Annual Report **2018**

AltaGas

AltaGas

ALTAGAS ANNOUNCES FOURTH QUARTER AND FULL-YEAR 2018 RESULTS AND REAFFIRMS 2019 OUTLOOK AND BALANCED FUNDING PLAN

AltaGas continues to focus on Midstream and U.S. Utilities segments as near-term priorities to drive performance, fund organic growth and de-lever company

Calgary, Alberta (February 28, 2019)

Highlights

(all financial figures are unaudited and in Canadian dollars unless otherwise noted)

Delivers $1.0 billion in 2018 Normalized EBITDA[1]

- Normalized EBITDA of $394 million for the fourth quarter of 2018 and $1.0 billion for the full-year, achieving a 27 percent year-over-year growth rate for the year.
- Fourth quarter 2018 normalized FFO[1] of $255 million and $657 million for full-year 2018.
- Approximately $1.0 billion in growth capital projects anticipated to come into service in 2019 including the Ridley Island Propane Export Terminal (RIPET), Townsend 2B Facility, Nig Creek Gas Plant, Mountain Valley Pipeline and the Marquette Connector Pipeline.
- Advanced AltaGas' cornerstone asset in Midstream – RIPET – the first propane export terminal off the west coast of Canada, commencing operations in early spring.
- Leveraged and extended AltaGas' footprint in northeast British Columbia, resulting in the Midstream business increasing core gas processing volumes by 25%.
- Agreements with Black Swan and Kelt enhanced Midstream's NGL capture area, triggering an expansion of the North Pine facility, and supporting the supply of propane at RIPET.
- Recovered US$125 million through accelerated replacement programs in Washington, DC, Maryland, Michigan and Virginia.

Reaffirms 2019 Outlook

- AltaGas reiterates its 2019 business outlook and expects normalized EBITDA in the range of $1.2 - $1.3 billion and normalized FFO of $850 - $950 million.
- Capital investment of $1.3 billion in 2019 primarily in Midstream and U.S. Utility projects.
- Closed the sale of remaining 55 percent interest in Northwest Hydro for net proceeds of approximately $1.37 billion. AltaGas has completed $3.8 billion in asset sales since mid-2018.
- Announced plans for an additional $1.5 - $2.0 billion in asset sales in 2019. The proceeds of the asset sales will be used to further reduce debt, as well as continue to sharpen AltaGas' focus on Midstream and U.S. Utilities.
- Maintained investment grade credit ratings.

AltaGas Ltd. (AltaGas) (TSX:ALA) today reported its fourth quarter and full-year results and provided an update on its recently announced balanced funding plan and growth opportunities in its Midstream and Utility segments.

AltaGas achieved normalized EBITDA of $394 million for the fourth quarter of 2018 and $1.0 billion for the full-year 2018, in line with guidance, representing 27 percent year-over-year growth for the year ended December 31, 2018. Normalized Funds from Operations (FFO) of $255 million for the fourth quarter of 2018 and $657 million for the year ended December 31, 2018 represented an increase of approximately 7 percent for full-year 2018, slightly lower than guidance of approximately 10 percent growth, due to lower hydrology at the Northwest Hydro Facilities and the delay of cash distribution receipts from equity investments to early 2019. AltaGas' net loss applicable to common

1. *Non-GAAP measure; see discussion in the advisories of this news release and reconciliation to US GAAP financial measures shown in AltaGas' Management's Discussion and Analysis (MD&A) as at and for the period ended December 31, 2018, which is available on www.sedar.com.*

shares for the period was $502 million ($2.25 per share), mainly due to provisions for assets. Normalized net income[1] for 2018 was $195 million or $0.88 per share.

"We will look back on 2018 as a transformational year, which saw AltaGas reposition itself through the WGL acquisition as a low-risk, high-growth Utility and Midstream company," said Randy Crawford, President and Chief Executive Officer of AltaGas. "In order to leverage the full growth potential of these assets, we must continue to strengthen our balance sheet and ultimately, reset our financial position.

"With our RIPET project coming online, as scheduled in early spring, as the first propane export terminal in Western Canada, we are poised to execute on our strategy to leverage this unique capability to attract new producer commitments that will increase utilization of our existing assets and provide new organic investment opportunities. At the same time, I see ample opportunity in our Utilities to renew and extend our distribution pipelines and drive higher returns through operational efficiencies, superior customer service and accelerated rate recovery mechanisms."

2019 Guidance and Balanced Funding Plan

AltaGas reiterates its outlook for 2019, with anticipated normalized EBITDA in the range of $1.2 - $1.3 billion and normalized FFO of $850 - $950 million. Year-over-year growth is expected to be driven by new capital projects coming into service (including RIPET, Townsend 2B Facility, Nig Creek Gas Plant and Mountain Valley Pipeline), a full-year of earnings from WGL and the Central Penn Pipeline, and the results of business optimization. The 2019 investment plan includes prudent capital allocation of approximately $1.3 billion to projects with strong risk-adjusted returns, near-term contributions to normalized FFO per share and normalized Earnings per Share (EPS), and secure commercial underpinnings.

AltaGas' previously announced balanced funding plan is designed to de-lever the balance sheet, fund the $1.3 billion capital program for 2019 and optimize per share cash flow and earnings growth. A combination of asset sales, a reset of the dividend payout, and a focused approach to strategic capital allocation will strengthen AltaGas' financial position and fund the capital program.

In addition to the $3.8 billion of asset sales AltaGas completed or announced in 2018, including the sale of its entire indirect equity interest in the Northwest Hydro Facilities and the initial public offering (IPO) of AltaGas Canada Inc. (ACI), the Corporation plans to monetize an additional $1.5 - $2.0 billion in non-core assets in 2019. Proceeds from these additional asset sales will be used to further reduce debt and focus the company's asset base where the opportunities are the greatest – Midstream and Utilities.

Midstream and Utilities Growth

Improving AltaGas' financial strength and flexibility through 2019 will position AltaGas to execute on the significant suite of attractive growth opportunities in its Midstream and Utilities segments.

Within its Midstream segment, AltaGas sees opportunities to optimize and grow its footprint, enhance its service offering and connect producers to new markets, including Asia. For example, AltaGas' integrated strategy in Western Canada provides producers with services across the energy value chain, including access to export markets overseas. The cornerstone of this strategy is RIPET, located near Prince Rupert, British Columbia, which is expected to be the first propane export facility off the west coast of Canada. RIPET leverages AltaGas' existing gathering, processing and fractionation assets, while also providing higher netbacks and market optionality to customers. The facility is scheduled to commence its operational phase in the first quarter of 2019, and the first cargo is expected to depart Canada's west coast in the second quarter of 2019. Also coming into service in 2019 are the Townsend 2B Facility and Nig Creek Gas Plant. These projects will attract additional natural gas liquids to AltaGas' integrated system, increase utilization of AltaGas' existing liquids pipelines, drive the need for an expansion of the North Pine Fractionator, and provide additional propane supply to RIPET. Both projects are expected to be online in the fourth quarter of 2019.

