Annual Report **2019**

AltaGas

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) dated February 27, 2020 is provided to enable readers to assess the results of operations, liquidity and capital resources of AltaGas Ltd. (AltaGas or the Corporation) as at and for the year ended December 31, 2019. 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, 2019.

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, 2019 or the Annual Information Form for the year ended December 31, 2019.

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: expectation that RIPET will be a catalyst for further growth in the Midstream business; expectation that the Townsend 2B expansion, North Pine expansion and the northeast BC pipeline projects will be completed in early 2020; expiration of the Northwest Hydro operating agreement in January 2021; conditions to and timing of the closing of the ACI Arrangement; expected cost savings related to the repayment of debt with proceeds of the December 2019 note offering; funding of the Petrogas put obligations; retirement of Daryl Gilbert from the Board of Directors; AltaGas' strategy for each of its core businesses; plan to focus on capitalization of significant growth potential of the Midstream and Utilities assets; plan to maximize structural advantage of the integrated platform in the Montney region; plan to increase utilization and export volumes at RIPET; expectation that volumes at RIPET will exceed 50,000 Bbls/d by the end of 2020; planned $900 million growth capital program; targeted 10 percent increase in the Utilities rate base; expected annual consolidated normalized EBITDA of approximately $1.275 to $1.325 billion in 2020; normalize earnings per share of approximately $1.20 to $1.30 per share in 2020; expected growth, EBITDA contributions and drivers behind each of the Midstream, Utilities and Power businesses; expectation that overall growth will more than offset lost EBITDA from a full year impact of asset sales completed in 2019; estimated exposure to frac spreads and the propane price differentials; expectation that the majority of the annual capacity of RIPET will be underpinned by tolling arrangements over the next several years; allocation of $900 million capital expenditures among and expected focus of spending within the Utilities, Midstream and Power businesses; expected sources of funding for the committed capital program; the estimated cost, status and expected in-service dates for grown capital projects in the Midstream and Utilities businesses; expected filing, procedure and decision dates for rate cases in the Utilities business; future changes in accounting policies and adoption of new accounting standards; and AltaGas' long term strategy. 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: assumptions regarding asset sales anticipated to close in 2020, effective tax rate of approximately 22 percent, propane price differentials, degree day variance from normal, the U.S/Canadian dollar exchange rate, financing initiatives, the performance of the businesses underlying each sector; impacts of the hedging program; commodity prices; weather; frac spread; access to capital; timing and receipt of regulatory approvals; timing of regulatory approvals related to Utilities projects; 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 risks; service interruptions; regulatory risks; litigation risk; decommissioning, abandonment and reclamation costs; climate and carbon tax risks; reputation risk; weather data; Indigenous land and rights claims; crown duty to consult with Indigenous peoples; changes in laws; capital market and liquidity risks; general economic conditions; internal credit risk; foreign exchange risk; debt financing, refinancing, and debt service risk; interest rates; cyber security, information, and control systems; technical systems and processes incidents; dependence on certain partners; growth strategy risk; construction and development; RIPET rail and marine transport; impact of competition in AltaGas' Midstream and Power businesses; commitments associated with regulatory approvals for the acquisition of WGL; counterparty credit risk; composition risk; collateral; regulatory agreements; non-controlling interests in investments; delays in U.S. federal government budget appropriations; consumption risk; market risk; market value of common shares and other securities; variability of dividends; potential sales of additional shares; volume throughput; natural gas supply risk; risk management costs and limitations; underinsured and uninsured losses; Cook Inlet gas supply; securities class action suits and derivative suits; electricity and resource adequacy prices; cost of providing retirement plan benefits; labor relations; key personnel; failure of service providers; compliance with Section 404(a) of Sarbanes-Oxley Act; integration of WGL; and the other factors discussed under the heading "Risk Factors" in the Corporation's Annual Information Form for the year ended December 31, 2019 (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 (Management) 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.sedar.com.

AltaGas Organization

The businesses of AltaGas are operated by AltaGas 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 Corporation, WGL Energy Services, Inc. (WGL Energy Services), and SEMCO Holding Corporation; in regards 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, and WGL Midstream Inc. (WGL Midstream); in regards to the Power business, AltaGas Power Holdings (U.S.) Inc., WGL Energy Systems, Inc. (WGL Energy Systems), and Blythe Energy Inc. (Blythe); and, in regards to the Utilities business, Washington Gas Light Company (Washington Gas), Hampshire Gas Company, and SEMCO Energy, Inc.

(SEMCO). SEMCO conducts its Michigan natural gas distribution business under the name SEMCO Energy Gas Company (SEMCO Gas), its Alaska natural gas distribution business under the name ENSTAR Natural Gas Company (ENSTAR) and its 65 percent interest in an Alaska regulated gas storage utility under the name Cook Inlet Natural Gas Storage Alaska LLC (CINGSA).

2019 Highlights

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

Growth and Operational Highlights

- In the second quarter of 2019, the Ridley Island Propane Export Terminal (RIPET) was completed, with its first shipment of propane to Asia departing on May 23, 2019. RIPET is the first propane marine export facility in Canada and its completion is expected to be a catalyst for further growth within AltaGas' Midstream business;
- In the fourth quarter of 2019, construction of the Marquette Connector Pipeline (MCP) was completed. The MCP connects the Great Lakes Gas Transmission pipeline to the Northern Natural Gas pipeline in Marquette, Michigan where it will provide system redundancy and increase deliverability, reliability, and diversity of supply to SEMCO Gas' customers;
- In the Midstream segment, AltaGas made significant progress on its growth capital projects, including the completion of the 50 Mmcf/d (net) Nig Creek gas processing facility in the third quarter of 2019 and expected early 2020 completions of the 198 Mmcf/d Townsend 2B expansion, the 10,000 Bbls/d North Pine expansion, and the northeast British Columbia pipeline projects; and
- In the Power segment, AltaGas announced the successful recontracting of the Blythe facility to Southern California Edison (SCE). Under the tolling agreement, SCE has exclusive rights to all capacity, energy, ancillary services, and resource adequacy benefits from August 1, 2020 to December 31, 2023. California Public Utilities Commission approval was received on January 16, 2020.

Asset Sales Completed

- On September 26, 2019, AltaGas closed the sale of its portfolio of U.S. distributed generation assets held by its subsidiaries WGL Energy Systems, Inc. and WGSW, Inc., to TerraForm Power, Inc., an affiliate of Brookfield Asset Management. Total cash proceeds received were approximately US$735 million and a pre-tax gain on disposition of $168 million was recorded in 2019. There are certain projects for which legal title has not yet transferred as various consents and approvals remain outstanding. These projects remain held for sale at December 31, 2019;
- On November 13, 2019, AltaGas completed the sale of its indirect, non-operating interest in the Central Penn Pipeline (Central Penn) held by its subsidiary WGL Midstream, Inc. to Meade Pipeline Investment, LLC, a subsidiary of NextEra Energy Partners, LP for net cash proceeds of approximately US$611 million, resulting in a pre-tax loss of $11 million;
- On May 31, 2019, AltaGas completed the disposition of WGL Midstream's entire interest in the Stonewall Gas Gathering System (Stonewall) to a wholly-owned subsidiary of DTE Energy Company for total gross proceeds of approximately $379 million (US$280 million), resulting in a pre-tax gain of $34 million;
- On February 1, 2019, AltaGas completed the sale of certain non-core Midstream and Power assets in Canada. Cash proceeds for the portion of the sale that closed in the first quarter of 2019 were approximately $88 million, resulting in a pre-tax loss of $1 million; and
- On January 31, 2019, AltaGas completed the sale of its remaining interest of approximately 55 percent in the Northwest Hydro Electric facilities in British Columbia (Northwest Hydro) for net cash proceeds of approximately $1.3 billion, resulting in a pre-tax gain of $688 million. AltaGas remains the operator of the facilities under an operating and maintenance agreement expiring January 31, 2021.

Regulatory Developments

- On December 6, 2019, the Michigan Public Service Commission (MPSC) issued a Final Order approving SEMCO's settlement agreement in its recent rate case, reflecting a base rate increase of approximately US$20 million effective January 1, 2020;

- On October 15, 2019, the Maryland Public Service Commission (PSC of MD) issued a Final Order approving Washington Gas' settlement agreement in its recent rate case, reflecting a US$27 million base rate increase effective October 15, 2019; and
- In September 2019, the Virginia Hearing Examiner assigned to Washington Gas' Virginia rate case issued a report with findings and recommendations to the State Corporation Commission of Virginia (SCC of VA), including the finding for no incremental revenues. In September 2019, the impact of these recommendations was recorded, resulting in a one-time reduction in normalized EBITDA of approximately $30 million and a reduction of approximately $14 million in net income after taxes. On October 21, 2019, Washington Gas filed comments on and exceptions to the Hearing Examiner's report, recommending the SCC of VA reject certain of the Hearing Examiner's findings. On December 20, 2019, the Commission issued a Final Order adjusting certain of the Hearing Examiner’s findings, some of which are favorable to Washington Gas, resulting in a $8 million increase to EBITDA in the fourth quarter of 2019. In January 2020, Washington Gas filed a petition for reconsideration regarding one of the findings in the Final Order. On January 30, 2020, the SCC of VA denied this request and the rate case is now final.

Other Highlights

- In 2019, AltaGas successfully de-levered its balance sheet, regained financial flexibility, maintained its investment grade credit rating, and repositioned the business to focus on organic growth opportunities in the Utilities and Midstream segments. In addition, AltaGas successfully executed its WGL integration strategy, making significant progress in achieving near- and long-term integration priorities, including strategy, organizational effectiveness, and people and culture;
- On December 17, 2019, AltaGas announced its 2020 guidance and provided an update on its 2020 strategic plan. This included an announcement that the Board of Directors approved the suspension of the Dividend Reinvestment and Optional Cash Purchase Plan (DRIP), with the December dividend (payable January 2020) being the last dividend payment eligible for reinvestment by participating shareholders under the DRIP, until further notice;
- On October 21, 2019, AltaGas Canada Inc. (ACI) announced that the Public Sector Pension Investment Board and the Alberta Teachers' Retirement Fund Board (together, the "Consortium") and ACI had concluded a definitive arrangement agreement (the "Arrangement Agreement") whereby the Consortium will indirectly acquire all of the issued and outstanding common shares of ACI (the "Common Shares") in an all-cash transaction for $33.50 per Common Share by way of arrangement under the *Canada Business Corporations Act* (the "Arrangement"). On December 19, 2019, the shareholders of ACI approved the Arrangement Agreement. In addition, on December 16, 2019, ACI received a "no-action letter" from the Canadian Competition Bureau confirming that the Commissioner of Competition does not at this time intend to challenge the proposed Arrangement. On December 20, 2019, ACI received the final order from the Court of Queen's Bench of Alberta approving the Arrangement. On February 18, 2020, the Alberta Utilities Commission issued a decision approving the Arrangement. The closing of the Arrangement remains subject to the receipt of approval from the British Columbia Utilities Commission, and the satisfaction or waiver of other customary closing conditions. ACI and the Consortium expect to close the Arrangement in the first half of 2020. AltaGas owns 11,025,000 Common Shares or approximately 37 percent of the total number of Common Shares;
- On September 30, 2019, 1,114,177 of the outstanding 8,000,000 Cumulative Redeemable Five-Year Fixed Rate Reset Preferred Shares, Series G were converted into Cumulative Floating Rate Preferred Shares, Series H;
- On December 16, 2019, AltaGas completed its aggregate issuance of $500 million of senior unsecured medium term notes with a coupon rate of 2.609 percent, maturing on December 16, 2022. The proceeds were used to pay down existing indebtedness under AltaGas' credit facilities and for general corporate purposes. Because the coupon rate is lower than the borrowing rate of the repaid debt, AltaGas expects cost savings of approximately $5 million per annum as a result of the debt repayment;
- On December 20, 2019, all outstanding Washington Gas preferred shares (US$4.25 series, US$4.80 series, and US $5.00 series) were redeemed. A pre-tax gain of $3 million was recognized upon redemption;
- On May 27, 2019, AltaGas announced the appointment of D. James Harbilas as Executive Vice President and Chief Financial Officer of AltaGas, effective June 10, 2019. Mr. Harbilas replaced Timothy Watson, who served as Executive Vice President and Chief Financial Officer until June 9, 2019;

- Effective December 16, 2019, AltaGas appointed Donald "Blue" Jenkins as Executive Vice President and President, Utilities and President, Washington Gas. Mr. Jenkins succeeds Adrian Chapman, who has retired; and
- On December 11, 2019, AltaGas released its inaugural Environmental, Social, and Governance (ESG) Report, highlighting the Company's 2018 performance in several key areas related to the long-term sustainability of its business, and demonstrating its ongoing commitment to transparency.

Financial Highlights

- Normalized EBITDA was $1,271 million compared to $1,009 million in 2018;
- Cash from operations was $616 million ($2.22 per share) compared to cash used by operations of $79 million ($0.35 per share) in 2018;
- Normalized funds from operations were $895 million ($3.23 per share) compared to $657 million ($2.95 per share) in 2018;
- Net income applicable to common shares was $769 million ($2.78 per share) compared to net loss applicable to common shares of $502 million ($2.25 per share) in 2018;
- Normalized net income was $324 million ($1.17 per share) compared to $195 million ($0.88 per share) in 2018;
- Net debt was $7.2 billion as at December 31, 2019, compared to $10.0 billion at December 31, 2018; and
- Net debt-to-total capitalization ratio was 49 percent as at December 31, 2019, compared to 57 percent as at December 31, 2018.

Highlights Subsequent to Year End

- On January 2, 2020, AltaGas advised that AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP) had received notice (the Put Notice) from SAM Holdings Ltd. (SAM) of its exercise of a put option (the Put Option) with respect to SAM's approximately one-third interest in Petrogas Energy Corp. (Petrogas). AIJVLP, a limited partnership owned 50 percent by AltaGas and 50 percent by Idemitsu Kosan Co., Ltd. (Idemitsu), owns the other approximately two-thirds of the outstanding common shares of Petrogas. Pursuant to the Petrogas unanimous shareholders agreement, a valid exercise of the Put Option by SAM after October 1, 2019, triggers a requirement for AIJVLP to purchase SAM's interest in Petrogas at the fair market value thereof, as determined by third-party valuators. AltaGas anticipates funding its portion of any such obligation with internal cash flow, the sale of remaining non-core assets, and debt. Valuations are underway;
- On January 9, 2020, AltaGas announced the appointment of two new independent Directors - Linda Sullivan and Nancy Tower to its Board of Directors. In addition, AltaGas announced the retirement of Daryl Gilbert from the Board of Directors, to be effective following the conclusion of AltaGas' next annual meeting of shareholders in May 2020;
- On January 13, 2020, Washington Gas filed a rate case in the District of Columbia requesting a US$35 million increase in base rates, including US$9 million of annual PROJECT*pipes* surcharges currently paid by customers for accelerated pipeline replacement. Washington Gas has also requested approval for a Revenue Normalization Adjustment mechanism to reduce customer bill fluctuations due to weather-related usage variations, similar to existing mechanisms in both Maryland and Virginia; and
- In February 2020, following evaluations of the diminished underlying economics for the proposed Constitution pipeline project, the partners of Constitution Pipeline Company, LLC (Constitution) elected not to proceed with the project. AltaGas held a 10 percent equity interest in Constitution. Upon the acquisition of WGL, AltaGas assigned a value of $nil to Constitution.

AltaGas' Vision and Objective

AltaGas' vision is to be a leading North American infrastructure company that connects natural gas and natural gas liquids to domestic and global markets. The Corporation strives to improve the lives of customers by safely delivering clean, affordable, and reliable natural gas solutions that meet their evolving energy needs - today and tomorrow.

Strategy

AltaGas' long-term strategy is largely focused on two core businesses - Utilities and Midstream - and is designed to deliver reliable, attractive long-term earnings and the potential for future dividend growth.

With infrastructure assets in some of the fastest growing energy markets in North America including a prominent position in the Montney region and utilities operations in five U.S. jurisdictions, AltaGas is developing an integrated footprint capable of delivering sustained value to stakeholders today and into the future. AltaGas is focused on developing high-quality energy infrastructure underpinned by strong market fundamentals and long-term commercial agreements that provide stable cash flow. AltaGas' balanced portfolio, including high-growth assets in the Midstream segment combined with predictable and regulated returns in the Utilities segment, provides a resilient and diversified platform for growth.

In 2020, AltaGas plans to focus on capitalizing on the significant growth potential of its Utilities and Midstream assets. Specific priorities include to:

- Ensure safe reliable operations, providing effective and cost-efficient service for customers;
- Enhance returns and capital efficiency through base rate cases, and facilitate timely recovery of expenditures and improve safety through increased utilization of accelerated rate recovery programs;
- Enhance the business through asset optimization and operational efficiencies to reduce costs and deliver an improved customer experience;
- Maximize the unique structural advantage within AltaGas' integrated platform in the Montney region;
- Increase utilization and export volumes at RIPET;
- Execute the planned $900 million growth capital program, including a targeted 10 percent increase in the Utilities rate base; and
- Pursue capital efficient organic growth through disciplined capital allocation while improving balance sheet strength and flexibility.

AltaGas' Board of Directors is actively engaged in AltaGas' strategy. The Corporation continually assesses the macro- and micro-economic trends impacting the businesses and seeks opportunities to generate value for stakeholders. The opportunities AltaGas pursues must meet strategic, operating, and financial criteria to ensure they align with the long-term strategy and provide ongoing organic growth potential, favorable risk profiles, and strong risk-adjusted returns.

2020 Outlook

In 2020, AltaGas expects to achieve annual consolidated normalized EBITDA of approximately $1.275 to $1.325 billion, and normalized earnings per share of approximately $1.20 to $1.30 per share assuming an effective tax rate of approximately 22 percent. This range is net of asset sales that are anticipated to close in 2020, including AltaGas' approximate 37 percent interest in ACI.

Growth is expected in 2020 in the Utilities and Midstream segments. The Utilities segment is expected to have the largest contribution to normalized EBITDA, with growth driven primarily by rate base growth and increased spend on accelerated capital programs. Growth in the Midstream segment is anticipated to largely be driven by a full year of contributions from RIPET, and increased volumes at Northeast British Columbia facilities, including North Pine, Townsend, and Aitken Creek, as well as higher expected margins on U.S. Midstream storage and transportation. Normalized EBITDA from AltaGas' remaining Power assets is also expected to grow primarily due to less expected downtime at Blythe. Overall growth is expected to more than offset lost EBITDA from a full year impact of asset sales completed in 2019.

The overall forecasted normalized EBITDA and earnings per share include assumptions around asset sales anticipated to close in 2020, the U.S./Canadian dollar exchange rate, and other financing initiatives. 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.

AltaGas estimates an average of approximately 10,000 Bbls/d of natural gas liquids (NGL) will be exposed to frac spreads prior to hedging activities. Pricing risk related to frac exposed propane is mitigated through export and the hedging program in place at RIPET. Hedges are in place for approximately 80 percent of frac exposed butane and condensate volumes.

At RIPET, AltaGas is exposed to the propane price differential between North American Indices and the Far East Index for contracts not under tolling arrangements. AltaGas estimates an average of approximately 30,000 Bbls/d will be exposed to these price differentials in 2020, of which approximately 74 percent have been hedged at an average FEI to Mont Belvieu spread of US$11/Bbl. AltaGas plans to manage the facility such that a majority of annual capacity will be underpinned by tolling arrangements, and expects to reach this objective over the next several years.

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 2020:

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	0.05	35
RIPET Propane Far East Index to Mont Belvieu spread (2)	US$1/Bbl	4
AECO/Station 2 gas prices(3)	$0.20/GJ	3
Pension discount rate	1 percent	17

(1) Degree days – Utilities relate to SEMCO Gas, ENSTAR, and Washington Gas 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 Gas, during the prior 10 years for ENSTAR, and during the prior 30 years for Washington Gas.

(2) The impact on EBITDA due to changes in the spread will vary and is being managed through an active hedging program.

(3) Price risk related to frac exposed propane is mitigated through export and the hedging program in place at RIPET. Butane and condensate are 80 percent hedged.

Growth Capital

Based on projects currently under review, development, or construction, AltaGas expects net capital expenditures of approximately $900 million in 2020. The majority of capital expenditures are expected to focus on projects within the Utilities business that are anticipated to deliver stable and transparent rate base growth and strong risk-adjusted returns. The Utilities segment is expected to account for approximately 75 to 80 percent of total capital expenditures, while the Midstream segment is expected to account for approximately 15 to 20 percent and the Power and Corporate segments are expected to account for any remainder. Midstream and Power maintenance capital is expected to be approximately $30 to $40 million of the total capital expenditures in 2020. AltaGas' capital expenditures for the Utilities segment will focus primarily on accelerated pipe replacement programs, customer growth, and system betterment. In the Midstream segment, capital expenditures are anticipated to primarily relate to the completion of Townsend and North Pine expansions and associated pipeline systems, maintenance and administrative capital, the completion of the Mountain Valley Pipeline expansion project (MVP Southgate), and new business development. The Power segment continues to pursue a capital-light strategy for remaining assets. The Corporation continues to focus on capital efficient organic growth and disciplined capital allocation while improving balance sheet strength and flexibility.

AltaGas' 2020 committed capital program is expected to be funded through internally-generated cash flow and normal course borrowings on existing committed credit facilities.

Growth Capital Project Updates

The following table summarizes the status of AltaGas' significant growth projects. For further description of these projects please refer to AltaGas' most recent Annual Information Form which is available through SEDAR at www.sedar.com.

Project	AltaGas' Ownership Interest	Estimated Cost [1]	Expenditures to Date [2]	Status	Expected In-Service Date
Midstream Projects					
Northeast B.C. Pipeline Projects	33% to 100%	$75 million	$56 million	The Northeast B.C. Pipeline projects consist of four pipelines: the Inga gas gathering pipeline (33% ownership), the Townsend East NGL pipeline (100% ownership), the Aitken Connector NGL pipeline (100% ownership), and the Gundy lateral pipeline (100% ownership). Construction of all segments is underway. The pipelines are expected to be in-service in the first quarter of 2020.	Q1 2020
Townsend 2B Expansion and Mercaptan Treating	100%	$165 million	$140 million	Field construction activities commenced in the second quarter of 2019 and are progressing according to plan. The expected completion date is the first quarter of 2020.	Q1 2020
North Pine Expansion	100%	$58 million	$44 million	Field construction activities commenced in the third quarter of 2019 and are progressing according to plan. The expected completion date is the first quarter of 2020.	Q1 2020
Mountain Valley Pipeline (Mountain Valley)	10%	US$352 million	US$352 million	Construction is underway. As at December 31, 2019, approximately 90% of the project is complete, which includes construction of all original interconnects and compressor stations. In the third quarter of 2019 there was a voluntary suspension of construction activities in a section of the pipeline and the Federal Energy Regulatory Commission (FERC) issued an order to suspend all construction. As a result, the in-service date is now expected to be late 2020. Despite the delays, AltaGas' exposure is contractually capped to the original estimated contributions of approximately US$352 million.	Late 2020 due to ongoing legal and regulatory challenges
MVP Southgate Project	5%	US$20 million	US$3 million	Construction is expected to begin in the fourth quarter of 2020. Expenditures to date relate to land surveys, land acquisition, and obtaining permits and regulatory approvals.	Mid 2021

Project	AltaGas' Ownership Interest	Estimated Cost (1)	Expenditures to Date (2)	Status	Expected In-Service Date
Utilities Projects					
Accelerated Utility Pipe Replacement Programs – ***District of Columbia***	100%	Estimated US$305 million over the five year period from April 2020 to December 2024, plus additional expenditures in subsequent periods.	$nil (3)	Washington Gas has submitted an application for the second phase of PROJECT*pipes* to the Public Service Commission of the District of Columbia (PSC of DC). In the interim, Phase 1 has been extended to March 31, 2020 for an amount not to exceed US$12.5 million.	Individual assets are placed into service throughout the program.
Accelerated Utility Pipe Replacement Programs – ***Maryland***	100%	Estimated US$350 million over the five year period from January 2019 to December 2023, plus additional expenditures in subsequent periods.	US$57 million (3)	The second phase of the accelerated utility pipe replacement programs in Maryland (STRIDE 2.0) began in January 2019.	Individual assets are placed into service throughout the program.
Accelerated Utility Pipe Replacement Programs – ***Virginia***	100%	Estimated US$500 million over the five year period from January 2018 to December 2022, plus additional expenditures in subsequent periods.	US$171 million (3)	The second phase of the accelerated pipe replacement programs in Virginia (SAVE 2.0) began in January 2018.	Individual assets are placed into service throughout the program.
Accelerated Mains Replacement Programs – ***Michigan***	100%	Estimated US$50 million over five year period from 2015 to 2020.	US$37 million (3)	The third phase of the Accelerated Mains Replacement Program (MRP3) in Michigan expires in May 2020. A new MRP program was agreed to in SEMCO's recently settled rate case. The new five-year MRP program begins in 2021 with a total spend of approximately US$60 million. In addition to the new MRP program, SEMCO was also granted a new 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.
Marquette Connector Pipeline	100%	US$154 million	US$152 million	The MCP has been completed and is in service. All interconnects have been commissioned and the pipeline is providing gas supply to SEMCO's Marquette service area in northern Michigan. Minor cleanup and restoration will take place in 2020. Community engagement, interaction, and media coverage was positive throughout the project.	Completed December 2019

(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 expenditures incurred from inception of the projects to December 31, 2019. For WGL projects, this also includes any expenditures prior to the close of the WGL Acquisition on July 6, 2018.

(3) The utility accelerated replacement programs are long-term projects with multiple phases for which expenditures are approved by the regulators and managed in five 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

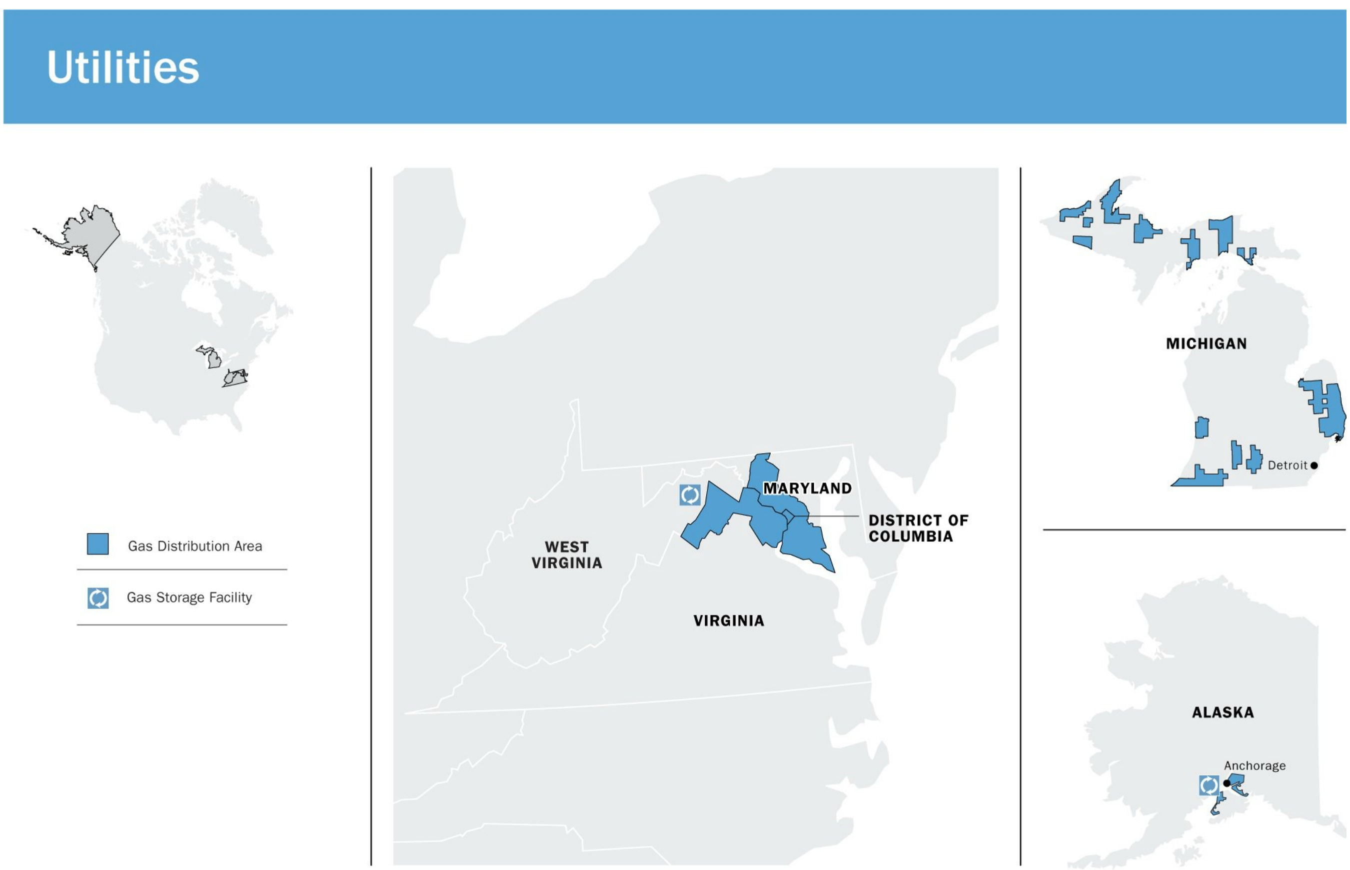
Description of Assets

AltaGas owns and operates utility assets that store and deliver natural gas to end-users in the District of Columbia, Virginia, Maryland, Michigan, and Alaska, serving approximately 1.7 million customers and with a combined rate base of approximately US$3.9 billion.

The utilities are underpinned by regulated returns and regulatory regimes that generally provide 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 generating economic returns by investing in regulated, long-life assets with stable earnings.

The Utilities segment includes:

- Washington Gas in Virginia, Maryland, and the District of Columbia;
- Hampshire, providing regulated interstate natural gas storage to Washington Gas;
- SEMCO Gas in Michigan;
- ENSTAR in Alaska;
- A 65 percent interest in Cook Inlet Natural Gas Storage Alaska LLC (CINGSA) in Alaska; and
- An approximate 37 percent interest in ACI.



All of the 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, Alaska, and the District of Columbia, earnings can be impacted by variations from normal weather resulting in delivered 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 public utility has been engaged in the natural gas distribution business since 1848, and provides regulated gas distribution services to end users in the District of Columbia, Virginia, and Maryland. At the end of 2019, Washington Gas had approximately 1.2 million customers, of which approximately 82 percent were residential. The number of customers at Washington Gas increased approximately 1 percent in 2019. The rate base at December 31, 2019 was approximately US$2.9 billion. At the end of 2019, the approved regulated ROE for Washington Gas in its various jurisdictions ranged from 9.2 percent to 9.7 percent based on an equity ratio ranging from 53.5 percent to 55.7 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 utility 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 has accelerated pipe replacement programs in place in each of its three jurisdictions. Washington Gas accelerates pipe replacement in order to reduce risk and further enhance the safety and reliability of the pipeline system. Each regulatory commission having jurisdiction over Washington Gas' retail rates has approved accelerated replacement programs with an associated surcharge mechanism to recover the cost, including a return, on those capital investments. In contrast to the traditional rate-making approach to capital investments, for the accelerated pipe replacement programs, Washington Gas is receiving recovery for these investments through the approved surcharges for each program and is authorized to invest in each of these programs over a five-year period.

Washington Gas' customers are eligible to purchase their natural gas from unregulated third-party marketers through natural gas unbundling. As at December 31, 2019, approximately 14 percent of its customers have chosen to purchase gas from marketers. This does not negatively impact Washington Gas' net income as the Corporation does not earn a margin on the sale of natural gas to firm customers, but 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, 2019, it had service agreements with four pipeline companies that provided firm transportation and storage services with contract expiration dates ranging from 2020 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 when those assets are not required to serve utility customers. The objective of this program is to derive a profit to be shared with its utility customers. These profits are earned by entering into commodity-related physical and financial contracts with third parties.

Hampshire

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 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 Gas

SEMCO owns and operates a regulated natural gas distribution utility in Michigan operating under the name SEMCO Gas and has an interest in a regulated natural gas storage facility in Michigan. At the end of 2019, SEMCO Gas had approximately 307,000 customers. Of these customers, approximately 91 percent are residential. In 2019, SEMCO Gas experienced customer growth of approximately 1 percent reflecting growth in the franchise areas and customer conversions with the favorable price of natural gas. The rate base at year end was approximately US$608 million. In 2019, the approved regulated ROE for SEMCO Gas was 10.35 percent with an approved capital structure based on 49.04 percent equity. For 2020, the approved regulated ROE is 9.87 percent with an approved capital structure based on 45.86 percent equity.

SEMCO Gas is regulated by the 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 Gas has an Accelerated Main Replacement Program (MRP) surcharge to recover a stated amount of accelerated main replacement capital expenditures in excess of what is authorized in its current base rates. The MRP began in 2011, was expanded in 2013 and renewed for an additional five years in 2015. SEMCO Gas has requested an additional renewal for the five year period beginning in 2020. The anticipated annual average capital spending over the five year period is approximately US$10 million. A new MRP was approved as part of the 2019 rate case. For the years 2021 to 2025 the anticipated annual average capital spending is approximately US$12 million. Additionally, a new Infrastructure Reliability Improvement Program was approved in the 2019 rate case. During the years 2020 to 2025, SEMCO Gas will complete certain projects totaling US$55 million to improve the reliability of infrastructure. Customers will be billed a surcharge beginning in 2021 for the IRIP.

ENSTAR and CINGSA

SEMCO owns and operates a regulated natural gas distribution utility in Alaska under the name ENSTAR. SEMCO, through a subsidiary, holds a 65 percent interest in CINGSA, a regulated natural gas storage utility in Alaska. At the end of 2019, ENSTAR had approximately 147,000 customers including residential, commercial, and transportation, and of these customers, approximately 91 percent are residential. In 2019, ENSTAR experienced customer growth of approximately 1 percent reflecting growth in the franchise areas and customer conversions with the favorable price of natural gas. The rate base at year end was approximately US$258 million for ENSTAR and US$68 million for CINGSA (SEMCO's 65 percent share).

ENSTAR and CINGSA are regulated by the Regulatory Commission of Alaska (RCA) and operate under cost-of-service regulation utilizing actual results from the most recently completed fiscal year along with known and measurable changes in their application for new rates.

ACI

AltaGas owns an approximate 37 percent equity interest in ACI. ACI holds certain assets formerly held by AltaGas, including rate-regulated utility distribution assets in British Columbia, Alberta, and Nova Scotia, minority interests in entities providing natural gas to the Town of Inuvik, a fully contracted 102 MW wind park located in British Columbia, and an approximate 10 percent interest in the Northwest Hydro facilities.

On October 21, 2019, ACI announced that the Consortium and ACI had concluded the Arrangement Agreement whereby the Consortium will indirectly acquire all of the Common Shares of ACI in an all-cash transaction for $33.50 per Common Share. On December 19, 2019, the shareholders of ACI approved the Arrangement Agreement. In addition, on December 16, 2019, ACI received a "no-action letter" from the Canadian Competition Bureau confirming that the Commissioner of Competition does not at this time intend to challenge the proposed Arrangement. On December 20, 2019, ACI received the final order from the Court of Queen's Bench of Alberta approving the Arrangement. On February 18, 2020, the Alberta Utilities Commission issued a decision approving the Arrangement. The closing of the Arrangement remains subject to the receipt of approval from the British Columbia Utilities Commission, and the satisfaction or waiver of other customary closing conditions. ACI and the Consortium expect to close the Arrangement in the first half of 2020.

Capitalize on Opportunities

While providing safe and reliable service, AltaGas pursues opportunities in the Utilities segment to deliver value to its customers and enhance long-term shareholder value. The Corporation's objectives are to:

- Ensure safe, reliable operations and infrastructure, providing effective and cost-efficient service for customers;
- Enhance returns and capital efficiency and more timely recovery of expenditures through rate cases and increased utilization of accelerated rate recovery programs;
- Enhance and grow the business through asset optimization, cost reduction initiatives, and operational efficiencies to reduce costs and deliver an improved customer experience;
- Improve business processes and drive down leak remediation costs, reinvesting savings into improving the customer experience;
- Attract and retain customers through exceptional customer service;
- Grow the consolidated Utilities rate base by a targeted 10 percent in 2020;
- Maintain strong relationships with local communities, Indigenous peoples, governments, and regulatory bodies; and
- Maintain strong community and regulatory relationships while ensuring fair returns to shareholders.

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 approximately 44 percent rate base growth over the past three years including the addition of WGL's rate base and after adjusting for the impact of foreign exchange translation. The growth in rate base is a direct result of the WGL Acquisition in 2018, 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 comprised of global export assets and strategically-located processing, fractionation, and liquids handling infrastructure in Canada that connects Western Canadian producers from wellhead to the coast and to the global export markets, as well as a pipeline investment, the sale of natural gas to retail customers, and underground natural gas storage facilities.

In Canada, AltaGas serves customers primarily in the Western Canada Sedimentary Basin (WCSB) and delivers natural gas into downstream pipeline systems, connecting producers to the global export markets for liquified petroleum gas (LPG). Subsequent to the disposition of the non-core Midstream assets in Canada which closed in February 2019, AltaGas transacts more than 1.4

Bcf/d of natural gas including natural gas gathering and processing, NGL extraction and fractionation, logistics, liquids handling, and global exports. Gas gathering systems move natural gas from producing wells to processing facilities where impurities and certain hydrocarbon components are removed. The gas is then compressed to meet downstream pipelines' operating specifications for transportation. Extraction and fractionation facilities reprocess natural gas to extract and recover ethane and NGL. Subsequent to the sale of the non-core Midstream assets in Canada, AltaGas has a total net licensed processing capacity of approximately 2.2 Bcf/d.

