changes on U.S. assets.

The following table shows goodwill and total assets by segment:

	Utilities	Midstream	Corporate/ Other	Total
As at December 31, 2023				
Goodwill	**$ 3,630**	**$ 1,640**	**$ —**	**$ 5,270**
Segmented assets	**$ 15,272**	**$ 7,578**	**$ 621**	**$ 23,471**
As at December 31, 2022				
Goodwill	$ 3,718	$ 1,532	$ —	$ 5,250
Segmented assets	$ 16,782	$ 6,728	$ 455	$ 23,965

33. Subsequent Events

On January 8, 2024, AltaGas issued $400 million of senior unsecured medium-term notes with a 4.67 percent coupon, due on January 8, 2029. The net proceeds were used to pay down existing indebtedness under AltaGas' credit facilities (part of which was incurred to fund the debt portion of the Pipestone Acquisition), to fund working capital, and for general corporate purposes.

Subsequent events have been reviewed through March 7, 2024, the date on which these audited Consolidated Financial Statements were issued.

SUPPLEMENTAL QUARTERLY OPERATING INFORMATION

	Q4-23	Q3-23	Q2-23	Q1-23	Q4-22
OPERATING HIGHLIGHTS					
UTILITIES					
Natural gas deliveries - end use (Bcf) (1)	**48.3**	8.5	15.3	61.3	54.3
Natural gas deliveries - transportation (Bcf) (1)	**30.5**	19.9	19.5	38.2	34.0
Service sites (thousands) (2)	**1,560**	1,553	1,553	1,554	1,704
Degree day variance from normal - SEMCO (%) (3)	**(9.8)**	(19.4)	(5.6)	(12.1)	(1.7)
Degree day variance from normal - ENSTAR (%) (3)	**n/a**	n/a	n/a	(4.9)	8.7
Degree day variance from normal - Washington Gas (%) (3) (4)	**(9.2)**	—	(27.0)	(22.2)	9.2
WGL retail energy marketing - gas sales volumes (Mmcf)	**16,863**	8,550	10,623	20,402	18,064
WGL retail energy marketing - electricity sales volumes (GWh)	**3,518**	4,134	3,365	3,322	3,328
MIDSTREAM					
LPG export volumes (Bbls/d) (5)	**90,996**	118,213	115,589	99,444	97,152
Total inlet gas processed (Mmcf/d) (5)	**1,312**	1,182	1,344	1,372	1,274
Extracted ethane volumes (Bbls/d) (5)	**23,879**	25,501	24,927	21,796	21,947
Extracted NGL volumes (Bbls/d) (5) (6)	**36,138**	36,070	35,765	34,390	34,782
Fractionation volumes (Bbls/d) (5) (7)	**38,150**	39,699	38,364	41,655	36,658
Frac spread - realized ($/Bbl) (5) (8)	**23.13**	23.75	23.87	27.04	25.14
Frac spread - average spot price ($/Bbl) (5) (9)	**20.55**	21.31	21.56	26.89	23.14
Propane Far East Index ("FEI") to Mont Belvieu spread (US$/Bbl) (5) (10)	**26.44**	21.30	14.54	20.46	18.95
Butane FEI to Mont Belvieu spread (US$/Bbl) (5) (11)	**27.74**	22.07	15.29	16.99	18.59

(1) Bcf is one billion cubic feet.
(2) Service sites reflect all of the service sites of the utilities, including transportation and non-regulated business lines.
(3) A degree day is a measure of coldness determined daily as the number of degrees the average temperature during the day in question is below 65 degrees Fahrenheit. Degree days for a particular period are determined by adding the degree days incurred during each day of the period. Normal degree days for a particular period are the average of degree days during the prior 15 years for SEMCO, during the prior 10 years for ENSTAR, and during the prior 30 years for Washington Gas. The degree day variance from normal for ENSTAR is for the period prior to the close of the Alaska Utilities Disposition on March 1, 2023.
(4) In certain of Washington Gas' jurisdictions (Virginia and Maryland) there are billing mechanisms in place that are designed to eliminate the effects of variance in customer usage caused by weather and other factors such as conservation. In the District of Columbia, there is no weather normalization billing mechanism nor does Washington Gas hedge to offset the effects of weather. As a result, colder or warmer weather will result in variances to financial results.
(5) Average for the period.
(6) NGL volumes refer to propane, butane, and condensate.
(7) Fractionation volumes include NGL mix volumes processed.
(8) Realized frac spread or NGL margin, expressed in dollars per barrel of NGL, is derived from sales recorded by the segment during the period for frac spread exposed volumes plus the settlement value of frac hedges settled in the period less extraction premiums, divided by the total frac exposed volumes produced during the period.
(9) Average spot frac spread or NGL margin, expressed in dollars per barrel of NGL, is indicative of the average sales price that AltaGas receives for propane, butane and condensate less extraction premiums, before accounting for hedges, divided by the respective frac spread exposed volumes for the period.
(10) Average propane price spread between FEI and Mont Belvieu TET commercial index.
(11) Average butane price spread between FEI and Mont Belvieu TET commercial index.

OTHER INFORMATION

DEFINITIONS

Bbls/d	barrels per day
Bcf	billion cubic feet
CBM	cubic meter
Dth	dekatherm
GJ	gigajoule
GWh	gigawatt-hour
Mmcf	million cubic feet
Mmcf/d	million cubic feet per day
MW	megawatt
MWh	megawatt-hour
US$	United States dollar

ABOUT ALTAGAS

AltaGas is a leading North American energy infrastructure Company that connects NGLs and natural gas to domestic and global markets. The Company operates a diversified, lower-risk, high-growth Utilities and Midstream business that is focused on delivering resilient and durable value for its stakeholders.

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