In the Marcellus Basin in the northeastern U.S., AltaGas' 10 percent interest in the 2.0 Bcf/d Mountain Valley Pipeline is targeted to be placed into service in the fourth quarter of 2019. The pipeline is estimated to span approximately 480 kilometres (300 miles) and provide access to the growing southeastern U.S. demand markets. AltaGas' capital commitment for the 10 percent ownership interest in the pipeline is capped at US$350 million.

AltaGas' Utilities segment is expected to grow significantly, reflecting exposure to higher growth markets with capital expenditures to support customer additions, general system betterment, and accelerated replacement programs. The Marquette Connector Pipeline, anticipated to be in service in the fourth quarter of 2019, is an example of a project that is putting new capital to work to provide system redundancy and increase deliverability, reliability and diversity of supply, while also connecting new customers.

AltaGas' near-term focus is to achieve its allowed return on new investments, and focus on three foundational principles to enhance returns across its Utilities:

- Drive operational excellence
- Improve the customer experience
- Achieve more timely recovery of invested capital

Financial Results

Normalized EBITDA [1]		Three Months Ended December 31				Year Ended December 31		
($ millions)		**2018**		2017		**2018**		2017
Utilities	**$**	**232**	$	90	**$**	**426**	$	298
Midstream		**93**		61		**277**		221
Power		**76**		72		**320**		303
Sub-total: Operating Segments		**401**		223		**1,023**		822
Corporate		**(7)**		(10)		**(14)**		(25)
	$	**394**	$	213	**$**	**1,009**	$	797

(1) Non-GAAP financial measure; See discussion in Non-GAAP Financial Measures section at the end of this news release

In the fourth quarter of 2018, normalized EBITDA was $394 million, and normalized FFO was $255 million. AltaGas' net income applicable to common shares for the period was $174 million ($0.64 per share), mainly due to increased EBITDA. Normalized net income for the fourth quarter of 2018 was $120 million or $0.44 per share.

The Utilities segment achieved normalized EBITDA of $232 million in the fourth quarter of 2018, an increase of more than 155 percent compared to the same period in 2017. The increase was mainly due to the impact of the WGL acquisition of $159 million, higher rates, growth in customer base, high customer usage, and colder weather in Michigan. The increase was partially offset by the impact of the sale of the Canadian Utilities to ACI in the fourth quarter of 2018, the 2018 impact related to the federal tax reductions at the U.S. Utilities, and warmer weather in Alaska.

In the fourth quarter of 2018, AltaGas' Midstream segment recorded normalized EBITDA of $93 million, an increase of 52 percent over the same period last year. The increase was driven by contributions from WGL Midstream assets of $31 million, the acquisition of 50 percent ownership in the Aitken Creek North Gas Plant in the fourth quarter of 2018, and higher revenues at Harmattan due to increased NGL activities. The increase was partially offset by the impact of reduced ownership at Younger, lower frac spreads, and lower NGL marketing margins.

In the fourth quarter of 2018, AltaGas' Power segment achieved normalized EBITDA of $76 million, up $4 million from the fourth quarter of 2017, primarily as a result of the addition of WGL's power assets of $33 million. The increase was partially offset by lower generation at the Northwest Hydro Facilities due to lower river flow, the impact of the sale of the San Joaquin facilities that closed in November 2018, the impact of the sale of the Bear Mountain

Wind Facility in October 2018, the expiry of the Ripon PPA on May 31, 2018, and lower contributions from Craven due to an extended planned outage and new contract terms.

The Power and Utility segments were also positively impacted by a stronger U.S. dollar in the fourth quarter of 2018.

Monthly Common Share Dividend and Quarterly Preferred Share Dividends

- The Board of Directors approved a dividend of $0.08 per common share. The dividend will be paid on April 15, 2019, to common shareholders of record on March 25, 2019. The ex-dividend date is March 22, 2019. This dividend is an eligible dividend for Canadian income tax purposes;
- The Board of Directors approved a dividend of $0.21125 per share for the period commencing December 31, 2018 and ending March 30, 2019, on AltaGas' outstanding Series A Preferred Shares. The dividend will be paid on March 29, 2019 to shareholders of record on March 15, 2019. The ex-dividend date is March 14, 2019;
- The Board of Directors approved a dividend of $0.26938 per share for the period commencing December 31, 2018 and ending March 30, 2019, on AltaGas' outstanding Series B Preferred Shares. The dividend will be paid on March 29, 2019 to shareholders of record on March 15, 2019. The ex-dividend date is March 14, 2019;
- The Board of Directors approved a dividend of US$0.330625 per share for the period commencing December 31, 2018 and ending March 30, 2019, on AltaGas' outstanding Series C Preferred Shares. The dividend will be paid on March 29, 2019 to shareholders of record on March 15, 2019. The ex-dividend date is March 14, 2019;
- The Board of Directors approved a dividend of $0.337063 per share for the period commencing December 31, 2018, and ending March 30, 2019, on AltaGas' outstanding Series E Preferred Shares. The dividend will be paid on March 29, 2019 to shareholders of record on March 15, 2019. The ex-dividend date is March 14, 2019;
- The Board of Directors approved a dividend of $0.296875 per share for the period commencing December 31, 2018, and ending March 30, 2019, on AltaGas' outstanding Series G Preferred Shares. The dividend will be paid on March 29, 2019 to shareholders of record on March 15, 2019. The ex-dividend date is March 14, 2019;
- The Board of Directors approved a dividend of $0.328125 per share for the period commencing December 31, 2018, and ending March 30, 2019, on AltaGas' outstanding Series I Preferred Shares. The dividend will be paid on March 29, 2019 to shareholders of record on March 15, 2019. The ex-dividend date is March 14, 2019; and
- The Board of Directors approved a dividend of $0.3125 per share for the period commencing December 31, 2018, and ending March 30, 2019, on AltaGas' outstanding Series K Preferred Shares. The dividend will be paid on March 29, 2019 to shareholders of record on March 15, 2019. The ex-dividend date is March 14, 2019.

Consolidated Financial Review

($ millions)	Three Months Ended December 31 2018	2017	Year Ended December 31 2018	2017
Revenue	**1,727**	745	**4,257**	2,556
Normalized EBITDA(1)	**394**	213	**1,009**	797
Net income (loss) applicable to common shares	**174**	(11)	**(502)**	30
Normalized net income(1)	**120**	63	**195**	204
Total assets	**23,488**	10,032	**23,488**	10,032
Total long-term liabilities	**11,746**	4,578	**11,746**	4,578
Net additions to property, plant and equipment	**16**	114	**573**	388
Dividends declared(2)	**121**	94	**463**	362
Normalized funds from operations(1)	**255**	179	**657**	615

($ per share, except shares outstanding)	Three Months Ended December 31 2018	2017	Year Ended December 31 2018	2017
Net income (loss) per common share - basic	**0.64**	(0.06)	**(2.25)**	0.18
Net income (loss) per common share - diluted	**0.64**	(0.06)	**(2.25)**	0.18
Normalized net income - basic(1)	**0.44**	0.36	**0.88**	1.19
Dividends declared(2)	**0.45**	0.54	**2.09**	2.12
Normalized funds from operations(1)	**0.94**	1.03	**2.95**	3.60
Shares outstanding - basic (millions)				
During the period(3)	**272**	174	**223**	171
End of period	**275**	175	**275**	175

(1) Non-GAAP financial measure; see discussion in Non-GAAP Financial Measures at the end of this news release.