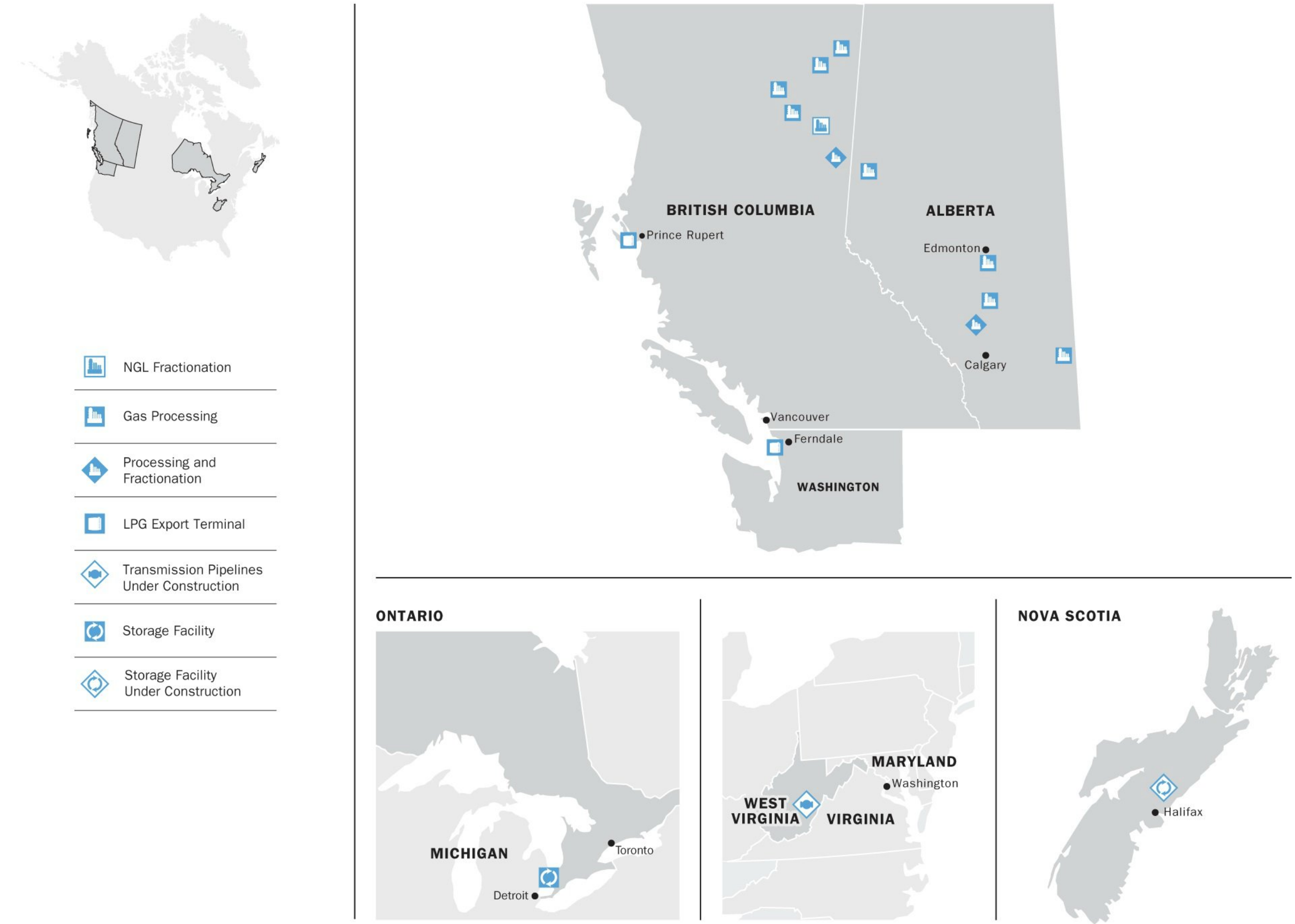
Through RIPET and the indirect interest in Ferndale, AltaGas is able to provide Western Canadian producers global market access and incremental value for Canadian NGLs. The Ferndale terminal is owned and operated by Petrogas, which exports LPG to Asian markets. See Global Exports section below for further details.

Liquids handling services include storage, rail logistics, pipelines, and truck loading as well as natural gas and NGL marketing initiatives. AltaGas identifies opportunities to buy and resell NGLs for producers, and exchange, reallocate, or resell pipeline capacity and storage to earn a profit. With the emergence of the global exports business, liquids handling provides integral support for managing RIPET's ocean and rail logistics as well as marketing the supply and offtake for RIPET. In support of the liquids handling operations, AltaGas manages a rail car fleet of approximately 1,200 rail cars.

In addition, the Midstream segment includes an investment in a pipeline in the northeastern United States, a wholesale gas asset management business, and a retail gas marketing business. AltaGas, through WGL Midstream, indirectly owns a 10 percent equity interest in the Mountain Valley pipeline. AltaGas' retail gas marketing business consists of the operations of WGL Energy Services, which sells natural gas directly to residential, commercial, and industrial customers in Maryland, Virginia, Delaware, Pennsylvania, and the District of Columbia.

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

Midstream



<u>Global Exports</u>

AltaGas' global export assets include RIPET and Petrogas, which provide Western Canadian producers with global market access and incremental value for Canadian NGLs.

- RIPET commenced commercial operations on May 23, 2019, with the first propane shipment departing from the terminal to Asia. RIPET is capable of storing 600,000 Bbls and currently has a propane export license of 40,000 Bbls/d. As AltaGas builds on the operational capabilities and global counterparty networks for RIPET, AltaGas expects to continue to increase throughput from RIPET. In November 2019, AltaGas filed an application to increase RIPET's propane export license to 80,000 Bbls/d. For 2020, AltaGas has in place multi-year agreements for the purchase of approximately 50 percent of the propane expected to be shipped from RIPET; and
- Petrogas is a leading North American integrated midstream company, with an extensive logistics network consisting of over 3,000 rail car leases used entirely to support its transportation needs. Petrogas owns and operates the Ferndale terminal, which is capable of handling LPG exports up to 50,000 Bbls/d with 750,000 Bbls of on-site storage capacity. AltaGas has an approximate one-third indirect ownership interest in Petrogas via its 50 percent interest in AIJVLP, which holds an approximate two-thirds ownership interest in Petrogas. The remaining 50 percent interest in AIJVLP is owned

by Idemitsu Kosan Co., Ltd. AIJVLP has received a Put Notice from SAM for the purchase of SAM's approximate one-third interest in Petrogas.

Gas Processing

Gas processing activities are comprised of gathering systems that move natural gas from producing wells to processing facilities where impurities and certain hydrocarbon components are removed. The gas is then compressed to meet downstream pipelines' operating specifications for transportation to North American natural gas markets. All AltaGas' processing facilities are capable of extracting NGL. The facilities provide fee-for-service revenues based on volumes processed as well as revenues based on take-or-pay contracts. A significant portion of contracts flow through operating costs to the producers. AltaGas' processing infrastructure includes:

- The Townsend facility, a 396 Mmcf/d gas processing facility, along with the related egress pipelines, truck terminal, and NGL treatment infrastructure (the Townsend complex), which is wholly owned by AltaGas. The majority of the processing capacity is contracted with Montney producers in the area under long-term take-or-pay agreements. In 2018, AltaGas entered into definitive agreements with Kelt Exploration Ltd. to provide an energy infrastructure solution for the liquids-rich Inga Montney development located in British Columbia. This project will add a 198 Mmcf/d C3+ deep cut gas processing facility and is expected to be on-stream in the first quarter of 2020. AltaGas is the operator of these facilities;
- The Gordondale facility, which has licensed capacity of 150 Mmcf/d of natural gas and is wholly owned and operated by AltaGas. The Gordondale facility processes gas gathered from Birchcliff Energy Ltd.'s Gordondale Montney development under a long-term take-or-pay contract. The plant is equipped with liquids extraction facilities to capture the NGL value for the producer;
- The Blair Creek facility, which has licensed capacity of 120 Mmcf/d of natural gas and is wholly owned and operated by AltaGas. The facility processes gas gathered from producers in the area. The plant is equipped with liquids extraction facilities to capture the NGL value for the producer;
- The Aitken Creek processing facilities, in which AltaGas has a 50 percent ownership interest. Black Swan Energy Ltd. (Black Swan) owns the remaining 50 percent interest. These facilities include Aitken Creek North, an operating shallow gas plant with a current capacity of 110 Mmcf/d (55 Mmcf/d net), and Nig Creek, a shallow gas plant with capacity of 100 Mmcf/d (50 Mmcf/d net) that came on-stream in the third quarter of 2019. The Aitken Creek processing facilities are located in the liquids rich Montney resource play in Northeast British Columbia (NEBC) and are operated by Black Swan. AltaGas and Black Swan have also entered into long-term processing, transportation, and marketing agreements that will include new AltaGas liquids handling infrastructure in NEBC;
- The Harmattan facility, which has a natural gas processing capacity of 490 Mmcf/d and is wholly owned and operated by AltaGas. Harmattan's natural gas processing consists of sour gas treating, co-stream processing, and NGL extraction. In addition, Harmattan has fractionation and terminalling facilities (see below section on Fractionation and Liquids Handling); and
- Interests in four NGL extraction plants with net licensed inlet capacity of 1.0 Bcf/d. The extraction plants consist of Edmonton Ethane Extraction Plant (EEEP), Joffre Ethane Extraction Plant (JEEP), Pembina Empress Extraction Plant (PEEP), and the Younger extraction plant (Younger). The extraction assets provide stable fixed-fee or cost-of-service type revenues and margin based revenues. The natural gas supply to EEEP, JEEP, and PEEP depends on natural gas demand pull from residential, commercial and industrial usage inside and outside of Western Canada, and gas liquids demand pull from the Alberta petrochemical market and propane heating. Natural gas supply to Younger is dependent on the amount of raw natural gas processed at the McMahon gas plant, which is based on the robust natural gas producing region of northeastern British Columbia.

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; Harmattan; and, in NEBC, Townsend and North Pine.

AltaGas' fractionation and liquids handling infrastructure includes:

- The North Pine facility, which is the only custom fractionation plant in British Columbia, providing area producers with a lower cost, higher netback alternative for their NGLs than transporting and fractionating in Edmonton. The first train of the North Pine facility is capable of processing up to 10,000 Bbls/d of NGL mix. Construction is ongoing for the second NGL separation train capable of processing up to an additional 10,000 Bbls/d of NGL mix and it is expected to be on-stream in the first quarter of 2020. The North Pine facility is connected to the Townsend truck terminal via the North Pine pipelines, to the Tourmaline Gundy facility, and also has access to the Canadian National rail network, allowing the transportation of propane, butane, and condensate to North American markets and propane to global markets via RIPET;
- The Harmattan gas processing complex, which has NGL fractionation capacity of 35,000 Bbls/d, a 450 Bbls/d capacity frac oil processing facility, and a 200 tonnes/d capacity industrial grade carbon dioxide (CO2) facility. Harmattan is the only deep-cut and full fractionation plant in its operating area;
- Younger, which has fractionation capacity of 19,500 Bbls/d (9,750 Bbls/d net). Effective April 1, 2018, AltaGas has a 50 percent interest in Younger's fractionation, storage, loading, treating, and terminalling of NGL and Pembina assumed plant operatorship. The remaining interest is held by Pembina;
- 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 two liquids egress lines, with a third line under construction, that connect the Townsend facility to the Townsend truck terminal on the Alaska Highway (30 km) and AltaGas' North Pine facility (70 km);
- NGL and spec propane lines currently under construction to connect the Townsend complex, in the North, to the Aitken Creek facilities through a 60 km NGL pipeline (Aitken Connector) and to the Tourmaline Gundy facility, in the West, through a 15 km spec propane line. The NGL and propane pipelines are currently under construction and are expected to be fully operational by the first quarter of 2020;
- A rail logistics network consisting of approximately 1,200 rail cars that AltaGas manages to support LPG and NGL handling;
- 50 percent ownership of the 5.3 Bcf Sarnia natural gas storage facility connected to the Dawn Hub in Eastern Canada; and
- The Alton Natural Gas Storage Project under construction.

In addition to supporting the other Midstream activities within AltaGas, the liquids handling business identifies opportunities to buy and resell NGLs for producers, and exchange, reallocate or resell pipeline capacity and storage 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 utility gas users and manages the third-party pipeline transportation requirements for many of its gas marketing customers.

Pipeline Investments

AltaGas has a 10 percent equity interest in Mountain Valley. The proposed pipeline will transport approximately 2.0 Bcf/d of natural gas and is expected to be placed into service in late 2020. In April 2018, AltaGas entered into a separate agreement to acquire a 5 percent equity interest in a lateral project to build an interstate natural gas pipeline (MVP Southgate) which will receive natural gas from Mountain Valley. The MVP Southgate pipeline is expected to be placed into service in mid-2021.

AltaGas also held a 10 percent interest in the Constitution pipeline through a 10 percent equity investment in Constitution Pipeline Company, LLC. The natural gas pipeline venture was proposed to transport natural gas from the Marcellus region in northern Pennsylvania to major northeastern markets. In February 2020, following evaluations of the diminished underlying economics for the proposed Constitution pipeline project, the partners of Constitution Pipeline Company, LLC elected not to proceed with the project.

Retail Energy Marketing

AltaGas' retail gas marketing business sells natural gas directly to residential, commercial, and industrial customers in Maryland, Virginia, Delaware, Pennsylvania, and the District of Columbia. AltaGas provides natural gas and NGL marketing and gas transportation services to optimize the value of the infrastructure assets and meet customer needs. Specifically, AltaGas provides natural gas related solutions to its customers and counterparties including producers, utilities, local distribution companies, power generators, wholesale energy suppliers, LNG exporters, pipelines, and storage facilities. In addition, AltaGas also contracts for storage and pipeline capacity in its trading activities through both long-term contracts and short-term transportation releases.

Capitalize on Opportunities

To take advantage of opportunities such as 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 business. New infrastructure is expected to be 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 and enhance long-term shareholder value. The Corporation's objectives are to:

- Maximize and grow the unique structural advantage within AltaGas' integrated platform in the Montney region, leveraging RIPET and the integrated value chain to attract volumes;
- Increase utilization and export volumes at RIPET, continuing to build on export competency, with volumes expected to be in excess of 50,000 Bbls/d by the end of 2020;
- Develop high quality assets that enhance the integrated Midstream offering and connect producers to the global markets;
- Consolidate its position in key markets to deliver optimal growth over the long-term;
- Provide a fully-integrated Midstream service offering including gas processing and NGL extraction, fractionation, liquids handling facilities, and transportation and marketing services to customers across the energy value chain, with higher producer netbacks resulting from global export access to higher value global markets, including Asia;
- Maintain strong relationships with Indigenous peoples, regulators, customers, partners, and service providers;
- Optimize existing rail infrastructure to gain scale and efficiencies;
- Increase utilization and throughput at existing facilities while maintaining top tier operating costs, high reliability and NGL recovery, highly efficient business administration, and effective safety and environmental programs;
- Mitigate commodity risk through effective hedging programs and risk management systems;

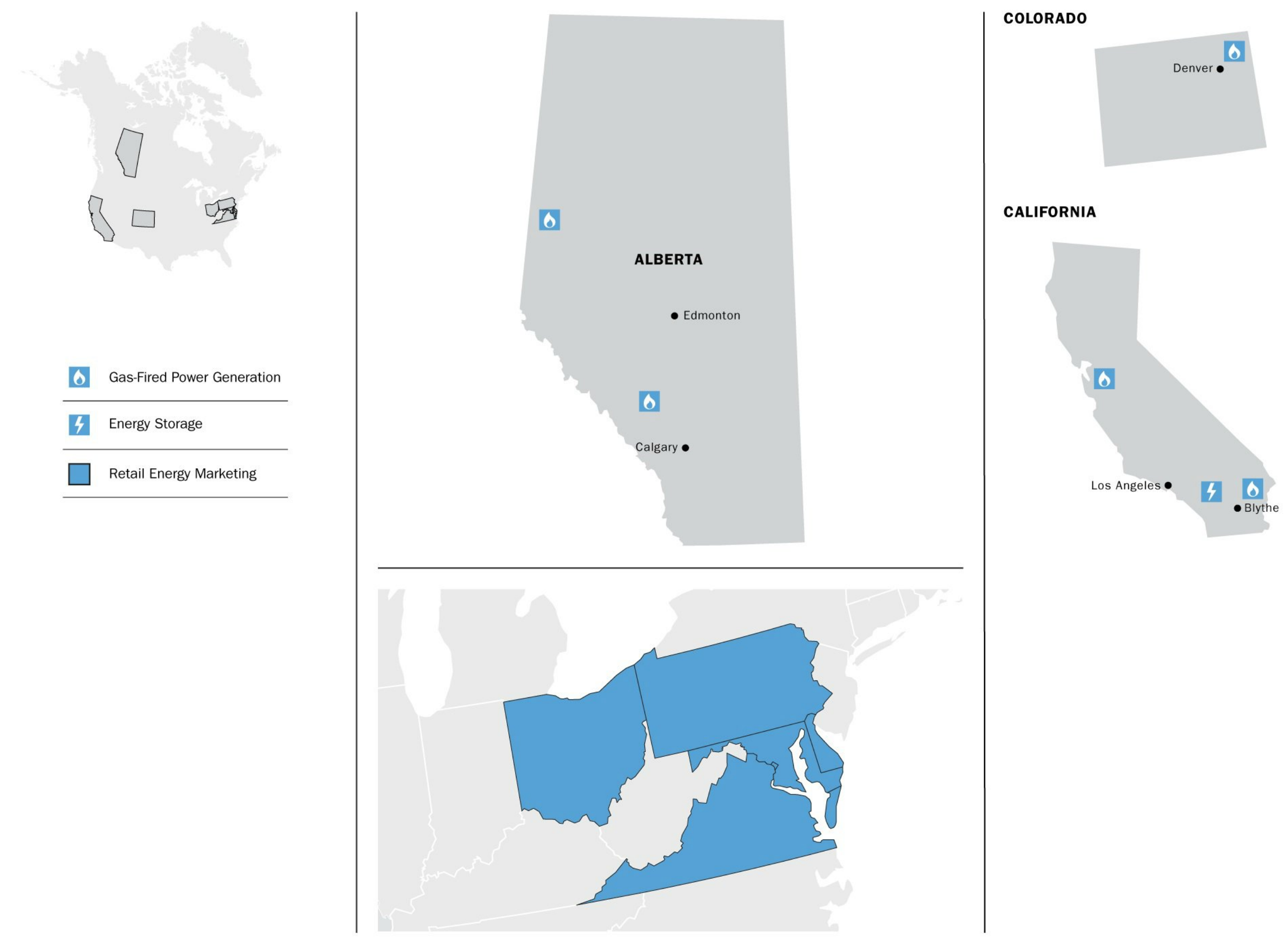
- Mitigate volume risk through contractual structures, redeployment of equipment, and expansion of geographic reach; and
- Mitigate counterparty risk through customer base growth and diversification.

Power

Description of Assets

AltaGas' Power segment includes 710 MW of operational gross capacity from natural gas-fired, distributed generation, and energy storage assets, certain of which are pending sale, located in Alberta, Canada, and the United States, primarily in California and Colorado. The Power business also includes WGL's retail power marketing business. Throughout 2018 and 2019, AltaGas has disposed of the majority of the assets in the Power segment and continues to operate under a capital-light power strategy.

Power



Specifically, the Power segment includes:

- Three natural gas-fired plants with 627 MW of generating capacity in the United States, including the 507 MW Blythe Energy Center (Blythe) and the 50 MW Ripon facility, located in California, and the 70 MW Brush II facility (Brush) in Colorado. Blythe is under a Power Purchase Arrangement (PPA) with a creditworthy utility;
- 45 MW of cogeneration and 3 MW of gas-fired peaking plant capacity in Alberta;
- 20 MW of lithium ion battery storage in Pomona, California, with a 10-year agreement for capacity under contract with SCE;
- WGL's retail power marketing business, which sells power directly to residential, commercial, and industrial customers in Maryland, Virginia, Delaware, Pennsylvania, Ohio, and the District of Columbia; and
- Certain remaining distributed generation assets.

In southern California, the 507 MW Blythe Energy Center utilizes gas-fired generation to produce power and serves the transmission grid operated by the California Independent System Operator (CAISO) to cover periods of high demand primarily driven by the Los Angeles area. Due to the structure of the long-term PPA with SCE, the majority of the revenue from the facility is derived from being available to produce and not from actual production, therefore providing stable cash flow. The facility is directly connected to a Southern California Gas Company natural gas pipeline for its supply and has reactivated an El Paso Gas Company connection as a second supply source, and interconnects to SCE and CAISO via a 67-mile transmission line also owned by Blythe and is part of the Blythe Energy Center. In 2019, AltaGas announced the successful recontracting of the Blythe facility to SCE. With the approval of the new PPA with SCE by the California Public Utilities Commission in January 2020, the Blythe Energy Center is contracted under a PPA until December 31, 2023. Under the tolling agreement(s), SCE has exclusive rights to all capacity, energy, ancillary services, and resource adequacy benefits during the PPA term.

Ripon, a natural gas-fired power asset, was acquired in early 2015. The PPA contract expired May 31, 2018, following which AltaGas negotiated bilateral Resource Adequacy (RA) contracts that included the remainder of 2018, as well as the majority of 2019 and 2020. AltaGas retains the rights to the energy and ancillary service attributes of the facility, which are sold on a merchant basis into the CAISO.

In early 2015, AltaGas acquired Pomona, which is strategically located in the east Los Angeles basin load pocket. AltaGas constructed, owns, and operates a 20 MW (80 MWh) lithium-ion battery storage facility at the Pomona site (the Pomona Energy Storage facility) which entered service in December of 2016 and is under contract for 20 MW of resource adequacy capacity with SCE under a 10-year energy services agreement. AltaGas retains the rights to the energy and ancillary service attributes of the facility, which are sold on a merchant basis into the CAISO. In addition, AltaGas is in the initial stages of permitting a new 40 MW stand-alone energy storage project in Goleta, California.

The U.S. retail power marketing business sells power to end users in Maryland, Virginia, 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 the states and jurisdictions where WGL operates. Electricity is 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 electricity deliveries, and thus, a secured power supply arrangement expiring in 2022 has been entered into with Shell Energy North America (US), L.P. for the majority of electricity requirements to service end users, which also reduces credit requirements.

Consolidated Financial Review

	Three Months Ended December 31		Year Ended December 31	
($ millions except where noted)	**2019**	2018	**2019**	2018
Revenue	**1,534**	1,727	**5,495**	4,257
Normalized EBITDA (1)	**425**	394	**1,271**	1,009
Net income (loss) applicable to common shares	**(103)**	174	**769**	(502)
Normalized net income (1)	**186**	120	**324**	195
Total assets	**19,795**	23,488	**19,795**	23,488
Total long-term liabilities	**9,301**	11,746	**9,301**	11,746
Net additions (dispositions) of property, plant and equipment	**240**	16	**(1,090)**	573
Dividends declared (2)	**67**	121	**266**	463
Cash from (used by) from operations	**16**	(60)	**616**	(79)
Normalized funds from operations (1)	**332**	255	**895**	657
Normalized adjusted funds from operations (1)	**307**	255	**835**	626
Normalized utility adjusted funds from operations (1)	**241**	192	**573**	460
Normalized effective income tax rate (%) (1)	**12.2**	13.1	**15.4**	14.0

	Three Months Ended December 31		Year Ended December 31	
($ per share, except shares outstanding)	**2019**	2018	**2019**	2018
Net income (loss) per common share - basic	**(0.37)**	0.64	**2.78**	(2.25)
Net income (loss) per common share - diluted	**(0.37)**	0.64	**2.77**	(2.25)
Normalized net income - basic (1)	**0.67**	0.44	**1.17**	0.88
Normalized net income - diluted (1)	**0.67**	0.44	**1.17**	0.87
Dividends declared (2)	**0.24**	0.45	**0.96**	2.09
Cash from (used by) from operations	**0.06**	(0.22)	**2.22**	(0.35)
Normalized funds from operations (1)	**1.19**	0.94	**3.23**	2.95
Normalized adjusted funds from operations (1)	**1.10**	0.94	**3.01**	2.81
Normalized utility adjusted funds from operations (1)	**0.87**	0.71	**2.07**	2.06
Shares outstanding - basic (millions)				
During the period (3)	**278**	272	**277**	223
End of period	**279**	275	**279**	275

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

(2) Dividends declared per common share per month: $0.1825 beginning on November 27, 2017, and $0.08 beginning on December 27, 2018.

(3) Weighted average.

Three Months Ended December 31

Normalized EBITDA for the fourth quarter of 2019 was $425 million, compared to $394 million for the same quarter in 2018. Factors positively impacting normalized EBITDA included contributions from RIPET which was placed into service in May 2019, higher contributions from Washington Gas' utilities primarily due to Virginia and Maryland rate cases, higher margins from WGL's retail gas and power marketing businesses, higher transportation and storage spreads from WGL Midstream assets, higher Allowance for Funds Used During Construction (AFUDC) related to Mountain Valley, higher NGL marketing EBITDA due to a strong spot market, and higher equity earnings from Petrogas primarily due to higher export volumes and domestic margins. These were partially offset by the impact of asset sales, including the U.S. distributed generation assets in September 2019, the San Joaquin facilities in the fourth quarter of 2018, the Northwest Hydro facilities in January 2019, WGL Midstream's indirect non-operating interest in Central Penn in November 2019, WGL Midstream's interest in Stonewall in May 2019, the initial public offering (IPO) of ACI in October 2018, and certain non-core Midstream and Power assets in February 2019. Other factors decreasing EBITDA in the fourth quarter of 2019 included higher operating costs at Washington Gas, the impact of CINGSA's rate case decision received in the third quarter of 2019, and higher corporate employee costs primarily due to incentive plans. For the three months ended December 31, 2019, fluctuations in the Canadian/U.S. dollar exchange rate resulted in a $1 million decrease in normalized EBITDA.

Net loss applicable to common shares for the fourth quarter of 2019 was $103 million ($0.37 per share), compared to net income of $174 million ($0.64 per share) for the same quarter in 2018. The decrease was mainly due to provisions recorded in the fourth quarter of 2019 and higher unrealized losses on risk management contracts, partially offset by the same previously referenced factors impacting normalized EBITDA, lower depreciation and amortization expense, lower interest expense, and gains on the sale of assets.

Normalized funds from operations for the fourth quarter of 2019 were $332 million ($1.19 per share), compared to $255 million ($0.94 per share) for the same quarter in 2018. The increase was mainly due to lower interest expense and the same factors impacting normalized EBITDA. In the fourth quarter of 2019, AltaGas received $3 million of dividend income from the Petrogas Preferred Shares (2018 - $3 million) and $2 million of common share dividends from Petrogas (2018 - $2 million).

Normalized adjusted funds from operations (AFFO) for the fourth quarter of 2019 were $307 million ($1.10 per share), compared to $255 million ($0.94 per share) for the same quarter in 2018. Factors impacting AFFO in the fourth quarter of 2019 included the same drivers as normalized funds from operations and higher net cash paid to non-controlling interests. In the fourth quarter of 2019, AltaGas paid $17 million of preferred share dividends (2018 - $17 million).

Normalized utility adjusted funds from operations (UAFFO) for the fourth quarter of 2019 were $241 million ($0.87 per share), compared to $192 million ($0.71 per share) for the same quarter in 2018. The increase was due to the same drivers as normalized adjusted funds from operations, partially offset by higher utilities depreciation.

In the fourth quarter of 2019, AltaGas recorded pre-tax provisions of approximately $415 million ($319 million after-tax). These provisions primarily related to various assets in the Power segment and a sour gas treatment facility in Alberta. In the fourth quarter of 2018, AltaGas recorded pre-tax provisions of approximately $31 million ($23 million after-tax). These provisions primarily related to a power development project in the U.S., a WGL Energy Systems financing receivable, and certain non-core Midstream assets. In addition, in the fourth quarter of 2018, AltaGas recorded a pre-tax provision of $15 million ($11 million after-tax) on its equity investment in Craven Wood Country Energy LP, which was sold in the third quarter of 2019.

Operating and administrative expenses for the fourth quarter of 2019 were $340 million, compared to $346 million for the same quarter in 2018. The decrease was mainly due to lower transaction costs on acquisitions and dispositions, the impact of the sale of the U.S. distributed generation assets in September 2019, the impact of the IPO of ACI in October 2018, the impact of the sale of the San Joaquin facilities in the fourth quarter of 2018, and the impact of the sale of Northwest Hydro in January 2019, partially offset by the impact of RIPET coming online in May 2019, and higher pipeline leak remediation costs at Washington Gas. Depreciation and amortization expense for the fourth quarter of 2019 was $109 million, compared to $126 million for the same quarter in 2018. The decrease was mainly due to the impact of asset sales completed in the fourth quarter of 2018 and throughout 2019, partially offset by new assets placed into service. Interest expense for the fourth quarter of 2019 was $77 million, compared to $110 million for the same quarter in 2018. The decrease was primarily due to lower average debt balances as a result of debt reduction from proceeds on asset sales.

AltaGas recorded an income tax recovery of $87 million for the fourth quarter of 2019 compared to $63 million in the same quarter in 2018. The increase in tax recovery was mainly due to tax recoveries booked on asset provisions in the fourth quarter of 2019, partially offset by a tax recovery on assets classified as held for sale in the fourth quarter of 2018.

Normalized net income was $186 million ($0.67 per share) for the fourth quarter of 2019, compared to $120 million ($0.44 per share) reported for the same quarter in 2018. The increase was mainly due to the same factors impacting normalized EBITDA, lower interest expense, and lower depreciation and amortization expense. Also driving the increase in normalized net income was a low normalized effective tax rate, which was impacted by the accretion of regulatory amounts through tax expense and non-taxable equity earnings. Normalizing items in the fourth quarter of 2019 increased normalized net income by $289 million and included after-tax amounts related to gains on sale of assets, changes in fair value of natural gas optimization inventory, recovery of transaction costs related to acquisitions and dispositions, unrealized losses on risk management contracts, provisions on assets, a statutory tax rate change in Alberta, a unitary tax adjustment related to the acquisition of WGL and U.S. asset sales, a gain on the redemption of Washington Gas preferred shares, and merger commitment costs. Normalizing items in the fourth quarter of 2018 reduced normalized net income by $54 million and included after-tax amounts related to change in fair value of natural gas optimization inventory, unrealized gains on risk management contracts, losses on sale of assets, losses on investments, transaction costs related to acquisitions and dispositions, tax adjustments as a result of the Northwest Hydro facilities being held for sale, provisions on assets, provisions on equity investments, and financing costs associated with the bridge facility for the WGL Acquisition of $3 million. 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, 2019 was $1.3 billion, compared to $1.0 billion in 2018. Factors positively impacting normalized EBITDA included a full year of contributions from WGL, contributions from RIPET which was placed into service in May 2019, higher equity earnings from Petrogas primarily due to higher export volumes and domestic margins, higher volumes from WGL's retail power business, equity earnings from ACI, higher AFUDC related to Mountain Valley, higher transportation and storage spreads from WGL Midstream assets, contributions from Central Penn which was placed into service in October 2018, the impact of the stronger U.S. dollar on reported results from U.S. assets, and contributions from the Aitken Creek facilities. These were partially offset by the impact of asset sales, including the San Joaquin facilities in the fourth quarter of 2018, the Northwest Hydro facilities in January 2019, the IPO of ACI in October 2018, the U.S. distributed generation assets in September 2019, certain non-core Midstream and Power assets in February 2019, WGL Midstream's interest in Stonewall in May 2019, the Busch Ranch facilities in the fourth quarter of 2018, and WGL Midstream's indirect non-operating interest in Central Penn in November 2019. Other factors negatively impacting normalized EBITDA included higher corporate costs primarily due to employee incentive plans, lower interest income, the impact of the extended planned outage at Blythe, and the impact of CINGSA's rate case decision received in the third quarter of 2019. For the year ended December 31, 2019, the average Canadian/ U.S. dollar exchange rate increased to 1.33 from an average of 1.30 in 2018, resulting in an increase in normalized EBITDA of approximately $5 million.

Net income applicable to common shares for the year ended December 31, 2019 was $769 million ($2.78 per share), compared to net loss applicable to common shares of $502 million ($2.25 per share) in 2018. The increase was mainly due to gains on asset sales, lower provisions on assets, the absence of 2018 merger commitment costs, and the same previously referenced factors impacting normalized EBITDA, partially offset by lower income tax recovery, higher interest expense, higher provisions on equity investments, higher depreciation and amortization expense, and higher unrealized losses on risk management contracts.

Normalized funds from operations for the year ended December 31, 2019 were $895 million ($3.23 per share), compared to $657 million ($2.95 per share) in 2018. The increase was mainly due to the same drivers as normalized EBITDA, partially offset by higher interest expense. In 2019, AltaGas received $13 million of dividend income from the Petrogas Preferred Shares (2018 - $13 million) and $6 million of common share dividends from Petrogas (2018 - $5 million).

Normalized adjusted funds from operations for the year ended December 31, 2019 were $835 million ($3.01 per share), compared to $626 million ($2.81 per share) in 2018. The increase was mainly due to the same drivers as normalized funds from operations and lower cash received from non-controlling interests. In 2019, AltaGas paid $68 million of preferred share dividends (2018 - $67 million).

Normalized utility adjusted funds from operations for the year ended December 31, 2019 were $573 million ($2.07 per share), compared to $460 million ($2.06 per share) in 2018. The increase was due to the same drivers as normalized adjusted funds from operations partially offset by higher utilities depreciation. The per share amount was impacted by the higher average number of shares outstanding in 2019 compared to 2018.

In 2019, AltaGas recorded pre-tax provisions of approximately $416 million ($320 million after-tax). These provisions primarily related to various assets in the Power segment and a sour gas treatment facility in Alberta. In addition, AltaGas recorded pre-tax provisions on equity investments of approximately $46 million ($29 million after-tax), including $44 million related to WGL Midstream's indirect, non-operating interest in Central Penn which was sold in November 2019, and $2 million related to biomass investments which were sold in the third quarter of 2019. In 2018, AltaGas recorded pre-tax provisions of approximately $729 million (after-tax $562 million). These provisions primarily related to the San Joaquin power assets in California which were sold in the fourth quarter of 2018, certain non-core Midstream and Power assets in Canada which were sold in the first quarter of 2019, and certain assets included in the 2018 IPO of ACI. In addition, pre-tax provisions of $37 million and $2 million were recorded on certain remaining Midstream assets and the Pomona Gas Repowering project respectively, $6 million was recorded on a WGL Energy Systems financing receivable, and $15 million ($11 million after-tax) against AltaGas' investment in Craven Wood Country Energy LP, which was subsequently sold in the third quarter of 2019.

Operating and administrative expenses for the year ended December 31, 2019 were $1.3 billion, compared to $1.1 billion in 2018. The increase was mainly due to the addition of WGL’s operating and administrative expenses for the first half of the year, and the impact of RIPET coming into service in May 2019, partially offset by the absence of merger commitment costs recorded in 2018 and the impact of asset sales completed in the fourth quarter of 2018 and throughout 2019. Depreciation and amortization expense for the year ended December 31, 2019 was $438 million, compared to $394 million in 2018. The increase was mainly due to depreciation and amortization expense on WGL assets for the first half of the year and new assets placed into service, partially offset by the impact of asset sales completed in the fourth quarter of 2018 and throughout 2019. Interest expense for the year ended December 31, 2019 was $346 million, compared to $309 million in 2018. The increase was primarily due a full year of interest on debt assumed in the WGL Acquisition, partly offset by lower average debt balances in the last half of 2019 as a result of proceeds on asset sales.

AltaGas recorded an income tax recovery of $28 million for the year ended December 31, 2019 compared to $263 million in 2018. The decrease in tax recovery was mainly due to tax expense incurred on the sale of the remaining interest in the Northwest Hydro facilities and tax on WGL’s earnings. These tax expenses were partially offset by a tax recovery on the sale of WGL's distributed generation assets, a unitary tax rate adjustment related to the acquisition of WGL and U.S. asset sales, and a tax rate adjustment related to the Alberta Job Creation Tax Cut. Current tax expense of approximately $63 million was recorded in 2019, of which approximately $37 million related to tax on asset sales.

Normalized net income was $324 million ($1.17 per share) for the year ended December 31, 2019, compared to $195 million ($0.88 per share) in 2018. The increase was mainly due to the same previously referenced factors impacting normalized EBITDA, partially offset by lower income tax recovery, higher interest expense, and higher depreciation and amortization expense. Also driving the increase was a low normalized effective tax rate, which was impacted by the accretion of regulatory amounts through tax expense and non-taxable equity earnings. Normalizing items in the year ended December 31, 2019 reduced normalized net income by $445 million and included after-tax amounts related to gains on sale of assets, changes in fair value of natural gas optimization inventory, merger commitment cost recovery due to a change in timing related to certain WGL merger commitments, transaction costs related to acquisitions and dispositions, unrealized losses on risk management contracts, losses on investments, provisions on assets, provisions on investments accounted for by the equity method, a gain on the redemption of Washington Gas preferred shares, the impact of a statutory tax rate change in Alberta, and a unitary tax adjustment related to the acquisition of WGL and U.S. asset sales. Normalizing items in the year ended December 31, 2018 increased normalized net income by $697 million and included after-tax amounts related to provisions on assets, provisions on equity investments, merger commitment costs associated with the WGL Acquisition, transaction costs related to acquisitions and dispositions, change in fair value of natural gas optimization inventory, realized losses on foreign exchange derivatives, unrealized gains on risk management contracts, a tax recovery as a result of the Northwest Hydro facilities being held for sale, financing costs of $21 million associated with the bridge facility for the WGL Acquisition, losses on sale of assets, and losses on investments. Please refer to the *Non-GAAP Financial Measures* section of this MD&A for further details on normalization adjustments.

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

Normalized EBITDA

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2019**	2018	**2019**	2018
Normalized EBITDA	**$ 425**	$ 394	**$ 1,271**	$ 1,009
Add (deduct):				
Transaction (costs) recoveries related to acquisitions and dispositions	**4**	(12)	**(12)**	(63)
Merger commitment recovery (costs)	**(1)**	—	**4**	(182)
Unrealized gains (losses) on risk management contracts	**(47)**	44	**(62)**	56
Changes in fair value of natural gas optimization inventory	**(6)**	12	**7**	15
Non-controlling interest related to HLBV investments	**—**	(22)	**(8)**	(39)
Realized losses on foreign exchange derivatives	**—**	—	**—**	(35)
Losses on investments	**—**	(10)	**(4)**	(10)
Gains (losses) on sale of assets	**56**	(12)	**875**	(10)
Provisions on assets	**(415)**	(31)	**(416)**	(729)
Provisions on investments accounted for by the equity method	**—**	(15)	**(46)**	(15)
Investment tax credits related to distributed generation assets	**—**	(2)	**(7)**	(5)
Accretion expenses	**(1)**	(3)	**(5)**	(11)
Foreign exchange gains (losses)	**(1)**	1	**(1)**	5
EBITDA	**$ 14**	$ 344	**$ 1,596**	$ (14)
Add (deduct):				
Depreciation and amortization	**(109)**	(126)	**(438)**	(394)
Interest expense	**(77)**	(110)	**(346)**	(309)
Income tax recovery	**87**	63	**28**	263
Net income (loss) after taxes (GAAP financial measure)	**$ (85)**	$ 171	**$ 840**	$ (454)

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 (Loss) using net income (loss) adjusted for pre-tax depreciation and amortization, interest expense, and income tax recovery.