(2) Dividends declared per common share per month: $0.175 beginning on August 25, 2016, $0.1825 beginning on November 27, 2017, and $0.08 beginning on December 27, 2018.

(3) Weighted average.

Conference Call and Webcast Details

AltaGas will hold a conference call today at 9:00 a.m. MT (11:00 a.m. ET) to discuss 2018 fourth quarter and full-year results, provide an update on the balanced funding plan, and share progress on construction activities and other corporate developments.

Members of the investment community and other interested parties may dial 1-647-427-7450 or toll free at 1-888-231-8191. Please note that the conference call will also be webcast. To listen, please go to http://www.altagas.ca/invest/events-and-presentations. The webcast will be archived for one year.

Shortly after the conclusion of the call, a replay will be available commencing at 2:00 p.m. MT (4:00 p.m. ET) on February 28, 2019 by dialing 403-451-9481 or toll free 1-855-859-2056. The passcode is 2068746. The replay will expire at 9:59 p.m. MT (11:59 p.m. ET) on March 7, 2019.

AltaGas' audited Consolidated Financial Statements and accompanying notes for the year ended December 31, 2018, as well as the related Management's Discussion and Analysis, are now available online at: www.altagas.ca. All documents will be filed with the Canadian securities regulatory authorities and will be posted under AltaGas' SEDAR profile at www.sedar.com.

About AltaGas

AltaGas is an energy infrastructure company with a focus on midstream, regulated utilities and power. AltaGas creates value by growing and optimizing its energy infrastructure, including a focus on clean energy sources. For more information visit: www.altagas.ca.

Investment Community	**Media**
1-877-691-7199	587-955-4504
investor.relations@altagas.ca	media.relations@altagas.ca

FORWARD-LOOKING INFORMATION

This news release 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", "schedule", "future", "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 news release contains forward-looking statements with respect to, among other things, business objectives, expected growth, results of operations, performance, business projects and opportunities and financial results. Specifically, such forward-looking statements included in this document include, but are not limited to, statements with respect to the following: AltaGas' business outlook for 2019; expectation of normalized EBITDA in the range of $1.2 - $1.3 billion and normalized FFO of $850 - $950 million for 2019; anticipation of approximately C$1.0 billion in growth capital projects coming into service in 2019; expectation that year-over-year growth will be driven by new capital projects coming into service including RIPET and Mountain Valley Pipeline, a full year of earnings from WGL and the Central Penn Pipeline, and the results of business optimization; expectation that RIPET will be the first propane export facility off the west coast of Canada; anticipated in-service dates for RIPET, Townsend 2B Facility, Aitken Creek, Mountain Valley Pipeline and the Marquette Connector Pipeline; anticipated operational impacts of Townsend 2B Facility and Aitken Creek; anticipated de-levering of the balance sheet; maintenance of an investment-grade credit rating; funding of growth in Midstream and U.S. Utilities; anticipated capital investment of $1.3 billion in 2019 primarily in Midstream and U.S. Utility projects; anticipated additional $1.5 to $2 billion in asset sales in 2019; use of proceeds from anticipated asset sales; expected priority of supporting Washington Gas in achieving its allowed return, creating operational efficiencies, and driving customer service; 2019 investment plan including anticipated capital allocation of approximately $1.3 billion to projects with strong risk-adjusted returns, near-term contributions to per share normalized FFO and normalized EPS, and secure commercial underpinnings; expected optimization and growth of AltaGas' footprint, enhancement of AltaGas' service offering and connection of producers to new markets, including Asia; expectation that the Utilities segment will grow significantly; expected near-term focus to achieve allowed return on new investments; timing and payment of declared dividends; and timing of investor conference call and filing of annual disclosure documents.

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: expected commodity supply, demand and pricing; volumes and rates; exchange rates; inflation; interest rates; credit rating; regulatory approvals and policies; future operating and capital costs; project completion dates; capacity expectations; implications of recent U.S. tax legislation changes; the outcomes of significant commercial contract negotiation; ability to declare dividends; and availability and sources of capital.

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: access to and use of capital markets; market value of AltaGas' securities; AltaGas' ability to pay dividends; AltaGas' ability to service or refinance its debt and manage its credit rating and risk; prevailing economic conditions; potential litigation; AltaGas' relationships with external stakeholders, including Indigenous stakeholders; volume throughput and the impacts of commodity pricing, supply, composition and other market risks; available electricity prices; interest rate, exchange rate and counterparty risks; legislative and regulatory environment; underinsured losses; weather, hydrology and climate changes; the potential for service interruptions; availability of supply from Cook Inlet; availability of biomass fuel; AltaGas' ability to economically and safely develop, contract and operate assets; AltaGas' ability to update infrastructure on a timely basis; AltaGas' dependence on certain partners; impacts of climate change and carbon taxing; effects of decommissioning, abandonment and reclamation costs; impact of labour relations and reliance on key personnel; cybersecurity risks; and other factors set forth under the heading "Risk Factors" in AltaGas' annual information form (AIF) for the year ended December 31, 2018. AltaGas' AIF is available under the Corporation's profile on www.sedar.com.

Many factors could cause AltaGas' or any particular business segment's actual results, performance or achievements to vary from those described in this news release, 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 news release as intended, planned, anticipated, believed, sought, proposed, estimated, forecasted, projected, targeted, scheduled, or expected, and such forward-looking statements included in this news release, 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 news release. 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 news release are expressly qualified by these cautionary statements.

Financial outlook information contained in this news release 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 management's assessment of the relevant information currently available. Readers are cautioned that such financial outlook information contained in this news release should not be used for purposes other than for which it is disclosed herein.

Non-GAAP Measures

This news release contains references to certain financial measures that do not have a standardized meaning prescribed by US GAAP and may not be comparable to similar measures presented by other entities. The non-GAAP measures and their reconciliation to US GAAP financial measures are shown in AltaGas' Management's Discussion and Analysis (MD&A) as at and for the period ended December 31, 2018. These non-GAAP measures provide additional information that management believes is meaningful regarding AltaGas' operational performance, liquidity and capacity to fund dividends, capital expenditures, and other investing activities. Readers are cautioned that these non-GAAP measures should not be construed as alternatives to other measures of financial performance calculated in accordance with US GAAP.