Normalized EBITDA includes additional adjustments for unrealized gains (losses) on risk management contracts, losses on investments, transaction (costs) recoveries related to acquisitions and dispositions, merger commitment recovery (costs) primarily due to a change in timing related to certain WGL merger commitments, gains (losses) on the sale of assets, accretion expenses related to asset retirement obligations, realized losses on foreign exchange derivatives, provisions on assets, provisions on investments accounted for by the equity method, foreign exchange gains (losses), distributed generation asset related investment tax credits, non-controlling interest of certain investments to which Hypothetical Liquidation at Book Value (HLBV) accounting is applied, and changes in fair value of natural gas optimization inventory. AltaGas presents normalized EBITDA as a supplemental measure. Normalized EBITDA 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

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2019**	2018	**2019**	2018
Normalized net income	**$ 186**	$ 120	**$ 324**	$ 195
Add (deduct) after-tax:				
Transaction (costs) recoveries related to acquisitions and dispositions	**3**	(9)	**(10)**	(50)
Merger commitment recovery (cost)	**(1)**	—	**5**	(135)
Unrealized gains (losses) on risk management contracts	**(36)**	30	**(47)**	34
Changes in fair value of natural gas optimization inventory	**(5)**	12	**4**	15
Realized loss on foreign exchange derivatives	**—**	—	**—**	(35)
Losses on investments	**—**	(10)	**(4)**	(1)
Gains (losses) on sale of assets	**42**	(36)	**814**	(35)
Provisions on assets	**(319)**	(23)	**(320)**	(562)
Provisions on investments accounted for by the equity method	**6**	(11)	**(29)**	(11)
Tax adjustment on assets held for sale	**—**	104	**—**	104
Unitary tax adjustment on acquisition of WGL and U.S. asset sales	**19**	—	**19**	—
Gain on redemption of preferred shares	**3**	—	**3**	—
Statutory tax rate change	**(1)**	—	**10**	—
Financing costs associated with the bridge facility	**—**	(3)	**—**	(21)
Net income (loss) applicable to common shares (GAAP financial measure)	**$ (103)**	$ 174	**$ 769**	$ (502)

Normalized net income represents net income (loss) applicable to common shares adjusted for the after-tax impact of unrealized gains (losses) on risk management contracts, losses on investments, transaction (costs) recoveries related to acquisitions and dispositions, merger commitment recovery (cost) primarily due to a change in timing related to certain WGL merger commitments, gains (losses) on the sale of assets, financing costs associated with the bridge facility for the WGL Acquisition, realized loss on foreign exchange derivatives, provisions on investments accounted for by the equity method, provisions on assets, a tax adjustment on assets that were held for sale, statutory tax rate change, unitary tax adjustment related to the acquisition of WGL and U.S. asset sales, gain on redemption of preferred shares, and changes in fair value of natural gas optimization inventory. This measure is presented in order to enhance the comparability of AltaGas' earnings, as it reflects the underlying performance of AltaGas' business activities.

Normalized Funds from Operations, AFFO, and UAFFO

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2019**	2018	**2019**	2018
Normalized utility adjusted funds from operations	**$ 241**	$ 192	**$ 573**	$ 460
Add (deduct):				
Utilities depreciation and amortization	**66**	63	**262**	166
Normalized adjusted funds from operations	**$ 307**	$ 255	**$ 835**	$ 626
Add (deduct):				
Net cash paid to (received from) non-controlling interests	**4**	(21)	**(34)**	(66)
Midstream and Power maintenance capital	**4**	4	**26**	30
Preferred dividends paid	**17**	17	**68**	67
Normalized funds from operations	**$ 332**	$ 255	**$ 895**	$ 657
Add (deduct):				
Transaction and financing recoveries (costs) related to acquisitions and dispositions	**4**	(12)	**(12)**	(63)
Merger commitment (costs) recovery	**(1)**	—	**4**	(182)
Current tax expense on asset sales	**(37)**	—	**(37)**	—
Funds from operations	**$ 298**	$ 243	**$ 850**	$ 412
Add (deduct):				
Net change in operating assets and liabilities	**(281)**	(301)	**(232)**	(487)
Asset retirement obligations settled	**(1)**	(2)	**(2)**	(4)
Cash from (used by) operations (GAAP financial measure)	**$ 16**	$ (60)	**$ 616**	$ (79)

Normalized funds from operations, normalized adjusted funds from operations, and normalized utility adjusted 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 are calculated from the Consolidated Statements of Cash Flows and are defined as cash from (used by) operations before net changes in operating assets and liabilities and expenditures incurred to settle asset retirement obligations. Normalized funds from operations is calculated based on cash from (used by) operations and adjusted for changes in operating assets and liabilities in the period and non-operating related expenses (net of current taxes) such as transaction and financing costs related to acquisitions, merger commitments, and current taxes due to asset sales. Normalized adjusted funds from operations is based on normalized funds from operations, further adjusted to remove the impact of cash transactions with non-controlling interests, Midstream and Power maintenance capital, and preferred share dividends paid. Normalized utility adjusted funds from operations is based on normalized adjusted funds from operations, further adjusted for Utilities segment depreciation and amortization.

Funds from operations, normalized funds from operations, normalized adjusted funds from operations, and normalized utility adjusted 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

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2019**	2018	**2019**	2018
Normalized income tax expense	**$ 29**	$ 21	**$ 74**	$ 46
Add (deduct) tax impact of:				
Transaction (costs) recoveries related to acquisitions and dispositions	**1**	(2)	**(2)**	(12)
Merger commitment recovery (cost)	**—**	—	**—**	(47)
Unrealized gains (losses) on risk management contracts	**(10)**	14	**(14)**	24
Changes in fair value of natural gas optimization inventory	**—**	—	**3**	(1)
Losses on investments	**—**	—	**—**	(10)
Gains (losses) on sale of assets	**14**	24	**61**	25
Provisions on assets	**(96)**	(9)	**(96)**	(167)
Provisions on investments accounted for by the equity method	**(6)**	(4)	**(18)**	(4)
Tax adjustment on assets held for sale	**—**	(104)	**—**	(104)
Statutory tax rate change	**1**	—	**(10)**	—
Unitary tax adjustment on acquisition of WGL and U.S. asset sales	**(19)**	—	**(19)**	—
Financing costs associated with the bridge facility	**—**	(1)	**—**	(8)
Investment tax credits related to distributed generation assets	**(1)**	(2)	**(7)**	(5)
Income tax recovery (GAAP financial measure)	**$ (87)**	$ (63)	**$ (28)**	$ (263)

Normalized income tax expense represents income tax recovery adjusted for the tax impact of unrealized gains (losses) on risk management contracts, losses on investments, transaction (costs) recoveries related to acquisitions and dispositions, merger commitment recovery (cost), gains (losses) on the sale of assets, financing costs associated with the bridge facility for the WGL Acquisition, provisions on investments accounted for by the equity method, provisions on assets, a tax adjustment on assets that were held for sale, statutory tax rate change, a unitary tax adjustment related to the acquisition of WGL and U.S. asset sales, distributed generation asset related investment tax credits, and changes in fair value of natural gas optimization inventory. This measure 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. Net debt is defined as short-term debt (excluding third-party project financing obtained for the construction of certain energy management services projects), plus current and long-term portions of long-term debt, 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.

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)	**2019**	2018	**2019**	2018
Normalized EBITDA	**$ 425**	$ 394	**$ 1,271**	$ 1,009
Add (deduct):				
Depreciation and amortization	**(109)**	(126)	**(438)**	(394)
Interest expense	**(77)**	(110)	**(346)**	(309)
Normalizing items impacting interest expense	**—**	4	**—**	28
Income tax recovery	**87**	63	**28**	263
Normalizing items impacting tax recovery	**(116)**	(84)	**(102)**	(309)
Accretion expenses	**(1)**	(3)	**(5)**	(11)
Foreign exchange gains (losses)	**(1)**	1	**(1)**	5
Non-controlling interest related to HLBV investments	**—**	(22)	**(8)**	(39)
Net (income) loss applicable to non-controlling interests	**(5)**	20	**(7)**	19
Preferred share dividends	**(17)**	(17)	**(68)**	(67)
Normalized net income	**$ 186**	$ 120	**$ 324**	$ 195

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.

	Three Months Ended December 31		Year Ended December 31	
($ millions, except where noted)	**2019**	2018	**2019**	2018
Normalized net income	**$ 186**	$ 120	**$ 324**	$ 195
Add (deduct):				
Normalized income tax expense	**29**	21	**74**	46
Net income (loss) applicable to non-controlling interests	**5**	(20)	**7**	(19)
Non-controlling interest related to HLBV investments	**—**	22	**8**	39
Preferred share dividends	**17**	17	**68**	67
Normalized net income before taxes	**$ 237**	$ 160	**$ 481**	$ 328
Normalized effective income tax rate (%) [1]	**12.2**	13.1	**15.4**	14.0

(1) Calculated as normalized income tax expense divided by normalized net income before taxes.

Results of Operations by Reporting Segment

Normalized EBITDA [1]	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2019**	2018	**2019**	2018
Utilities	**$ 244**	$ 232	**$ 657**	$ 426
Midstream	**171**	93	**501**	277
Power	**22**	76	**154**	320
Sub-total: Operating Segments	**$ 437**	$ 401	**$ 1,312**	$ 1,023
Corporate	**(12)**	(7)	**(41)**	(14)
	$ 425	$ 394	**$ 1,271**	$ 1,009

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

Revenue	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2019**	2018	**2019**	2018
Utilities	**$ 801**	$ 818	**$ 2,591**	$ 1,766
Midstream	**424**	489	**1,581**	1,435
Power	**319**	412	**1,367**	1,171
Sub-total: Operating Segments	**$ 1,544**	$ 1,719	**$ 5,539**	$ 4,372
Corporate	**—**	28	**—**	(2)
Intersegment eliminations	**(11)**	(20)	**(44)**	(113)
	$ 1,533	$ 1,727	**$ 5,495**	$ 4,257

Utilities

Operating Statistics

	Three Months Ended December 31		Year Ended December 31	
	2019	2018	**2019**	2018
Natural gas deliveries - end-use (Bcf) [1]	**52.2**	53.3	**159.4**	107.3
Natural gas deliveries - transportation (Bcf) [1]	**38.3**	39.1	**134.4**	89.2
Service sites (thousands) [2]	**1,653**	1,643	**1,653**	1,643
Degree day variance from normal - SEMCO Gas (%) [3]	**4.3**	7.5	**5.0**	5.6
Degree day variance from normal - ENSTAR (%) [3]	**(20.6)**	(19.6)	**(17.7)**	(11.5)
Degree day variance from normal - Washington Gas (%) [3] [4]	**(3.2)**	0.4	**(7.9)**	(2.5)

(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 Gas, during the prior 10 years for ENSTAR, and during the prior 30 years for Washington Gas.
(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	
	2019	2018
Approved ROE (%) (1)	**10.1**	10.6
Approved return on debt (%) (1)	**5.4**	5.4
Rate base *($ millions)* (2) (3) (4)	**3,865**	3,684

(1) Average of all the 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) Reflects AltaGas' 65 percent interest in Cook Inlet Natural Gas Storage Alaska LLC.
(4) In U.S. dollars

During the fourth quarter of 2019, AltaGas' Utilities segment experienced warmer weather at all of its jurisdictions compared to the same quarter in 2018. The increase in customers compared to the same period of 2018 represents the growth in customer base.

For the year ended December 31, 2019, AltaGas' Utilities segment experienced warmer weather at SEMCO and ENSTAR compared to 2018. Washington Gas also experienced warmer than normal weather. The increase in transportation represents the addition of Washington Gas natural gas deliveries for the first half of the year.

Service sites at December 31, 2019 increased by approximately 10 thousand sites compared to December 31, 2018 due to growth in customer base.

Three Months Ended December 31

The Utilities segment reported normalized EBITDA of $244 million in the fourth quarter of 2019, compared to $232 million in the same quarter in 2018. The increase in normalized EBITDA was mainly due to the impact of Washington Gas' 2018 and 2019 Maryland rate cases, positive impacts from the final decision in the Virginia rate case, and higher revenue from accelerated pipe replacement program spend, partially offset by higher operating expenses, the impact of the ACI IPO in 2018, warmer weather in Michigan and Alaska, and the unfavorable impact of the weaker U.S. dollar.

Year Ended December 31

On July 31, 2018, Washington Gas filed an application with the SCC of VA to increase its base rates for natural gas service. In September 2019, the Virginia Hearing Examiner assigned to Washington Gas' Virginia rate case issued a report with findings and recommendations to the SCC of VA, including the finding for no incremental revenues. In September 2019, the impact of these recommendations was recorded, resulting in a one-time reduction in normalized EBITDA of approximately $30 million and a reduction of approximately $14 million in net income after taxes. The adjustments included a lower ROE, a revised amortization period for returning excess deferred income taxes as a result of the *Tax Cuts and Jobs Act* (TCJA) combined with a one-time refund liability related to the effect of the TCJA in 2018, lower revenue from the Virginia SAVE program, and a one-time write-off of regulatory assets related to the utility distribution integrity management program (DIMP). On October 21, 2019, Washington Gas filed comments on and exceptions to the Hearing Examiner's report, recommending the SCC of VA reject certain of the Hearing Examiner's findings. On December 20, 2019, the Commission issued a Final Order adjusting certain of the Hearing Examiner's findings, some of which are favorable to Washington Gas, resulting in a $8 million increase to EBITDA in the fourth quarter of 2019. In January 2020, Washington Gas filed a petition for reconsideration regarding one of the findings in the Final Order. On January 30, 2020, the SCC of VA denied this request and the rate case is now final.

The Utilities segment reported normalized EBITDA of $657 million in the year ended December 31, 2019, compared to $426 million in 2018. The increase in normalized EBITDA was mainly due to a full year of contributions from Washington Gas, higher rates at Washington Gas related to the Maryland rate case impact, the favorable impact of the stronger U.S. dollar, growth in customer base, and colder weather in Michigan. The increase was partially offset by the impacts from the Virginia rate case, the impact of the ACI IPO in 2018, higher expenses at Washington Gas, lower storage revenue at CINGSA, the 2019 revenue impact related to the federal tax reduction at the U.S. utilities, and warmer weather in Alaska.

Rate Case Updates

Utility/ Jurisdiction	Date Filed	Request	Status	Expected Timing of Decision
Washington Gas - Maryland	May 2018	US$56 million increase in base rates, including US$15 million in annual surcharges currently paid by customers for system upgrades.	In December 2018, the PSC of MD approved a rate increase of US$29 million (vs. US$56 million requested). Washington Gas requested a rehearing on two of the issues. In June 2019, the PSC of MD issued an order partially allowing for approximately US$1 million of overtime in its revenue adjustment and denied the other item.	Complete
Washington Gas - Maryland	April 2019	US$36 million increase in base rates, of which US$5 million relates to costs being collected through the monthly STRIDE surcharges for system upgrades.	A settlement agreement was filed for a US$27 million rate increase (vs. US$36 million applied for). Approval was received from the PSC of MD in October 2019.	Complete
Washington Gas - Virginia	July 2018	US$38 million increase in base rates, of which approximately US$15 million relates to costs being collected through the monthly SAVE surcharges for accelerated pipeline replacement.	The SCC of VA Hearing Examiner's report was issued in September 2019 recommending no incremental revenue increase and Washington Gas comments were provided on October 21, 2019. On December 20, 2019, the Commission issued a Final Order adjusting certain of the Hearing Examiner’s findings, some of which are favorable to Washington Gas but still resulted in no incremental revenue increase. In January 2020, Washington Gas filed a petition for rehearing regarding one of the findings. On January 30, 2020, the SCC of VA denied this request and the rate case is now final.	Complete
Washington Gas - District of Columbia	January 2020	US$35 million increase in base rates, including US$9 million of annual PROJECT*pipes* surcharges currently paid by customers for accelerated pipeline replacement.	Washington Gas filed this rate case on January 13, 2020. Washington Gas has also requested approval for a Revenue Normalization Adjustment mechanism to reduce customer bill fluctuations due to weather-related usage variations, similar to existing mechanisms in both Maryland and Virginia. A conference to discuss process schedule is expected to be held in March 2020.	Not yet known
CINGSA - Alaska	April 2018	US$4 million reduction in rates, due to lower rate base, lower returns on equity, and lower federal income tax.	A decision was received in August 2019. The decision included an ROE of 10.25% (compared to 11.875% requested) and 100% of Interruptible Storage Service revenues payable to customers (versus 50% requested). CINGSA filed a petition for partial reconsideration on September 3, 2019. The Commission denied the petition and CINGSA partially appealed the Commission's decision to the Superior Court.	Complete
SEMCO - Michigan	May 2019	US$38 million increase in base rates.	In November 2019, a settlement agreement was filed for an approximately US$20 million rate increase (vs. US$38 million applied for) and an allowed return on equity of 9.87 percent. The MPSC approved the settlement in December 2019 and the new rates were effective January 1, 2020.	Complete

Midstream

Operating Statistics

	Three Months Ended December 31		Year Ended December 31	
	2019	2018	**2019**	2018
Total inlet gas processed (Mmcf/d) (1)	**1,413**	1,413	**1,407**	1,378
Extraction ethane volumes (Bbls/d) (1)	**25,951**	25,448	**23,826**	24,346
Extraction NGL volumes (Bbls/d) (1) (2)	**34,354**	39,074	**37,546**	38,128
Total extraction volumes (Bbls/d) (1) (3)	**60,305**	64,522	**61,372**	62,474
Frac spread - realized ($/Bbl) (1) (4)	**16.54**	15.84	**17.47**	16.49
Frac spread - average spot price ($/Bbl) (1) (5)	**8.29**	21.00	**11.05**	22.79
RIPET export volumes (Bbls/d) (1) (6)	**36,394**	—	**35,446**	—
Propane Far East Index (FEI) to Mont Belvieu spread (US$/Bbl) (1) (7)	**17.95**	—	**14.88**	—
Natural gas optimization inventory (Bcf)	**41.4**	30.8	**41.4**	30.8
WGL retail energy marketing - gas sales volumes (Mmcf)	**20,131**	20,750	**64,460**	28,906

(1) Average for the period.

(2) NGL volumes refer to propane, butane, and condensate.

(3) Includes Harmattan NGL processed on behalf of customers.

(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 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 exposed volumes for the period.

(6) Energy export volumes represents propane volumes exported at RIPET since facility was placed into service in May 2019.

(7) Average propane spot price spread between Argus Far East Index and Mont Belvieu TET commercial index for the period beginning May 2019.

With RIPET commencing operations in late May 2019, propane volumes exported to Asia for the three months and year ended December 31, 2019 averaged 36,394 Bbls/d and 35,446 Bbls/d, respectively. There were 6 shipments in the fourth quarter of 2019 and 15 shipments in total for the year.

Inlet gas processing volumes were unchanged at 1,413 Mmcf/d for the fourth quarter of 2019, consistent with the same quarter of 2018. Factors positively impacting inlet gas processing volumes in the fourth quarter of 2019 included new volumes from the recently constructed Nig Creek facility which was placed in-service in September 2019, higher volumes at EEEP due to downstream gas demand, and higher volumes at Younger. These increases were offset by the disposal of certain non-core facilities in the first quarter of 2019 and lower volumes at the Townsend complex.

Inlet gas processing volumes for the year ended December 31, 2019 increased by 29 Mmcf/d compared to 2018. The increase was primarily due to a full year of operations at the Aitken Creek North facility and new volumes from the Nig Creek facility, higher volumes at Harmattan Co-stream, and new volumes from the Eagle Hill facility at Harmattan, partially offset by the disposition of certain non-core facilities in the first quarter of 2019.

Average ethane production volumes for the fourth quarter of 2019 increased by 503 Bbls/d, while average NGL production volumes decreased by 4,720 Bbls/d compared to the same quarter in 2018. Higher ethane volumes were a result of higher contracted ethane volumes at EEEP, partially offset by reinjected ethane production volumes at Harmattan and PEEP. Lower NGL volumes were a result of lower inlet volumes at the Townsend complex, Blair Creek, and the disposition of certain non-core facilities in the first quarter of 2019, partially offset by higher NGL volumes at EEEP due to higher inlet.

Average ethane production volumes for the year ended December 31, 2019 decreased by 520 Bbls/d, and average NGL production volumes decreased by 582 Bbls/d compared to 2018. Lower ethane volumes were a result of reinjected ethane production volumes at Harmattan and Younger due to uneconomic pricing in the first half of 2019, partially offset by new contracted ethane volumes at EEEP, and higher volumes at JEEP and PEEP due to higher inlet. Lower NGL volumes were a result of temporary outages in 2019 and reduced ownership interest at the Younger facility, and the disposition of certain non-core facilities in the first quarter of 2019, partially offset by additional volumes produced from EEEP and the Townsend complex.

For the fourth quarter of 2019, U.S. retail sales volumes were 20,131 Mmcf, compared to 20,750 Mmcf in the same period of 2018. The decrease was primarily due to warmer weather in the fourth quarter of 2019 compared to the same period of 2018.

For the year ended December 31, 2019, U.S. retail sales volumes were 64,460 Mmcf, compared to 28,906 Mmcf in the same period of 2018. The increase in retail sale volumes was primarily due to the addition of WGL volumes for the first half of 2019.

Natural gas optimization inventory as at December 31, 2019 was 41.4 Bcf (December 31, 2018 - 30.8 Bcf). The increase in natural gas optimization inventory was primarily due to lower withdrawals of inventory in the fourth quarter of 2019 as a result of lower natural gas prices.

Three Months Ended December 31

The Midstream segment reported normalized EBITDA of $171 million in the fourth quarter of 2019, compared to $93 million in the same quarter in 2018. The increase was mainly due to contributions from RIPET which was placed in-service in May 2019, higher NGL revenues due to higher netbacks, favorable U.S. storage results, higher margins from WGL's retail gas business, higher AFUDC related to Mountain Valley, and contributions from the Nig Creek facility which was placed in-service in September 2019. These were partially offset by the impact of the sale of WGL Midstream's indirect non-operating interest in Central Penn in November 2019, the impact of the sale of Stonewall in the second quarter of 2019, the disposition of certain non-core facilities in the first quarter of 2019, and lower third-party volumes and rates at Townsend. During the fourth quarter of 2019, AltaGas recorded equity earnings of $31 million from Petrogas compared to $5 million in the same quarter of 2018, mainly due to higher export volumes and improved export margins together with improved contributions from Petrogas' other core business segments. In addition, Petrogas earnings included a one-time payment related to the termination of a customer contract.

During the fourth quarter of 2019, AltaGas hedged approximately 6,228 Bbls/d of NGL volumes at an average price of $40/Bbl excluding basis differentials. During the fourth quarter of 2018, AltaGas hedged 7,500 Bbls/d of NGL at an average price of $33/Bbl, excluding basis differentials. The average indicative spot NGL frac spread for the fourth quarter of 2019 was approximately $8/Bbl, compared to $21/Bbl in the same quarter of 2018 inclusive of basis differentials. The realized frac spread of approximately $17/Bbl in the fourth quarter of 2019 (2018 - $16/Bbl) was higher than the same period in 2018 due to frac hedge gains. For RIPET, during the fourth quarter of 2019, AltaGas hedged approximately 23,070 Bbls/d of propane export volumes at the FEI to Mont Belvieu spread of US$10/Bbl.

During the fourth quarter of 2019, the Midstream segment recorded a pre-tax provision of $35 million related to the Pouce Coupe sour gas treatment facility in Alberta. In addition, the Midstream segment recognized a pre-tax loss of $11 million on the sale of WGL Midstream's indirect non-operating interest in Central Penn. During the fourth quarter of 2018, the Midstream segment recognized a pre-tax provision of $2 million on certain non-core Midstream assets.

Year Ended December 31

The Midstream segment reported normalized EBITDA of $501 million in the year ended December 31, 2019, compared to $277 million in 2018. The increase in normalized EBITDA was due to contributions from RIPET which was placed in-service in May 2019, a full year of contributions from WGL Midstream assets and the WGL retail marketing business, higher AFUDC related to Mountain Valley, higher margins from WGL's retail gas business, the full year impact from the acquisition of the Aitken Creek North facility, contributions from the Nig Creek facility which was placed in-service in September 2019, higher NGL revenues due to higher netbacks, and higher revenues at Harmattan due to increased NGL activities. These were partially offset by the disposition of certain non-core facilities in the first quarter of 2019, the impact of the sale of Stonewall in the second quarter of 2019, and lower revenues at Younger due to change in operatorship. During the year ended December 31, 2019, AltaGas recorded equity earnings of $75 million from Petrogas, compared to $15 million in 2018. The increase in Petrogas earnings was due to higher export volumes and margins at the Ferndale terminal, the absence of the 2018 planned turnaround, and improved contributions from Petrogas' other core business segments. In addition, Petrogas earnings in the fourth quarter of 2019 included a payment related to a termination of a customer contract.

During the year ended December 31, 2019, AltaGas hedged approximately 6,228 Bbls/d of NGL volumes at an average price of $40/Bbl, excluding basis differentials. For the year ended December 31, 2018, AltaGas hedged 7,500 Bbls/d of NGL at an average price of $33/Bbl, excluding basis differentials. The average indicative spot NGL frac spread for year ended December 31, 2019 was approximately $11/Bbl compared to $23/Bbl in 2018 inclusive of basis differentials. The realized frac spread of $17/Bbl for the year ended December 31, 2019 (2018 - $16/Bbl) was higher than the same period in 2018 due to frac hedge gains. For RIPET, during the year ended December 31, 2019, AltaGas hedged approximately 21,106 Bbls/d of propane export volumes at the FEI to Mont Belvieu spread of US$11/Bbl.

During the year ended December 31, 2019, AltaGas recognized a pre-tax gain of $34 million on the disposition of WGL Midstream's equity investment in Stonewall, a pre-tax gain of $5 million on the sale of remaining non-core Midstream processing facilities, and a pre-tax loss of $11 million on the sale of WGL Midstream's indirect non-operating interest in Central Penn. During the year ended December 31, 2018, AltaGas recognized a pre-tax gain of $1 million on the sale of a non-core gas processing facility, as well as a realized loss of $2 million on the sale of its investment in Tidewater Midstream and Infrastructure Inc.

During the year ended December 31, 2019, AltaGas recognized pre-tax provisions of $35 million in the Midstream segment related to the Pouce Coupe sour gas treatment facility in Alberta. Also, during the year ended December 31, 2019, AltaGas recognized a pre-tax provision on equity investments of $44 million in the Midstream segment related to the sale of WGL Midstream's indirect non-operating interest in Central Penn. During the year ended December 31, 2018, AltaGas recognized pre-tax provisions of $117 million on certain non-core Midstream assets that were classified as held for sale, and a pre-tax impairment of $37 million related to shut-in assets in the South, Cold Lake, and Northwest operating areas.

Power

Operating Statistics

	Three Months Ended December 31		Year Ended December 31	
	2019	2018	**2019**	2018
Renewable power sold (GWh)	**10**	233	**616**	1,551
Conventional power sold (GWh)	**478**	985	**1,793**	3,728
Renewable capacity factor (%)	**11.4**	14.6	**17.7**	29.7
Contracted conventional equivalent availability factor (%) (1)	**92.9**	97.4	**75.4**	97.2
WGL retail energy marketing - electricity sales volumes (GWh)	**3,291**	2,911	**13,218**	5,906

(1) Calculated as the availability factor contracted under long-term tolling arrangements adjusted for occasions where partial or excess capacity payments have been added or deducted.

During the fourth quarter of 2019, the volume of renewable power sold decreased by 223 GWh and the volume of conventional power sold decreased by 507 GWh compared to the same quarter in 2018. The decrease in renewable volumes was primarily due to asset sales, including the sale of Northwest Hydro in January 2019, the Bear Mountain wind facility in October 2018, and the WGL distributed generation business in September 2019. The decrease in conventional volumes sold was primarily due to the sale of the San Joaquin facilities in November 2018 and the sale of AltaGas' interest in the biomass facilities in August 2019.

The contracted conventional equivalent availability factor was slightly lower for the fourth quarter of 2019 as a result of a minor planned outage at Blythe during October. The renewable capacity factor was lower for the fourth quarter of 2019 due to the sale of the Northwest Hydro facilities, the Bear Mountain wind facility, and the majority of the WGL distributed generation business.

U.S. retail sales volumes were 3,291 in the fourth quarter of 2019, compared to 2,911 GWh in the same period of 2018. The increase was primarily due to an increase in customers served by the business.

For the year ended December 31, 2019, the volume of renewable power sold decreased by 935 GWh and the volume of conventional power sold decreased by 1,935 GWh. The change in volumes was primarily due to the same reasons as noted above for the fourth quarter of 2019.

The renewable capacity factor variance for the year ended December 31, 2019 was due to the same factors as noted above for the fourth quarter of 2019, while the contracted conventional availability factor variance for the same period was due to the same factors as noted above for the fourth quarter of 2019, as well as an extended planned outage at the Blythe facility during the spring of 2019.

For the year ended December 31, 2019, U.S. retail sales volumes were 13,218 GWh, compared to 5,906 in the same period of 2018. The increase was primarily due to the addition of WGL for the first half of the year and the previously mentioned factors impacting the fourth quarter of 2019.

Three Months Ended December 31

The Power segment reported normalized EBITDA of $22 million during the fourth quarter of 2019, compared to $76 million the same quarter in 2018. Normalized EBITDA decreased as a result of the impact of asset sales, including Northwest Hydro (January 2019), the San Joaquin facilities (November 2018), Canadian non-core Power assets (February 2019), the Biomass facilities (August 2019), the Busch Ranch facility (December 2018), and the WGL distributed generation business (September 2019). These decreases were partially offset by higher contributions to EBITDA from WGL retail energy marketing due to higher volumes and improved margins compared to the same period in 2018.

In the fourth quarter of 2019, certain additional distributed generation projects were transferred to the purchaser, resulting in a pre-tax gain of $68 million. Also in the fourth quarter of 2019, pre-tax provisions of $380 million were recorded related to various assets in the Power segment. During the fourth quarter of 2018, the Power segment recorded pre-tax provisions on assets of $6 million related to a WGL Energy Systems financing receivable that was classified as held for sale at December 31, 2018, and $23 million related to a development project in the U.S.

Year Ended December 31

The Power segment reported normalized EBITDA of $154 million in the year ended December 31, 2019, compared to $320 million in 2018. Normalized EBITDA decreased primarily for the same reasons noted above for the fourth quarter of 2019. Other events contributing to decreased normalized EBITDA for the year included the extended major planned outage at the Blythe facility impacting the first quarter and second quarter of 2019, and the sale of the Bear Mountain facility in October 2018, partially offset by the full year of contributions from WGL's Power business.

Asset sales completed in 2019 included the sale of the U.S. portfolio of distributed generation assets resulting in a pre-tax gain of $168 million, the sale of the remaining interest in the Northwest Hydro facilities resulting in a pre-tax gain of $688 million, the sale of Canadian non-core Power assets resulting in a pre-tax loss of $6 million, and the sale of a WGL Energy Systems financing receivable resulting in a pre-tax loss of $1 million. Other asset sales completed in 2019 include the sale of AltaGas' equity ownership interest in two biomass plants in the United States for net cash proceeds of approximately US$18 million and the sale of a capital spare for proceeds of US$4 million. There were no gains or losses recorded on the dispositions of the biomass assets or the capital spare.

In the year ended December 31, 2019, AltaGas recognized pre-tax provisions on various assets in the Power segment of approximately $381 million. In addition, a pre-tax provision on equity investments of $2 million was recorded in 2019 related to biomass investments which were sold in the third quarter of 2019. During the year ended December 31, 2018, the Power segment recorded pre-tax provisions on assets of $381 million, including approximately $340 million for the Tracy, Hanford and Henrietta gas-fired power assets in California, $10 million for certain gas-fired peaking plants in Alberta, $6 million related to a WGL Energy Systems financing receivable that was classified as held for sale at December 31, 2018, $23 million related to a development project in the U.S, and $2 million related to the Pomona Repowering project. During the year ended December 31, 2018, the Power segment also recorded a provision on equity investments of $15 million related to investments in biomass assets in the U.S.

Corporate

Three Months Ended December 31

In the Corporate segment, normalized EBITDA for the fourth quarter of 2019 was a loss of $12 million, compared to a loss of $7 million in the same quarter in 2018. The increased loss was mainly due to higher expenses related to employee incentive plans, and lower interest income due to the absence of interest earned on loans provided to ACI subsequent to its IPO.

Year Ended December 31

In the Corporate segment, normalized EBITDA for the year ended December 31, 2019 was a loss of $41 million, compared to a loss of $14 million in 2018. The increased loss was a result of a number of factors, including higher expenses related to employee incentive plans as a result of the increasing share price in 2019, lower interest income due to the absence of interest earned on funds that were held in escrow for the WGL Acquisition in 2018 and on loans provided to ACI, and higher information technology related costs.

Invested Capital

					Three Months Ended December 31, 2019
($ millions)	Utilities	Midstream	Power	Corporate	Total
Invested capital:					
Property, plant and equipment	$ 145	$ 93	$ 2	$ —	$ 240
Intangible assets	21	1	—	2	24
Long-term investments	—	3	—	—	3
Contributions from non-controlling interest	—	(7)	—	—	(7)
Invested capital	166	90	2	2	260
Disposals:					
Property, plant and equipment	(1)	—	—	—	(1)
Equity method investments	—	(812)	—	—	(812)
Net invested capital	$ 165	$ (722)	$ 2	$ 2	$ (553)

($ millions)		Utilities		Midstream		Power		Corporate		Three Months Ended December 31, 2018 Total
Invested capital:										
Property, plant and equipment	$	177	$	217	$	14	$	2	$	410
Intangible assets		18		1		—		4		23
Long-term investments		—		150		—		—		150
Contributions from non-controlling interest		—		(14)		—		—		(14)
Invested capital		195		354		14		6		569
Disposals:										
Property, plant and equipment		—		—		(394)		—		(394)
Net invested capital	$	195	$	354	$	(380)	$	6	$	175

During the fourth quarter of 2019, AltaGas' invested capital was $260 million, compared to $569 million in the same quarter in 2018. The decrease in invested capital was primarily due to lower additions to property, plant and equipment and lower contributions to WGL's equity investments in the Mountain Valley pipeline and Central Penn which was sold in November 2019.

The decrease in additions to property, plant and equipment in the fourth quarter of 2019 was mainly due to the absence of construction costs related to RIPET which was placed in-service in May 2019, and the acquisition of 50 percent ownership in Black Swan's Aitken Creek North gas processing facility in the fourth quarter of 2018. The disposal of equity method investments in the fourth quarter of 2019 related to the disposition of Central Penn in November 2019. The disposals of property, plant and equipment in 2018 primarily related to the disposition of the San Joaquin facilities in California, the Busch Ranch wind farm in Colorado, and a development stage wind asset.

The invested capital in the fourth quarter of 2019 included maintenance capital of $3 million (2018 - $2 million) in the Midstream segment and $1 million (2018 - $2 million) in the Power segment. Maintenance capital incurred in the fourth quarter of 2019 primarily related to maintenance at the Harmattan facility.

($ millions)		**Utilities**		**Midstream**		**Power**		**Corporate**		**Year Ended December 31, 2019 Total**
Invested capital:										
Property, plant and equipment	**$**	**841**	**$**	**438**	**$**	**38**	**$**	**1**	**$**	**1,318**
Intangible assets		**23**		**5**		**—**		**9**		**37**
Long-term investments		**—**		**179**		**—**		**—**		**179**
Contributions from non-controlling interest		**—**		**(41)**		**—**		**—**		**(41)**
Invested capital		**864**		**581**		**38**		**10**		**1,493**
Disposals:										
Property, plant and equipment		**(1)**		**(87)**		**(2,319)**		**—**		**(2,407)**
Equity method investments		**—**		**(1,191)**		**(25)**		**—**		**(1,216)**
Net invested capital	**$**	**863**	**$**	**(697)**	**$**	**(2,306)**	**$**	**10**	**$**	**(2,130)**

Year Ended December 31, 2018					
($ millions)	Utilities	Midstream	Power	Corporate	Total
Invested capital:					
Property, plant and equipment	$ 507	$ 391	$ 74	$ 4	$ 976
Intangible assets	22	5	12	7	46
Long-term investments	—	228	—	—	228
Business acquisition	4,682	1,525	892	(1,168)	5,931
Contributions from non-controlling interest	—	(49)	—	—	(49)
Invested capital	5,211	2,100	978	(1,157)	7,132
Disposals:					
Property, plant and equipment	—	(8)	(395)	—	(403)
Net invested capital	$ 5,211	$ 2,092	$ 583	$ (1,157)	$ 6,729

During the year ended December 31, 2019, AltaGas' invested capital was $1.5 billion, compared to $7.1 billion in 2018. The decrease in invested capital in the year ended December 31, 2019 was mainly due to the absence of the 2018 cash payment of $5.9 billion for the WGL acquisition, partly offset by higher additions to property, plant and equipment and contributions to WGL's investments in the Central Penn and Mountain Valley pipelines. Net invested capital expenditures (excluding disposals, utility asset removal costs, and certain contributions to equity investments) were approximately $1.39 billion in 2019. This was slightly higher than the previously estimated range of $1.3 to $1.36 billion due to accelerated timing on certain growth capital projects and the timing of close of certain asset sales.

The increase in additions to property, plant and equipment in the year ended December 31, 2019 was mainly due to capital expenditures related to system betterment and accelerated pipeline replacement programs at Washington Gas, construction of the Marquette Connector pipeline, construction costs at RIPET, construction of Nig Creek and the Townsend expansion, and capital expenditures related to WGL's distributed generation projects. The disposals of property, plant and equipment for the year ended December 31, 2019 primarily related to the Northwest Hydro facilities, certain non-core Canadian Midstream and Power assets, and WGL's distributed generation projects, while in 2018 the disposals of property, plant, and equipment related to the disposition of the San Joaquin facilities in California, the Busch Ranch wind farm in Colorado, a development stage wind asset, and certain other non-core facilities in the Midstream segment. The disposals of equity method investments in 2019 related to the disposition of Stonewall in May 2019, the disposition of biomass investments in August 2019, and the disposition of Central Penn in November 2019.

The invested capital for the year ended December 31, 2019 included maintenance capital of $6 million (2018 - $17 million) in the Midstream segment and $20 million (2018 - $13 million) in the Power segment. The decrease in maintenance capital for the Midstream segment was primarily due to reduced turnaround expenditures. The increase in maintenance capital for the Power segment was primarily due to a planned turnaround at the Blythe facility.

Risk Management

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. 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, 2019 and December 31, 2018, the fair values of the Corporation's derivatives were as follows:

($ millions)		**December 31, 2019**		December 31, 2018
Natural gas	**$**	**(77)**	$	(137)
Energy exports		**(75)**		—
NGL frac spread		**(2)**		16
Power		**(12)**		(9)
Foreign exchange		**—**		(1)
Net derivative liability	**$**	**(166)**	$	(131)

Summary of Risk Management Contracts

Commodity Price Contracts

The Corporation executes gas, power, 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 i) designated as "normal purchases and normal sales", ii) do not qualify as derivative instruments due to the significance of their notional amount relative to the applicable liquid markets, or iii) 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 power, natural gas, and NGL contracts that qualify as derivatives was calculated using estimated forward prices based on published sources for the relevant period. AltaGas has not elected hedge accounting for any of its derivative contracts currently in place. For AltaGas' Midstream and Power segments, changes in the fair value of these derivative contracts are recorded in the Consolidated Statements of Income (Loss) 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 (Loss) 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, 2019 was approximately $11/Bbl (2018 – $23/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, 2019 was approximately $17/Bbl inclusive of basis differentials (2018 - $16/Bbl).
- For 2020, AltaGas estimates an average of approximately 10,000 Bbls/d of NGL will be exposed to frac spreads prior to hedging activities. Pricing risk related to frac exposed propane is mitigated through export and the hedging program in place at RIPET. Hedges are in place for approximately 80 percent of frac exposed butane and condensate volumes.
- At RIPET, AltaGas is exposed to the propane price differential between North American Indices and the Far East Index for contracts not under tolling arrangements. AltaGas estimates an average of approximately 30,000 Bbls/d will be exposed to these price differentials in 2020. To date for 2020, AltaGas has hedges in place for approximately 74 percent of these exposed propane volumes at an average FEI to Mont Belvieu spread of US$11/Bbl.