Normalized EBITDA includes additional adjustments for unrealized gains (losses) on certain risk management contracts, realized losses on foreign exchange derivatives, gains (losses) on investments, transaction costs related to acquisitions and dispositions, merger commitment costs, losses on the sale of assets, provisions on assets, provisions on equity investments, accretion expenses related to asset retirement obligations and the Northwest Transmission Line liability, foreign exchange gains, development costs, 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 represents net income (loss) applicable to common shares adjusted for the after-tax impact of unrealized gains (losses) on certain risk management contracts, realized loss on foreign exchange derivatives, gains (losses) on investments, merger commitment costs, transaction costs related to acquisitions and dispositions, losses on the sale of assets, provisions on assets, provisions on equity investments, a tax recovery as a result of the Northwest Hydro facilities being held for sale, financing costs associated with the bridge facility for the WGL Acquisition, development costs, the impact of the recent U.S. tax changes, 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 is used to assist management and investors in analyzing the liquidity of the Corporation without regard to changes in operating assets and liabilities in the period and non-operating related expenses (net of current taxes) such as development costs and transaction and financing costs related to acquisitions and dispositions. Funds from operations are calculated from the Consolidated Statement of Cash Flows and are defined as cash from operations before net changes in operating assets and liabilities and expenditures incurred to settle asset retirement obligations. Management uses this measure to understand the ability to generate funds for capital investments, debt repayment, dividend payments and other investing activities. Funds from operations and normalized funds from operations as presented should not be viewed as an alternative to cash from operations or other cash flow measures calculated in accordance with GAAP.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The Management's Discussion and Analysis (MD&A) of operations 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, 2018. This MD&A, dated February 27, 2019, 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, 2018.

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.

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", "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, the anticipated benefits of acquisitions and other major projects, the anticipated timing of commercial operations, investment decisions, expenditures and licensing and permitting, expected growth and drivers of growth, capital expenditures (including in respect of the 2019 capital program, expected allocation per business segment and project and anticipated sources of financing thereof), results of operations, operational and financial performance, business projects, opportunities and financial results.

Specifically, such forward looking statements are set forth under the headings: "Recent Developments", "2018 Financial Highlights", "Strategy", "2019 Outlook", "Sensitivity Analysis", "Growth Capital", "Utilities", "Midstream", "Power", "Contractual Obligations" and "Future Changes in Accounting Principles" and under those headings specifically include AltaGas' expectation of additional asset sales in 2019; expectations regarding the effect of the dividend reset on anticipated retained cash dividends through 2023; expectation that the dividend reset will provide an efficient source of funding for future growth; AltaGas' belief that it can help to meet the growing global demand for clean energy, while continuing to deliver sustainable benefits to shareholders; expectation regarding consolidated normalized EBITDA that will be achieved in 2019; expectation regarding the normalized funds from operations in 2019; expectation that the WGL Acquisition will drive growth in all three business segments; expectation that growth in the Midstream segment will largely be driven by a full year of WGL results and RIPET coming into service; first scheduled ship expected to RIPET early in the second quarter of 2019; the expectation that the Power segment will be impacted by the non-core power sales and the sale of the remaining interest in the Northwest Hydro facilities; the average exposure to frac spreads prior to hedging activities; exposure to the propane price differential between Mont Belvieu and Far East Index once RIPET is in service; the effect of changes in commodity prices, exchange rates and weather on AltaGas' expected normalized EBITDA for 2019; expected net invested capital expenditures in 2019; anticipated capital expenditure allocations between the three business segments; expected maintenance capital expenditures; expected funding sources for the 2019 committed capital program; expectation for RIPET to be the first propane export facility off the west coast of Canada; expected construction cost of RIPET; expectation that RIPET will ship 1.2 million tonnes of propane per annum; expectation that RIPET will begin its operational phase in the first quarter of 2019; expectation of having physical volumes equal to the initial 40,000 Bbls/d target by RIPET's in-service date; expected ownership percentage in the expansion of Leidy South; Leidy South's anticipated in-service date; expected transport capacity, span, construction completion date and in-service date of the Mountain Valley Pipeline; expectation regarding WGL Midstream's investment in Mountain Valley; proposed commitment of WGL Midstream in and in-service date of the MVP Southgate project; estimated project cost and on-stream date for Townsend 2B; expected capital investment in and on-stream date for Nig Creek Plant 2; cost and expected on stream timing for North Pine; the timing of judicial appeals regarding, capacity of and commencement date for first phase of the Alton Natural Gas Storage Project; anticipated future expenditures for the Washington Gas accelerated pipe replacement program; timing, magnitude and cost to Washington Gas of PROJECTpipes; estimated cost of the second STRIDE plan; expected 2019 customer growth for Washington Gas, SEMCO and ENSTAR; expected date for PSC of MD and SCC of VA decisions on various Washington Gas applications; anticipated construction completion and in-service dates for the Marquette Connector Pipeline; anticipation that ENSTAR will *address excess deferred income taxes in its next rate case to be filed in 2021; anticipated timing of pending CINGSA rulings and rate case hearings; AltaGas' objectives; expectations regarding the growth of AltaGas' infrastructure; expected sources of growth and increased volumes in the Midstream segment; expected source of funds to pay contractual obligations; potential impacts of risk mitigation strategies and expected future changes in accounting principles.*

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 at the time the statement was made. Material assumptions include, but are not limited to: expected commodity supply, demand and pricing; volumes and rates; exchange rates; inflation; interest rates; credit rating; regulatory approvals and policies; future operating and capital costs; project completion dates; capacity expectations; weather patterns; counterparty contract compliance; the outcomes of significant commercial contract negotiations and availability of financing.

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: access to and use of capital markets; market value of AltaGas' securities; AltaGas' ability to pay dividends; AltaGas' ability to service or refinance its debt and manage its credit rating and risk; prevailing economic conditions; potential litigation; AltaGas' relationships with external stakeholders, including Indigenous stakeholders; volume throughput and the impacts of commodity pricing, supply, composition and other market risks; available electricity prices; interest rate, exchange rate and counterparty risks; legislative and regulatory environment; underinsured losses; weather, hydrology and climate changes; the potential for service interruptions; availability of supply from Cook Inlet; availability of biomass fuel; AltaGas' ability to economically and safely develop, contract and operate assets; AltaGas' ability to update infrastructure on a timely basis; AltaGas' dependence on certain partners; impacts of climate change and carbon taxing; effects of decommissioning, abandonment and reclamation costs; impact of labour relations and reliance on key personnel; cybersecurity risks; and other factors set forth under the heading "Risk Factors" in AltaGas' annual information form (AIF) for the year ended December 31, 2018. AltaGas' AIF is available under the Corporation's profile on www.sedar.com.

Many factors could cause AltaGas' or any of its business segments' actual results, performance or achievements to vary from those described in this MD&A including, without limitation, those listed above as well as 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. These 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 applicable 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, AIF, and press releases are available through AltaGas' website at www.altagas.ca or through SEDAR at www.sedar.com.

RECENT DEVELOPMENTS

2019 Planned Asset Sales and Balanced Funding Plan

On December 13, 2018, AltaGas announced that it has reached an agreement for the sale of its remaining interest of approximately 55 percent in the Northwest Hydro Electric facilities in British Columbia (Northwest Hydro). Total proceeds are approximately $1.37 billion and the sale closed in January 2019. Including this sale, AltaGas has successfully monetized approximately $3.8 billion of non-core assets since mid-2018, providing an efficient source of capital, as well as reshaping the asset portfolio and allowing AltaGas to prioritize core focus areas. Additional asset sales of approximately $1.5 to $2.0 billion are planned for 2019, which are expected to further de-lever the Corporation, fund future growth, and minimize the need for any near-term common equity requirements.

As part of the balanced funding plan, approximately US$2.2 billion of the bridge facility used to finance the acquisition of WGL Holdings, Inc. (the WGL Acquisition) was repaid in December 2018 and refinanced with a new US$1.2 billion revolving credit facility. In addition, the Board of Directors (the Board) approved a reset of the dividend to improve the financial strength of AltaGas and ensure greater funding flexibility. The Board declared a January 2019 dividend of $0.08 per common share, which equates to $0.96 annually and represented a 56 percent reduction from 2018. The dividend reset is expected to result in an additional approximate $1.3 billion in anticipated retained cash dividends through 2023, providing an efficient source of funding for future growth.

Public Offering of AltaGas Canada Inc.

On October 25, 2018, the initial public offering (IPO) of AltaGas Canada Inc. (ACI) was successfully completed, reflecting a final price of $14.50 per common share of ACI. The over-allotment option was exercised in full, and as a result, AltaGas holds approximately 37 percent of ACI common shares at December 31, 2018. Net proceeds (consisting of cash and debt) to AltaGas after the deduction of underwriting fees and expenses were approximately $892 million. ACI holds Canadian rate-regulated natural gas distribution utility assets and contracted wind power in Canada, as well as an approximate 10 percent indirect equity interest in the Northwest Hydro facilities.

Sales of Non-Core Midstream and Power Assets

On September 10, 2018, AltaGas announced that it had entered into definitive agreements for the sale of non-core midstream and power assets in Canada and power assets in the United States, for total gross proceeds of approximately $560 million.

In November 2018, AltaGas completed the sale of gas-fired power assets in California to Middle River Power III (Middle River), a whole owned-subsidiary of Avenue Capital, for a gross purchase price of approximately US$299 million. The assets comprise the Tracy, Hanford and Henrietta plants totaling 523 MW of capacity. The effective date of the transaction was September 1, 2018. In addition, in the fourth quarter of 2018, AltaGas' 50 percent interest in the Busch Ranch wind asset in the United States was sold for approximately US$16 million.

The sale of non-core midstream and power assets in Canada was to Birch Hill Equity Partners Management Inc., as general partner of Birch Hill Equity Partners Fund V (Birch Hill). Included in the sale was AltaGas' commercial and industrial customer portfolio in Canada as well as 43.7 million shares of Tidewater Midstream and Infrastructure Inc. (Tidewater). The net proceeds, including approximately $63 million for the Tidewater shares, was approximately $165 million. The sale of the Tidewater shares was completed in September 2018 for proceeds of approximately $63 million, while the remainder of the transaction closed in February 2019.

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., 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, and WGL Midstream Inc. (WGL Midstream); in regards to the Power business, AltaGas Power Holdings (U.S.) Inc., WGSW, Inc., WGL Energy Systems, Inc., and Blythe Energy Inc. (Blythe); and, in regards to the Utility business, Washington Gas Light Company, 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) and its Alaska natural gas distribution business under the name ENSTAR Natural Gas Company (ENSTAR).

OVERVIEW OF THE BUSINESS

AltaGas, a Canadian corporation, is a leading North American clean energy infrastructure company with strong growth opportunities and a focus on owning and operating assets to provide clean and affordable energy to its customers. The Corporation's long-term strategy is to grow in attractive areas across its Utility, Midstream, and Power 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 both coasts of North America via the Corporation's footprint in two of the most prolific gas plays – the Montney and Marcellus. To optimize capital deployment, the Corporation seeks to invest in U.S utilities located in strong growth markets with increasing construction to support customer additions, system improvement and accelerated replacement programs. In the Power business, AltaGas seeks to create innovative solutions with light capital investment utilizing the Corporation's clean energy expertise. AltaGas has three business segments:

- Utilities, which serves approximately 1.6 million customers with a rate base of approximately US$3.7 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, subsequent to the sale of non-core midstream assets in Canada that closed in February 2019, transacts more than 1.5 Bcf/d of natural gas and includes natural gas gathering and processing, natural gas liquids (NGL) extraction and fractionation, transmission, storage, natural gas and NGL marketing, the Corporation's 50 percent interest in AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP), an indirectly held one-third ownership investment in Petrogas Energy Corp. (Petrogas), through which AltaGas' interest in the Ferndale Terminal is held, an interest in four regulated pipelines in the Marcellus/Utica gas formation in the northeastern United States and WGL's retail gas marketing business; and
- Power, which, subsequent to the sale of non-core power assets in Canada that closed in February 2019, and the sale of the remaining 55 percent interest in the Northwest Hydro facilities which closed in January 2019, includes 1,105 MW of operational gross capacity from natural gas-fired, biomass, solar, other distributed generation and energy storage assets located in Alberta, Canada and 20 states and the District of Columbia in the United States. The Power business also includes energy efficiency contracting and WGL's retail power marketing business.

2018 GROWTH AND OPERATIONAL HIGHLIGHTS

- On April 3, 2018, AltaGas entered into a long-term natural gas processing arrangement with Birchcliff Energy Ltd. (Birchcliff) at AltaGas' deep-cut sour gas processing facility located in Gordondale, Alberta. Under the arrangement, Birchcliff is provided with up to 120 MMcf/d of natural gas processing on a firm-service basis, and Birchcliff's take-or-pay obligation is 100 MMcf/d;
- On July 6, 2018, following the receipt of all required regulatory approvals, AltaGas completed the acquisition of WGL Holdings, Inc. for an aggregate purchase price of approximately $9.3 billion (US$7.1 billion), including the assumption of debt and preferred shares. Upon closing of the WGL Acquisition, 84.5 million subscription receipts were exchanged for common shares;
- On July 25, 2018, AltaGas announced the resignation of David Harris, President and CEO. David Cornhill, the Founder and Chairman of AltaGas, and Phillip Knoll, an experienced industry executive and Board member, acted as interim co-CEOs from July 25, 2018 to December 9, 2018;
- On July 26, 2018, AltaGas announced the expansion of its Board of Directors (the Board) from nine to twelve seats and the appointment of three new directors. The expansion of the Board reflects AltaGas' scope and growing complexity and the experience and expertise required by the Board to support AltaGas' business, operations and strategic objectives;
- On August 27, 2018, AltaGas announced that it has entered into definitive agreements with Kelt Exploration Ltd. (Kelt) to provide an energy infrastructure solution for the liquids-rich Inga Montney development located in British Columbia. This underpins the expansion of AltaGas' Townsend complex including the addition of a 198 MMcf per day C3+ deep cut gas

processing facility and provides Kelt with firm processing of 75 MMcf per day of raw gas under an initial 10 year take-or-pay agreement;

- On September 26, 2018, AltaGas announced that it had entered into a definitive agreement with Black Swan Energy Ltd. (Black Swan) to acquire 50 percent ownership in certain existing and future natural gas processing plants of Black Swan at Aitken Creek. AltaGas and Black Swan will also enter into long term processing, transportation and marketing agreements that include new AltaGas liquids handling infrastructure, strengthening AltaGas' Northeast B.C. value proposition and connecting producers with additional options for energy exports. The total capital investment by AltaGas is expected to be approximately $230 million and the transaction closed on October 2, 2018;
- On October 4, 2018, the Federal Energy Regulatory Commission (FERC) issued its authorization to place the Central Penn Pipeline (Central Penn) into service. The pipeline began operations on October 6, 2018; and
- On November 20, 2018, AltaGas announced the appointment of Randall Crawford as Chief Executive Officer and member of the Board of Directors, effective December 10, 2018. Mr. Crawford has extensive experience in AltaGas' base businesses and will lead and develop AltaGas' ongoing strategy.