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. To serve retail customers, AltaGas enters into retail sales contracts that contain optionality as well as physical and financial contracts which qualify as derivative instruments.

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.

The Power segment has various fixed-for-floating power purchase and sale contracts in the Alberta market, which are expected to be settled over the next five years. Additionally, to serve retail electric customers, AltaGas enters into both physical and financial contracts for the purchase and sale of electricity.

<u>Foreign Exchange Contracts</u>

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 and/or preferred shares outstanding. AltaGas may also enter into foreign exchange forward derivatives to manage the risk of fluctuating cash flows due to variations in foreign exchange rates.

- As at December 31, 2019, Management has designated US$300 million of outstanding U.S. dollar denominated long-term debt to hedge against the currency translation effect of its foreign investments (December 31, 2018 - US$1.5 billion).
- For the year ended December 31, 2019, AltaGas incurred an after-tax unrealized gain of $60 million arising from the translation of debt in other comprehensive income (2018 - after-tax unrealized loss of $80 million).

<u>Interest Rate Contracts</u>

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. As a result, AltaGas reduces its interest expense by taking advantage of the interest rate spread between the Banker's Acceptance (BA) rate and the London Inter-bank Offered Rate (LIBOR) without any additional foreign exchange risk.

<u>Weather Instruments</u>

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, 2019, a pre-tax loss of $2 million (2018 - pre-tax loss of $1 million) was recorded related to heating degree day (HDD) and cooling degree day (CDD) instruments.

The Effects of Derivative Instruments on the Consolidated Statements of Income (Loss)

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

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2019**	2018	**2019**	2018
Natural gas	**$ 14**	$ 13	**$ 23**	$ (2)
Energy exports	**(65)**	—	**(87)**	—
NGL frac spread	**(11)**	45	**(17)**	40
Power	**(2)**	12	**(5)**	9
Foreign exchange	**—**	(1)	**1**	34
	$ (64)	$ 69	**$ (85)**	$ 81

Please refer to Note 23 of the 2019 Annual Consolidated Financial Statements for further details regarding AltaGas' risk management activities.

Corporation Risks

AltaGas manages its exposure to risks using the strategies outlined in the following table:

Risks	Strategies and Organizational Capability to Mitigate Risks
Operations	• Maintain safe and reliable operations • Ensure appropriate policies, procedures, and systems are in place and internal controls are operating efficiently • Programs to manage pipeline system integrity including accelerated replacement of aging pipeline and infrastructure based on risk mitigation • Contractual provisions often provide for recovery of operating costs • Centralized procurement strategy to reduce costs • Maintain control over operational decisions, operating costs, and capital expenditures by operating certain jointly-owned facilities • Maintain standard operating practices, assess and document employee competency, and maintain formal inspection, maintenance, environmental, health, and safety programs • Carry property and business interruption insurance • Fixed price operating and maintenance contracts with equipment manufacturers • Hedging strategy used to balance price and operating risk
Environment, Health and Safety	• Measure, monitor emissions and seek new technologies to reduce greenhouse gas (GHG) emissions from operations • Programs in place to reduce fugitive methane emissions • Projects designed to limit impacts and throughout operations, monitor land, air, and water quality, where appropriate • Strong process safety management systems • Pipeline and asset integrity programs in place • Accelerated replacement of mature pipeline infrastructure • Preventative and remedial measures to address increased leak rates within Washington Gas' distribution system • Continuous process improvement strategy employed • Comprehensive Environmental, Health and Safety management system to protect people • Purchase and maintain general liability and business interruption insurance

Risks	Strategies and Organizational Capability to Mitigate Risks
Regulatory and Stakeholder	• Strong working relationships with regulatory authorities • Regulatory and commercial personnel monitor and manage regulatory issues • Development of consistent framework for stakeholder communication and community consultation • Safe Digging campaign, emergency preparedness and 24/7 Gas Control and dispatch to protect utility customers and public • Public ESG disclosure and key ESG performance data updates • Utilities seek rate recovery through rate cases with regulatory commissions and agencies
Legislative	• Ongoing identification of public policy issues to determine risks to the Corporation • Development of advocacy strategies to address risks • Where appropriate, engagement in advocacy at the state/provincial and federal level including joint participation with trade associations
Liquidity	• Forecast cash flow on a continuous basis to maintain adequate cash balances to fund financial obligations as they come due and to support business operations • Maintain financial flexibility and access to multiple credit facilities and continually monitor covenant compliance • Execute financing plans and strategies to maintain and improve credit ratings to minimize financing costs and support ready access to capital markets
Foreign exchange	• Issue long-term debt and preferred shares in U.S. dollars which hedge the Corporation's net investment in U.S. subsidiaries • Employ hedging practices when appropriate, such as entering foreign exchange forward contracts
Interest rates	• Optimize financing plans to maintain and improve credit ratings to minimize interest costs • Monitor and proactively manage the Corporation's debt maturity profile • Employ hedging practices such as entering into interest rate swaps • Monitor and manage the mix of fixed versus floating rate debt exposures
Credit ratings	• Maintain open dialogue with credit rating agencies and request feedback to understand any potential implications to the Corporation's credit rating
Information security	• Strong identity and access management controls • Improved information management and control of electronic and physical information, in accordance with data classification, data handling, privacy regulations, and data retention requirements • Ongoing cybersecurity communication and phishing tests, including targeted training to higher risk teams and individuals • Implementation of new information security standards and policies • Procedures to ensure regulatory compliance • Enhanced penetration and vulnerability testing • Incident response protocols
Construction	• Major projects group manages and monitors significant construction projects • Strong in-house project control and management framework • Appropriate internal management structure and processes • Engage specialists in designing and building major projects • Contractual arrangements to mitigate cost and schedule risks

Risks	Strategies and Organizational Capability to Mitigate Risks
Long-term natural gas volume declines	• Long-term contracts such as take-or-pay, area of mutual interest, geographic franchise with economic out • Increase market share by expanding existing facilities or acquiring or constructing new facilities in productive resource play regions • Increase geographic and customer diversity to reduce exposure to any one individual customer or area of the WCSB • Strategically locate facilities to provide secure access to gas supply • Capitalize on integrated aspects of AltaGas' business to increase volumes through its processing facilities
Commodity price	• Contracting terms and processing, storage, and transportation fees independent of commodity prices through fee-for-service, take-or-pay, fixed-fee, or cost-of-service provisions • Hedging strategy to reduce exposure to commodity prices and earnings volatility with hedge targets approved by the Board of Directors and monitor hedge transactions through Risk Management Committee • Regulatory recovery mechanisms for gas purchases to serve utility customers • Matching natural gas and electricity purchase obligations with sales commitments in terms of volume and pricing • AltaGas' Commodity Risk Policy prohibits transactions for speculative purposes • Employ strong systems and processes for monitoring and reporting compliance with the Commodity Risk Policy • In-depth knowledge and experience of transportation systems, natural gas, NGL, and power markets where AltaGas operates • Hedge power costs • Direct marketing to end-use commercial and industrial customers • Execute long-term inflation adjusted electricity purchase arrangements with power buyers
Counterparty	• Strong credit policies and procedures • Continuous review of counterparty creditworthiness • Establish credit thresholds using appropriate credit metrics • Closely monitor exposures and impact of price shocks on liquidity • Build a diverse customer and supplier base • Active accounts receivable monitoring and collections processes in place • Credit terms, netting arrangements, and margining provisions included in contractual agreements
Weather	• Anticipated volumes for SEMCO Gas and ENSTAR are determined based on the 15-year and 10- year rolling average for weather, respectively • In Maryland and Virginia, Washington Gas has in place regulatory mechanisms and rate designs that eliminate deviations in customer usage caused by variations in weather from normal levels • Use of weather derivative instruments by WGL Energy Services
Labor relations	• Maintain access to strong labor markets to attract qualified talent • Positive employee relations to retain existing talent and maintain strong relations with unions
Litigation	• Proactive management of lawsuits and other claims • Continuous monitoring of defense and settlement costs of lawsuits and claims • Experienced in-house legal department • Use of expert third parties when needed
Compliance with regulations and Section 404(a) of the *Sarbanes-Oxley Act of 2002*	• Experienced in-house legal department • Use of expert third parties when needed • Ensure appropriate policies, procedures, and systems are in place and internal controls are operating effectively • Continuous monitoring of laws and regulations in applicable jurisdictions • Continuous monitoring of the related rules of the Securities Exchange Commission and the Public Company Accounting Oversight Board

Risks	Strategies and Organizational Capability to Mitigate Risks
Adequate natural gas supply and storage capacity to meet customer demand	• Maintain diverse capacity portfolio of firm transportation, storage, and peaking services across different transmission lines for supply flexibility • Capacity reserve portfolio maintained for maximum forecasted load under extreme conditions plus a reserve margin approved by regulators
Natural disasters and catastrophic events, including terrorist acts	• Maintain a comprehensive insurance program that covers losses from natural disasters and catastrophic events such as fires, earthquakes, explosions, floods, tornados, terrorist acts, and other similar occurrences. This program provides a risk transfer mechanism that facilitates timely recovery from losses and mitigates financial impact
Government trade policy	• Supply chain personnel monitor potential impacts of government trade policy and tariffs on costs for goods used in the normal course of business
Non-controlling interest in pipeline investments	• Invest in pipeline projects where the developer/builder/operator of the projects are experienced companies with a history of successful project completion • Engage specialists in reviewing project assumptions • Structure investment agreements to provide mitigation for cost overruns • Ensure the structure of the project governance requires timely information flow regarding project status • In-house regulatory affairs and public policy resources to validate the information from the developer/builder/operator • Appropriate internal management structure and processes
Volume of power generated	• PPA for the Blythe facility includes specified target availability levels and pay fixed capacity payments upon achieving target availability, and as a result, volumes of power sold have a minimal impact on the Corporation

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 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)	**2019**	2018
Cash from (used by) operations	**$ 616**	$ (79)
Investing activities	**2,184**	(5,834)
Financing activities	**(2,874)**	5,987
Increase (decrease) in cash, cash equivalents, and restricted cash	**$ (74)**	$ 74

Cash From (Used by) Operations

Cash from (used by) operations increased by $695 million for the year ended December 31, 2019 compared to 2018, primarily due to higher net income after taxes, higher distributions from equity investments, and a favorable variance in the net change in operating assets and liabilities. The majority of the variance in net change in operating assets and liabilities was due to the addition of WGL's operating assets and liabilities in the third quarter of 2018 and the impact of asset sales completed in late 2018 and throughout 2019.

Working Capital

($ millions except working capital ratio)		**December 31, 2019**		December 31, 2018
Current assets	**$**	**2,196**	$	4,033
Current liabilities		**3,125**		4,102
Working deficiency	**$**	**(929)**	$	(69)
Working capital ratio [1]		**0.70**		0.98

(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, accounts receivable, and cash and cash equivalents, and increases in the current portion of long-term debt, regulatory liabilities, risk management liabilities, and operating lease liabilities. These were partially offset by increases in prepaid expenses and other current assets, and decreases in short-term debt, liabilities associated with assets held for sale, and accounts payable and accrued liabilities. AltaGas' working capital will fluctuate in the normal course of business and given the seasonality of the utilities, is typically lower than average in the fourth quarter of each year. The working capital deficiency is expected to be funded using cash flow from operations, proceeds from asset sales, and available credit facilities as required.

Investing Activities

Cash from investing activities for the year ended December 31, 2019 was $2.2 billion, compared to cash used in investing activities of $5.8 billion in 2018. Investing activities for the year ended December 31, 2019 primarily included proceeds of $3.6 billion from asset sales completed in the year ended December 31, 2019 (including the Northwest Hydro facilities, distributed generation assets, Central Penn, Stonewall, biomass assets, and non-core Canadian Midstream and Power assets) and proceeds of $73 million from the sale of a WGL Energy Systems financing receivable, partially offset by expenditures of approximately $1.3 billion for property, plant, and equipment and intangible assets, and approximately $179 million of contributions to equity investments. Investing activities for the year ended December 31, 2018 primarily included the cash payment of $5.9 billion for the WGL Acquisition, expenditures of approximately $990 million for property, plant and equipment and $38 million for intangible assets, and contributions to equity investments of $235 million, partially offset by proceeds of approximately $859 million from the IPO of ACI, proceeds from the disposition of assets (primarily relating to the San Joaquin facilities) of $404 million, and proceeds of $77 million from the disposition of investments (primarily related to the Tidewater shares).

Financing Activities

Cash used in financing activities for the year ended December 31, 2019 was $2.9 billion, compared to cash from financing activities of $6.0 billion in 2018. Financing activities for the year ended December 31, 2019 were primarily comprised of net repayments of short and long-term debt of $1.6 billion, net repayments under credit facilities of $1.9 billion, and dividends of $334 million, partially offset by debt issuances of $889 million, contributions from non-controlling interests of $48 million, and net proceeds from the issuance of common shares of $68 million (mainly from common shares issued through the DRIP). Financing activities for the year ended December 31, 2018 were primarily comprised of net short and long-term debt issuances of $2.3 billion, net proceeds from the issuance of common shares of $2.6 billion, net borrowings under credit facilities of $846 million, repayment of long-term debt of $279 million, the proceeds from the sale of the non-controlling interest in the Northwest Hydro facilities of $909 million (net of transaction costs) and contributions from non-controlling interests of $96 million, partially offset by dividends of $540 million. Total dividends paid to common and preferred shareholders of AltaGas for the year ended December 31, 2019 were $334 million (2018 - $540 million), of which $68 million was reinvested through the DRIP (2018 - $326 million). The decrease in dividends paid was due to the reduction in dividends on common shares declared in the fourth quarter of 2018, partially offset by more common shares outstanding.

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) 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, 2019**		December 31, 2018
Short-term debt (1)	**$**	**389**	$	1,145
Current portion of long-term debt		**923**		890
Long-term debt (2)		**5,928**		8,067
Total debt		**7,240**		10,102
Less: cash and cash equivalents		**(57)**		(102)
Net debt	**$**	**7,183**	$	10,000
Shareholders' equity		**7,215**		7,020
Non-controlling interests		**154**		621
Total capitalization	**$**	**14,552**	$	17,641
Net debt-to-total capitalization (%)		**49**		57

(1) For the purposes of the net debt calculation, short-term debt excludes third-party project financing obtained on behalf of the United States federal government to provide funds for the construction of certain energy management services projects. As this debt was obtained on behalf of the U.S. government, AltaGas would only need to repay in the event that the project is not completed or accepted by the government. See Note 15 of the 2019 Annual Consolidated Financial Statements for additional details. At December 31, 2019, the project financing balance excluded from short-term debt in above table was $71 million (December 31, 2019 - $65 million).

(2) Net of debt issuance costs of $36 million as at December 31, 2019 (December 31, 2018 - $35 million).

As at December 31, 2019, AltaGas' total debt primarily consisted of outstanding medium-term notes (MTNs) of $3.0 billion (December 31, 2018 - $2.7 billion), WGL and Washington Gas long-term debt of $2.7 billion (December 31, 2018 - $2.7 billion), SEMCO long-term debt of $466 million (December 31, 2018 - $496 million), $643 million drawn under the bank credit facilities (December 31, 2018 - $3.0 billion) and short-term debt of $460 million (December 31, 2018 - $1.2 billion). In addition, AltaGas had $307 million of letters of credit outstanding (December 31, 2018 - $271 million).

As at December 31, 2019, AltaGas' total market capitalization was approximately $5.5 billion based on approximately 279 million common shares outstanding and a closing trading price on December 31, 2019 of $19.78 per common share.

AltaGas' earnings interest coverage for the rolling twelve months ended December 31, 2019 was 3.2 times (twelve months ended December 31, 2018 – (1.2) times).

Credit Facilities *($ millions)*	Borrowing capacity	**Drawn at December 31, 2019**	Drawn at December 31, 2018
AltaGas unsecured demand credit facilities (1) (2)	$ 330	**$ 156**	$ 153
AltaGas unsecured extendible revolving letter of credit facilities (1) (2)	540	**150**	117
AltaGas unsecured revolving credit facilities (1) (2)	3,348	**90**	2,890
AltaGas bridge facility (1) (3)	—	**—**	113
AltaGas unsecured term credit facility (1) (2)	390	**390**	—
SEMCO Energy US$200 million unsecured credit facilities (1) (2)	195	**164**	1
WGL US$250 million unsecured revolving credit facility (2) (4)	325	**—**	—
Washington Gas US$450 million unsecured revolving credit facility (2) (4)	584	**—**	—
	$ 5,712	**$ 950**	$ 3,274

(1) Amount drawn at December 31, 2019 converted at the month-end rate of 1 U.S. dollar = 1.2988 Canadian dollar (December 31, 2018 - 1 U.S. dollar = 1.3642 Canadian dollar).

(2) All US$ borrowing capacity was converted at the December 31, 2019 U.S./Canadian dollar month-end exchange rate.

(3) The remaining balance on the bridge facility was paid in full on February 1, 2019.

(4) 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$350 million and US$550 million on their respective 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, 2019, commercial paper outstanding totaled US$583 million for WGL and Washington Gas (December 31, 2018 – US$840 million).

Effective July 19, 2019, WGL and Washington Gas amended and restated their unsecured, revolving credit facilities. The WGL facility was reduced from US$650 million to US$250 million for a period of three years. The Washington Gas facility was increased from US$350 million to US$450 million for a period of five years. The facilities both have a US$100 million accordion option and there were no changes to the financial covenants. The commercial paper programs supported by these facilities have been revised to match the new facility amounts.

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, 2019 and December 31, 2018.

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, 2019**
Bank debt-to-capitalization (1)	not greater than 65 percent	less than 50%
Bank EBITDA-to-interest expense (1) (2)	not less than 2.5x	greater than 3.5x
Bank debt-to-capitalization (SEMCO) (3)	not greater than 60 percent	less than 41%
Bank EBITDA-to-interest expense (SEMCO) (3)	not less than 2.25x	greater than 7.5x
Bank debt-to-capitalization (WGL) (4)	not greater than 65 percent	less than 51%
Bank debt-to-capitalization (Washington Gas) (4)	not greater than 65 percent	less than 53%

(1) Calculated in accordance with the Corporation's US$1.2 billion credit facility agreement, which is available on SEDAR at www.sedar.com. 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 similar 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 September 25, 2019, a $2.0 billion base shelf prospectus for the issuance of certain types of future public debt and/or equity issuances was filed. This enables AltaGas to access the Canadian capital markets on a timely basis during the 25-month period that the base shelf prospectus remains effective. As at December 31, 2019, approximately $1.5 billion was available under the base shelf prospectus.

On June 13, 2018, AltaGas filed a US$2.0 billion final short form prospectus for the issuance of both debt securities and preferred shares in Alberta and a corresponding F-10 in the U.S. As at December 31, 2019, US$2.0 billion was available under the base shelf prospectus. On January 21, 2020, AltaGas filed a final short form base shelf prospectus in both Alberta and the U.S. This will enable AltaGas to access the U.S. capital markets during the 25-month period that the base shelf prospectus remains effective. US$2.0 billion is available under the base shelf prospectus.

Contractual Obligations

December 31, 2019		Payments Due by Period							
($ millions)		Total		Less than 1 year		1 - 3 years		4 - 5 years		After 5 years
Short-term debt [1]	$	460	$	460	$	—	$	—	$	—
Long-term debt [1]		6,793		921		1,489		921		3,462
Operating leases [2]		226		28		53		45		100
Purchase obligations		43,336		3,941		6,865		5,445		27,085
Capital project commitments		7		7		—		—		—
Pension plan and retiree benefits [3]		40		40		—		—		—
Merger commitments [4]		22		8		6		4		4
Environmental commitments		14		7		5		2		—
Other liabilities [5]		15		15		—		—		—
Total contractual obligations [6]	$	50,913	$	5,427	$	8,418	$	6,417	$	30,651

(1) Excludes deferred financing costs, discounts, finance lease liabilities, and the fair value adjustment on the WGL Acquisition.
(2) Payments are presented on an undiscounted cash basis.
(3) Assumes only required payments will be made into the pension plans in 2020. Contributions are made in accordance with independent actuarial valuations.
(4) Relates to merger commitments arising from the WGL Acquisition. Represents the estimated future payments of merger commitments that have been accrued but not paid. In addition, there are certain additional merger commitments that will be expensed when costs are incurred in the future, including the investment of up to US$70 million over a ten year period to further extend natural gas service, investment of US$8 million for leak mitigation within three years of the merger, hiring damage prevention trainers in each jurisdiction for a total of US$2 million over five years, and developing 15 megawatts of either electric grid energy storage or Tier 1 renewable resources within five years. As at December 31, 2019, the cumulative amount of merger commitments that have been expensed but not yet paid is approximately US$17 million.
(5) Excludes non-financial liabilities.
(6) U.S. dollar commitments have been converted to Canadian dollars using the December 31, 2019 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 2019 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 (Loss).

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-	Affirmed on December 11, 2019 and outlook was revised from negative to stable.
		Senior unsecured	BBB-	Affirmed on December 11, 2019 and outlook was revised from negative to stable.
		Preferred shares	P-3	Affirmed on December 11, 2019.
	DBRS Limited (DBRS)	Issuer	BBB(low)	Affirmed on December 12, 2019 with stable outlook.
		Preferred shares	Pfd-3(low)	Affirmed on December 12, 2019.
	Fitch Ratings (Fitch)	Issuer	BBB	Affirmed on September 6, 2019.
		Preferred shares	BB+	Affirmed on September 6, 2019.
Washington Gas	Moody's Investors Service (Moody's)	Senior unsecured	A3	Downgraded to A3 from A2 on January 30, 2020. Stable outlook rating on February 4, 2020.
		Commercial paper	P-2	Downgraded to P-2 from P-1 on January 30, 2020. Stable outlook rating on February 4, 2020.
	S&P	Issuer and unsecured debt	A-	Raised from BBB+ to A- on December 11, 2019.
		Commercial paper	A-2	Affirmed on December 11, 2019.
	Fitch	Issuer	A-	Affirmed on September 6, 2019 with stable outlook.
WGL	Moody's	Senior unsecured	Baa1	Affirmed on January 30, 2020 and changed outlook from stable to negative. Stable outlook rating on February 4, 2020.
		Commercial paper	P-2	Affirmed on January 30, 2020 and changed outlook from stable to negative. Stable outlook rating on February 4, 2020.
	S&P	Issuer	BBB-	Affirmed on December 11, 2019 and outlook was revised from negative to stable.
		Senior unsecured	BB+	Affirmed on December 11, 2019.
		Commercial paper	A-3	Affirmed on December 11, 2019.
	Fitch	Issuer	BBB	Affirmed on September 6, 2019 with stable outlook.
SEMCO	Moody's	Long-term issuer	Baa1	Affirmed on January 29, 2020 with stable outlook.
		Senior secured notes	A2	Affirmed on January 29, 2020.
	S&P	Long-term issuer	BBB	Raised from BBB- to BBB on December 12, 2019.
		Senior secured notes	A-	Raised from BBB+ to A- on December 12, 2019.

According to the S&P rating system, an obligor rated BBB has adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. A P-3 rating by S&P is the third highest of eight categories granted by S&P under its Canadian preferred share rating scale and a P-3 rating directly corresponds with a BB rating under its global preferred rating scale. The Canadian preferred share rating scale is fully determined by the global preferred rating scale and there are no additional analytical criteria associated with the determination of ratings on the Canadian preferred share rating scale. According to the S&P rating system, while securities rated P-3 are regarded as having significant speculative characteristics, they are less vulnerable to non-payment than other speculative issues. However, it faces major ongoing uncertainties or exposure to adverse business, financial, or economic conditions which could lead to the obligor's inadequate capacity to meet its financial commitment on the obligation.

The ratings from P-1 to P-5 may be modified by "high" and "low" grades which indicate relative standing within the major rating categories.

According to the DBRS rating system, debt securities rated BBB are of adequate credit quality. The capacity for the payment of financial obligations is considered acceptable, but may be vulnerable to future events. "High" or "Low" grades are used to indicate the relative standing within a particular rating category. A Pfd-3 rating by DBRS is the third highest of six categories granted by DBRS. According to the DBRS rating system, preferred shares rated Pfd-3 are of adequate credit quality. While protection of dividends and principal is still considered acceptable, the issuing entity is more susceptible to adverse changes in financial and economic conditions, and there may be other adversities present which detract from debt protection. Pfd-3 ratings normally correspond with companies whose bonds are rated in the higher end of the BBB category. "High" or "Low" grades are used to indicate the relative standing within a rating category. The absence of either a "High" or "Low" designation indicates the rating is in the middle of the category.

According to the Fitch rating system, 'BBB' ratings indicate that expectations of default risk are currently low. The capacity for payment of financial commitments is considered adequate, but adverse business or economic conditions are more likely to impair this capacity. A 'BB' rating by Fitch indicates an elevated vulnerability to default risk, particularly in the event of adverse changes in business or economic conditions over time; however, business or financial flexibility exists that support the servicing of financial commitments.

According to the Moody's rating system, Baa ratings indicate moderate credit risk. Obligations rated Baa are considered medium-grade and as such may possess speculative characteristics.

The credit ratings accorded to the securities by the rating agencies are not recommendations to purchase, hold, or sell the securities in as much as such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant.

Share Information

	As at February 21, 2020
Issued and outstanding	
Common shares	279,425,083
Preferred Shares	
Series A	5,511,220
Series B	2,488,780
Series C	8,000,000
Series E	8,000,000
Series G	6,885,823
Series H	1,114,177
Series I	8,000,000
Series K	12,000,000
Issued	
Share options	9,349,556
Share options exercisable	2,891,857

Dividends

AltaGas declares and pays a monthly dividend to its common shareholders. Dividends on preferred shares are 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:

Dividends

Year Ended December 31				
($ per common share)		**2019**		2018
First quarter	**$**	**0.240000**	$	0.547500
Second quarter		**0.240000**		0.547500
Third quarter		**0.240000**		0.547500
Fourth quarter		**0.240000**		0.445000
Total	**$**	**0.960000**	$	2.087500

Series A Preferred Share Dividends

Year Ended December 31				
($ per preferred share)		**2019**		2018
First quarter	**$**	**0.211250**	$	0.211250
Second quarter		**0.211250**		0.211250
Third quarter		**0.211250**		0.211250
Fourth quarter		**0.211250**		0.211250
Total	**$**	**0.845000**	$	0.845000

Series B Preferred Share Dividends

Year Ended December 31				
($ per preferred share)		**2019**		2018
First quarter	**$**	**0.269380**	$	0.217600
Second quarter		**0.270510**		0.238720
Third quarter		**0.273921**		0.249530
Fourth quarter		**0.270830**		0.262770
Total	**$**	**1.084641**	$	0.968620

Series C Preferred Share Dividends

Year Ended December 31				
(US$ per preferred share)		**2019**		2018
First quarter	**$**	**0.330625**	$	0.330625
Second quarter		**0.330625**		0.330625
Third quarter		**0.330625**		0.330625
Fourth quarter		**0.330625**		0.330625
Total	**$**	**1.322500**	$	1.322500

Series E Preferred Share Dividends

Year Ended December 31				
($ per preferred share)		**2019**		2018
First quarter	**$**	**0.337063**	$	0.312500
Second quarter		**0.337063**		0.312500
Third quarter		**0.337063**		0.312500
Fourth quarter		**0.337063**		0.312500
Total	**$**	**1.348252**	$	1.250000

Series G Preferred Share Dividends

Year Ended December 31				
($ per preferred share)		**2019**		2018
First quarter	**$**	**0.296875**	$	0.296875
Second quarter		**0.296875**		0.296875
Third quarter		**0.296875**		0.296875
Fourth quarter		**0.265125**		0.296875
Total	**$**	**1.155750**	$	1.187500

Series H Preferred Share Dividends

Year ended December 31				
($ per preferred share)		**2019**		2018
Third quarter	**$**	**—**	$	—
Fourth quarter		**0.296040**		—
Total	**$**	**0.296040**	$	—

Series I Preferred Share Dividends

Year Ended December 31				
($ per preferred share)		**2019**		2018
First quarter	**$**	**0.328125**	$	0.328125
Second quarter		**0.328125**		0.328125
Third quarter		**0.328125**		0.328125
Fourth quarter		**0.328125**		0.328125
Total	**$**	**1.312500**	$	1.312500

Series K Preferred Share Dividends

Year Ended December 31				
($ per preferred share)		**2019**		2018
First quarter	**$**	**0.312500**	$	0.312500
Second quarter		**0.312500**		0.312500
Third quarter		**0.312500**		0.312500
Fourth quarter		**0.312500**		0.312500
Total	**$**	**1.250000**	$	1.250000

US$4.25 series Preferred Share Dividends [(1)]

Year Ended December 31				
(US$ per preferred share)		**2019**		2018
First quarter	**$**	**1.062500**	$	—
Second quarter		**1.062500**		—
Third quarter		**—**		1.062500
Fourth quarter		**—**		1.062500
Total	**$**	**2.125000**	$	2.125000

(1) These Washington Gas preferred shares were redeemed on December 20, 2019.

US$4.80 series Preferred Share Dividends [(1)]

Year Ended December 31				
(US$ per preferred share)		**2019**		2018
First quarter	**$**	**1.200000**	$	—
Second quarter		**1.200000**		—
Third quarter		**—**		1.200000
Fourth quarter		**—**		1.200000
Total	**$**	**2.400000**	$	2.400000

(1) These Washington Gas preferred shares were redeemed on December 20, 2019.

US$5.00 series Preferred Share Dividends [(1)]

Year Ended December 31				
(US$ per preferred share)		**2019**		2018
First quarter	**$**	**1.250000**	$	—
Second quarter		**1.250000**		—
Third quarter		**—**		1.250000
Fourth quarter		**—**		1.250000
Total	**$**	**2.500000**	$	2.500000

(1) These Washington Gas preferred shares were redeemed on December 20, 2019.

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 2019 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 Gas, ENSTAR and Washington Gas engage in the delivery and sale of natural gas. SEMCO Gas and ENSTAR are regulated by the MPSC and RCA, respectively. 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. The fair value used in the quantitative impairment test of goodwill requires estimating future cash flows as well as appropriate discount rates. AltaGas has assessed goodwill for impairment as at December 31, 2019 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.

Substantial deferred income tax assets and liabilities are recognized in the Consolidated Financial Statements. 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 2019 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. Notes 2 and 28 of the 2019 Annual Consolidated Financial Statements include information on the assumptions used for the purposes of recording the funding status of the plans and the associated expenses.

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, 2019, 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, 2019, AltaGas adopted the following Financial Accounting Standards Board (FASB) issued Accounting Standards Updates (ASU):

- ASU No. 2016-02 “Leases” and all related amendments (collectively “ASC 842”). AltaGas has applied ASC 842 using the modified retrospective approach as of the effective date of the new standard. Comparative information has not been restated and continues to be reported under the previous lease guidance ASC 840. AltaGas has applied the package of transition practical expedients which permitted the Corporation to not reassess (a) whether any expired or existing contracts contain leases, (b) lease classifications for any expired or existing leases, and (c) initial direct costs for any existing leases. In addition, AltaGas applied the transition practical expedient that permitted the Corporation to grandfather its accounting policy for land easements that existed as of, or expired, before January 1, 2019. The transition practical expedient to not separate lease and non-lease components for its building, office equipment, transportation equipment, and vehicle leases has been elected for lessee arrangements. The transition practical expedient to not separate lease and non-lease components for its lessor arrangements related to certain assets has also been elected. AltaGas has applied the short-term lease recognition exemption under which lease arrangements with a term of twelve months or less, including extension options that are reasonably certain of being exercised, are exempt from the recognition of a right-of-use asset and lease liability and recorded as an expense over the term of the lease. This exemption applies to all classes of assets.

  On adoption of ASC 842, all operating leases were recognized on the Consolidated Balance Sheets. The adoption resulted in an increase to long-term assets of approximately $181 million and an increase to long-term liabilities of approximately $171 million (net of the current portion that is recorded in current liabilities of approximately $23 million). The lease related liabilities were measured using the present value of the remaining minimum lease payments for existing leases discounted using the Corporation’s incremental borrowing rate as of January 1, 2019. For operating leases, the associated right-of-use assets were measured at the amount equal to the lease liabilities on January 1, 2019, adjusted for any prepaid or accrued lease payments and the remaining balance of any lease incentives received. The adoption of ASC 842 did not impact lessor accounting, the Consolidated Statements of Income (Loss), or the Consolidated Statements of Cash Flows.

  Please also refer to Note 10 of the Consolidated Financial Statements as at and for the year ended December 31, 2019 for further details;

- ASU No. 2017-08 “Receivables – Nonrefundable Fees and Other Costs: Premium Amortization on Purchased Callable Debt Securities". The amendments in this ASU shorten the amortization period for certain callable debt securities held at a premium. Specifically, the amendments require the premium to be amortized to the earliest call date. The adoption of this ASU did not have a material impact on AltaGas’ consolidated financial statements;

- ASU No. 2017-11 “Earnings per Share and Derivatives and Hedging – Distinguishing Liabilities from Equity: Accounting for Certain Financial Instruments with Down Round Features, Replacement of the Indefinite Deferral for Mandatorily Redeemable Financial Instruments of Certain Nonpublic Entities and Certain Mandatorily Redeemable Non-controlling Interests with a Scope Exception”. The amendments in this ASU simplify the accounting for certain equity-linked financial instruments and embedded features with down round features that reduce the exercise price when pricing of a future round of financing is lower. The amendments in this ASU also require entities that present earnings per share under ASC 260 to recognize the effect of a down round feature in a freestanding equity-classified financial instrument only when it is triggered. The adoption of this ASU did not have a material impact on AltaGas’ consolidated financial statements;

- ASU No. 2018-07 “Compensation – Stock Compensation: Improvements to Nonemployee Share-Based Payment Accounting”. The amendments in this ASU expand the scope of Topic 718 to include share-based payment transactions for acquiring goods and services from nonemployees, with the objective of making the measurement consistent with employee share based payment awards. The adoption of this ASU did not have a material impact on AltaGas’ consolidated financial statements;

- ASU No. 2018-08 “Not-for-Profit-Entities – Clarifying the Scope and the Accounting Guidance for Contributions Received and Contributions Made”. The amendments in this ASU clarify whether a transfer of assets is a contribution or an exchange transaction. The adoption of this ASU did not have a material impact on AltaGas’ consolidated financial statements;

- ASU No. 2018-15 “Intangibles – Goodwill and Other – Internal-Use Software: Customer’s Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement (CCA) that is a Service Contract”. The amendments in this ASU align the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software (and hosting arrangements that include an internal use software license). The adoption of this ASU did not have a material impact on AltaGas’ consolidated financial statements; and

- ASU No. 2018-16 “Derivatives and Hedging: Inclusion of the Second Overnight Financing Rate (SOFR) Overnight Index Swap (OIS) Rate as a Benchmark Interest Rate for Hedge Accounting Purposes”. The amendments in this ASU permit the use of Overhead Index Swap (OIS) rate based on SOFR as a U.S. benchmark interest rate for hedge accounting purposes. The adoption of this ASU did not have a material impact on AltaGas’ consolidated financial statements.

Future Changes in Accounting Principles

In June 2016, FASB issued ASU No. 2016-13 “Financial Instruments – Credit Losses: Measurement of Credit Losses on Financial Instruments”. The amendments in this ASU replace the current “incurred loss” impairment methodology with an “expected loss” model for financial assets measured at amortized cost. The amendments in this ASU are effective for fiscal years beginning after December 15, 2020, and interim periods within those fiscal years. Early adoption is permitted. AltaGas will adopt this standard on January 1, 2020 using a modified-retrospective approach through a cumulative-effect adjustment to retained earnings. AltaGas has completed scoping and evaluation activities for this new accounting standard, and has quantified the impact of this ASU on its opening Consolidated Balance Sheet as at January 1, 2020. Upon adoption, "accounts receivable, net of allowances" is expected to decrease by less than 1 percent of the outstanding accounts receivable balance, with an offsetting increase to "accumulated deficit".

In August 2018, FASB issued ASU No. 2018-13 “Fair Value Measurement – Disclosure Framework: Changes to the Disclosure Requirements for Fair Value Measurement”. The amendments in this ASU modify the disclosure requirements on fair value measurements. The amendments in this update are effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

In August 2018, FASB issued ASU No. 2018-14 “Compensation-Retirement Benefits-Defined Benefit Plans – General: Disclosure Framework – Changes to the Disclosure Requirements for the Defined Benefit Plans”. The amendments in this ASU modify the disclosure requirements on defined benefit pension and other post-retirement plans. The amendments in this ASU are effective for fiscal years beginning after December 15, 2020, and interim periods within those fiscal years. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

In October 2018, FASB issued ASU No. 2018-17 “Consolidation: Targeted Improvements to Related Party Guidance for Variable Interest Entities”. The amendments in this ASU provide a private-company scope exception to the VIE guidance for certain entities and clarify that indirect interest held through related parties under common control will be considered on a proportional basis when determining whether fees paid to decision makers and service providers are variable interests. The amendments in this ASU are effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. An entity should apply the amendments retrospectively with a cumulative-effect adjustment to retained earnings at the beginning of the earliest period presented. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

In March 2019, FASB issued ASU No. 2019-01 “Leases: Codification Improvements”. The amendments in this ASU provide a fair value exception for lessors that are not manufacturers or dealers, clarify the presentation of principal payments received under sales-type and direct finance leases on the statements of cash flows, and clarify transition disclosure requirements for the adoption of ASC 842. The amendments on the fair value exception and on the presentation on the statement of cash flows are effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted. The amendment on the transition disclosure requirement is effective upon adoption of ASC 842. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

In April 2019, FASB issued ASU No. 2019-04 “Financial Instruments - Credit Losses, Derivatives and Hedging, and Codification Improvements”. The amendments in this ASU provide clarification and improve the codification in recently issued accounting standards on credit losses (ASU 2016-13), hedging (ASU 2017-12), and recognizing and measuring financial instruments (ASU 2016-01). The amendments related to credit losses have the same effective date and transition requirements as ASU 2016-13, the amendments related to hedge accounting are effective as of the beginning of the first annual period beginning after issuance of this ASU and may be applied retrospectively to the date ASU 2017-12 was adopted or prospectively with some exceptions, and the amendments related to financial instruments are effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

In May 2019, FASB issued ASU No. 2019-05 “Financial Instruments - Credit Losses: Targeted Transition Relief". The amendments in this ASU provide entities that have certain instruments within the scope of Subtopic 326-20 - Financial Instruments - Credit Losses - Measured at Amortized Cost (other than held-to-maturity debt securities) a one-time irrevocable option to elect fair value treatment on an eligible instrument-by-instrument basis. The effective date and transition methodology for the amendments in this ASU are the same as ASU 2016-13. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

In November 2019, FASB issued ASU No. 2019-11 "Financial Instruments - Credit Losses: Codification Improvements". The amendments in this ASU provide clarification and improve the codification in ASU 2016-13. The effective date and transition methodology for the amendments in this ASU are the same as ASU 2016-13. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

In December 2019, FASB issued ASU No. 2019-12 "Income Taxes: Simplifying the Accounting for Income Taxes". The amendments in this ASU simplify the accounting for income taxes by clarifying certain aspects of current guidance and removing some exceptions to the general principles in ASC 740. The amendments in this ASU are effective for fiscal years beginning after December 15, 2020, and interim periods within those fiscal years. Early adoption is permitted. AltaGas is assessing the impact of this ASU on its consolidated financial statements.