2018 FINANCIAL 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.)

- Normalized EBITDA was $1,009 million, an increase of 27 percent compared to $797 million in 2017;
- Normalized funds from operations were $657 million ($2.95 per share), a 7 percent increase compared to $615 million ($3.60 per share) in 2017;
- Net loss applicable to common shares was $502 million ($2.25 per share) compared to net income of $30 million ($0.18 per share) in 2017;
- Normalized net income was $195 million ($0.88 per share), compared to $204 million ($1.19 per share) in 2017;
- Net debt was $10.1 billion as at December 31, 2018, compared to $3.6 billion as at December 31, 2017;
- Net debt to total capitalization ratio was 57 percent as at December 31, 2018, compared to 44 percent as at December 31, 2017;
- On June 13, 2018, a US$2 billion short form base shelf prospectus for the issuance of both debt securities and preferred shares was filed in both Alberta and the U.S. This will enable AltaGas to access the U.S. capital markets on a timely basis over the following 25 months, subject to market conditions;
- On June 13, 2018, AltaGas announced that it had entered into a definitive agreement to indirectly sell 35 percent of its interest in the Northwest Hydro facilities for gross proceeds of $922 million. The transaction closed on June 22, 2018;
- On September 10, 2018, AltaGas announced that it had entered into definitive agreements for the sale of non-core midstream and power assets in Canada and power assets in the United States for total proceeds of approximately $560 million. The sale of the power assets in the United States was completed in the fourth quarter of 2018, and the sale of non-core midstream and power assets in Canada was completed in February 2019;
- On October 25, 2018, the Initial Public Offering (IPO) of AltaGas Canada Inc. (ACI) was successfully completed. Final pricing was $14.50 per ACI common share. The over-allotment option was exercised in full, and as a result, AltaGas owned approximately 37 percent of ACI common shares at December 31, 2018. Net proceeds (consisting of cash and debt) to AltaGas after the deduction of underwriting fees and expenses were approximately $892 million. A previously wholly owned subsidiary of AltaGas, ACI holds Canadian rate-regulated natural gas distribution utility assets and contracted wind power in Canada, as well as an approximate 10 percent indirect equity interest in the Northwest Hydro facilities in British Columbia;
- On October 29, 2018, the Board suspended, until further notice, its Premium Dividend Reinvestment Plan (PDRIP), effective December 18, 2018. The Dividend Reinvestment Plan remained unchanged;
- On November 28, 2018, AltaGas announced that it did not intend to exercise its right to redeem all or any of its currently outstanding Cumulative Redeemable Five-Year Reset Preferred Shares, Series E (the Series E Shares) on December 31, 2018. As a result, subject to certain conditions, the holders of the Series E Shares had the right to convert all or part of their Series E Shares on a one-for-one basis into Cumulative Redeemable Floating Rate Preferred Shares, Series F (the

Series F Shares) on December 31, 2018. Based on conversion notices received, less than the 1 million Series E Shares required to give effect to conversions to Series F Shares were tendered. As a result, none of AltaGas' outstanding Series E shares were converted to Series F Shares on December 31, 2018; and

- On December 13, 2018, AltaGas announced its 2019 funding plan, financial outlook, and capital plan. This included the announcement of a dividend reset to $0.96 per common share annually, representing a 56 percent reduction. AltaGas also announced that it has reached an agreement for the sale of its remaining indirect equity interest of approximately 55 percent in the Northwest Hydro facilities for proceeds of approximately $1.37 billion. The transaction closed in January 2019. AltaGas also announced the intention to complete additional asset sales of approximately $1.5 to $2.0 billion in 2019.

HIGHLIGHTS SUBSEQUENT TO YEAR END

- On January 31, 2019, AltaGas completed the sale of its remaining interest in the Northwest Hydro facilities for net proceeds of approximately $1.37 billion, enhancing AltaGas' financial strength and further sharpening the focus on the Midstream and U.S. Utilities businesses; and
- On February 1, 2019, AltaGas completed the sale of Canadian non-core Midstream and Power assets.

ALTAGAS' VISION AND OBJECTIVE

AltaGas' vision is to enhance its position as a leading North American diversified energy infrastructure company. The Corporation's overall objective is to deliver premium service to customers while achieving superior and timely returns on invested capital in the Midstream and Utilities segments. In the Power segment, AltaGas seeks to create innovative solutions with a capital-light investment strategy.

STRATEGY

AltaGas leverages the strength of its assets and expertise along the energy value chain to connect customers with premier energy solutions – from the wellsites of upstream producers to the doorsteps of homes and businesses, to new markets around the world. This strategy is underpinned by the growing demand for clean, reliable and affordable energy and the mounting need for market optionality for North America's energy industry.

With infrastructure assets in some of the fastest growing energy markets in North America, including prominent positions in the Montney and Marcellus/Utica basins, and utility operations in five states, AltaGas is developing an integrated footprint capable of delivering sustained value to shareholders and customers alike. 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.

AltaGas' Board of Directors is actively engaged in an annual review of AltaGas' strategy. The Corporation continually assesses the macro and micro-economic trends impacting the businesses and seeks opportunities to generate value for shareholders. 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.

To achieve the overarching strategy, AltaGas is focused on five strategic imperatives:

Delivering Operational Excellence

AltaGas is focused on continually improving how it operates, in order to deliver products and services as safely, efficiently and reliably as possible. With nearly 25 years of experience developing and operating premier assets throughout the energy value chain, AltaGas has the expertise to deliver high-quality capital projects on time and on budget, in close partnership with Indigenous peoples and community stakeholders, without compromising on safety or environmental performance. The

Corporation's disciplined approach to reliability, cost and safety results in a superior quality of service for customers, ensures the safety of employees and members of nearby communities, and enhances returns to shareholders.

Maximizing the Value of the Asset Footprint

AltaGas' strategy is focused on two core and complementary business segments, Midstream and Utilities. Specifically, AltaGas is targeting opportunities to develop high-quality energy assets that complement its existing integrated infrastructure footprint, and to consolidate its position in key markets to deliver optimal growth over the long term. With a rich and diverse platform of organic growth opportunities, AltaGas' capital is allocated to projects with strong organic growth potential, strong expected risk-adjusted returns, and long-term, secure commercial underpinning. This highly disciplined approach to capital allocation ensures that investment dollars are directed in a manner that is consistent with AltaGas' strategy and drive superior and timely expected returns on invested capital. Further, the Corporation continues to assess opportunities to upgrade its portfolio and further align the business to the core strategy.

Advancing AltaGas' Transformation

On July 6, 2018, AltaGas announced the closing of the acquisition of WGL Holdings, Inc. With the transaction complete, AltaGas is focused on integration, achieving synergies and moving forward as one company with one vision and one strategy. AltaGas has identified near- and long-term integration priorities, including strategy, organizational effectiveness, growth, financial strength and people and culture. Significant progress has been made integrating the WGL leadership team, its operations and some of its core processes, and this will remain a priority for AltaGas moving forward.