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 has 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).

During the year ended December 31, 2019, 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, 2019 and concluded that as at December 31, 2019 AltaGas' DCP and ICFR were effective.

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)	**Q4-19**	Q3-19	Q2-19	Q1-19	Q4-18	Q3-18	Q2-18	Q1-18
Total revenue	**1,534**	888	1,174	1,898	1,727	1,041	610	878
Normalized EBITDA (2)	**425**	178	203	466	394	226	166	223
Net income (loss) applicable to common shares	**(103)**	22	41	809	174	(726)	1	49
($ per share)	**Q4-19**	Q3-19	Q2-19	Q1-19	Q4-18	Q3-18	Q2-18	Q1-18
Net income (loss) per common share								
Basic	**(0.37)**	0.08	0.15	2.93	0.64	(2.78)	0.01	0.28
Diluted	**(0.37)**	0.08	0.15	2.93	0.64	(2.78)	0.01	0.28
Dividends declared	**0.24**	0.24	0.24	0.24	0.45	0.55	0.55	0.55

(1) Amounts may not add due to rounding.

(2) Non-GAAP financial measure. 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:

- Revenue from WGL after the acquisition closed in the third quarter of 2018;
- The weaker U.S. dollar in the first half of 2018 on translated results of the U.S. assets;
- The seasonally colder weather experienced at several of the utilities throughout 2018, and the first quarter of 2019;
- Losses on risk management contracts recorded in the first half of 2018 related to the foreign currency option contracts entered into to mitigate the foreign exchange risks associated with the cash purchase price of WGL;
- The impact of the sale of non-core U.S. Power assets in the fourth quarter of 2018;
- The impact of the sale of the Canadian utilities to ACI and ACI's IPO in the fourth quarter of 2018;
- The impact of the sale of the Northwest Hydro facilities and non-core Canadian Midstream and Power assets in the first quarter of 2019;
- RIPET entering commercial service in the second quarter of 2019;
- The impact of the sale of the U.S. distributed generation assets in the third quarter of 2019; and
- The impact of the sale of WGL Midstream's indirect non-operating interest in Central Penn in the fourth quarter of 2019.

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:

- The impact of WGL income for the period after the close of the acquisition on July 6, 2018;
- Higher depreciation and amortization expense due to new assets placed into service, partially offset by the impact of asset sales;
- After-tax transaction costs of approximately $50 million incurred throughout 2018 predominantly due to the WGL Acquisition;
- After-tax merger commitment costs of $135 million associated with the WGL Acquisition recorded in the second half of 2018;
- After-tax provisions of approximately $562 million recognized in 2018 primarily related to assets held for sale;
- An income tax recovery of approximately $104 million related to the Northwest Hydro facilities held for sale classification at December 31, 2018;
- The impact of the sale of non-core U.S. Power assets in the fourth quarter of 2018;
- The impact of the sale of the Canadian utilities to ACI and ACI's IPO in the fourth quarter of 2018;
- The impact of the sale of the Northwest Hydro facilities and non-core Canadian Midstream and Power assets in the first quarter of 2019;
- The impact of the sale of the U.S. distributed generation assets in the third quarter of 2019;
- The impact of the sale of WGL Midstream's indirect non-operating interest in Central Penn in the fourth quarter of 2019; and
- After-tax provisions of approximately $319 million recognized in the fourth quarter of 2019, primarily related to Power assets.

SELECTED ANNUAL FINANCIAL INFORMATION

($ millions, except where noted)	**2019**	2018	2017
Revenue	**5,495**	4,257	2,556
Net income (loss) applicable to common shares	**769**	(502)	30
Net income (loss) per common share - basic	**2.78**	(2.25)	0.18
Net income (loss) per common share - diluted	**2.77**	(2.25)	0.18
Total assets	**19,795**	23,488	10,032
Total long-term liabilities	**9,301**	11,746	4,578
Weighted average number of common shares outstanding (millions)	**277**	223	171
Dividends declared per common share ($ per share)	**0.960000**	2.087500	2.115000
Preferred share dividends declared ($ per share)			
Series A	**0.845000**	0.845000	0.845000
Series B	**1.084641**	0.968620	0.806380
Series C (US$)	**1.322500**	1.322500	1.155625
Series E	**1.348252**	1.250000	1.250000
Series G	**1.155750**	1.187500	1.187500
Series H	**0.296040**	-	-
Series I	**1.312500**	1.312500	1.312500
Series K	**1.250000**	1.250000	1.063400
Washington Gas $4.80 series (US$) (1)	**2.400000**	2.400000	-
Washington Gas $4.25 series (US$) (1)	**2.125000**	2.125000	-
Washington Gas $5.00 series (US$) (1)	**2.500000**	2.500000	-

(1) Washington Gas preferred shares were redeemed on December 20, 2019.

MANAGEMENT'S REPORT

The Consolidated Financial Statements of AltaGas Ltd. (AltaGas or the Corporation) 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, 2019.

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) "Randall Crawford"

RANDALL CRAWFORD
President and
Chief Executive Officer of
AltaGas Ltd.

(signed) "James Harbilas"

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

February 27, 2020

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders of AltaGas Ltd.

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated financial statements of AltaGas Ltd. (the “Company”), which comprise the consolidated balance sheets as at December 31, 2019 and 2018, and the consolidated statements of income (loss), comprehensive income (loss), equity and cash flows for each of the years then ended, and the related notes (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of AltaGas Ltd as at December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the years then ended, in conformity with United States generally accepted accounting principles.

Change in Accounting Principle

As discussed in Note 2 to the consolidated financial statements, the Company changed its method of accounting for leases under ASC 842 in 2019 due to the adoption of ASU 2016-02, Leases.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company‘s management. Our responsibility is to express an opinion on the Company‘s consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the US federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

We have served as AltaGas Ltd. auditor since 1997.

Ernst & Young LLP

Chartered Professional Accountants

Calgary, Canada
February 27, 2020

CONSOLIDATED BALANCE SHEETS

As at December 31		2019		2018
ASSETS				
Current assets				
Cash and cash equivalents *(note 31)*	**$**	**57.1**	$	101.6
Accounts receivable, net of allowances *(note 23)*		**1,222.4**		1,547.5
Inventory *(note 7)*		**505.6**		515.9
Restricted cash holdings from customers *(note 31)*		**4.0**		4.1
Regulatory assets *(note 21)*		**12.8**		21.0
Risk management assets *(note 23)*		**86.6**		114.1
Prepaid expenses and other current assets *(notes 28 and 31)*		**280.2**		199.9
Assets held for sale *(note 5)*		**27.5**		1,528.9
		2,196.2		4,033.0
Property, plant and equipment *(note 8)*		**10,125.5**		10,929.6
Intangible assets *(note 9)*		**585.6**		711.9
Operating right-of-use assets *(note 10)*		**169.8**		—
Goodwill *(note 11)*		**3,942.1**		4,068.2
Regulatory assets *(note 21)*		**486.7**		663.0
Risk management assets *(note 23)*		**39.1**		57.7
Restricted cash holdings from customers *(note 31)*		**3.9**		6.1
Prepaid post-retirement benefits *(note 28)*		**487.5**		342.7
Long-term investments and other assets *(notes 12, 28, and 31)*		**296.5**		283.1
Investments accounted for by the equity method *(note 14)*		**1,461.6**		2,392.4
	$	**19,794.5**	$	23,487.7
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities				
Accounts payable and accrued liabilities *(notes 17, 18, 23, and 28)*	**$**	**1,324.9**	$	1,488.2
Dividends payable *(note 23)*		**22.3**		22.0
Short-term debt *(notes 15 and 23)*		**460.0**		1,209.9
Current portion of long-term debt *(notes 16 and 23)*		**922.9**		890.2
Customer deposits		**76.6**		98.0
Regulatory liabilities *(note 21)*		**145.5**		114.9
Risk management liabilities *(note 23)*		**124.8**		89.3
Operating lease liabilities *(note 10)*		**27.3**		—
Other current liabilities *(note 23)*		**17.0**		18.1
Liabilities associated with assets held for sale *(note 5)*		**3.8**		171.4
		3,125.1		4,102.0
Long-term debt *(notes 16 and 23)*		**5,927.8**		8,066.9
Asset retirement obligations *(note 17)*		**362.0**		500.6
Unamortized investment tax credits *(note 20)*		**3.8**		190.1
Deferred income taxes *(note 20)*		**959.1**		957.9
Regulatory liabilities *(note 21)*		**1,383.2**		1,392.8
Risk management liabilities *(note 23)*		**167.0**		213.0
Operating lease liabilities *(note 10)*		**153.4**		—
Other long-term liabilities *(notes 19 and 23)*		**101.8**		122.0
Future employee obligations *(note 28)*		**242.5**		302.2
	$	**12,425.7**	$	15,847.5

As at December 31		2019		2018
Shareholders' equity				
Common shares, no par values, unlimited shares authorized; 2019 - 279.1 million and 2018 - 275.2 million issued and outstanding *(note 25)*	**$**	**6,719.0**	$	6,653.9
Preferred shares *(note 25)*		**1,277.1**		1,318.8
Contributed surplus		**376.7**		373.2
Accumulated deficit		**(1,402.8)**		(1,905.3)
Accumulated other comprehensive income (AOCI) *(note 22)*		**244.9**		579.0
Total shareholders' equity		**7,214.9**		7,019.6
Non-controlling interests		**153.9**		620.6
Total equity	**$**	**7,368.8**	$	7,640.2
	$	**19,794.5**	$	23,487.7

Variable interest entities (note 13)
Commitments, guarantees and contingencies (note 29)
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) "Randall Crawford"

RANDALL CRAWFORD

Director

(signed) "Robert B. Hodgins"

ROBERT B. HODGINS

Director

CONSOLIDATED STATEMENTS OF INCOME (LOSS)

Year Ended December 31		2019		2018
REVENUE *(note 24)*	**$**	**5,495.0**	$	4,256.7
EXPENSES				
Cost of sales, exclusive of items shown separately		**3,227.1**		2,455.3
Operating and administrative		**1,298.7**		1,129.0
Accretion expenses *(note 17)*		**5.1**		10.9
Depreciation and amortization *(notes 8 and 9)*		**438.0**		394.0
Provisions on assets *(note 6)*		**415.8**		728.7
		5,384.7		4,717.9
Income from equity investments *(note 14)*		**141.1**		47.9
Other income *(note 27)*		**908.1**		0.9
Foreign exchange gains (losses)		**(1.0)**		4.5
Interest expense		**(345.8)**		(309.0)
Income (loss) before income taxes		**812.7**		(716.9)
Income tax expense (recovery) *(note 20)*				
Current		**63.3**		24.4
Deferred		**(90.9)**		(287.6)
Net income (loss) after taxes		**840.3**		(453.7)
Net income (loss) applicable to non-controlling interests		**6.8**		(18.6)
Net income (loss) applicable to controlling interests		**833.5**		(435.1)
Preferred share dividends		**(68.5)**		(66.6)
Gain on redemption of preferred shares *(note 25)*		**3.5**		—
Net income (loss) applicable to common shares	**$**	**768.5**	$	(501.7)
Net income (loss) per common share *(note 26)*				
Basic	**$**	**2.78**	$	(2.25)
Diluted	**$**	**2.77**	$	(2.25)
Weighted average number of common shares outstanding (millions) *(note 26)*				
Basic		**276.9**		222.6
Diluted		**277.4**		222.6

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

Year Ended December 31		2019		2018
Net income (loss) after taxes	**$**	**840.3**	$	(453.7)
Other comprehensive income (loss), net of taxes				
Gain (loss) on foreign currency translation		**(406.2)**		458.5
Unrealized gain (loss) on net investment hedge *(note 23)*		**60.0**		(80.2)
Actuarial gain (loss) on pension plans and post-retirement benefit (PRB) plans *(note 28)*		**12.0**		(10.8)
Reclassification of actuarial gains and prior service credits on defined benefit (DB) and post-retirement benefit plans (PRB) to net income *(note 28)*		**0.8**		0.5
Curtailment of DB and PRB plan *(note 28)*		**—**		2.7
Adoption of ASU 2016-01		**—**		7.1
Other comprehensive income (loss) from equity investees		**(0.7)**		2.1
Total other comprehensive income (loss) (OCI), net of taxes *(note 22)*		**(334.1)**		379.9
Comprehensive income (loss) attributable to controlling interests and non-controlling interests, net of taxes	**$**	**506.2**	$	(73.8)
Comprehensive income (loss) attributable to:				
Non-controlling interests	**$**	**6.8**	$	(18.6)
Controlling interests		**499.4**		(55.2)
	$	**506.2**	$	(73.8)

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF EQUITY

Year Ended December 31		2019		2018
Common shares *(note 25)*				
Balance, beginning of year	$	**6,653.9**	$	4,007.9
Shares issued for cash on exercise of options		**1.2**		1.3
Shares issued under DRIP [1]		**67.8**		325.8
Deferred taxes on share issuance costs		**(3.9)**		13.3
Shares issued on conversion of subscription receipts, net of issuance costs		**—**		2,305.6
Balance, end of year	$	**6,719.0**	$	6,653.9
Preferred shares *(note 25)*				
Balance, beginning of year	$	**1,318.8**	$	1,277.7
Preferred shares acquired through WGL Acquisition *(note 3)*		**—**		41.1
Redemption of WGL preferred shares		**(41.1)**		—
Deferred taxes on share issuance costs		**(0.6)**		—
Balance, end of year	$	**1,277.1**	$	1,318.8
Contributed surplus				
Balance, beginning of year	$	**373.2**	$	22.3
Share options expense		**3.7**		0.9
Exercise of share options		**(0.1)**		(0.1)
Forfeiture of share options		**(0.1)**		(0.1)
Sale of non-controlling interest		**—**		350.2
Balance, end of year	$	**376.7**	$	373.2
Accumulated deficit				
Balance, beginning of year	$	**(1,905.3)**	$	(933.6)
Net income (loss) applicable to controlling interests		**833.5**		(435.1)
Common share dividends		**(266.0)**		(462.9)
Preferred share dividends		**(68.5)**		(66.6)
Gain on redemption of preferred shares		**3.5**		—
Adoption of ASU No. 2016-01		**—**		(7.1)
Balance, end of year	$	**(1,402.8)**	$	(1,905.3)
AOCI *(note 22)*				
Balance, beginning of year	$	**579.0**	$	199.1
Other comprehensive income (loss)		**(334.1)**		379.9
Balance, end of year	$	**244.9**	$	579.0
Total shareholders' equity	$	**7,214.9**	$	7,019.6
Non-controlling interests				
Balance, beginning of year	$	**620.6**	$	65.8
Net income (loss) applicable to non-controlling interests		**6.8**		(18.6)
Sale of non-controlling interest		**—**		498.4
Adjustment on disposition of assets		**(508.0)**		—
Contributions from non-controlling interests to subsidiaries		**47.9**		96.3
Distributions by subsidiaries to non-controlling interests		**(13.4)**		(30.3)
Acquisition of non-controlling interest through WGL Acquisition *(note 3)*		**—**		9.0
Balance, end of year	$	**153.9**	$	620.6
Total equity	$	**7,368.8**	$	7,640.2

(1) Premium Dividend™, Dividend Reinvestment and Optional Cash Purchase Plan.

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31	2019	2018
Cash from (used by) operations		
Net income (loss) after taxes	**$ 840.3**	$ (453.7)
Items not involving cash:		
Depreciation and amortization	**438.0**	394.0
Provisions on assets *(note 6)*	**415.8**	728.7
Accretion expenses	**5.1**	10.9
Share-based compensation *(note 25)*	**3.5**	0.8
Deferred income tax recovery *(note 20)*	**(90.9)**	(287.6)
Losses (gains) on sale of assets *(notes 4 and 27)*	**(875.8)**	10.6
Income from equity investments *(note 14)*	**(141.1)**	(47.9)
Unrealized losses (gains) on risk management contracts *(note 23)*	**85.3**	(80.8)
Realized loss on expiry of foreign exchange options	**—**	36.0
Losses on investments *(note 27)*	**4.1**	10.1
Amortization of deferred financing costs	**11.5**	29.7
Provision for doubtful accounts	**26.7**	17.0
Net change in pension and other post-retirement benefits *(note 28)*	**8.1**	(3.8)
Other	**9.2**	3.6
Asset retirement obligations settled *(note 17)*	**(2.5)**	(4.2)
Distributions from equity investments	**109.7**	44.5
Changes in operating assets and liabilities *(note 31)*	**(231.5)**	(486.5)
	$ 615.5	$ (78.6)
Investing activities		
Business acquisitions, net of cash acquired	**—**	(5,931.0)
Acquisition of property, plant and equipment	**(1,296.8)**	(990.4)
Acquisition of intangible assets	**(37.7)**	(38.1)
Contributions to equity investments	**(178.7)**	(235.4)
Loan to affiliate, net of repayment *(note 30)*	**—**	30.0
Financing receivable	**—**	(8.7)
Proceeds from disposition of investments	**—**	76.5
Proceeds from initial public offering of AltaGas Canada Inc.	**—**	858.9
Proceeds from disposition of assets, net of transaction costs *(note 4)*	**3,623.4**	403.8
Proceeds from disposition of financing receivable *(note 4)*	**73.5**	—
	$ 2,183.7	$ (5,834.4)
Financing activities		
Net issuance (repayment) of short-term debt	**(700.9)**	497.7
Issuance of long-term debt, net of debt issuance costs	**888.6**	1,851.9
Repayment of long-term debt	**(873.3)**	(278.8)
Net borrowing (repayment) under credit facilities	**(1,919.7)**	846.2
Dividends - common shares	**(265.7)**	(472.9)
Dividends - preferred shares	**(68.5)**	(66.6)
Distributions to non-controlling interest	**(13.4)**	(30.3)
Contributions from non-controlling interests	**47.9**	96.3
Net proceeds from shares issued on exercise of options	**1.1**	1.2
Net proceeds from issuance of common shares	**67.8**	2,633.7
Redemption of preferred shares *(note 25)*	**(37.6)**	—
Net proceeds from sale of non-controlling interest	**—**	908.6
	$ (2,873.7)	$ 5,987.0
Change in cash, cash equivalents, and restricted cash	**(74.5)**	74.0
Effect of exchange rate changes on cash, cash equivalents, and restricted cash	**(9.1)**	7.3
Net change in cash classified within assets held for sale	**4.9**	(4.9)
Restricted cash acquired *(note 31)*	**—**	81.0
Cash, cash equivalents, and restricted cash beginning of year	**201.1**	43.7
Cash, cash equivalents, and restricted cash end of year *(note 31)*	**$ 122.4**	$ 201.1

See accompanying notes to the Consolidated Financial Statements.

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 AltaGas 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 Corporation, WGL Energy Services, Inc. (WGL Energy Services), and SEMCO Holding Corporation; in regards 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, and WGL Midstream Inc. (WGL Midstream); in regards to the Power business, AltaGas Power Holdings (U.S.) Inc., WGL Energy Systems, Inc. (WGL Energy Systems), and Blythe Energy Inc. (Blythe); and, in regards to the Utilities business, Washington Gas Light Company (Washington Gas), Hampshire Gas Company, and SEMCO Energy, Inc. (SEMCO). SEMCO conducts its Michigan natural gas distribution business under the name SEMCO Energy Gas Company (SEMCO Gas), its Alaska natural gas distribution business under the name ENSTAR Natural Gas Company (ENSTAR) and its 65 percent interest in an Alaska regulated gas storage utility under the name Cook Inlet Natural Gas Storage Alaska LLC (CINGSA).

AltaGas, a Canadian corporation, is a leading North American energy infrastructure company that connects natural gas liquids (NGLs) and natural gas to domestic and global markets. The Corporation's long-term strategy is to grow in attractive areas across its Utilities and Midstream business segments seeking optimal capital deployment. In the Midstream business, the Corporation is focused on optimizing the full value chain of energy exports by providing producers with solutions, including global market access off the West Coast of Canada via the Corporation's footprint in the Montney region. In the Utilities business, the Corporation seeks to grow through rate base investment and the use of accelerated rate recovery programs, while providing effective and cost-efficient service for customers. AltaGas has three business segments:

- Utilities, which serves approximately 1.7 million customers with a rate base of approximately US$3.9 billion through ownership of regulated natural gas distribution utilities across five jurisdictions in the United States and two regulated natural gas storage utilities in the United States, delivering clean and affordable natural gas to homes and businesses. The Utilities business also includes storage facilities and contracts for interstate natural gas transportation and storage services;
- Midstream, which includes a 70 percent interest in the recently completed Ridley Island Propane Export Terminal, allowing AltaGas to leverage its assets along the energy value chain in Western Canada including natural gas gathering and processing, NGL extraction and fractionation, and natural gas and NGL marketing. The Midstream segment also includes transmission, storage, an interest in a regulated pipeline in the Marcellus/Utica gas formation in the northeastern United States, WGL's retail gas marketing business, the Corporation's 50 percent interest in AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP), and an indirectly held approximate one-third ownership investment in Petrogas Energy Corp. (Petrogas), through which AltaGas' interest in the Ferndale terminal is held; and
- Power, which includes 710 MW of operational capacity from natural gas-fired, distributed generation, and energy storage assets, certain of which are pending sale, located in Alberta, Canada and the United States, primarily in California and Colorado. The Power business also includes energy efficiency contracting and WGL's retail power marketing business.

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), financial statements of an “SEC issuer” may be prepared in accordance with U.S. GAAP. On July 13, 2018, AltaGas filed a final short form base shelf prospectus in Alberta and a corresponding registration statement on Form F-10 in the United States, by virtue of which AltaGas is now required to file reports under section 15(d) of the *Securities Exchange Act of 1934* with the United States Securities and Exchange Commission. As a result, AltaGas became an SEC issuer at such time and is now entitled to prepare its financial statements in accordance with U.S. GAAP.

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 certain equity method investments as well as consolidating equity investments with non-controlling interests 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. The majority of AltaGas' HLBV investments were sold during 2019.

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 (or loss) of consolidated subsidiaries are shown as an allocation of the consolidated net income (loss) and are presented separately in "net income (loss) 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; 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.

SIGNIFICANT ACCOUNTING POLICIES

Rate-Regulated Operations

SEMCO Gas, ENSTAR, Washington Gas, and Hampshire Gas (collectively the Utilities) engage in the delivery, sale, and storage of natural gas. SEMCO Gas and ENSTAR are regulated by the Michigan Public Service Commission (MPSC) and Regulatory Commission of Alaska (RCA), respectively. 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, RCA, 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, RCA, 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 doubtful accounts 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 doubtful accounts 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, renewable energy credits, and emission compliance instruments which are valued at the lower of cost or net realizable value. 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	2 to 45 years
Power generation assets	3 to 46 years
Corporate assets	3 to 7 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 (Loss). 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 (Loss).

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	5 to 19 years
Electricity service agreements	2 to 60 years
Software	3 to 10 years
Land rights	5 to 64 years
Franchises and consents	9 to 25 years
Extraction and Transmission (E&T) Contracts	25 years
Commodity contracts	5 to 20 years

The intangible assets recorded in the purchase price allocation for certain WGL commodity contracts are amortized based on the estimated fair value of the deliveries over the term of the contracts, which are over a period of 20 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 (Loss).

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 (Loss).

Financial Instruments

Non-Utility Operations

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 (Loss) 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 (Loss).

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 HDD’s falls above or below the contractual HDD’s 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 has designated certain U.S. dollar-denominated debt as a net investment hedge of its U.S. subsidiaries. No other derivatives have been designated as hedges under ASC Topic 815.

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.

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 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 gas 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 (Loss). 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 some of its U.S. dollar denominated long-term debt as a foreign currency hedge of its investment in foreign operations. Accordingly, foreign exchange gains and losses, from the dates of designation, on the translation of the U.S. dollar denominated long-term debt are included in OCI.

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, formerly the medium-term incentive plan) for employees and executive officers which includes two types of awards: restricted units (RUs) and performance units (PUs). A portion of 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. The other portion of RU's and PUs are valued at US$1 per unit. Upon vesting, the RUs and PUs are paid in cash. All PUs are also subject to a performance multiplier ranging from 0 to 2.4 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.

In addition, AltaGas has a deferred share unit plan (DSUP) for directors, officers, and employees as an additional form of long-term variable compensation incentive. Although the DSUP is available to directors, officers, and 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.

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. The expected average remaining service period of the active members covered by the defined benefit pension plans and post-retirement benefit plans is 9.0 years and 13.2 years, respectively.

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.

Net Income (Loss) per Share

Basic net income (loss) 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 upon the adoption of ASC 842:

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 and long-term debt 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.

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.

Collaborative Arrangements

WGL has collaborative arrangements with a third party to facilitate the asset optimization program. The collaborative arrangements allocate a tiered or fixed percentage of profits or losses to the third party as compensation for its participation. The income recorded related to the collaborative arrangements totaled $1.4 million for the year ended December 31, 2019 (2018 - expense of $0.2 million).

ADOPTION OF NEW ACCOUNTING STANDARDS

Effective January 1, 2019, AltaGas adopted the following Financial Accounting Standards Board (FASB) issued Accounting Standards Updates (ASU):

- ASU No. 2016-02 “Leases” and all related amendments (collectively “ASC 842”). AltaGas has applied ASC 842 using the modified retrospective approach as of the effective date of the new standard. Comparative information has not been restated and continues to be reported under the previous lease guidance ASC 840. AltaGas has applied the package of transition practical expedients which permitted the Corporation to not reassess (a) whether any expired or existing contracts contain leases, (b) lease classifications for any expired or existing leases, and (c) initial direct costs for any existing leases. In addition, AltaGas applied the transition practical expedient that permitted the Corporation to grandfather its accounting policy for land easements that existed as of, or expired, before January 1, 2019. The transition practical expedient to not separate lease and non-lease components for its building, office equipment, transportation equipment, and vehicle leases has been elected for lessee arrangements. The transition practical expedient to not separate lease and non-lease components for its lessor arrangements related to certain assets has also been elected. AltaGas has applied the short-term lease recognition exemption under which lease arrangements with a term of twelve months or less, including extension options that are reasonably certain of being exercised, are exempt from the recognition of a right-of-use asset and lease liability and recorded as an expense over the term of the lease. This exemption applies to all classes of assets.

  On adoption of ASC 842, all operating leases were recognized on the Consolidated Balance Sheets. The adoption resulted in an increase to long-term assets of approximately $181.0 million and an increase to long-term liabilities of approximately $170.5 million (net of the current portion that is recorded in current liabilities of approximately $23.3 million). The lease related liabilities were measured using the present value of the remaining minimum lease payments for existing leases discounted using the Corporation's incremental borrowing rate as of January 1, 2019. For operating leases, the associated right-of-use assets were measured at the amount equal to the lease liabilities on January 1, 2019, adjusted for any prepaid or accrued lease payments and the remaining balance of any lease incentives received. The adoption of ASC 842 did not impact lessor accounting, the Consolidated Statements of Income (Loss), or the Consolidated Statements of Cash Flows.

Please also refer to Note 10 of the Consolidated Financial Statements as at and for the year ended December 31, 2019 for further details;

- ASU No. 2017-08 "Receivables – Nonrefundable Fees and Other Costs: Premium Amortization on Purchased Callable Debt Securities". The amendments in this ASU shorten the amortization period for certain callable debt securities held at a premium. Specifically, the amendments require the premium to be amortized to the earliest call date. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements;

- ASU No. 2017-11 "Earnings per Share and Derivatives and Hedging – Distinguishing Liabilities from Equity: Accounting for Certain Financial Instruments with Down Round Features, Replacement of the Indefinite Deferral for Mandatorily Redeemable Financial Instruments of Certain Nonpublic Entities and Certain Mandatorily Redeemable Non-controlling Interests with a Scope Exception". The amendments in this ASU simplify the accounting for certain equity-linked financial instruments and embedded features with down round features that reduce the exercise price when pricing of a future round of financing is lower. The amendments in this ASU also require entities that present earnings per share under ASC 260 to recognize the effect of a down round feature in a freestanding equity-classified financial instrument only when it is triggered. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements;

- ASU No. 2018-07 "Compensation – Stock Compensation: Improvements to Nonemployee Share-Based Payment Accounting". The amendments in this ASU expand the scope of Topic 718 to include share-based payment transactions for acquiring goods and services from nonemployees, with the objective of making the measurement consistent with employee share based payment awards. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements;

- ASU No. 2018-08 "Not-for-Profit-Entities – Clarifying the Scope and the Accounting Guidance for Contributions Received and Contributions Made". The amendments in this ASU clarify whether a transfer of assets is a contribution or an exchange transaction. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements;

- ASU No. 2018-15 "Intangibles – Goodwill and Other – Internal-Use Software: Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement (CCA) that is a Service Contract". The amendments in this ASU align the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software (and hosting arrangements that include an internal use software license). The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements; and

- ASU No. 2018-16 "Derivatives and Hedging: Inclusion of the Second Overnight Financing Rate (SOFR) Overnight Index Swap (OIS) Rate as a Benchmark Interest Rate for Hedge Accounting Purposes". The amendments in this ASU permit the use of Overhead Index Swap (OIS) rate based on SOFR as a U.S. benchmark interest rate for hedge accounting purposes. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements.

FUTURE CHANGES IN ACCOUNTING PRINCIPLES

In June 2016, FASB issued ASU No. 2016-13 “Financial Instruments – Credit Losses: Measurement of Credit Losses on Financial Instruments”. The amendments in this ASU replace the current “incurred loss” impairment methodology with an “expected loss” model for financial assets measured at amortized cost. The amendments in this ASU are effective for fiscal years beginning after December 15, 2020, and interim periods within those fiscal years. Early adoption is permitted. AltaGas will adopt this standard on January 1, 2020 using a modified-retrospective approach through a cumulative-effect adjustment to retained earnings. AltaGas has completed scoping and evaluation activities for this new accounting standard, and has quantified the impact of this ASU on its opening Consolidated Balance Sheet as at January 1, 2020. Upon adoption, "accounts receivable, net of allowances" is expected to decrease by less than 1 percent of the outstanding accounts receivable balance, with an offsetting increase to "accumulated deficit".

In August 2018, FASB issued ASU No. 2018-13 “Fair Value Measurement – Disclosure Framework: Changes to the Disclosure Requirements for Fair Value Measurement”. The amendments in this ASU modify the disclosure requirements on fair value measurements. The amendments in this update are effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

In August 2018, FASB issued ASU No. 2018-14 “Compensation-Retirement Benefits-Defined Benefit Plans – General: Disclosure Framework – Changes to the Disclosure Requirements for the Defined Benefit Plans”. The amendments in this ASU modify the disclosure requirements on defined benefit pension and other post-retirement plans. The amendments in this ASU are effective for fiscal years beginning after December 15, 2020, and interim periods within those fiscal years. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

In October 2018, FASB issued ASU No. 2018-17 “Consolidation: Targeted Improvements to Related Party Guidance for Variable Interest Entities”. The amendments in this ASU provide a private-company scope exception to the VIE guidance for certain entities and clarify that indirect interest held through related parties under common control will be considered on a proportional basis when determining whether fees paid to decision makers and service providers are variable interests. The amendments in this ASU are effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. An entity should apply the amendments retrospectively with a cumulative-effect adjustment to retained earnings at the beginning of the earliest period presented. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

In March 2019, FASB issued ASU No. 2019-01 “Leases: Codification Improvements”. The amendments in this ASU provide a fair value exception for lessors that are not manufacturers or dealers, clarify the presentation of principal payments received under sales-type and direct finance leases on the statements of cash flows, and clarify transition disclosure requirements for the adoption of ASC 842. The amendments on the fair value exception and on the presentation on the statement of cash flows are effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted. The amendment on the transition disclosure requirement is effective upon adoption of ASC 842. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

In April 2019, FASB issued ASU No. 2019-04 “Financial Instruments - Credit Losses, Derivatives and Hedging, and Codification Improvements”. The amendments in this ASU provide clarification and improve the codification in recently issued accounting standards on credit losses (ASU 2016-13), hedging (ASU 2017-12), and recognizing and measuring financial instruments (ASU 2016-01). The amendments related to credit losses have the same effective date and transition requirements as ASU 2016-13, the amendments related to hedge accounting are effective as of the beginning of the first annual period beginning after issuance of this ASU and may be applied retrospectively to the date ASU 2017-12 was adopted or prospectively with some exceptions, and the amendments related to financial instruments are effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

In May 2019, FASB issued ASU No. 2019-05 “Financial Instruments - Credit Losses: Targeted Transition Relief". The amendments in this ASU provide entities that have certain instruments within the scope of Subtopic 326-20 - Financial Instruments - Credit Losses - Measured at Amortized Cost (other than held-to-maturity debt securities) a one-time irrevocable option to elect fair value treatment on an eligible instrument-by-instrument basis. The effective date and transition methodology for the amendments in this ASU are the same as ASU 2016-13. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

In November 2019, FASB issued ASU No. 2019-11 "Financial Instruments - Credit Losses: Codification Improvements". The amendments in this ASU provide clarification and improve the codification in ASU 2016-13. The effective date and transition methodology for the amendments in this ASU are the same as ASU 2016-13. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

In December 2019, FASB issued ASU No. 2019-12 "Income Taxes: Simplifying the Accounting for Income Taxes". The amendments in this ASU simplify the accounting for income taxes by clarifying certain aspects of current guidance and removing some exceptions to the general principles in ASC 740. The amendments in this ASU are effective for fiscal years beginning after December 15, 2020, and interim periods within those fiscal years. Early adoption is permitted. AltaGas is assessing the impact of this ASU on its consolidated financial statements.

3. Acquisition of WGL Holdings, Inc.

Following the receipt of all required federal, state, and local regulatory approvals, on July 6, 2018 the Corporation acquired WGL. The WGL Acquisition was accounted for 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 was recognized as goodwill at the acquisition date.

The following table summarizes the final purchase price allocation representing the consideration paid and the fair value of the net assets acquired as at July 6, 2018 using an exchange rate of 1.31 to convert U.S. dollars to Canadian dollars. The purchase price allocation was finalized on June 30, 2019 and reflects Management's best estimate of the fair value of WGL's assets and liabilities. In the first half of 2019, based on new information obtained in the period and further refinement of assumptions, adjustments to the purchase price allocation included amounts relating to intangible assets, deferred income taxes, pension liabilities, current liabilities, other long-term liabilities, valuation of equity investments in Midstream pipelines, and deferred rent, resulting in a net increase to goodwill of approximately $92.2 million (Note 11).

Purchase consideration	**$**	**5,973**
Fair value assigned to net assets		
Current assets	$	1,220
Property, plant and equipment		5,884
Intangible assets		577
Regulatory assets		408
Long-term investments		1,475
Other long-term assets		462
Current liabilities		(1,916)
Long-term debt		(2,548)
Preferred shares		(41)
Regulatory liabilities		(1,126)
Deferred income taxes		(741)
Other long-term liabilities		(959)
Non-controlling interest		(9)
Accumulated other comprehensive income		(2)
Fair value of net assets acquired	**$**	**2,684**
Goodwill	**$**	**3,289**

4. Dispositions

Northwest Hydro Electric Facilities

On January 31, 2019, AltaGas completed the disposition of its remaining 55 percent indirect interest in the Northwest Hydro Electric facilities in British Columbia (Northwest Hydro) for net cash proceeds of approximately $1.3 billion. The disposition was completed through the sale of 55 percent of Northwest Hydro Limited Partnership, a subsidiary of AltaGas which indirectly held the Northwest Hydro facilities. As a result, AltaGas recognized a pre-tax gain on disposition of approximately $687.6 million in the Consolidated Statements of Income (Loss) under the line item “other income” for the year ended December 31, 2019.

Non-Core Midstream and Power Assets in Canada

On February 1, 2019, AltaGas completed the disposition of certain non-core Midstream and Power assets for gross cash proceeds of approximately $87.8 million. As a result, AltaGas recognized a pre-tax loss on disposition of approximately $1.2 million in the Consolidated Statements of Income (Loss) under the line item “other income” for the year ended December 31, 2019.

Architect of the Capitol (AOC) Project

In February 2019, AltaGas completed the disposition of a financing receivable related to the construction of an energy management services project for gross cash proceeds of approximately $73.5 million. As a result, AltaGas recognized a pre-tax loss on disposition of approximately $1.3 million in the Consolidated Statements of Income (Loss) under the line item “other income” for the year ended December 31, 2019.

Stonewall Gas Gathering System

On May 31, 2019, AltaGas completed the disposition of WGL Midstream's entire interest in the Stonewall Gas Gathering System (Stonewall) to a wholly-owned subsidiary of DTE Energy Company for gross cash proceeds of approximately $379.2 million (US $280 million). As a result, AltaGas recognized a pre-tax gain on disposition of $34.1 million in the Consolidated Statements of Income (Loss) under the line item “other income” for the year ended December 31, 2019.

Biomass Assets

On August 13, 2019, AltaGas completed the disposition of its equity ownership interests in Craven County Wood Energy LP and Grayling Generation Station LP for net proceeds of approximately $24.5 million (US$18.5 million). There was no gain or loss resulting from this disposition.

Distributed Generation Assets

On September 26, 2019, AltaGas closed the disposition of its portfolio of U.S. distributed generation assets for gross cash proceeds of approximately $975.0 million (US$735.0 million). As a result, AltaGas recognized a pre-tax gain on disposition of approximately $167.5 million in the Consolidated Statements of Income (Loss) under the line item "other income" for the year ended December 31, 2019. There are certain projects for which ownership will not legally transfer to the purchaser until various consents and approvals are obtained. As such, the carrying value of the assets and liabilities relating to these projects remain classified as held for sale on the Consolidated Balance Sheets as at December 31, 2019 (Note 5). The portion of the purchase price relating to these projects is approximately $32.2 million (US$24.8 million) and is recorded within "accounts payable and accrued liabilities" on the Consolidated Balance Sheets until these projects are legally transferred to the purchaser. The pre-tax gain related to these remaining projects has also been deferred and will be recognized as these projects are legally transferred. The purchaser is entitled to after-tax earnings from the distributed generation projects, including those awaiting consent, beginning September 1, 2019.

Capital Spare

In the third quarter of 2019, AltaGas completed the sale of a capital spare turbine in the Power segment for gross cash proceeds of $4.6 million (US$3.5 million). There was no gain or loss resulting from this disposition in the year ended December 31, 2019.

Investment in Meade

On November 13, 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 (Central Penn), for cash proceeds of approximately $811.5 million (US$610.8 million). As a result, AltaGas recognized a pre-tax loss on disposition of $11.1 million in the Consolidated Statements of Income (Loss) under the line item “other income” for the year ended December 31, 2019. During 2019, AltaGas also recognized a pre-tax provision of $44.2 million against AltaGas' investment in Meade Pipeline Co. LLC (Note 14).

5. Assets Held For Sale

As at		December 31, 2019		December 31, 2018
Assets held for sale				
Cash	**$**	**—**	$	4.9
Accounts receivable		**—**		85.2
Inventory		**—**		0.5
Property, plant and equipment		**22.9**		1,189.6
Intangible assets		**—**		248.7
Operating right-of-use assets		**0.4**		—
Goodwill		**1.0**		—
Other long-term assets		**3.2**		—
	$	**27.5**	$	1,528.9
Liabilities associated with assets held for sale				
Accounts payable and accrued liabilities	**$**	**—**	$	23.8
Asset retirement obligations		**0.2**		10.8
Unamortized investment tax credits		**3.2**		—
Operating lease liabilities - long-term		**0.4**		—
Other long-term liabilities		**—**		136.8
	$	**3.8**	$	171.4

Distributed Generation Assets

In September 2019, AltaGas closed the sale of its portfolio of U.S. distributed generation assets (Note 4). However, there are certain projects for which ownership will not legally transfer to the purchaser until various consents and approvals are obtained. As such, the carrying value of the assets and liabilities related to these projects remain classified as held for sale at December 31, 2019. These assets are recorded in the Power segment.

6. Provisions on Assets

Year Ended December 31		2019		2018
Utilities	**$**	**—**	$	193.7
Midstream		**35.2**		153.7
Power		**380.6**		381.3
	$	**415.8**	$	728.7

Utilities

There were no provisions recorded in the Utilities segment in 2019. In 2018, AltaGas recorded pre-tax provisions of $193.7 million related to certain rate-regulated natural gas distributed utility assets that were classified as held for sale in the third quarter of 2018.

Midstream

In 2019, AltaGas recorded pre-tax provisions of $35.2 million related to the Pouce Coupe sour gas treatment facility in Alberta. The pre-tax provisions were comprised of $35.0 million on property, plant and equipment and $0.2 million on intangible assets.

In 2018, AltaGas recorded pre-tax provisions of $153.7 million related to certain non-core Midstream assets that were classified as held for sale at December 31, 2018 and shut-in assets in the South, Cold Lake and Northwest operating areas.

Power

In 2019, AltaGas recorded pre-tax provisions totaling $380.6 million in the Power segment. The pre-tax provisions were recorded against property, plant and equipment. In 2018, AltaGas recorded pre-tax provisions of $381.3 million primarily related to the Tracy, Hanford, and Henrietta gas-fired peaking plants in California that were disposed of in the fourth quarter of 2018, a development project in the U.S., the Pomona natural gas-fired co-generation facility in the United States, and non-core Power assets in Canada and a WGL Energy Systems financing receivable that were classified as held for sale at December 31, 2018.

7. Inventory

As at December 31		**2019**		2018
Natural gas held in storage [a]	**$**	**359.0**	$	418.0
Materials and supplies		**56.3**		53.3
Renewable energy credits and emission compliance instruments		**64.1**		38.2
Natural gas liquids		**26.2**		6.4
	$	**505.6**	$	515.9

(a) As at December 31, 2019, $214.3 million of the natural gas held in storage was held by rate-regulated utilities (2018 - $270.4 million).

8. Property, Plant and Equipment

As at	**December 31, 2019**			December 31, 2018		
	Cost	**Accumulated amortization**	**Net book value**	Cost	Accumulated amortization	Net book value
Utilities	**$ 7,316.1**	**$ (155.0)**	**$ 7,161.1**	$ 7,090.5	$ (89.7)	$ 7,000.8
Midstream	**3,182.0**	**(585.4)**	**2,596.6**	3,178.2	(845.7)	2,332.5
Power	**976.7**	**(594.6)**	**382.1**	4,633.9	(1,858.3)	2,775.6
Corporate	**49.5**	**(40.9)**	**8.6**	49.4	(39.1)	10.3
Reclassified to assets held for sale	**(25.2)**	**2.3**	**(22.9)**	(2,999.3)	1,809.7	(1,189.6)
	$ 11,499.1	**$ (1,373.6)**	**$ 10,125.5**	$ 11,952.7	$ (1,023.1)	$ 10,929.6

Interest capitalized on long-term capital construction projects for the year ended December 31, 2019 was $14.5 million (2018 - $12.6 million).

As at December 31, 2019, the Corporation had approximately $725.2 million (December 31, 2018 - $872.7 million) of capital projects under construction that were not yet subject to amortization.

Depreciation expense related to property, plant and equipment (including assets under capital leases) for the year ended December 31, 2019 was $357.8 million (2018 - $324.3 million).

9. Intangible Assets

As at		December 31, 2019			December 31, 2018	
	Cost	**Accumulated amortization**	**Net book value**	Cost	Accumulated amortization	Net book value
E&T contracts	**$ 26.6**	**$ (15.2)**	**$ 11.4**	$ 26.6	$ (14.3)	$ 12.3
Electricity service agreements	**8.5**	**(7.8)**	**0.7**	269.5	(25.9)	243.6
Energy services relationships	**91.6**	**(27.4)**	**64.2**	176.1	(33.8)	142.3
Software	**303.7**	**(101.2)**	**202.5**	293.9	(77.7)	216.2
Land rights	**1.1**	**(0.1)**	**1.0**	1.4	(0.2)	1.2
Commodity contracts	**327.1**	**(21.3)**	**305.8**	346.3	(6.3)	340.0
Franchises and consents	**—**	**—**	**—**	5.0	—	5.0
Reclassified to assets held for sale *(note 5)*	**—**	**—**	**—**	(277.4)	28.7	(248.7)
	$ 758.6	**$ (173.0)**	**$ 585.6**	$ 841.4	$ (129.5)	$ 711.9

Amortization expense related to intangible assets for the year ended December 31, 2019 was 80.2 million (2018 - $69.7 million).

As at December 31, 2019, the Corporation excluded $184.5 million (December 31, 2018 - $196.4 million) from the asset base subject to amortization. Items excluded relate to gas transportation capacity contracts, software assets under development, 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:

2020	**$ 79.1**
2021	**$ 70.6**
2022	**$ 69.7**
2023	**$ 62.3**
2024	**$ 24.2**
Thereafter	**$ 95.2**

10. Leases

Lessee

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

The components of lease expense were as follows:

	Year Ended December 31, 2019
Operating lease cost (includes variable lease payments)	**$ 29.2**
Finance lease cost	
Amortization of right-of-use assets	**$ 3.4**
Interest on lease liabilities	**0.3**
Total finance lease cost	**$ 3.7**
Total lease cost	**$ 32.9**

Supplemental cash flow information related to leases was as follows:

		Year Ended December 31, 2019
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows from finance leases	$	(0.3)
Operating cash flows from operating leases	$	(20.6)
Financing cash flows from finance leases [(a)]	$	(3.7)
Right-of-use assets obtained in exchange for new lease liabilities		
Operating leases	$	50.4
Finance leases	$	5.4

(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, 2019
Operating Leases		
Operating lease right-of-use assets		
Long-term	$	169.8
Included in assets held for sale *(note 5)*		0.4
Total operating lease right-of-use assets	$	170.2
Operating lease liabilities		
Current	$	(27.3)
Long-term		(153.4)
Included in liabilities associated with assets held for sale *(note 5)*		(0.4)
Total operating lease liabilities	$	(181.1)
Finance Leases		
Property and equipment, gross	$	13.2
Accumulated depreciation		(3.3)
Property and equipment, net	$	9.9
Current portion of long-term debt	$	(3.5)
Long-term debt		(6.4)
Total finance lease liabilities	$	(9.9)

As at	December 31, 2019
Weighted average remaining lease term (years)	
Operating leases	10.9
Finance leases	5.2
Weighted average discount rate (%)	
Operating leases	3.51
Finance leases	3.68

Maturity analysis of lease liabilities was as follows:

	Operating Leases	Finance Leases
2020	$ 27.8	$ 3.5
2021	27.1	2.9
2022	26.5	2.0
2023	24.5	1.1
2024	20.1	0.4
Thereafter	100.1	2.0
Total lease payments	226.1	11.9
Less: imputed interest	(45.0)	(2.0)
Total	$ 181.1	$ 9.9

As of December 31, 2019, AltaGas has additional operating leases, primarily for rail cars, that have not yet commenced of $4.8 million. These operating leases will commence in 2020 with lease terms of up to 6 years.

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
2020	$ 118.3
2021	115.4
2022	115.6
2023	115.9
2024	47.8
Thereafter	477.5
Total	$ 990.5

The carrying value of property, plant, and equipment associated with these leases was approximately $0.5 billion as at December 31, 2019.

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.

11. Goodwill

As at	December 31, 2019	December 31, 2018
Balance, beginning of year	**$ 4,068.2**	$ 817.3
Provisions on assets	**—**	(124.2)
Business acquisition *(note 3)*	**—**	3,196.4
Adjustment to goodwill on business acquisition *(note 3)*	**92.2**	—
Goodwill included in dispositions *(note 4)*	**(29.1)**	—
Reclassified to assets held for sale *(note 5)*	**(1.0)**	—
Foreign exchange translation	**(188.2)**	178.7
Balance, end of year	**$ 3,942.1**	$ 4,068.2

12. Long-Term Investments and Other Assets

As at	December 31, 2019	December 31, 2018
Investments in publicly-traded entities	**$ 4.3**	$ 8.4
Loan to affiliate	**45.0**	45.0
Deferred lease receivable	**17.4**	24.4
Debt issuance costs associated with credit facilities	**6.2**	7.9
Refundable deposits	**8.9**	16.2
Prepayment on long-term service agreements	**80.6**	82.5
Cash calls from joint venture partners	**9.5**	—
Contract asset *(note 24)*	**30.0**	11.5
Rabbi trust *(notes 28 and 31)*	**32.0**	61.7
Other long-term receivables *(note 29)*	**33.1**	—
Other	**29.5**	25.5
	$ 296.5	$ 283.1

13. Variable Interest Entities

Consolidated VIEs

AltaGas consolidates VIEs 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.

Disposal of Consolidated VIE Investments

Prior to the close of the U.S. distributed generation asset sale in the third quarter of 2019, a subsidiary of WGL was the primary beneficiary of SFGF LLC, SFRC LLC, SFGF II LLC, SFEE LLC, and ASD Solar LP, because of its ability to direct the activities most significant to the economic performance of those entities plus the right to receive potentially significant benefits or the obligation to absorb potentially significant losses. These VIEs were consolidated until the close of the distributed generation asset sale (Note 4). As at December 31, 2019, these entities are no longer VIEs of AltaGas.

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

As at		**December 31, 2019**		December 31, 2018
Current assets	**$**	**6.4**	$	1,383.5
Property, plant and equipment		**371.1**		619.2
Long-term investments and other assets		**53.3**		48.0
Operating right-of-use assets		**0.1**		—
Current liabilities		**(3.6)**		(161.8)
Asset retirement obligations		**(3.3)**		(0.9)
Other long-term liabilities		**(0.1)**		(3.0)
Net assets	**$**	**423.9**	$	1,885.0

The decrease in current assets, property, plant and equipment, and current liabilities associated with AltaGas' consolidated VIEs as at December 31, 2019 compared to December 31, 2018 is primarily due to the sale of Northwest Hydro Limited Partnership in January 2019 and the sale of VIEs included in the sale of WGL's distributed generation portfolio (Note 4).

Disposal of Unconsolidated VIE Investments

Prior to the sale of AltaGas' investment in Meade and indirect, non-operating interest in Central Penn (Note 4), WGL Midstream owned a 55 percent interest in Meade (21 percent indirect interest in Central Penn). Although WGL Midstream held a greater than 50 percent interest in Meade, Meade was not consolidated by WGL Midstream and instead was accounted for under the equity method of accounting. WGL Midstream was not the primary beneficiary of Meade as it did not have the power to direct the activities most significant to the economic performance of Meade. WGL Midstream applied the HLBV equity method of accounting and any profits and losses were included in "income from equity investments" in the accompanying Consolidated Statements of Income (Loss) and were added to or subtracted from the carrying amount of AltaGas' investment balance until the close of the Meade sale. As at December 31, 2019, Meade is no longer a VIE of AltaGas.

14. Investments Accounted for by the Equity Method

Description	Location	Ownership Percentage	Carrying value as at December 31 2019	2018	Equity income (loss) for the year ended December 31 2019	2018
AltaGas Canada Inc. (ACI) [(a)]	Canada	**37**	**$ 163.9**	$ 112.5	**$ 17.0**	$ 5.4
AltaGas Idemitsu Joint Venture LP	Canada	**50**	**431.3**	342.9	**62.5**	2.1
Constitution Pipeline, LLC (Constitution) [(b)]	United States	**10**	**0.1**	—	**(0.5)**	(0.2)
Craven County Wood Energy LP [(c)]	United States	**50**	**—**	7.8	**0.1**	(14.1)
Eaton Rapids Gas Storage System	United States	**50**	**27.0**	29.4	**1.3**	2.0
Grayling Generating Station LP [(c)]	United States	**50**	**—**	29.0	**0.3**	3.6
Inuvik Gas Ltd. [(d)]	Canada	**33**	**—**	—	**—**	(0.2)
Meade Pipeline Co. LLC [(c) (e)]	United States	**55**	**—**	757.8	**(3.6)**	12.2
Mountain Valley Pipeline, LLC (Mountain Valley) [(f)]	United States	**10**	**671.3**	532.5	**42.8**	11.5
Sarnia Airport Storage Pool LP	Canada	**50**	**18.0**	18.7	**1.0**	1.0
Petrogas Preferred Shares	Canada	**n/a**	**150.0**	150.0	**12.8**	12.8
Stonewall Gas Gathering Systems LLC [(c)]	United States	**30**	**—**	411.8	**7.4**	11.8
			$ 1,461.6	$ 2,392.4	**$ 141.1**	$ 47.9

(a) As at December 31, 2019, the aggregate market value of AltaGas' investment in ACI was $367.9 million (11,025,000 shares at the quoted closing market price of $33.37 on December 31, 2019). As at December 31, 2018, the aggregate market value was $178.8 million (11,025,000 shares at the quoted closing market price of $16.22 on December 31, 2018).

(b) The equity method is considered appropriate because Constitution is a Limited Liability Company (LLC) with specific ownership accounts and ownership between five and fifty percent, resulting in WGL Midstream exercising a more than minor influence over the investee's operating and financing policies. In February 2020, the partners of Constitution elected not to proceed with the pipeline project (Note 33).

(c) Disposed of in 2019 (Note 4).

(d) Inuvik Gas Ltd. was sold to AltaGas Canada Inc. in October 2018.

(e) Meade was a VIE prior to disposition in November 2019 (Notes 4 and 13).

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

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 Mountain Valley.

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

Year Ended December 31	2019	2018
Revenues	**$ 1,109.3**	$ 351.6
Expenses	**(355.0)**	(142.7)
	$ 754.3	$ 208.9

As at December 31	2019	2018
Current assets	**$ 411.1**	$ 1,204.6
Property, plant and equipment	**$ 8,033.8**	$ 7,602.5
Intangible assets	**$ 21.9**	$ 22.9
Long-term investments and other assets	**$ 1,458.8**	$ 1,326.6
Current liabilities	**$ (393.8)**	$ (1,015.2)
Other long-term liabilities	**$ (992.1)**	$ (949.6)

(a) For equity investments that were disposed of in the year (Note 4), revenues and expenses reflect the period prior to disposition and balance sheet amounts as at December 31 are $nil.

Provisions on investments accounted for by the equity method

During the year ended December 31, 2019, AltaGas recorded a pre-tax provision of $44.2 million against AltaGas' investment in Meade Pipeline Co. LLC as a result of the sale of WGL Midstream's interest in Central Penn. The disposition of the investment in this entity was completed in the fourth quarter of 2019 (Note 4). This equity investment was in the Midstream segment and the provision was recorded in the Consolidated Statements of Income (Loss) under the line item "income from equity investments".

In addition, during the year ended December 31, 2019, AltaGas recorded a pre-tax provision of $2.2 million against AltaGas' investment in Craven County Wood Energy LP as a result of a pending sale. The disposition of the investment in this entity was completed in the third quarter of 2019 (Note 4). This equity investment was in the Power segment and the provision was recorded in the Consolidated Statements of Income (Loss) under the line item "income from equity investments".

During the year ended December 31, 2018, AltaGas recorded a pre-tax provision of $14.5 million against AltaGas' investment in Craven Wood County Energy LP.

AltaGas Canada Inc.

On October 21, 2019, ACI announced that the Public Sector Pension Investment Board and the Alberta Teachers' Retirement Fund Board (together, the "Consortium") and ACI had concluded a definitive arrangement agreement (the "Arrangement Agreement") whereby the Consortium will indirectly acquire all of the issued and outstanding common shares of ACI (the "Common Shares") in an all-cash transaction for $33.50 per Common Share by way of arrangement under the *Canada Business Corporations Act* (the "Arrangement"). On December 19, 2019, the shareholders of ACI approved the Arrangement Agreement. In addition, on December 16, 2019, ACI received a "no-action letter" from the Canadian Competition Bureau confirming that the Commissioner of Competition does not at this time intend to challenge the proposed Arrangement. On December 20, 2019, ACI received the final order from the Court of Queen's Bench of Alberta approving the Arrangement. On February 18, 2020, the Alberta Utilities Commission issued a decision approving the Arrangement. The closing of the Arrangement remains subject to the receipt of approval from the British Columbia Utilities Commission, and the satisfaction or waiver of other customary closing conditions. ACI and the Consortium expect to close the Arrangement in the first half of 2020.

15. Short-term Debt

As at	**December 31, 2019**	December 31, 2018
Bank indebtedness	**$ —**	$ 0.2
Commercial paper [(a)]	**389.0**	1,145.2
Project financing	**71.0**	64.5
	$ 460.0	$ 1,209.9

(a) 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, 2019, certain commercial paper balances have been classified as long-term debt as they are supported by long-term extendible committed credit facilities with maturities ranging from 2022 to 2024 (see Note 16).

Project Financing

WGL and certain of its subsidiaries previously obtained third-party project financing on behalf of the United States federal government to provide funds for the construction of certain energy management services projects entered into under Washington Gas' area-wide contract. When these projects are formally accepted by the government and deemed complete, the ownership of the receivable is assigned to the third-party lender in satisfaction of the obligation, removing both the receivable and the obligation related to the financing from the Consolidated Financial Statements. As at December 31, 2019, draws related to project financing were $71.0 million (December 31, 2018 - $64.5 million).

Other Credit Facilities

As at December 31, 2019, the Corporation held a $70.0 million (December 31, 2018 - $70.0 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. Letters of credit outstanding under this facility as at December 31, 2019 were $nil (December 31, 2018 - $nil).

As at December 31, 2019, AltaGas held a $150.0 million (December 31, 2018 - $150.0 million) unsecured four-year extendible revolving letter of 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. Letters of credit outstanding under this facility as at December 31, 2019 were $25.5 million (December 31, 2018 - $117.0 million).

As at December 31, 2019, AltaGas held a US$200.0 million (December 31, 2018 - US$200.0 million) unsecured bilateral letter of credit demand facility 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, 2019 were $156.4 million (December 31, 2018 - $147.3 million).

As at December 31, 2019, AltaGas held a US$300.0 million (December 31, 2018 - US$300.0 million) unsecured extendible revolving letter of credit facility. Borrowings on the facility incur fees and interest at rates relevant to the nature of the draws made. Letters of credit outstanding on this facility as at December 31, 2019 were $124.6 million (December 31, 2018 - $nil).

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, 2019, commercial paper outstanding classified as short-term debt totaled US$299.5 million (December 31, 2018 - US$839.5 million).

16. Long-Term Debt

As at	Maturity date	December 31, 2019	December 31, 2018
Credit facilities			
$1,400 million unsecured extendible revolving facility [a]	15-May-2023	**$ 89.6**	$ 964.7
US$300 million unsecured extendible revolving facility [b]	15-May-2022	**—**	287.8
Acquisition credit facility [c]	6-Jan-2020	**—**	113.2
US$1,200 million unsecured revolving credit facility [d]	28-Dec-2021	**—**	1,637.0
US$300 million unsecured term facility	27-Feb-2021	**389.6**	—
US$150 million unsecured extendible revolving facility	20-Dec-2023	**163.5**	—
Commercial paper [e]	Various	**367.4**	—
AltaGas Ltd. medium-term notes (MTNs)			
$200 million Senior unsecured - 4.55 percent	17-Jan-2019	**—**	200.0
$200 million Senior unsecured - 4.07 percent	1-Jun-2020	**200.0**	200.0
$350 million Senior unsecured - 3.72 percent	28-Sep-2021	**350.0**	350.0
$500 million Senior unsecured - 2.61 percent	16-Dec-2022	**500.0**	—
$300 million Senior unsecured - 3.57 percent	12-Jun-2023	**300.0**	300.0
$200 million Senior unsecured - 4.40 percent	15-Mar-2024	**200.0**	200.0
$300 million Senior unsecured - 3.84 percent	15-Jan-2025	**300.0**	299.9
$350 million Senior unsecured - 4.12 percent	7-Apr-2026	**349.9**	349.8
$200 million Senior unsecured - 3.98 percent	4-Oct-2027	**199.9**	199.9
$100 million Senior unsecured - 5.16 percent	13-Jan-2044	**100.0**	100.0
$300 million Senior unsecured - 4.50 percent	15-Aug-2044	**299.8**	299.8
$250 million Senior unsecured - 4.99 percent	4-Oct-2047	**250.0**	250.0
WGL and Washington Gas MTNs			
US$450 million Senior unsecured - 2.25 to 4.76 percent [f]	Nov 2019	**—**	682.1
US$250 million Senior unsecured - 2.44 percent [g]	12-Mar-2020	**324.7**	341.1
US$20 million Senior unsecured - 6.65 percent	20-Mar-2023	**26.0**	27.3
US$40.5 million Senior unsecured - 5.44 percent	11-Aug-2025	**52.6**	55.3
US$53 million Senior unsecured - 6.62 to 6.82 percent	Oct - 2026	**68.8**	72.3
US$72 million Senior unsecured - 6.40 to 6.57 percent	Feb - Sep 2027	**93.5**	98.2
US$52 million Senior unsecured - 6.57 to 6.85 percent	Jan - Mar 2028	**67.5**	70.9
US$8.5 million Senior unsecured - 7.50 percent	1-Apr-2030	**11.0**	11.6
US$50 million Senior unsecured - 5.70 to 5.78 percent	Jan - Mar 2036	**64.9**	68.2
US$75 million Senior unsecured - 5.21 percent	3-Dec-2040	**97.4**	102.3
US$75 million Senior unsecured - 5.00 percent	15-Dec-2043	**97.4**	102.3
US$300 million Senior unsecured - 4.22 to 4.60 percent	Sep - Dec 2044	**389.6**	409.3
US$450 million Senior unsecured - 3.80 percent	15-Sep-2046	**584.5**	613.9
US$300 million Senior unsecured - 3.65 percent	16-Sep-2049	**389.6**	—
SEMCO long-term debt			
US$300 million SEMCO Senior Secured - 5.15 percent [h]	21-Apr-2020	**389.6**	409.3
US$82 million SEMCO Senior Secured - 4.48 percent [i]	2-Mar-2032	**76.1**	86.3
Fair value adjustment on WGL Acquisition *(note 3)*		**84.3**	89.0
Finance lease liabilities *(note 10)*		**9.9**	0.8
		$ 6,887.1	$ 8,992.3
Less debt issuance costs		**(36.4)**	(35.2)
		$ 6,850.7	$ 8,957.1
Less current portion		**(922.9)**	(890.2)
		$ 5,927.8	$ 8,066.9

(a) Borrowings on the facility can be by way of prime loans, U.S. base-rate loans, LIBOR 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.
(b) Borrowings on the facility can be by way of U.S. base-rate loans, U.S. prime loans, LIBOR loans, or letters of credit.
(c) The acquisition facility was repaid in full and canceled on February 1, 2019.
(d) Borrowings on the facility can be by way of U.S. base-rate loans, U.S. prime loans, or LIBOR loans.
(e) Commercial paper is supported by the availability of long-term committed credit facilities with maturity dates ranging from 2022 to 2024.
(f) Certain MTNs have a floating rate per annum reset quarterly based on terms set forth in the prospectus supplement filed by WGL pursuant to *Securities Act* Rule 424 on November 27, 2017.
(g) Floating rate per annum reset quarterly based on terms set forth in the prospectus filed by WGL pursuant to *Securities Act* Rule 424 on March 13, 2018.

(h) Collateral for the U.S. dollar MTNs is certain SEMCO assets.
(i) Collateral for the CINGSA Senior secured loan is certain CINGSA assets. Alaska Storage Holding Company, LLC, a subsidiary in which AltaGas has a controlling interest, is the non-recourse guarantor of this loan.

Other Credit Facilities

As at December 31, 2019, WGL held a US$250.0 million (December 31, 2018 - US$650.0 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, 2019 or December 31, 2018.

As at December 31, 2019, Washington Gas held a US$450.0 million (December 31, 2018 - US$350.0 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, 2019 or December 31, 2018.

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, 2019, outstanding commercial paper classified as long-term debt totaled US$283.5 million (December 31, 2018 - $nil).

17. Asset Retirement Obligations

As at December 31		**2019**		2018
Balance, beginning of year	**$**	**500.6**	$	88.3
Obligations acquired *(note 3)*		**—**		399.1
New obligations		**7.0**		3.3
Obligations settled		**(2.5)**		(4.2)
Disposals		**(6.2)**		(1.6)
Revision in estimated cash flow		**(128.5)**		3.8
Accretion expense [(a)]		**18.9**		12.3
Foreign exchange translation		**(20.7)**		20.3
Reclassified to liabilities associated with assets held for sale *(note 5)*		**(0.2)**		(10.8)
Total	**$**	**368.4**	$	510.5
Less current portion (included in accounts payable and accrued liabilities)		**(6.4)**		(9.9)
Balance, end of year	**$**	**362.0**	$	500.6

(a) 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 (Loss).

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, 2019 was $727.0 million (December 31, 2018 - $770.0 million).

The asset retirement obligations have been recorded in the Consolidated Financial Statements at estimated values discounted at rates between 2.0 and 8.5 percent (December 31, 2018 - between 1.5 to 8.5 percent) and are expected to be incurred between 2020 and 2137 (December 31, 2018 - between 2019 and 2064). 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, 2019, a liability of $13.8 million has been recorded on an undiscounted basis related to future environmental response costs (December 31, 2018 - $15.4 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, 2019, AltaGas estimated the maximum liability associated with all of its sites to be approximately $39.9 million (December 31, 2018 - $40.1 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, 2019, AltaGas reported a regulatory asset of $17.7 million (December 31, 2018 - $19.9 million) for the portion of environmental response costs that are expected to be recoverable in future rates (Note 21).

19. Other Long-term Liabilities

As at		**December 31, 2019**		December 31, 2018
Deferred lease payable	**$**	**—**	$	13.1
Deferred revenue		**4.0**		3.9
Customer advances for construction		**63.9**		58.6
Sundance B PPAs termination expense [(a)]		**—**		2.0
Lease inducement		**—**		2.7
Merger commitments		**14.0**		21.4
Other long-term liabilities		**19.9**		20.3
	$	**101.8**	$	122.0

(a) In 2016, AltaGas Pipeline Partnership and the Government of Alberta reached a definitive settlement agreement regarding the termination of the Sundance B Power Purchase Arrangements (PPAs). Under the settlement agreement, AltaGas has agreed to make a total of $6.0 million in cash payments in equal annual installments over three years starting in 2018, $2.0 million of which has been recorded under “accounts payable and accrued liabilities”.

20. Income Taxes

Year Ended December 31		**2019**		2018
Income (loss) before income taxes - consolidated	**$**	**812.7**	$	(716.9)
Statutory income tax rate (%)		**26.5**		27.0
Expected taxes at statutory rates	**$**	**215.4**	$	(193.6)
Add (deduct) the tax effect of:				
Permanent differences	**$**	**10.9**	$	(1.0)
Statutory and other rate differences		**(51.6)**		(19.6)
Rate adjustment for change in tax rates		**(10.7)**		1.3
Deferred income tax recovery on regulated assets		**(24.8)**		(7.3)
Tax differences on divestitures and transactions		**(158.2)**		(32.3)
Non-controlling interests		**3.5**		4.7
Change in valuation allowance		**(11.1)**		(22.3)
Other		**(1.0)**		6.9
	$	**(27.6)**	$	(263.2)
Income tax provision				
Current				
Canada	**$**	**26.7**	$	23.7
United States		**36.6**		0.7
	$	**63.3**	$	24.4
Deferred				
Canada	**$**	**11.6**	$	(166.1)
United States		**(102.5)**		(121.5)
	$	**(90.9)**	$	(287.6)
Effective income tax rate (%)		**(3.4)**		36.7

Net deferred income tax liabilities were composed of the following:

As at		**December 31, 2019**		December 31, 2018
PP&E and intangible assets	**$**	**1,450.6**	$	1,764.6
Regulatory assets		**(204.1)**		(166.3)
Tax pools, deferred financing, and compensation		**(138.2)**		(453.6)
Other		**(161.2)**		(209.9)
Valuation allowance		**12.0**		23.1
	$	**959.1**	$	957.9

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.

The Alberta government passed the Job Creation Tax Cut in 2019 which reduced Alberta's corporate tax rate from 12 percent to 11 percent on July 1, 2019. The tax rate will further be reduced from 11 percent to 10 percent on January 1, 2020 and by 1 percent each year until 2022. The rate from 2022 onwards will ultimately be 8 percent.

The B.C. government increased the corporate tax rate to 12 percent from 11 percent beginning in 2018.

As at December 31, 2019, the Corporation had tax-effected non-capital losses of approximately $170.4 million, which will be available to offset future taxable income. If not used, these losses will expire between 2024 and 2039.

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 2012 to 2018 remain subject to examination by taxation authorities. In the United States, both the federal and state tax returns filed for the years 2013 to 2018 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		**2019**		2018
Balance, beginning of year	**$**	**2.2**	$	5.9
Net changes during the year		**(0.2)**		(3.7)
Balance, end of year	**$**	**2.0**	$	2.2

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 (Loss) by a non-rate-regulated entity. These deferred regulatory assets and liabilities are included in the Consolidated Statements of Income (Loss) 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, RCA, 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 (Loss) 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, 2019 and 2018, over which the Corporation expects to realize or settle the assets or liabilities:

As at December 31		2019		2018	Recovery Period
Regulatory assets - current					
Deferred cost of gas [(a)]	$	**7.6**	$	20.4	Less than one year
Accelerated replacement recovery mechanisms [(b)]		**2.5**		—	Less than one year
Interruptible sharing [(a)]		**2.7**		0.6	Less than one year
	$	**12.8**	$	21.0	
Regulatory assets - non-current					
Deferred regulatory costs [(a) (c)]	$	**149.5**	$	215.5	1 - 51 years
Future recovery of pension and other retirement benefits [(a)]		**128.2**		192.9	Various
Future recovery of non-retirement employee benefits [(a) (d)]		**19.4**		21.3	Various
Deferred pension costs [(e)]		**—**		7.8	—
Deferred environmental costs [(a) (f)]		**17.7**		19.9	Various
Deferred loss on debt transactions and derivative instruments [(a) (g)]		**99.2**		109.3	Various
Deferred future income taxes [(a) (h)]		**42.7**		67.0	Various
Energy efficiency program - Maryland [(i)]		**12.1**		4.6	Various
Other		**17.9**		24.7	Various
	$	**486.7**	$	663.0	
Regulatory liabilities - current					
Deferred cost of gas [(a)]	$	**60.2**	$	71.2	Less than one year
Refundable tax credit [(j)]		**1.9**		3.8	Less than one year
Federal income tax rate change [(k)]		**33.1**		26.2	Less than one year
Virginia rate refund [(l)]		**40.4**		—	Less than one year
Accelerated replacement recovery mechanisms [(b)]		**0.4**		5.2	Less than one year
Interruptible sharing [(a)]		**0.4**		2.3	Less than one year
Other		**9.1**		6.2	Less than one year
	$	**145.5**	$	114.9	
Regulatory liabilities - non-current					
Refundable tax credit [(j)]		**3.9**		6.1	2 years
Future expense of pension and other retirement benefits [(a)]		**261.2**		166.7	Various
Future removal and site restoration costs [(m)]		**483.9**		514.7	Various
Deferred gain on debt transactions and derivative instruments [(a) (g)]		**1.6**		1.8	Various
Federal income tax rate change [(k)]		**628.3**		698.4	Various
Other		**4.3**		5.1	Various
	$	**1,383.2**	$	1,392.8	

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

(d) 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. Certain utilities have recovered pension costs related to regulated operations in rates, and as such the Corporation has recorded a regulatory asset for the unamortized costs associated with the defined benefit and post-retirement benefit plans. Depending on the method utilized by the utility, the recovery period can be either the expected service life of the employees, the benefit period for employees, or a specific recovery period as approved by the respective regulator.

(e) In 2018, this balance related to previously deferred pension and other post-retirement benefits expenses that were fully amortized in 2019.

(f) This balance represents allowed environmental remediation expenditures at SEMCO Gas and Washington Gas sites to be recovered through rates.

(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 fiscal 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, 2019, this also includes a fair value adjustment of $79.8 million (December 31, 2018 - $87.3 million) recorded on the WGL Acquisition (Note 3).

(h) This balance reflects the amount of deferred income taxes expected to be refunded, or recovered from, customers in future rates.

(i) Represents amounts for deferred credits associated with Washington Gas' participation in the energy conservation and efficiency program EmPower in Maryland.

(j) On September 18, 2013, CINGSA received a US$15.0 million gas storage facility tax credit from the State of Alaska for the benefit of its firm storage service customers. CINGSA will derive no direct or indirect benefit from the tax credit. Following receipt of the tax credit, CINGSA deposited it in a separate interest-bearing account. CINGSA will act as a custodian of the tax credit and any interest earned for the benefit of CINGSA's customers. On an annual basis, covering the years 2012 through 2021, CINGSA will disburse to the customers 1/10th of the amount of the tax credit not subject to refund to the State and interest earned. The RCA has approved the disbursement methodology.

(k) 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 Gas and Washington Gas are required to refund to ratepayers.

(l) Represents estimated refunds related to customers billed at a higher rate during the interim period as part of the 2019 Virginia rate case.

(m) This amount and timing of draw down is dependent upon the cost of removal of underlying utility property, plant and equipment and the life of property, plant and equipment.

22. Accumulated Other Comprehensive Income

($ millions)	Available-for-sale	Defined benefit pension and PRB plans	Hedge net investments	Translation foreign operations	Equity investee	Total
Opening balance, January 1, 2019	**$ —**	**$ (19.0)**	**$ (209.2)**	**$ 801.4**	**$ 5.8**	**$ 579.0**
OCI before reclassification	**—**	**15.2**	**68.2**	**(406.2)**	**(0.7)**	**(323.5)**
Amounts reclassified from OCI	**—**	**1.1**	**—**	**—**	**—**	**1.1**
Current period OCI (pre-tax)	**—**	**16.3**	**68.2**	**(406.2)**	**(0.7)**	**(322.4)**
Income tax on amounts retained in AOCI	**—**	**(3.2)**	**(8.2)**	**—**	**—**	**(11.4)**
Income tax on amounts reclassified to earnings	**—**	**(0.3)**	**—**	**—**	**—**	**(0.3)**
Net current period OCI	**—**	**12.8**	**60.0**	**(406.2)**	**(0.7)**	**(334.1)**
Ending balance, December 31, 2019	**$ —**	**$ (6.2)**	**$ (149.2)**	**$ 395.2**	**$ 5.1**	**$ 244.9**
Opening balance, January 1, 2018	$ (7.1)	$ (11.4)	$ (129.0)	$ 342.9	$ 3.7	$ 199.1
OCI before reclassification	—	(14.1)	(90.6)	458.5	2.1	355.9
Amounts reclassified from AOCI	—	0.7	—	—	—	0.7
Adoption of ASU No. 2016-01	7.1	—	—	—	—	7.1
Curtailment of DB and PRB plan	—	4.2	—	—	—	4.2
Current period OCI (pre-tax)	7.1	(9.2)	(90.6)	458.5	2.1	367.9
Income tax on amounts retained in AOCI	—	3.3	10.4	—	—	13.7
Income tax on amounts reclassified to earnings	—	(0.2)	—	—	—	(0.2)
Income tax on amounts related to curtailment of DB and PRB plan	—	(1.5)	—	—	—	(1.5)
Net current period OCI	7.1	(7.6)	(80.2)	458.5	2.1	379.9
Ending balance, December 31, 2018	$ —	$ (19.0)	$ (209.2)	$ 801.4	$ 5.8	$ 579.0

Reclassification From Accumulated Other Comprehensive Income

AOCI components reclassified	Income statement line item	**Year Ended December 31, 2019**	Year Ended December 31, 2018
Defined benefit pension and PRB plans	Other income	**$ 1.1**	$ 0.7
Deferred income taxes	Income tax expense – deferred	**(0.3)**	(0.2)
		$ 0.8	$ 0.5

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 and NGL 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. The fair value of foreign exchange option contracts was calculated using a variation of the Black-Scholes pricing model.

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. A variety of valuation methodologies are used to determine the fair value of Level 3 derivative contracts, including developed valuation inputs and pricing models. The prices used in the valuations are corroborated using multiple pricing sources, and the Corporation periodically conducts assessments to determine whether each valuation model is appropriate for its intended purpose. 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.

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 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 and NGL 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.

Equity securities – the fair value of equity securities was calculated using quoted market prices.