Enhancing Financial Strength

With high-quality assets and numerous attractive opportunities for organic growth, a strong balance sheet is crucial. As a growth-oriented energy infrastructure company, AltaGas creates value for investors through minimizing the cost of capital and maximizing return on invested capital in a timely manner. This contributes to the expected maintenance and growth of operating cash flows. Accordingly, the funding plan is designed to strengthen the balance sheet and optimize per share cash flow and earnings growth by taking advantage of attractive growth opportunities in the Midstream and Utilities segments, with the aim of improving credit metrics and providing greater financial flexibility.

A key element of AltaGas' business model is mitigating exposure to certain market price risks, as well as volume risk. AltaGas has developed risk management processes that mitigate earnings volatility from commodity price risk and volume risk, and proactively hedge foreign exchange rates and commodity price exposures when it is prudent to do so. As well, AltaGas prioritizes the continued management of counterparty credit risk. The Corporation partially mitigates the foreign exchange exposure on U.S. investments by incorporating U.S. dollar (US$) denominated capital, both debt and preferred shares, into the financing strategy.

Responsibility for People, Communities and Environment

The Corporation adheres to a strong set of core values, which reflect the commitment to corporate responsibility and sustainability. AltaGas recognizes the broad range of stakeholders that are reached through its operations, including its employees, members of nearby communities, Indigenous peoples, governments and regulators. As the Corporation continues to evolve and expand its diversified energy assets, AltaGas is committed to operating in a safe, reliable manner, while working closely with stakeholders to maintain positive relationships. By balancing economic priorities with social and environmental values, AltaGas believes it can help meet the growing global demand for clean energy, while continuing to deliver sustainable benefits to shareholders.

2019 OUTLOOK

With 2019 being the first full year of operations including WGL, AltaGas expects to achieve consolidated normalized EBITDA of approximately $1.2 to $1.3 billion, and normalized funds from operations of approximately $850 to $950 million. This range is net of anticipated asset sales expected to close in 2019, which includes the remaining 55 percent interest in the Northwest Hydro facilities and additional expected 2019 asset sales of approximately $1.5 to $2.0 billion.

The WGL Acquisition is expected to drive growth in all three business segments. The Utilities segment is expected to have the largest contribution to EBITDA, followed by the Midstream and Power segments. Specifically for Utilities, a full year of WGL results will be the largest contributor to growth, along with new capital and rate base growth. Growth in the Midstream segment will largely be driven by a full year of WGL results and Ridley Island Propane Export Terminal (RIPET) coming into service, with the first scheduled ship expected early in the second quarter of 2019. Recent agreements with Kelt, Black Swan and other producers will see increased use of AltaGas' integrated infrastructure in Northeastern British Columbia, including the North Pine facility (North Pine). In addition, 2019 will be the first full year of operations for the Central Penn Pipeline and AltaGas' first full year of results from the Stonewall Gas Gathering System (Stonewall). Finally, the Power segment is expected to be impacted by the non-core power sales completed in 2018, as well as the sale of the remaining 55 percent interest in the Northwest Hydro facilities which was completed in January 2019. This will be partially offset by a full year of contributions from WGL's existing contracted renewable power business and power marketing business.

The overall forecasted normalized EBITDA and funds from operations include assumptions around asset sales anticipated to close in 2019, 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 funds from operations.

AltaGas estimates an average of approximately 9,700 Bbls/d will be exposed to frac spreads prior to hedging activities. For 2019, AltaGas has frac hedges in place for approximately 6,200 Bbls/d at an average price of approximately $40/Bbl excluding basis differentials. Once RIPET is in service, AltaGas will be exposed to the propane price differential between Mont Belvieu and Far East Index. AltaGas plans to actively manage this differential through hedging activities.

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 2019.

Factor	Increase or decrease	Approximate impact on normalized EBITDA *($ millions)*
Natural gas liquids fractionation spread [(1)]	$1/Bbl	1
Degree day variance from normal - U.S. utilities [(2)]	5 percent	5
Change in CAD per US$ exchange rate	0.05	36
FG&P and extraction inlet volumes	10 percent	16
RIPET Propane Far East Index to Mont Belvieu spread [(3)]	US$0.02/gal	8

(1) Based on approximately 60 percent of frac spread exposed NGL volumes being hedged.

(2) Degree days - U.S. utilities relate to SEMCO Gas, ENSTAR, and Washington Gas service areas. For U.S. utilities, degree days are 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.

(3) Assumes RIPET in-service date of early in the second quarter of 2019.The impact on EBITDA due to changes in the spread will vary and will be mitigated through an active hedging program.

GROWTH CAPITAL

Based on projects currently under review, development or construction, AltaGas expects net invested capital expenditures of approximately $1.3 billion in 2019. The focused and strategic approach to capital expenditures in 2019 will target projects that provide ongoing growth potential, favorable risk profiles, and the strongest risk-adjusted returns with immediate payback, as AltaGas continues to strengthen its balance sheet. The Utilities segment is expected to account for approximately 60 to 65 percent of total capital expenditures, while the Midstream segment is expected to account for approximately 35 to 40 percent and the Power segment is expected to account for the remainder. Midstream and Power maintenance capital is expected to be approximately $30 to $40 million of the total capital expenditures in 2019. The majority of AltaGas' capital expenditures for the Utilities segment will focus on approved system betterment across all Utilities, accelerated pipe replacement programs in Virginia, Maryland, the District of Columbia and Michigan, new customer additions, and the construction of the Marquette Connector Pipeline. In the Midstream segment, capital expenditures are anticipated to primarily relate to the completion of RIPET, the Townsend expansion, the Aitken Creek integrated development project, the second train of North Pine, and WGL's investments in the Mountain Valley gas pipeline development and Central Penn Pipeline expansion. The Power segment remains on a capital-light strategy with expenditures focused on selected smaller investments in distributed generation and potential energy storage projects across the United States. The Corporation continues to focus on enhancing productivity and streamlining businesses.

AltaGas' 2019 committed capital program is expected to be funded through internally-generated cash flow, asset sales, the Dividend Reinvestment and Optional Cash Purchase Plan (DRIP), proceeds from hybrid securities and preferred share offerings, and normal course borrowings on existing committed credit facilities.

Midstream Projects

Ridley Island Propane Export Terminal

RIPET is located near Prince Rupert, British Columbia, and is expected to be the first propane export facility off the west coast of Canada. The site has a locational advantage given very short shipping distances to markets in Asia, notably a 10-day shipping time compared to 25 days from the U.S. Gulf Coast. The construction cost of RIPET is estimated to be approximately $450 to $500 million and RIPET is expected to ship 1.2 million tonnes of propane per annum (which is equivalent to approximately 40,000 Bbls/d of export capacity). RIPET is a strategic part of AltaGas' integrated energy value chain in Western Canada, and AltaGas expects to leverage this in pursuing future Midstream growth.