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, 2019				
	Carrying Amount	Level 1	Level 2	Level 3	Total Fair Value
Financial assets					
Fair value through net income [(a)]					
Risk management assets - current	$ 81.4	$ —	$ 30.4	$ 51.0	$ 81.4
Risk management assets - non-current	30.9	—	6.7	24.2	30.9
Equity securities [(b)]	4.3	4.3	—	—	4.3
Fair value through regulatory assets [(a)]					
Risk management assets - current	5.2	—	—	5.2	5.2
Risk management assets - non-current	8.2	—	0.4	7.8	8.2
Amortized cost					
Loans and receivables [(b)]	45.0	—	46.1	—	46.1
	$ 175.0	$ 4.3	$ 83.6	$ 88.2	$ 176.1
Financial liabilities					
Fair value through net income [(a)]					
Risk management liabilities - current	$ 120.6	$ —	$ 98.7	$ 21.9	$ 120.6
Risk management liabilities - non-current	77.0	—	19.2	57.8	77.0
Fair value through regulatory liabilities [(a)]					
Risk management liabilities - current	4.2	—	0.6	3.6	4.2
Risk management liabilities - non-current	90.0	—	—	90.0	90.0
Amortized cost					
Current portion of long-term debt	922.9	—	922.9	—	922.9
Long-term debt	5,927.8	—	6,263.8	—	6,263.8
Other current liabilities [(c)]	15.4	—	15.4	—	15.4
	$ 7,157.9	$ —	$ 7,320.6	$ 173.3	$ 7,493.9

(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) Included under the line item "long-term investments and other assets" on the Consolidated Balance Sheets.

(c) Excludes non-financial liabilities.

As at	December 31, 2018				
	Carrying Amount	Level 1	Level 2	Level 3	Total Fair Value
Financial assets					
Fair value through net income[(a)]					
Risk management assets - current	$ 99.0	$ —	$ 68.3	$ 30.7	$ 99.0
Risk management assets - non-current	49.0	—	18.0	31.0	49.0
Equity securities[(b)]	8.4	8.4	—	—	8.4
Fair value through regulatory assets [(a)]					
Risk management assets - current	15.1	—	2.7	12.4	15.1
Risk management assets - non-current	8.7	—	—	8.7	8.7
Amortized cost					
Loans and receivables [(b)]	45.0	—	45.2	—	45.2
	$ 225.2	$ 8.4	$ 134.2	$ 82.8	$ 225.4
Financial liabilities					
Fair value through net income[(a)]					
Risk management liabilities - current	$ 72.0	$ —	$ 41.3	$ 30.7	$ 72.0
Risk management liabilities - non-current	103.4	—	15.3	88.1	103.4
Fair value through regulatory liabilities [(a)]					
Risk management liabilities - current	17.3	—	2.9	14.4	17.3
Risk management liabilities - non-current	109.6	—	0.1	109.5	109.6
Amortized cost					
Current portion of long-term debt	890.2	—	884.4	—	884.4
Long-term debt	8,066.9	—	8,040.3	—	8,040.3
Other current liabilities [(c)]	11.2	—	11.2	—	11.2
Other long-term liabilities [(c)]	2.0	—	2.0	—	2.0
	$ 9,272.6	$ —	$ 8,997.5	$ 242.7	$ 9,240.2

(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) Included under the line item "long-term investments and other assets" on the Consolidated Balance Sheets.

(c) Excludes non-financial liabilities.

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, 2019:

	Net Fair Value	Valuation Technique	Unobservable Inputs	Range
Natural gas	$ (83.8)	Discounted Cash Flow	Natural Gas Basis Price (per dekatherm)	$ (1.18) - $ 3.27
Natural gas	$ (1.4)	Option Model	Natural Gas Basis Price (per dekatherm)	$ (1.19) - $ 3.30
			Annualized Volatility of Spot Market Natural Gas	29 % - 906 %
Electricity	$ 0.1	Discounted Cash Flow	Electricity Congestion Price (per megawatt hour)	$ (6.73) - $ 65.26

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	2019			2018		
	Natural Gas	**Electricity**	**Total**	Natural Gas	Electricity	Total
Balance, beginning of year	**$ (148.5)**	**$ (14.7)**	**$ (163.2)**	$ —	$ —	$ —
Acquired *(note 3)*	**—**	**—**	**—**	(136.1)	(10.6)	(146.7)
Realized and unrealized gains (losses):						
Recorded in income	**47.6**	**1.4**	**49.0**	(8.3)	(6.5)	(14.8)
Recorded in regulatory assets	**23.6**	**—**	**23.6**	(5.9)	—	(5.9)
Transfers into Level 3	**(9.0)**	**—**	**(9.0)**	—	—	—
Transfers out of Level 3	**12.3**	**—**	**12.3**	7.3	—	7.3
Purchases	**—**	**(11.4)**	**(11.4)**	—	6.4	6.4
Settlements	**(17.1)**	**24.4**	**7.3**	0.3	(3.4)	(3.1)
Foreign exchange translation	**5.9**	**0.4**	**6.3**	(5.8)	(0.6)	(6.4)
Balance, end of year	**$ (85.2)**	**$ 0.1**	**$ (85.1)**	$ (148.5)	$ (14.7)	$ (163.2)

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, 2019 were due to an increase in valuations using observable market inputs. Transfers into Level 3 during the year ended December 31, 2019 were due to an increase in unobservable market inputs used in valuations.

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

Year Ended December 31	2019	2018
Recorded to revenue	**$ 75.2**	$ (11.1)
Recorded to cost of sales	**(26.2)**	(3.7)
	$ 49.0	$ (14.8)

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

Year Ended December 31	2019	2018
Natural gas	**$ 22.5**	$ (2.2)
Energy exports	**(86.7)**	—
NGL frac spread	**(17.4)**	40.0
Power	**(4.9)**	9.3
Foreign exchange	**1.2**	33.7
	$ (85.3)	$ 80.8

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, 2019**			
Risk management assets [(a)]	**Gross amounts of recognized assets/liabilities**	**Gross amounts offset in balance sheet**	**Netting of collateral**	**Net amounts presented in balance sheet**
Natural gas	**$ 121.2**	**$ (53.7)**	**$ —**	**$ 67.5**
Energy exports	**9.7**	**(2.7)**	**4.4**	**11.4**
NGL frac spread	**0.3**	**(0.2)**	**—**	**0.1**
Power	**53.5**	**(6.8)**	**—**	**46.7**
	$ 184.7	**$ (63.4)**	**$ 4.4**	**$ 125.7**
Risk management liabilities [(b)]				
Natural gas	**$ 226.1**	**$ (53.7)**	**$ (27.7)**	**$ 144.7**
Energy exports	**89.5**	**(2.7)**	**—**	**86.8**
NGL frac spread	**1.7**	**(0.2)**	**—**	**1.5**
Power	**68.7**	**(6.8)**	**(3.1)**	**58.8**
	$ 386.0	**$ (63.4)**	**$ (30.8)**	**$ 291.8**

(a) Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $86.6 million and risk management assets (non-current) balance of $39.1 million.

(b) Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $124.8 million and risk management liabilities (non-current) balance of $167.0 million.

As at	December 31, 2018			
Risk management assets [(a)]	Gross amounts of recognized assets/liabilities	Gross amounts offset in balance sheet	Netting of collateral	Net amounts presented in balance sheet
Natural gas	$ 200.8	$ (82.0)	$ —	$ 118.8
NGL frac spread	18.7	(0.7)	—	18.0
Power	42.8	(7.8)	—	35.0
	$ 262.3	$ (90.5)	$ —	$ 171.8
Risk management liabilities [(b)]				
Natural gas	$ 340.4	$ (82.0)	$ (3.3)	$ 255.1
NGL frac spread	2.7	(0.7)	—	2.0
Power	50.6	(7.8)	1.2	44.0
Foreign exchange	1.2	—	—	1.2
	$ 394.9	$ (90.5)	$ (2.1)	$ 302.3

(a) Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $114.1 million and risk management assets (non-current) balance of $57.7 million.

(b) Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $89.3 million and risk management liabilities (non-current) balance of $213.0 million.

Cash Collateral

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

As at	**December 31, 2019**	December 31, 2018
Collateral posted with counterparties	**$ 29.1**	$ 27.6
Cash collateral held representing an obligation	**$ 0.3**	$ 0.8

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, 2019, AltaGas has posted $5.5 million (December 31, 2018 - $nil) of 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, 2019		December 31, 2018
Risk management liabilities with credit-risk-contingent features	**$**	**42.2**	$	14.7
Maximum potential collateral requirements	**$**	**29.0**	$	7.5

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. AltaGas does not make use of derivative instruments for speculative purposes.

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 2033. 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 forward contracts and commodity swaps outstanding related to the activities in the energy services business as at December 31, 2019 and 2018:

December 31, 2019	**Fixed price (per GJ)**	**Period (months)**	**Notional volume (GJ)**		**Fair Value**
Sales	**1.32 to 6.81**	**1-166**	**698,126,985**	**$**	**28.9**
Purchases	**0.22 to 6.81**	**1-167**	**1,406,991,689**	**$**	**(104.4)**
Swaps	**0.22 to 10.24**	**1-51**	**541,652,374**	**$**	**(1.7)**

December 31, 2018	Fixed price (per GJ)	Period (months)	Notional volume (GJ)		Fair Value
Sales	1.07 to 12.19	1-178	858,640,810	$	19.0
Purchases	0.69 to 16.26	1-179	1,638,207,391	$	(179.5)
Swaps	2.56 to 15.37	1-231	621,578,572	$	20.9

Energy Exports

AltaGas entered into a series of swaps to lock in a portion of the volumes exposed to the propane price differential between North American Indices and the Far East Index for contracts not under tolling arrangements at RIPET. AltaGas had the following contracts outstanding as at December 31, 2019:

December 31, 2019	Fixed price (per Bbl)	Period (months)	Notional volume (Bbl)		Fair Value
Propane	**21.49 to 29.71**	**1-27**	**9,374,826**	**$**	**(75.4)**

NGL Frac Spread

AltaGas entered into a series of swaps to lock in a portion of the volumes exposed to NGL frac spread. AltaGas had the following contracts outstanding as at December 31, 2019 and 2018:

December 31, 2019	Fixed price	Period (months)	Notional volume		Fair Value
Butane swaps	**73.02 to 75.15/Bbl**	**1-12**	**346,852 Bbl**	**$**	**(0.5)**
Crude oil swaps	**73.02 to 75.15/Bbl**	**1-12**	**212,587 Bbl**	**$**	**(0.9)**
Natural gas swaps	**1.58 to 1.86/GJ**	**1-12**	**3,883,992 GJ**	**$**	**—**

December 31, 2018	Fixed price	Period (months)	Notional volume		Fair Value
Propane swaps	$38.89 to $47.63/Bbl	1-12	1,725,114 Bbl	$	12.6
Butane swaps	$52.95 to $55.26/Bbl	1-12	74,371 Bbl	$	1.2
Crude oil swaps	$79.64 to $86.28/Bbl	1-12	329,230 Bbl	$	6.0
Natural gas swaps	$1.38 to $1.68/GJ	1-12	9,490,365 GJ	$	(3.8)

Power

AltaGas sells power to the Alberta Electric System Operator at market prices. AltaGas also sells power 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 Alberta 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 2024. As at December 31, 2019, AltaGas had no intention to terminate any contracts prior to maturity. AltaGas had the following power commodity forward contracts and commodity swaps outstanding as at December 31, 2019 and 2018:

December 31, 2019	Fixed price (per MWh)	Period (months)	Notional volume (MWh)		Fair Value
Power sales	**31.63 to 66.76**	**1-42**	**8,034,024**	**$**	**39.0**
Power purchases	**31.63 to 66.76**	**1-60**	**8,552,467**	**$**	**(27.3)**
Swap purchases	**(7.88) to 74.26**	**1-48**	**25,058,577**	**$**	**(23.8)**

December 31, 2018	Fixed price (per MWh)	Period (months)	Notional volume (MWh)		Fair Value
Power sales	26.90 to 95.03	1-60	11,881,575	$	(1.9)
Power purchases	25.50 to 50.25	1-42	8,507,874	$	16.4
Swap purchases	(6.07) to 76.18	1-48	20,957,180	$	(22.3)

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, 2019:

Factor	Increase or decrease to forward prices	Increase or decrease to income before tax ($ millions)
Alberta power price	$1/MWh	2.3
PJM power price	US$1/MWh	1.9
AECO natural gas price	$0.50/GJ	1.1
NYMEX natural gas price	US$0.50/GJ	2.6
Energy Exports:		
Propane Far East Index to Mont Belvieu spread	$1/Bbl	3.4
Baltic LPG Freight	$1/Bbl	6.1
NGL frac spread:		
Western Texas Intermediate (WTI) crude oil	$1/Bbl	0.6
Natural gas	$0.50/GJ	1.9

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 and/or preferred shares outstanding. AltaGas may also enter into foreign exchange forward derivatives to manage the risk of fluctuating cash flows due to variations in foreign exchange rates. As at December 31, 2019 and December 31, 2018, AltaGas did not have any outstanding foreign exchange forward contracts.

AltaGas may designate its U.S. dollar-denominated debt as a net investment hedge of its U.S. subsidiaries. As at December 31, 2019, AltaGas has designated US$300.0 million of outstanding debt as a net investment hedge (December 31, 2018 - US$1,494.0 million). For the year ended December 31, 2019, AltaGas incurred after-tax unrealized gains of $60.0 million arising from the translation of debt in OCI (2018 - after-tax unrealized loss of $80.2 million).

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, 2019, approximately 76 percent of AltaGas' total outstanding short-term and long-term debt was at fixed rates (December 31, 2018 - 59 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, 2019.

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, 2019, 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, 2019, a pre-tax loss of $1.9 million was recorded related to these instruments (2018 - pre-tax loss of $1.0 million).

Accounts Receivable Past Due or Impaired

AltaGas had the following past due or impaired accounts receivable (AR):

As at December 31, 2019	Total	AR accruals	Receivables impaired	Less than 30 days	31 to 60 days	61 to 90 days	Over 90 days
Trade receivable	**$ 1,238.2**	**$ 343.5**	**$ 33.2**	**$ 757.9**	**$ 61.2**	**$ 11.6**	**$ 30.8**
Other	**17.4**	**—**	**—**	**17.3**	**—**	**—**	**0.1**
Allowance for credit losses	**(33.2)**	**—**	**(33.2)**	**—**	**—**	**—**	**—**
	$ 1,222.4	**$ 343.5**	**$ —**	**$ 775.2**	**$ 61.2**	**$ 11.6**	**$ 30.9**

As at December 31, 2018	Total	AR accruals	Receivables impaired	Less than 30 days	31 to 60 days	61 to 90 days	Over 90 days
Trade receivable	$ 1,574.6	$ 447.5	$ 54.7	$ 961.5	$ 74.1	$ 12.8	$ 24.0
Other	27.6	—	—	27.5	—	—	0.1
Allowance for credit losses	(54.7)	—	(54.7)	—	—	—	—
	$ 1,547.5	$ 447.5	$ —	$ 989.0	$ 74.1	$ 12.8	$ 24.1

Allowance for credit losses	December 31, 2019	December 31, 2018
Balance, beginning of year	**$ 54.7**	$ 2.4
Foreign exchange translation	**(2.6)**	0.1
New allowance [(a)]	**27.5**	53.1
Change in allowance [(b)]	**(9.2)**	(0.9)
Allowance applied to uncollectible customer accounts	**(37.2)**	—
Balance, end of year	**$ 33.2**	$ 54.7

(a) Upon close of the WGL Acquisition in 2018, AltaGas acquired WGL's allowance for credit losses of approximately $52.9 million.

(b) Includes removal of allowance related to asset disposals of approximately $8.1 million in 2019.

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			
As at December 31, 2019	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**After 5 years**
Accounts payable and accrued liabilities	**$ 1,324.9**	**$ 1,324.9**	**$ —**	**$ —**	**$ —**
Dividends payable	**22.3**	**22.3**	**—**	**—**	**—**
Short-term debt	**460.0**	**460.0**	**—**	**—**	**—**
Other current liabilities [(a)]	**15.4**	**15.4**	**—**	**—**	**—**
Risk management contract liabilities	**291.8**	**124.8**	**34.1**	**13.2**	**119.7**
Current portion of long-term debt [(b)]	**920.4**	**920.4**	**—**	**—**	**—**
Long-term debt [(b)]	**5,872.5**	**—**	**1,489.2**	**921.3**	**3,462.0**
	$ 8,907.3	**$ 2,867.8**	**$ 1,523.3**	**$ 934.5**	**$ 3,581.7**

(a) Excludes non-financial liabilities.
(b) Excludes deferred financing costs, discounts, finance lease liabilities, and the fair value adjustment on the WGL Acquisition.

		Contractual maturities by period			
As at December 31, 2018	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Accounts payable and accrued liabilities	$ 1,488.2	$ 1,488.2	$ —	$ —	$ —
Dividends payable	22.0	22.0	—	—	—
Short-term debt	1,209.9	1,209.9	—	—	—
Other current liabilities [(a)]	11.2	11.2	—	—	—
Other long-term liabilities [(a)]	2.0	—	2.0	—	—
Risk management contract liabilities	302.3	89.3	113.3	33.3	66.4
Current portion of long-term debt [(b)]	888.5	888.5	—	—	—
Long-term debt [(b)]	8,014.8	—	3,063.4	1,592.6	3,358.8
	$ 11,938.9	$ 3,709.1	$ 3,178.7	$ 1,625.9	$ 3,425.2

(a) Excludes non-financial liabilities.
(b) Excludes deferred financing costs, discounts, finance lease liabilities, and the fair value adjustment on the WGL Acquisition.

24. Revenue

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

	Year Ended December 31, 2019				
	Utilities	**Midstream**	**Power**	**Corporate**	**Total**
Revenue from contracts with customers					
Commodity sales contracts	**$ —**	**$ 1,093.7**	**$ 1,131.4**	**$ —**	**$ 2,225.1**
Midstream service contracts	**—**	**145.0**	**—**	**—**	**145.0**
Gas sales and transportation services	**2,501.4**	**—**	**—**	**—**	**2,501.4**
Storage services	**28.1**	**—**	**—**	**—**	**28.1**
Other	**9.2**	**2.7**	**29.0**	**—**	**40.9**
Total revenue from contracts with customers	**$ 2,538.7**	**$ 1,241.4**	**$ 1,160.4**	**$ —**	**$ 4,940.5**
Other sources of revenue					
Revenue from alternative revenue programs [(a)]	**$ 29.5**	**$ —**	**$ —**	**$ —**	**$ 29.5**
Leasing revenue [(b)]	**0.9**	**136.6**	**105.1**	**—**	**242.6**
Risk management and trading activities [(c)] [(d)]	**—**	**196.2**	**65.9**	**0.2**	**262.3**
Other	**(4.9)**	**0.1**	**24.9**	**—**	**20.1**
Total revenue from other sources	**$ 25.5**	**$ 332.9**	**$ 195.9**	**$ 0.2**	**$ 554.5**
Total revenue	**$ 2,564.2**	**$ 1,574.3**	**$ 1,356.3**	**$ 0.2**	**$ 5,495.0**

(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 Power 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. The majority of revenue generated by the Midstream and Power segments is from the physical sale and delivery of natural gas and power to end users, except for WGL Midstream (see footnote d).

(d) WGL Midstream trading margins are reported in risk management and trading activities from the Midstream segment. WGL Midstream enters into derivative contracts for the purpose of optimizing its storage and transportation capacity as well as managing the transportation and storage assets on behalf of third parties. The trading margins of WGL Midstream, including unrealized gains and losses on derivative instruments, are netted within revenues. Gross revenues for the year ended December 31, 2019 of $504.5 million associated with the GAIL Global (USA) LNG LLC (GAIL) contract, which are in scope of ASC 606, are reported within risk management and trading activities. While the GAIL contract is individually not accounted for as a derivative, it is inseparable from the overall trading portfolio of WGL Midstream. Revenue is recognized 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. The GAIL contract has a term of 20 years and began on March 31, 2018.

	Year Ended December 31, 2018				
	Utilities	Midstream	Power	Corporate	Total
Revenue from contracts with customers					
Commodity sales contracts	$ —	$ 665.2	$ 497.5	$ —	$ 1,162.7
Midstream service contracts	—	205.0	—	—	205.0
Gas sales and transportation services	1,684.3	—	—	—	1,684.3
Storage services	35.4	—	—	—	35.4
Other	10.7	0.6	25.1	—	36.4
Total revenue from contracts with customers	$ 1,730.4	$ 870.8	$ 522.6	$ —	$ 3,123.8
Other sources of revenue					
Revenue from alternative revenue programs [a]	$ 21.7	$ —	$ —	$ —	$ 21.7
Leasing revenue [b]	0.6	96.6	354.9	—	452.1
Risk management and trading activities [c] [d]	1.0	377.6	268.5	(2.9)	644.2
Other	(1.1)	(0.4)	16.0	0.4	14.9
Total revenue from other sources	$ 22.2	$ 473.8	$ 639.4	$ (2.5)	$ 1,132.9
Total revenue	$ 1,752.6	$ 1,344.6	$ 1,162.0	$ (2.5)	$ 4,256.7

(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 Power 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. Revenue generated by the Midstream and Power segments is from the physical sale and delivery of natural gas and power to end users, except for WGL Midstream (see footnote d).

(d) WGL Midstream trading margins are reported in risk management and trading activities from the Midstream segment. WGL Midstream enters into derivative contracts for the purpose of optimizing its storage and transportation capacity as well as managing the transportation and storage assets on behalf of third parties. The trading margins of WGL Midstream, including unrealized gains and losses on derivative instruments, are netted within revenues. Gross revenues for the year ended December 31, 2018 of $264.2 million associated with the GAIL Global (USA) LNG LLC (GAIL) contract, which are in scope of ASC 606, are reported within risk management and trading activities. While the GAIL contract is individually not accounted for as a derivative, it is inseparable from the overall trading portfolio of WGL Midstream. Revenue is recognized 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. The GAIL contract has a term of 20 years and began on March 31, 2018.

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.

Gas Storage Services

Gas storage customers are billed monthly for services provided. Customer billings are based on four components: (i) reservation charges; (ii) capacity charges; (iii) injection/withdrawal charges; and (iv) excess charges. Reservation charges are based on the customer’s contract withdrawal quantity, capacity charges are based on the customer’s total contract quantity, and injection/ withdrawal charges are based on the volume of gas delivered to or from the customer. Excess charges are applied to each day that the storage quantity exceeds 100 percent of the customer’s maximum storage quantity. Revenue is recognized as the service has been performed over time on a monthly basis, which corresponds to the invoice amount. The majority of these contracts have terms extending beyond one year.

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 the RIPET generate revenue from the sale and delivery of liquid propane purchased from upstream producers. Revenue from these sales contracts is recognized when propane is 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 propane loaded on a vessel.

Commodity sales also include gas sales to residential, commercial, and industrial customers in certain jurisdictions 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 Service Contracts

AltaGas earns revenue from its field gathering and processing facilities, extraction facilities, 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.

Power Segment

For the Power segment, a significant amount of revenue earned is 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.

Commodity Sales

Energy generated from commercial solar and combined heating and power assets is sold under long-term power purchase agreements with a general duration of approximately 20 years. These long-term purchase agreements provide stable cash flow by way of contracted prices for the underlying commodities. During 2019, AltaGas closed the sale of its U.S. portfolio of distributed generation assets, which included wholly owned solar and fuel cell projects and tax equity partnership interests (Note 4). Subsequent to the sale, AltaGas will continue to generate energy from its combined heating and power assets.

Commodity sales also include electricity sales to residential, commercial, and industrial customers in certain jurisdictions 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 meter readings or the amount of energy delivered to the customer. Revenue is recognized based on the amount the Corporation is entitled to invoice the customer.

Contract Balances

As at December 31, 2019, a contract asset of $30.0 million has been recorded within long-term investments and other assets on the Consolidated Balance Sheets (December 31, 2018 – $11.5 million). This contract asset represents the difference in revenue recognized under a new rate in a blend-and-extend contract modification with a customer. Revenue from this contract modification will be recognized at the pre-modification rate for the remainder of the original term with the excess revenue recorded as a contract asset. The contract asset will be drawn down over the remaining term of the modified contract.

In addition, at December 31, 2019 there is a contract asset of $58.6 million (December 31, 2018 - $47.3 million) recorded within prepaid expenses and other current assets on the Consolidated Balance Sheets for WGL Energy Systems' unbilled revenue relating to design-build construction contracts. The contract asset represents unbilled amounts typically resulting from sales under contracts when the cost-to-cost method of revenue recognition is utilized, and revenue recognized exceeds the amount billed to the customer. Right to payment is achieved when the projects are formally "accepted" by the federal government. At December 31, 2019, contract liabilities of $1.7 million (December 31, 2018 - $2.2 million) have been recorded within accounts payable and accrued liabilities on the Consolidated Balance Sheets. The contract liabilities consist of advance payments and billings in excess of revenue recognized and deferred revenue. Contract assets and liabilities are reported in a net position on a contract-by-contract basis at the end of each reporting period.

Contract Assets

As at	December 31, 2019	December 31, 2018
Balance, beginning of year	**$ 58.8**	$ —
Additions	**32.3**	130.1
Transfers to held for sale [(a)]	**—**	(72.2)
Transfers to accounts receivable [(b)]	**—**	(3.7)
Foreign exchange translation	**(2.5)**	4.6
Balance, end of year	**$ 88.6**	$ 58.8

(a) In the fourth quarter of 2018, WGL Energy Systems reached an agreement for the sale of a financing receivable included in the contract asset balance. Accordingly, the receivable was classified as held for sale at December 31, 2018. In February 2019, WGL Energy Systems completed the sale of the financing receivable (Note 4).

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

Contract Liabilities

As at	December 31, 2019	December 31, 2018
Balance, beginning of year	**$ 2.2**	$ —
Additions	**1.9**	2.6
Revenue recognized from contract liabilities [(a)]	**(2.2)**	(0.5)
Foreign exchange translation	**(0.2)**	0.1
Balance, end of year	**$ 1.7**	$ 2.2

(a) Recognition of revenue related to performance obligations satisfied in the current period for amounts that were previously included in contract liabilities.

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, 2019:

	2020	2021	2022	2023	2024	2025 & beyond	Total
Midstream service contracts	$ 113.1	$ 89.8	$ 88.9	$ 86.5	$ 86.4	$ 971.9	**$ 1,436.6**
Storage services	24.2	24.2	23.5	23.2	23.2	168.4	**286.7**
Other	19.4	8.9	2.0	2.0	2.0	12.0	**46.3**
	$ 156.7	$ 122.9	$ 114.4	$ 111.7	$ 111.6	$ 1,152.3	**$ 1,769.6**

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.

Dividend Reinvestment and Optional Cash Purchase Plan (DRIP or the Plan)

The Plan consists of two components: a Dividend Reinvestment component and an Optional Cash Purchase component. The Premium Dividend™ component of the plan was suspended in December 2018. The Dividend Reinvestment and Optional Cash Purchase component was suspended in December 2019, with the December dividend (payable January 2020) being the last dividend payment eligible for reinvestment by participating shareholders under the DRIP. The Plan in its entirety will remain suspended until further notice.

The Plan provided eligible holders of common shares with the opportunity to, at their election, reinvest the cash dividends paid by AltaGas on their common shares towards the purchase of new common shares at a 3 percent discount to the average market price (as defined below) of the common shares on the applicable dividend payment date (the Dividend Reinvestment component of the Plan).

In addition, the Plan provided shareholders who are enrolled in the Dividend Reinvestment component of the Plan with the opportunity to purchase new common shares at the average market price (with no discount) on the applicable dividend payment date (the Optional Cash Purchase component of the Plan).

Each of the components of the Plan was subject to prorating and other limitations on availability of new common shares in certain events. The "average market price", in respect of a particular dividend payment date, refers to the arithmetic average (calculated to four decimal places) of the daily volume weighted average trading prices of common shares on the Toronto Stock Exchange for the trading days on which at least one board lot of common shares is traded during the 10 business days immediately preceding the applicable dividend payment date. Such trading prices will be appropriately adjusted for certain capital changes (including common share subdivisions, common share consolidations, certain rights offerings and certain dividends). Shareholders resident outside of Canada (other than the U.S.) may participate in the Dividend Reinvestment component or the Optional Cash Purchase component of the Plan only if their participation is permitted by the laws of the jurisdiction in which they reside and provided that AltaGas is satisfied, in its sole discretion, that such laws do not subject the Plan or AltaGas to additional legal or regulatory requirements.

Common Shares Issued and Outstanding	Number of shares		Amount
January 1, 2018	175,279,216	$	4,007.9
Shares issued on conversion of subscription receipts, net of issuance costs	84,510,000		2,305.6
Shares issued for cash on exercise of options	57,275		1.3
Deferred taxes on share issuance cost	—		13.3
Shares issued under DRIP	15,377,575		325.8
December 31, 2018	275,224,066	$	6,653.9
Shares issued for cash on exercise of options	76,177		1.2
Deferred taxes on share issuance cost	—		(3.9)
Shares issued under DRIP	3,774,442		67.8
Issued and outstanding at December 31, 2019	**279,074,685**	**$**	**6,719.0**

Preferred Shares

As at	December 31, 2019			December 31, 2018		
Issued and Outstanding	**Number of shares**		**Amount**	Number of shares		Amount
Series A	**5,511,220**	**$**	**137.8**	5,511,220	$	137.8
Series B	**2,488,780**		**62.2**	2,488,780		62.2
Series C	**8,000,000**		**205.6**	8,000,000		205.6
Series E	**8,000,000**		**200.0**	8,000,000		200.0
Series G	**6,885,823**		**172.1**	8,000,000		200.0
Series H	**1,114,177**		**27.9**	—		—
Series I	**8,000,000**		**200.0**	8,000,000		200.0
Series K	**12,000,000**		**300.0**	12,000,000		300.0
Washington Gas						
$4.80 series	**—**		**—**	150,000		19.7
$4.25 series	**—**		**—**	70,600		9.4
$5.00 series	**—**		**—**	60,000		7.9
Share issuance costs, net of taxes			**(28.5)**			(27.9)
Fair value adjustment on WGL Acquisition *(note 3)*			**—**			4.1
	52,000,000	**$**	**1,277.1**	52,280,600	$	1,318.8

On December 20, 2019, all outstanding Washington Gas preferred shares (US$4.25 series, US$4.80 series, and US$5.00 series) were redeemed. A gain of $3.5 million was recognized upon redemption.

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

	Current yield	Annual dividend per share[(b)]	Redemption price per share	Redemption and conversion option date[(c)(d)]	Right to convert into[(d)]
Series A [(e)]	3.380%	$0.84500	$25	September 30, 2020	Series B
Series B [(f) (g)]	Floating	Floating	$25	September 30, 2020	Series A
Series C [(h)]	5.290%	US$1.32250	US$25	September 30, 2022	Series D
Series E [(e)]	5.393%	$1.34825	$25	December 31, 2023	Series F
Series G [(e)]	4.620%	$1.15575	$25	September 30, 2024	Series H
Series H [(f) (g)]	Floating	Floating	$25	September 30, 2024	Series G
Series I [(i)]	5.250%	$1.31250	$25	December 31, 2020	Series J
Series K [(j)]	5.000%	$1.25000	$25	March 31, 2022	Series L

(a) This table only includes those series of preferred shares that are currently issued and outstanding. The Corporation is authorized to issue up to 8,000,000 of each of Series D Shares, Series F Shares, and Series J Shares, and up to 12,000,000 of Series L 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, Series J Shares, and Series L Shares are also redeemable for $25.50, and Series D Shares are redeemable for US$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, Series C Shares, Series E Shares, Series G Shares, Series I Shares, and Series K 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 D Shares, Series F Shares, Series J Shares, and Series L 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, Series E 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), 3.17 percent (Series E 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, 2019, the floating quarterly dividend rate is $0.26803 per share for Series B Shares and $0.29289 per share for Series H Shares for the period starting December 31, 2019 to, but excluding, March 31, 2020.

(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) Holders of Series C Shares will be entitled to receive cumulative quarterly fixed dividends, which will reset on the redeemable and conversion option date and every fifth year thereafter, at a rate equal to the sum of the five-year U.S. Government bond yield plus 3.58 percent.

(i) Holders of Series I Shares will be entitled to receive cumulative quarterly fixed dividends, which will reset on the redeemable and conversion option date and every fifth year thereafter, at a rate equal to the then five-year Government of Canada bond yield plus 4.19 percent, provided that, in any event, such rate shall not be less than 5.25 percent per annum.

(j) Holders of Series K Shares will be entitled to receive cumulative quarterly fixed dividends, which will reset on the redeemable and conversion option date and every fifth year thereafter, at a rate equal to the then five-year Government of Canada bond yield plus 3.80 percent, provided that, in any event, such rate shall not be less than 5.00 percent per annum.

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, 2019, 13,915,160 shares were reserved for issuance under the plan. As at December 31, 2019, share options granted under the plan have a term between six and ten years until expiry and vest no longer than over a four-year period.

As at December 31, 2019, the unexpensed fair value of share option compensation cost associated with future periods was $4.5 million (December 31, 2018 - $3.7 million).

The following table summarizes information about the Corporation's share options:

As at	**December 31, 2019 Options outstanding**			December 31, 2018 Options outstanding		
	Number of options		**Exercise price [(a)]**	Number of options		Exercise price [(a)]
Share options outstanding, beginning of year	**6,309,183**	**$**	**25.18**	4,533,761	$	32.35
Granted	**2,287,385**		**19.12**	2,811,460		16.69
Exercised	**(76,177)**		**14.52**	(57,275)		20.68
Forfeited	**(1,165,435)**		**27.31**	(878,013)		36.47
Expired	**(311,000)**		**36.16**	(100,750)		14.60
Share options outstanding, end of year	**7,043,956**	**$**	**22.49**	6,309,183	$	25.18
Share options exercisable, end of year	**2,921,642**	**$**	**27.70**	2,897,723	$	32.01

(a) Weighted average.

As at December 31, 2019, the aggregate intrinsic value of the total share options exercisable was $3.3 million (December 31, 2018 - $nil), the total intrinsic value of share options outstanding was $12.1 million (December 31, 2018 - $nil) and the total intrinsic value of share options exercised was $0.4 million (December 31, 2018 - $0.3 million).

The following table summarizes the employee share option plan as at December 31, 2019:

	Options outstanding				**Options exercisable**			
	Number outstanding		Weighted average exercise price	Weighted average remaining contractual life	Number exercisable		Weighted average exercise price	Weighted average remaining contractual life
$14.52 to $18.00	2,557,328	$	15.19	4.98	638,385	$	14.62	4.79
$18.01 to $25.08	1,961,805		19.78	4.77	305,750		21.05	0.96
$25.09 to $46.70	2,524,823		32.00	2.72	1,977,507		32.95	2.39
	7,043,956	**$**	**22.49**	**4.11**	**2,921,642**	**$**	**27.70**	**2.77**

The fair value of each option granted is estimated on the date of grant using the Black-Scholes-Merton option pricing model. The weighted average grant date fair value and assumptions are as follows:

Year ended December 31	2019	2018
Fair value per options ($)	**2.30**	1.27
Risk-free interest rate (%)	**1.48**	1.99
Expected life (years)	**6**	6
Expected volatility (%)	**24.84**	23.23
Annual dividend per share ($) [(a)]	**0.96**	1.18
Forfeiture rate (%)	**—**	—

(a) Annual dividend per share is calculated based on a weighted average share price and forward dividend yields as the grant dates.

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

AltaGas has a Phantom Plan for employees and executive officers, 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, which allows granting of deferred share units (DSUs) to directors. 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)*	**2019**	2018
Balance, beginning of year	**9,908,154**	564,549
Acquired [(a)]	**—**	5,291,621
Converted to cash [(a)]	**—**	(5,291,621)
Granted	**674,971**	9,502,347
Exercised	**(113,668)**	—
Vested and paid out	**(677,667)**	(148,154)
Forfeited	**(3,377,962)**	(66,522)
Units in lieu of dividends	**71,003**	55,934
Outstanding, end of year	**6,484,831**	9,908,154

(a) Upon close of the WGL Acquisition in 2018, AltaGas acquired WGL's PUs. These were converted to a fixed cash amount at a value of US$1.00 per unit. At December 31, 2019, the WGL PUs comprised approximately 4.9 million of the outstanding units (December 31, 2018 - 8.9 million).

For the year ended December 31, 2019, the compensation expense recorded for the Phantom Plan and DSUP was $21.7 million (2018 – $16.6 million). As at December 31, 2019, the unrecognized compensation expense relating to the remaining vesting period for the Phantom Plan was $21.8 million (December 31, 2018 - $26.9 million) and is expected to be recognized over the vesting period.

26. Net Income (Loss) Per Common Share

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

	Year Ended December 31	
	2019	2018
Numerator:		
Net income (loss) applicable to controlling interests	**$ 833.5**	$ (435.1)
Less: Preferred share dividends	**(68.5)**	(66.6)
Gain on redemption of preferred shares *(note 25)*	**3.5**	—
Net income (loss) applicable to common shares	**$ 768.5**	$ (501.7)
Denominator:		
(millions)		
Weighted average number of common shares outstanding	**276.9**	222.6
Dilutive equity instruments [(a)]	**0.5**	—
Weighted average number of common shares outstanding - diluted	**277.4**	222.6
Basic net income (loss) per common share	**$ 2.78**	$ (2.25)
Diluted net income (loss) per common share	**$ 2.77**	$ (2.25)

(a) Includes all options that have a strike price lower than the average share price of AltaGas' common shares during the periods noted.

For the year ended December 31, 2019, 4.3 million share options (2018 – 4.0 million) were excluded from the diluted net income (loss) per share calculation as their effects were anti-dilutive.

27. Other Income

Year Ended December 31		2019		2018
Gains (losses) from sale of assets	**$**	**875.8**	$	(10.6)
Other components of net benefit cost *(note 28)*		**27.4**		18.9
Interest income and other revenue		**9.0**		2.7
Losses on investments		**(4.1)**		(10.1)
	$	**908.1**	$	0.9

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 was $19.8 million for the year ended December 31, 2019 (2018 - $15.4 million).

Defined Benefit Plans

AltaGas has several defined benefit pension plans for unionized and non-unionized employees, including one in Canada (which is comprised of five divisions) and six in the United States. The plans in the United States include a qualified, trusteed, non-contributory defined benefit pension plan, and a non-funded defined benefit restoration plan maintained by Washington Gas.

The defined benefit plans are partially funded except for two of the divisions in Canada which are fully funded and one of the plans in the United States which is not funded.

AltaGas' most recent actuarial valuation of the Canadian defined benefit plans for funding purposes was completed in 2016. AltaGas is required to file an actuarial valuation of its Canadian defined benefit plans with the pension regulators at least every three years. The next actuarial valuation for funding purposes is required to be completed as of a date no later than December 31, 2019, and will be filed with the pension regulators in 2020. Actuarial valuations for funding purposes are required annually for AltaGas' U.S. defined benefit plans.

Supplemental Executive Retirement Plans (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). This defined benefit SERP was closed to new entrants beginning January 1, 2010.

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 Medical 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. One of these benefit plans is partially funded and three of them are fully funded.

Rabbi Trusts

Rabbi trusts of $57.4 million as at December 31, 2019 have been funded to satisfy the employee benefit obligations associated with WGL’s various pension plans (December 31, 2018 - $89.3 million). These balances are included in prepaid expenses and other current assets and long-term investments and other assets in 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, 2019	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	$ 34.3	$ 1.9	$ 1,635.3	$ 458.0	$ 1,669.6	$ 459.9
Actuarial loss (gain)	2.1	0.2	182.0	(14.8)	184.1	(14.6)
Current service cost	2.6	—	23.8	8.5	26.4	8.5
Member contributions	—	—	—	2.2	—	2.2
Interest cost	1.2	0.1	67.8	19.1	69.0	19.2
Benefits paid	(4.0)	(0.1)	(77.3)	(24.4)	(81.3)	(24.5)
Expenses paid	(0.1)	—	(0.6)	(0.1)	(0.7)	(0.1)
Settlements	—	—	(24.7)	—	(24.7)	—
Plan amendments	—	—	0.3	—	0.3	—
Other	—	—	—	1.0	—	1.0
Foreign exchange translation	—	—	(82.0)	(21.8)	(82.0)	(21.8)
Balance, end of year	$ 36.1	$ 2.1	$ 1,724.6	$ 427.7	$ 1,760.7	$ 429.8
Plan assets						
Fair value, beginning of year	$ 13.8	$ —	$ 1,354.1	$ 791.2	$ 1,367.9	$ 791.2
Actual return on plan assets	0.9	—	284.2	177.4	285.1	177.4
Employer contributions	4.3	0.1	38.7	0.1	43.0	0.2
Member contributions	—	—	—	2.2	—	2.2
Benefits paid	(4.0)	(0.1)	(77.3)	(23.7)	(81.3)	(23.8)
Expenses paid	(0.1)	—	(0.6)	(0.1)	(0.7)	(0.1)
Settlements	—	—	(25.7)	—	(25.7)	—
Other	—	—	—	0.1	—	0.1
Foreign exchange translation	—	—	(69.5)	(41.3)	(69.5)	(41.3)
Fair value, end of year	$ 14.9	$ —	$ 1,503.9	$ 905.9	$ 1,518.8	$ 905.9
Funded status	$ (21.2)	$ (2.1)	$ (220.7)	$ 478.2	$ (241.9)	$ 476.1

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

Year Ended December 31, 2018	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	$ 165.6	$ 15.8	$ 303.8	$ 82.7	$ 469.4	$ 98.5
Plans disposed	(132.1)	(13.6)	—	—	(132.1)	(13.6)
Actuarial gain	(0.8)	(0.1)	(67.7)	(33.8)	(68.5)	(33.9)
Current service cost	2.4	0.1	16.2	5.3	18.6	5.4
Member contributions	—	—	—	2.1	—	2.1
Interest cost	1.2	0.1	38.0	10.9	39.2	11.0
Benefits paid	(2.7)	—	(43.2)	(13.4)	(45.9)	(13.4)
Expenses paid	—	—	(0.9)	(0.1)	(0.9)	(0.1)
Plan combinations	0.7	—	1,311.7	382.9	1,312.4	382.9
Plan amendments	—	(0.4)	—	—	—	(0.4)
Foreign exchange translation	—	—	77.4	21.4	77.4	21.4
Balance, end of year	$ 34.3	$ 1.9	$ 1,635.3	$ 458.0	$ 1,669.6	$ 459.9
Plan assets						
Fair value, beginning of year	$ 115.2	$ 8.1	$ 248.7	$ 70.8	$ 363.9	$ 78.9
Plans disposed	(102.1)	(8.1)	—	—	(102.1)	(8.1)
Actual return on plan assets	(0.3)	—	(54.7)	(37.2)	(55.0)	(37.2)
Employer contributions	3.4	—	7.6	2.5	11.0	2.5
Member contributions	—	—	—	2.1	—	2.1
Benefits paid	(2.7)	—	(43.2)	(13.4)	(45.9)	(13.4)
Expenses paid	—	—	(0.9)	(0.1)	(0.9)	(0.1)
Plan combinations	0.3	—	1,133.2	732.7	1,133.5	732.7
Foreign exchange translation	—	—	63.4	33.8	63.4	33.8
Fair value, end of year	$ 13.8	$ —	$ 1,354.1	$ 791.2	$ 1,367.9	$ 791.2
Funded status	$ (20.5)	$ (1.9)	$ (281.2)	$ 333.2	$ (301.7)	$ 331.3

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

The following amounts were included in the Consolidated Balance Sheets:

	December 31, 2019			December 31, 2018		
	Defined Benefit	**Post-Retirement Benefits**	**Total**	Defined Benefit	Post-Retirement Benefits	Total [(a)]
Prepaid post-retirement benefits	**$ —**	**$ 486.8**	**$ 486.8**	$ —	$ 341.4	$ 341.4
Accounts payable and accrued liabilities	**(25.7)**	**—**	**(25.7)**	(27.6)	—	(27.6)
Future employee obligations	**(216.2)**	**(10.7)**	**(226.9)**	(274.1)	(10.1)	(284.2)
	$ (241.9)	**$ 476.1**	**$ 234.2**	$ (301.7)	$ 331.3	$ 29.6

(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, 2019**		December 31, 2018	
	Canada	**United States**	Canada	United States
Accumulated benefit obligation [(a)]	**$ 34.7**	**$ 1,616.4**	$ 32.9	$ 1,525.6

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

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, 2019	**Canada**		**United States**		**Total**	
	Defined Benefit	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**
Past service credit (cost)	**$ (0.2)**	**$ 0.3**	**$ 0.1**	**$ —**	**$ (0.1)**	**$ 0.3**
Net actuarial gain (loss)	**(9.4)**	**(0.7)**	**(14.9)**	**18.2**	**(24.3)**	**17.5**
Recognized in AOCI pre-tax	**$ (9.6)**	**$ (0.4)**	**$ (14.8)**	**$ 18.2**	**$ (24.4)**	**$ 17.8**
Increase (decrease) by the amount included in deferred tax liabilities	**2.3**	**0.1**	**7.0**	**(9.0)**	**9.3**	**(8.9)**
Net amount in AOCI after-tax	**$ (7.3)**	**$ (0.3)**	**$ (7.8)**	**$ 9.2**	**$ (15.1)**	**$ 8.9**

Year Ended December 31, 2018	Canada		United States		Total	
	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Past service credit (cost)	$ (0.3)	$ 0.4	$ (0.2)	$ —	$ (0.5)	$ 0.4
Net actuarial loss	(8.7)	(0.5)	(10.7)	(5.0)	(19.4)	(5.5)
Recognized in AOCI pre-tax	$ (9.0)	$ (0.1)	$ (10.9)	$ (5.0)	$ (19.9)	$ (5.1)
Increase by the amount included in deferred tax liabilities	2.4	—	2.2	1.4	4.6	1.4
Net amount in AOCI after-tax	$ (6.6)	$ (0.1)	$ (8.7)	$ (3.6)	$ (15.3)	$ (3.7)

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, 2019	**Canada**		**United States**		**Total**	
	Defined Benefit	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**
Past service cost (credit)	**$ —**	**$ —**	**$ 1.1**	**$ (105.4)**	**$ 1.1**	**$ (105.4)**
Net actuarial loss (gain)	**—**	**—**	**127.1**	**(155.8)**	**127.1**	**(155.8)**
Recognized in regulatory asset (liability)	**$ —**	**$ —**	**$ 128.2**	**$ (261.2)**	**$ 128.2**	**$ (261.2)**

Year Ended December 31, 2018	**Canada**		**United States**		**Total**	
	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Past service cost (credit)	$ —	$ —	$ 0.8	$ (110.2)	$ 0.8	$ (110.2)
Net actuarial loss (gain)	—	—	188.2	(52.6)	188.2	(52.6)
Recognized in regulatory asset (liability)	$ —	$ —	$ 189.0	$ (162.8)	$ 189.0	$ (162.8)

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.

Amounts to be amortized in the next fiscal year from AOCI	**Defined Benefit**	Post-Retirement Benefits
Past service cost (credit)	$ 0.2	$ (0.7)
Actuarial loss	4.0	0.3
Total	**$ 4.2**	**$ (0.4)**

Amounts to be amortized in the next fiscal year from regulatory assets (liabilities)	**Defined Benefit**	Post-Retirement Benefits
Past service credit (cost)	$ (0.2)	$ 16.7
Actuarial gain (loss)	(17.1)	0.5
Total	**$ (17.3)**	**$ 17.2**

The net pension expense by plan was as follows:

	Year Ended December 31, 2019					
	Canada		**United States**		**Total**	
	Defined Benefit	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**
Current service cost [a]	**$ 2.6**	**$ —**	**$ 23.8**	**$ 8.5**	**$ 26.4**	**$ 8.5**
Interest cost [b]	**1.2**	**0.1**	**67.8**	**19.1**	**69.0**	**19.2**
Expected return on plan assets [b]	**(0.5)**	**—**	**(74.6)**	**(37.1)**	**(75.1)**	**(37.1)**
Amortization of past service cost (credit) [b]	**0.1**	**—**	**0.4**	**(21.9)**	**0.5**	**(21.9)**
Amortization of net actuarial loss [b]	**0.9**	**—**	**11.7**	**0.1**	**12.6**	**0.1**
Plan settlements [b]	**—**	**—**	**4.1**	**—**	**4.1**	**—**
Other [b]	**—**	**—**	**—**	**0.9**	**—**	**0.9**
Net benefit cost (income) recognized	**$ 4.3**	**$ 0.1**	**$ 33.2**	**$ (30.4)**	**$ 37.5**	**$ (30.3)**

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

	Year Ended December 31, 2018					
	Canada		United States		Total	
	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Current service cost [a]	$ 2.4	$ 0.1	$ 16.2	$ 5.3	$ 18.6	$ 5.4
Interest cost [b]	1.2	0.1	38.0	10.9	39.2	11.0
Expected return on plan assets [b]	(0.5)	—	(49.9)	(21.6)	(50.4)	(21.6)
Amortization of past service cost (credit) [b]	0.1	—	0.1	(11.5)	0.2	(11.5)
Amortization of net actuarial loss [b]	0.6	—	7.7	0.4	8.3	0.4
Net benefit cost (income) recognized	$ 3.8	$ 0.2	$ 12.1	$ (16.5)	$ 15.9	$ (16.3)

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

The objective for fund returns, 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. 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).

The Corporation's target asset mix for the Canadian plans is 45 percent to 55 percent fixed income assets. The target asset mix for SEMCO plans is 33 percent fixed income assets and for WGL plans is 50 percent to 60 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 plans are as follows as at December 31, 2019:

Canada	**Fair value**	Level 1	Level 2	Percentage of Plan Assets (%)
Cash and short-term equivalents	**$ 1.9**	$ 1.9	$ —	12.8
Canadian equities	**4.1**	4.1	—	27.5
Foreign equities	**2.4**	2.4	—	16.0
Fixed income	**5.7**	5.7	—	38.3
Real estate	**0.8**	—	0.8	5.4
	$ 14.9	$ 14.1	$ 0.8	100.0

United States	**Fair value**	Level 1	Level 2	Percentage of Plan Assets (%)
Cash and short-term equivalents	**$ 10.8**	$ 10.8	$ —	0.4
Canadian equities	**2.6**	2.6	—	0.1
Foreign equities [(a)]	**302.5**	302.2	0.3	12.6
Fixed income	**933.0**	123.2	809.8	38.7
Derivatives	**(0.2)**	—	(0.2)	—
Other [(b)]	**12.0**	—	12.0	0.5
Total investments in the fair value hierarchy	**$ 1,260.7**	$ 438.8	$ 821.9	52.3
Investments measured at net asset value using the NAV practical expedient [(c)]				
Commingled funds [(d)]	**$ 648.9**			26.9
Private equity/limited partnership [(e)]	**55.6**			2.3
Pooled separate accounts [(f)]	**32.0**			1.3
Collective trust fund [(g)]	**433.8**			18.1
Total fair value of plan investments	**$ 2,431.0**			100.9
Net payable [(h)]	**(21.2)**			(0.9)
	$ 2,409.8			100.0

(a) Investments in foreign equities include U.S. and international securities.
(b) As at December 31, 2019, 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, 2019, investments in commingled funds consisted of approximately 58 percent common stock of large-cap U.S. companies, 18 percent U.S. Government fixed income securities, and 24 percent corporate bonds for WGL's post-retirement benefit plans.
(e) As at December 31, 2019, investments in a private equity/limited partnership consisted of common stock of international companies.
(f) As at December 31, 2019, investments in pooled separate accounts consisted of income producing properties located in the United States.
(g) As at December 31, 2019, investments in collective trust funds consisted primarily of 90 percent common stock of U.S, companies, 8 percent income producing properties located in the United States, and 2 percent short-term money market investments.
(h) As at December 31, 2019, this net payable primarily represents pending trades for investments purchased net of pending trades for investments sold and interest receivable.

Total		Fair value		Level 1		Level 2	Percentage of Plan Assets (%)
Cash and short-term equivalents	$	**12.7**	$	12.7	$	—	0.5
Canadian equities		**6.7**		6.7		—	0.3
Foreign equities [(a)]		**304.9**		304.6		0.3	12.6
Fixed income		**938.7**		128.9		809.8	38.7
Derivatives		**(0.2)**		—		(0.2)	—
Real estate		**0.8**		—		0.8	—
Other [(b)]		**12.0**		—		12.0	0.5
Total investments in the fair value hierarchy	$	**1,275.6**	$	452.9	$	822.7	52.6
Investments measured at net asset value using the NAV practical expedient [(c)]							
Commingled funds[(d)]	$	**648.9**					26.8
Private equity/limited partnership [(e)]		**55.6**					2.3
Pooled separate accounts [(f)]		**32.0**					1.3
Collective trust fund [(g)]		**433.8**					17.9
Total fair value of plan investments	$	**2,445.9**					100.9
Net payable [(h)]		**(21.2)**					(0.9)
	$	**2,424.7**					100.0

(a) Investments in foreign equities include U.S. and international securities.
(b) As at December 31, 2019, 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, 2019, investments in commingled funds consisted of approximately 58 percent common stock of large-cap U.S. companies, 18 percent U.S. Government fixed income securities, and 24 percent corporate bonds for WGL's post-retirement benefit plans.
(e) As at December 31, 2019, investments in a private equity/limited partnership consisted of common stock of international companies.
(f) As at December 31, 2019, investments in pooled separate accounts consisted of income producing properties located in the United States.
(g) As at December 31, 2019, investments in collective trust funds consisted primarily of 90 percent common stock of U.S, companies, 8 percent income producing properties located in the United States, and 2 percent short-term money market investments.
(h) As at December 31, 2019, this net payable primarily represents pending trades for investments purchased net of pending trades for investments sold and interest receivable.

Year Ended December 31	**2019**		2018	
Significant actuarial assumptions used in measuring net benefit plan costs	**Defined Benefit**	**Post-Retirement Benefits**	Defined Benefit	Post-Retirement Benefits
Discount rate (%)	**2.90 - 4.40**	**3.90 - 4.50**	3.25 - 4.30	3.60 - 4.30
Expected long-term rate of return on plan assets (%) [(a)]	**5.75 - 7.15**	**4.66 - 7.15**	3.20 - 7.60	3.75 - 7.60
Rate of compensation increase (%)	**2.75 - 4.10**	**4.10**	2.75 - 4.10	4.10
Average remaining service life of active employees (years)	**9.0**	**13.2**	9.6	14.1

(a) Only applicable for funded plans

As at December 31	**2019**		2018	
Significant actuarial assumptions used in measuring benefit obligations	**Defined Benefit**	**Post-Retirement Benefits**	Defined Benefit	Post-Retirement Benefits
Discount rate (%)	**2.90 - 3.50**	**3.10 - 3.60**	3.60 - 4.40	3.90 - 4.50
Rate of compensation increase (%)	**2.75 - 4.00**	**3.50**	2.75 - 4.10	4.10

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 6.3 percent. The health care cost trend rates were assumed to decline to between 2.0 and 4.5 percent by 2027.

The assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one percentage point change in the assumed health care trend rates would have the following effects for 2019:

	Increase	Decrease
Service and interest costs	$ 1.9	$ (1.5)
Accrued benefit obligation	$ 22.7	$ (18.4)

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:		
2020	$ 37.0	$ 3.2
Expected benefit payments:		
2020	$ 104.6	$ 23.8
2021	$ 85.1	$ 22.6
2022	$ 93.3	$ 22.5
2023	$ 90.0	$ 22.3
2024	$ 90.7	$ 22.1
2025 - 2028	$ 474.1	$ 112.6

29. Commitments, Guarantees, and Contingencies

Commitments

AltaGas has long-term natural gas purchase and transportation arrangements, propane purchase agreements, electricity purchase arrangements, service agreements, pipeline and storage contracts, capital commitments, environmental commitments, merger commitments, and operating leases for office space, office equipment, rail cars, and automobile 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, 2019 are estimated as follows:

	2020	2021	2022	2023	2024	2025 & beyond	Total
Gas purchase [(a)]	$ 2,374.0	$ 2,488.2	$ 2,323.6	$ 2,076.1	$ 1,959.5	$ 22,772.0	**$ 33,993.4**
Propane purchase [(b)]	220.2	127.2	94.9	86.5	58.4	127.1	**714.3**
Electricity purchase [(c)]	567.2	318.1	160.0	56.4	11.0	0.4	**1,113.1**
Service agreements [(d) (e) (f)]	58.7	44.0	28.2	23.4	22.9	309.1	**486.3**
Pipeline and storage services [(g)]	721.2	652.5	627.8	600.4	550.5	3,876.7	**7,029.1**
Capital projects [(h)]	6.9	—	—	—	—	—	**6.9**
Operating leases [(i)]	27.8	27.1	26.5	24.5	20.1	100.1	**226.1**
Environmental [(j)]	6.5	4.3	1.0	1.0	0.6	0.4	**13.8**
Merger commitments [(k)]	8.2	3.8	1.9	1.9	1.9	4.3	**22.0**
	$ 3,990.7	$ 3,665.2	$ 3,263.9	$ 2,870.2	$ 2,624.9	$ 27,190.1	**$ 43,605.0**

(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 forward prices, which may fluctuate significantly from period to period.

(b) AltaGas enters into contracts to purchase propane for its operations at RIPET. These contracts are used to ensure that there is an adequate supply of propane to meet shipment commitments and to minimize exposure to market price fluctuations. Propane purchase commitments are valued based on forward prices, which may fluctuate significantly from period to period.

(c) 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$17.4 million of commitments related to renewable energy credits.

(d) In 2014, AltaGas' Blythe facility entered into a Long-Term Service Agreement (LTSA) with Siemens 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, 2019, the total commitment was $167.9 million payable over the next 16 years, of which $45.4 million is expected to be paid over the next five years.

(e) In 2017, AltaGas entered into a 12-year service agreement for tug services to support the marine operations of RIPET.

(f) In 2015, AltaGas entered into a Project Agreement that contemplated the sublease of lands from Ridley Terminals Inc. (RTI), provision of certain terminal services, and access to RTI's terminal facilities to support RIPET's operations for an initial term of 20 years ending in 2039. In 2019, RILE LP and RTI executed a Terminal Services Agreement that formalized the concepts outlined in the Project Agreement.

(g) Pipeline and storage commitments include minimum payments for natural gas transportation, storage and peaking contracts that have expiration dates through 2044.

(h) Commitments for capital projects. Estimated amounts are subject to variability depending on the actual construction costs.

(i) Operating leases include lease arrangements for office spaces, vehicles, rail cars, land, and office and other equipment.

(j) Environmental commitments include committed payments related to certain environmental response costs.

(k) Represents the estimated future payments of merger commitments that have been accrued but not paid. In addition, there are certain additional merger commitments that will be expensed when costs are incurred in the future, including the investment of up to US$70 million over a ten year period to further extend natural gas service, investment of US$8 million for leak mitigation within three years of the merger, hiring damage prevention trainers in each jurisdiction for a total of US$2 million over five years, and developing 15 megawatts of either electric grid energy storage or Tier 1 renewable resources within five years. As at December 31, 2019, the cumulative amount of merger commitments that have been expensed but not yet paid is approximately US$17 million.

Guarantees

AltaGas has guaranteed payments primarily for certain commitments on behalf of some of its subsidiaries. AltaGas has also guaranteed payments for certain of its external partners. As at December 31, 2019, AltaGas has no guarantees to 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.

Antero Contract

In June 2019, a jury trial was held in the County Court for Denver, Colorado to consider a contractual dispute relating to gas pricing between Washington Gas and WGL Midstream (together, the Companies) and Antero Resources Corporation (Antero). Following the trial, the jury returned a verdict in favor of Antero for approximately US$96 million, of which approximately US$11 million was against Washington Gas with the remainder against WGL Midstream. Following the official entry of the judgment, the Companies filed an appeal on August 16, 2019.

AltaGas recorded a net reduction to the acquired working capital of WGL of approximately US$45 million to account for the verdict in favor of Antero net of tax and other expected recoveries. Expected recoveries include a $33.1 million receivable recorded in "Long-term investments and other assets" on the Consolidated Balance Sheets for amounts expected to be recovered under a commercial arrangement with a third party.

Silver Spring, Maryland Incident

On April 23, 2019, the National Transportation and Safety Board (NTSB) held a hearing during which it found, among other things, that the probable cause of the August 10, 2016, explosion and fire at an apartment complex on Arliss Street in Silver Spring, Maryland “was the failure of an indoor mercury service regulator with an unconnected vent line that allowed natural gas into the meter room where it accumulated and ignited from an unknown ignition source. Contributing to the accident was the location of the mercury service regulators where leak detection by odor was not readily available.” Washington Gas disagrees with the NTSB’s probable cause findings. Following this hearing, on June 10, 2019, the NTSB issued an accident report.

A total of 37 civil actions related to the incident were filed against WGL and Washington Gas in the Circuit Court for Montgomery County, Maryland. All of these suits sought unspecified damages for personal injury and/or property damage. All personal injury and property damage claims asserted by residents at the Flower Branch Apartments have been settled and paid. Washington Gas has been reimbursed by its insurers for the amounts paid in the settlements.

In connection with the incident, on September 5, 2019, the PSC of MD ordered Washington Gas, within 30 days, to (i) provide a detailed response to the NTSB’s probable cause findings and (ii) provide evidence regarding the status of a 2003 mercury regulator replacement program and, if the program was not completed, to show cause why the PSC of MD should not impose a civil penalty on Washington Gas. On November 18, 2019, the Technical Staff of the PSC of MD, the MD Office of People’s Counsel (OPC), Montgomery County, MD and the Apartment and Office Building Association of Metropolitan Washington (AOBA) filed written comments on Washington Gas' response to the Show-Cause Order. Technical Staff commented that the PSC of MD may impose a civil penalty but did not expressly recommend same. Montgomery County, MD, OPC and AOBA requested that the PSC of MD impose a civil penalty on Washington Gas. On December 17, 2019, the PSC of MD held a public hearing near the apartment complex at Arliss Street, at which some residents requested that Washington Gas accelerate and complete its mercury service regulator program and that Washington Gas absorb the cost of same. Washington Gas intends to file comments with the PSC of MD responding to all written comments and resident testimony. Management believes that the likelihood of a civil penalty is probable and has accrued US$0.3 million to reflect the minimum liability expected to result from the proceeding. Though Washington Gas is unable to estimate the maximum possible penalty, other parties recommended penalties ranging from US$32 million (AOBA, which argued that Washington Gas should absorb all costs of removal and relocation of mercury service regulators) to US$123.3 million (OPC, which argued that Washington Gas should absorb all costs of removal and relocation of mercury service regulators and pay a fine of US$25,000 per day for each day mercury service regulators remain on Washington Gas’ system).

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, 2019		December 31, 2018
Due from related parties				
Accounts receivable [(a)]	**$**	**17.8**	$	60.8
Long-term investments and other assets [(b)]		**45.0**		45.0
	$	**62.8**	$	105.8
Due to related parties				
Accounts payable [(c)]	**$**	**2.7**	$	6.3
Risk management liabilities - current [(d)]		**—**		0.9
	$	**2.7**	$	7.2

(a) Receivables from joint ventures and ACI.

(b) AltaGas has provided a $100.0 million interest bearing secured loan facility to Petrogas of which $50.0 million is committed. The facility is available for Petrogas to draw upon from time to time for general corporate purposes. The facility is subject to annual renewal and has a maturity date of June 27, 2021. As at December 31, 2019, Petrogas had drawn $45.0 million (December 31, 2018 - $45.0 million) under the facility.

(c) Payables to joint venture.

(d) Foreign exchange hedge with ACI.

The following transactions with related parties have been recorded on the Consolidated Statements of Income (Loss) for the years ended December 31, 2019 and 2018:

Year Ended December 31		2019		2018
Revenue [(a)]	**$**	**114.9**	$	68.4
Cost of sales [(b)]	**$**	**12.8**	$	4.2
Operating and administrative recoveries [(c)]	**$**	**(1.8)**	$	(1.3)
Other income [(d)]	**$**	**3.2**	$	9.2

(a) In the ordinary course of business, AltaGas sold natural gas and natural gas liquids to a joint venture and ACI. For the year ended December 31, 2018, revenue also includes an unrealized loss on a foreign exchange hedge with ACI of $0.2 million.

(b) In the ordinary course of business, AltaGas obtained natural gas storage services from a joint venture as well as incurred costs related to the sale of natural gas liquids to affiliates.

(c) Administrative costs recovered from joint ventures. In addition, subsequent to the initial public offering (IPO) of ACI, AltaGas is providing certain day-to-day services to ACI under a Transition Services Agreement on a cost recovery basis. The Transition Services Agreement will operate until June 30, 2020, subject to earlier termination in certain circumstances, and is extendable by mutual agreement of the parties.

(d) Interest income from loans to Petrogas (secured loan facility) and loans to ACI. Subsequent to the IPO of ACI, AltaGas provided certain loans to ACI for a portion of 2018. Loans to ACI were fully repaid by December 31, 2018.

31. Supplemental Cash Flow Information

The following table details the changes in operating assets and liabilities from operating activities:

	Year Ended December 31	
	2019	2018
Source (use) of cash:		
Accounts receivable	**$ 168.4**	$ (526.9)
Inventory	**(2.1)**	(100.8)
Other current assets	**(85.5)**	12.5
Regulatory assets - current	**7.1**	(15.8)
Accounts payable and accrued liabilities	**(280.2)**	237.9
Customer deposits	**(16.9)**	(13.3)
Regulatory liabilities - current	**34.2**	69.2
Risk management liabilities - current	**1.1**	—
Other current liabilities	**(5.6)**	(5.9)
Other operating assets and liabilities	**(52.0)**	(143.4)
Changes in operating assets and liabilities	**$ (231.5)**	$ (486.5)

The following cash payments have been included in the determination of earnings:

	Year Ended December 31	
	2019	2018
Interest paid (net of capitalized interest)	**$ 351.7**	$ 288.9
Income taxes paid	**$ 67.2**	$ 36.9

The following table is a reconciliation of cash and restricted cash balances:

As at December 31	**2019**	2018
Cash and cash equivalents	**$ 57.1**	$ 101.6
Restricted cash holdings from customers - current	**4.0**	4.1
Restricted cash holdings from customers - non-current	**3.9**	6.1
Restricted cash included in prepaid expenses and other current assets [(a)]	**25.4**	27.6
Restricted cash included in long-term investments and other assets [(a)]	**32.0**	61.7
Cash, cash equivalents, and restricted cash per Consolidated Statements of Cash Flows	**$ 122.4**	$ 201.1

(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 four reporting segments:

Utilities	▪ rate-regulated natural gas distribution assets in Michigan, Alaska, the District of Columbia, Maryland, and Virginia; ▪ rate-regulated natural gas storage in the United States; and ▪ equity investment in AltaGas Canada Inc.
Midstream	▪ NGL processing and extraction plants; ▪ transmission pipelines to transport natural gas and NGL; ▪ natural gas gathering lines and field processing facilities; ▪ purchase and sale of natural gas; ▪ natural gas storage facilities; ▪ liquefied petroleum gas (LPG) terminal; ▪ natural gas and NGL marketing; ▪ equity investment in Petrogas, a North American entity engaged in the marketing, storage and distribution of NGL, drilling fluids, crude oil and condensate diluents; ▪ interest in a regulated pipeline in the Marcellus/Utica gas formation; and ▪ sale of natural gas to residential, commercial and industrial customers in Washington D.C., Maryland, Virginia, Delaware, and Pennsylvania.
Power	▪ natural gas-fired and distributed generation assets, certain of which are pending sale, whereby outputs are generally sold under power purchase agreements, both operational and under development; ▪ energy storage; and ▪ sale of power to residential, commercial, and industrial users in Washington D.C., Maryland, Virginia, Delaware, Pennsylvania, and Ohio.
Corporate	▪ the cost of providing corporate services, financing and general corporate overhead, investments in certain public and private entities, corporate assets, financing other segments and the effects of changes in the fair value of certain risk management contracts.

The following table provides a reconciliation of segment revenue to the disaggregated revenue table as disclosed under Note 24:

	Year Ended December 31, 2019				
	Utilities	**Midstream**	**Power**	**Corporate**	**Total**
External revenue *(note 24)*	$ **2,564.2**	$ **1,574.3**	$ **1,356.3**	$ **0.2**	$ **5,495.0**
Intersegment revenue	**26.6**	**6.9**	**10.9**	**—**	$ **44.4**
Segment revenue	$ **2,590.8**	$ **1,581.2**	$ **1,367.2**	$ **0.2**	$ **5,539.4**

	Year Ended December 31, 2018				
	Utilities	Midstream	Power	Corporate	Total
External revenue *(note 24)*	$ 1,752.6	$ 1,344.6	$ 1,162.0	$ (2.5)	$ 4,256.7
Intersegment revenue	13.0	90.4	9.0	0.1	112.5
Segment revenue	$ 1,765.6	$ 1,435.0	$ 1,171.0	$ (2.4)	$ 4,369.2

Geographic Information

Year Ended December 31		2019		2018
Revenue [(a)]				
Canada	$	**1,244.8**	$	1,626.8
United States		**4,325.5**		2,553.0
TOTAL	$	**5,570.3**	$	4,179.8

(a) Operating revenue from external customers, excluding unrealized gains (losses) or risk management contracts.

As at December 31		2019		2018
Property, plant and equipment				
Canada	$	**2,682.2**	$	2,348.2
United States		**7,443.3**		8,581.4
TOTAL	$	**10,125.5**	$	10,929.6

The following tables show the composition by segment:

	Year Ended December 31, 2019					
	Utilities	Midstream	Power	Corporate	Intersegment Elimination [(a)]	Total
Segment revenue	$ **2,590.8**	$ **1,581.2**	$ **1,367.2**	$ **0.2**	$ **(44.4)**	$ **5,495.0**
Cost of sales	**(1,117.9)**	**(1,057.7)**	**(1,084.4)**	**—**	**32.9**	**(3,227.1)**
Operating and administrative	**(860.7)**	**(249.1)**	**(159.8)**	**(40.6)**	**11.5**	**(1,298.7)**
Accretion expenses	**(0.1)**	**(3.9)**	**(1.1)**	**—**	**—**	**(5.1)**
Depreciation and amortization	**(261.6)**	**(92.1)**	**(72.3)**	**(12.0)**	**—**	**(438.0)**
Provisions on assets *(note 6)*	**—**	**(35.2)**	**(380.6)**	**—**	**—**	**(415.8)**
Income from equity investments	**18.3**	**122.4**	**0.4**	**—**	**—**	**141.1**
Other income (loss)	**27.0**	**28.7**	**853.8**	**(1.4)**	**—**	**908.1**
Foreign exchange gains (losses)	**—**	**(4.5)**	**—**	**3.5**	**—**	**(1.0)**
Interest expense	**—**	**—**	**—**	**(345.8)**	**—**	**(345.8)**
Income (loss) before income taxes	$ **395.8**	$ **289.8**	$ **523.2**	$ **(396.1)**	$ **—**	$ **812.7**
Net additions (reductions) to:						
Property, plant and equipment[(b)]	$ **839.6**	$ **350.3**	$ **(2,281.3)**	$ **1.2**	$ **—**	$ **(1,090.2)**
Intangible assets	$ **22.6**	$ **4.9**	$ **—**	$ **9.0**	$ **—**	$ **36.5**

(a) Intersegment transactions are recorded at market value.

(b) 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, 2018					
	Utilities	Midstream	Power	Corporate	Intersegment Elimination [a]	Total
Segment revenue	$ 1,765.6	$ 1,435.0	$ 1,171.0	$ (2.4)	$ (112.5)	$ 4,256.7
Cost of sales	(838.3)	(976.4)	(743.7)	—	103.1	(2,455.3)
Operating and administrative	(727.4)	(201.7)	(159.1)	(50.6)	9.8	(1,129.0)
Accretion expenses	(0.1)	(4.0)	(6.8)	—	—	(10.9)
Depreciation and amortization	(165.8)	(84.4)	(130.5)	(13.3)	—	(394.0)
Provision on assets *(note 6)*	(193.7)	(153.7)	(381.3)	—	—	(728.7)
Income (loss) from equity investments	7.2	51.1	(10.4)	—	—	47.9
Other income (loss)	4.5	0.7	(5.9)	2.0	(0.4)	0.9
Foreign exchange gains (losses)	—	(0.2)	(0.1)	4.8	—	4.5
Interest expense	(103.9)	(10.6)	(8.9)	(185.6)	—	(309.0)
Income (loss) before income taxes	$ (251.9)	$ 55.8	$ (275.7)	$ (245.1)	$ —	$ (716.9)
Net additions (reductions) to:						
Property, plant and equipment [b]	$ 507.0	$ 383.4	$ (321.9)	$ 4.0	$ —	$ 572.5
Intangible assets	$ 21.8	$ 4.7	$ 12.5	$ 6.7	$ —	$ 45.7

(a) Intersegment transactions are recorded at market value.

(b) 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	Power	Corporate	Total
As at December 31, 2019					
Goodwill	**$ 3,573.0**	**$ 246.5**	**$ 122.6**	**$ —**	**$ 3,942.1**
Segmented assets	**$ 13,097.1**	**$ 5,471.4**	**$ 1,019.9**	**$ 206.1**	**$ 19,794.5**
As at December 31, 2018					
Goodwill	$ 3,450.8	$ 426.4	$ 191.0	$ —	$ 4,068.2
Segmented assets	$ 12,991.3	$ 6,398.8	$ 3,814.7	$ 282.9	$ 23,487.7

33. Subsequent Events

Subsequent events have been reviewed through February 27, 2020, the date on which these audited Consolidated Financial Statements were issued.

Segment Change

During the first quarter of 2020, AltaGas began evaluating the structure of its business following asset sales that were completed as part of its 2019 asset monetization program. As a result of these changes, AltaGas has refocused on its core Utilities and Midstream segments and will no longer have a Power segment beginning in the first quarter of 2020. Consistent with Management's strategic view of the business and the basis on which it assesses performance and allocates resources, beginning in 2020, segmented financial information will be presented under the Utilities, Midstream, and Corporate/Other segments. The retail energy marketing operations for natural gas and electricity, which were previously included in the Midstream and Power segments, respectively, will be included within the Utilities segment, and other remaining Power assets will be included in within Corporate/Other.

Petrogas Put Option

On January 2, 2020, AltaGas advised that AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP) has received notice (the Put Notice) from SAM Holdings Ltd. (SAM) of its exercise of a put option (the Put Option) with respect to SAM's approximately one-third interest in Petrogas Energy Corp. (Petrogas). AIJVLP, a limited partnership owned 50 percent by AltaGas and 50 percent by Idemitsu Kosan Co., Ltd. (Idemitsu), owns the other approximately two-thirds of the outstanding common shares of Petrogas. Pursuant to the Petrogas unanimous shareholders agreement, a valid exercise of the Put Option by SAM after October 1, 2019, triggers a requirement for AIJVLP to purchase SAM's approximately one-third interest in Petrogas at the fair market value thereof, as determined by third-party valuators. AltaGas anticipates funding its portion of any such obligation with internal cash flow, the sale of remaining non-core assets and debt.

Constitution Pipeline

In February 2020, following evaluations of the diminished underlying economics for the proposed Constitution pipeline project, the partners of Constitution Pipeline Company, LLC elected not to proceed with the project. AltaGas held a 10 percent equity interest in Constitution. Upon the acquisition of WGL, AltaGas assigned a value of $nil to Constitution.

SUPPLEMENTAL QUARTERLY OPERATING INFORMATION

	Q4-19	Q3-19	Q2-19	Q1-19	Q4-18
OPERATING HIGHLIGHTS					
UTILITIES					
Natural gas deliveries - end use (Bcf) (1)	**52.2**	11.1	20.7	75.4	53.3
Natural gas deliveries - transportation (Bcf) (1)	**38.3**	23.3	25.2	47.6	52.0
Service sites (thousands) (2)	**1,653**	1,647	1,648	1,647	1,643
Degree day variance from normal - SEMCO Gas (%) (3)	**4.3**	(47.2)	14.5	5.7	7.5
Degree day variance from normal - ENSTAR (%) (3)	**(20.6)**	(42.8)	(16.1)	(9.4)	(19.6)
Degree day variance from normal - Washington Gas (%) (3) (4)	**(3.2)**	—	(44.5)	(1.1)	0.4
MIDSTREAM					
Total inlet gas processed (Mmcf/d) (5)	**1,413**	1,307	1,417	1,481	1,413
Extraction volumes (Bbls/d) (5) (6)	**60,305**	65,831	56,990	62,332	64,522
Frac spread - realized ($/Bbl) (5) (7)	**16.54**	17.12	19.50	16.84	15.84
Frac spread - average spot price ($/Bbl) (5) (8)	**8.29**	9.17	15.27	11.79	21.00
RIPET export volumes (Bbls/d) (9)	**36,394**	36,225	31,711	—	—
Propane Far East Index to Mont Belvieu spread (US$/Bbl) (10)	**17.95**	12.00	14.27	—	—
Natural gas optimization inventory (Bcf)	**41.4**	35.7	31.9	13.2	35.9
WGL retail energy marketing - gas sales volumes (Mmcf)	**20,131**	6,476	9,360	27,411	20,750
POWER					
Renewable power sold (GWh)	**10**	136	150	141	233
Conventional power sold (GWh)	**478**	672	361	263	985
Renewable capacity factor (%)	**11.4**	21.7	22.3	12.2	14.6
Contracted conventional availability factor (%) (11)	**92.9**	98.9	66.7	43.2	97.4
WGL retail energy marketing - electricity sales volumes (GWh)	**3,291**	3,723	3,125	3,080	2,911

(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 Gas, during the prior 10 years for ENSTAR, and during the prior 30 years for Washington Gas.
(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) Includes Harmattan NGL processed on behalf of customers.
(7) 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 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.
(8) 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 exposed volumes for the period.
(9) Energy export volumes represents propane volumes exported at RIPET since facility was placed into service in May 2019.
(10) Average propane spot price spread between Argus Far East Index and Mont Belvieu TET commercial index for the period beginning May 2019.
(11) Calculated as the availability factor contracted under long-term tolling arrangements adjusted for occasions where partial or excess capacity payments have been added or deducted.

OTHER INFORMATION

DEFINITIONS

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

ABOUT ALTAGAS

AltaGas is an energy infrastructure company with a focus on regulated Utilities and Midstream. The Corporation creates value by acquiring, growing, and optimizing its energy infrastructure, including a focus on clean energy sources. For more information visit: www.altagas.ca.

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