Construction of RIPET commenced during the second quarter of 2017. LPG tank construction and related infrastructure is advancing as planned and remains on schedule. Rail and marine loading infrastructure are also progressing, with construction of the retaining wall complete and rail offloading modules installed. The gangway has been installed and commissioned and jetty module fabrication is ongoing, with the majority of the overland modules in place. The team is simultaneously continuing construction of the balance of plant, with the operational building and warehouse buildings substantially complete. The site construction management team and project support teams have successfully hit all critical milestones to date on the RIPET master schedule and members of the operations team are now permanently on site to initiate a smooth transition. After comprehensive commissioning activities, the facility is scheduled to begin its operational phase in the first quarter of 2019 with the introduction of feedstock propane and filling the refrigerated storage tank with liquefied product. First cargo is expected early in the second quarter of 2019 which aligns with the propane contract year.

Based on production from its existing facilities and commercial contracts executed or currently under negotiation, AltaGas anticipates having physical volumes equal to the initial 40,000 Bbls/d target by the project in-service date. AltaGas plans to operate 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.

AltaGas LPG Limited Partnership (AltaGas LPG) and Astomos have entered into a multi-year agreement for the purchase of at least 50 percent of the 1.2 million tonnes per annum of propane expected to be available to be shipped from RIPET each year. Commercial agreements to secure the remaining capacity commitments are currently under negotiation.

In 2017, 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 Ridley Island LPG Export Limited Partnership (RILE LP) to develop, own, and operate RIPET. AltaGas' subsidiaries hold a 70 percent interest while Vopak holds a 30 percent interest in RILE LP. The construction cost of RIPET will be funded by AltaGas LPG and Vopak in proportion to their respective interests in RILE LP. RILE LP will be consolidated by AltaGas. AltaGas LPG has the right to 100 percent of the capacity of RIPET.

Central Penn Pipeline

Central Penn is a new 185 mile pipeline originating in Susquehanna County, Pennsylvania and extending to Lancaster County, Pennsylvania, and is an integral part of the larger Atlantic Sunrise project operated by The Williams Companies through Transcontinental Gas Pipeline Company LLC (Transco). Central Penn is regulated by the FERC. The Atlantic Sunrise project is designed to supply enough natural gas to meet the daily needs of more than 7 million American homes in the region. WGL Midstream owns an indirect 21 percent interest in Central Penn, which has the capacity to transport and deliver up to approximately 1.7 Bcf/d of natural gas from the northeastern Marcellus producing area to markets in the mid-Atlantic and Southeastern regions of the United States. Central Penn was placed in service in early October 2018.

In February 2014, WGL Midstream and certain partners formed Meade Pipeline Co LLC (Meade). Meade (39 percent) and Transco (61 percent) have joint ownership of Central Penn. WGL Midstream owns a 55 percent interest in Meade (21 percent indirect interest in Central Penn) and on a cash basis, as of December 31, 2018, WGL Midstream has spent approximately US$446 million on its share of the construction costs.

In addition to the investment in Meade, WGL Midstream entered into an agreement with Cabot Oil & Gas Corporation (Cabot) whereby WGL Midstream will purchase 0.5 Bcf/d of natural gas from Cabot over a 15 year term. As part of this agreement, Cabot has acquired 0.5 Bcf/d of firm gas transportation capacity on Transco's Atlantic Sunrise project. This capacity has been released to WGL Midstream.

In August 2018, Meade executed an agreement with Transco to participate in an expansion of the Central Penn Pipeline (Leidy South) with an estimated capital investment of up to US$50 million by WGL Midstream. Leidy South is expected to add an estimated 0.6 Bcf/d of natural gas capacity to Central Penn through the addition of compression at new and existing stations. Meade will own 40 percent of the expanded capacity. WGL Midstream will indirectly own 22 percent of the expanded capacity through its 55 percent ownership interest in Meade. Leidy South is anticipated to be in-service as early as the fourth quarter of 2021 assuming all necessary regulatory approvals are received in a timely manner.

Mountain Valley Pipeline, LLC (Mountain Valley)

WGL Midstream owns a 10 percent equity interest in Mountain Valley. The proposed pipeline, which will be operated by EQM Gathering Opco, LLC (EQM) and developed, constructed, and owned by Mountain Valley (a venture of EQT Midstream Partners, LP (EQT) and other entities), will transport approximately 2.0 Bcf/d and will extend from Equitrans, LP's system in Wetzel County, West Virginia to Transco's Station 165 in Pittsylvania County, Virginia. The pipeline is estimated to span approximately 300 miles and provide access to the growing Southeast demand markets.

On October 13, 2017, the FERC issued the Certificate of Public Convenience and Necessity for the pipeline. In early 2018, the FERC granted several notices to proceed with certain construction activities on the pipeline. Mountain Valley has submitted additional requests to the FERC for notices to proceed. There are several pending challenges to certain aspects of the Mountain Valley project that must be resolved before the project can be completed. Mountain Valley is working to respond to the court and agency decisions and restore all permits. The pipeline is targeted to be placed in service during the fourth quarter of 2019, subject to litigation and regulatory-related delay. As of December 31, 2018, approximately 70 percent of the project is complete, which includes the welding of approximately 60 percent of the pipeline and ongoing construction work of all compressor stations and interconnects that are expected to be complete by February 2019. Most recently, the Mountain Valley construction team has been focused on stabilizing the right-of-way for the winter season.

WGL Midstream expects to invest approximately US$350 million through the in-service date of the pipeline based on scheduled capital contributions and its contracted share of project costs. On a cash basis, as of December 31, 2018, WGL Midstream has invested approximately US$271 million in the pipeline. In addition, WGL has gas purchase commitments to buy approximately 0.5 Bcf/day of natural gas, at index-based prices, for a 20-year term, and will also be a shipper on the proposed pipeline.

In April 2018, WGL Midstream entered into a separate agreement with EQM to acquire a 5 percent equity interest in a project to build an interstate natural gas pipeline (the MVP Southgate project). The proposed pipeline will receive gas from the Mountain Valley Pipeline mainline in Pittsylvania County, Virginia and extend approximately 73 miles south to new delivery points in

Rockingham and Alamance counties, North Carolina. The total commitment by WGL Midstream is expected to be approximately US$20 million and the lateral pipeline is expected to be placed into service in late 2020.

Northeastern British Columbia Expansion Projects

Townsend 2B

On August 27, 2018, AltaGas announced that it entered into definitive agreements with Kelt to provide an energy infrastructure solution for the liquids-rich Inga Montney development located in Northeast British Columbia. The commercial arrangements underpin the expansion of AltaGas' Townsend complex including the addition of a 198 MMcf per day C3+ deep cut gas processing facility consisting of 99MMcf per day of new deep cut gas processing capacity and repurposing 99 MMcf per day of the Townsend facility's existing shallow cut capacity with deep cut gas processing capabilities. The facility will provide Kelt with firm processing of 75 MMcf per day of raw gas under an initial 10 year take-or-pay agreement. The additional natural gas liquids will increase utilization in AltaGas' existing liquids pipelines, position the Corporation well for an expansion of the North Pine fractionator, and provide additional propane supply to RIPET. The expansion of the Townsend complex coupled with enhanced NGL recovery will provide producers with more options for energy exports. The estimated project cost is approximately $180 million. Long lead equipment has been ordered and the project is on track to be on stream in the fourth quarter of 2019.

Aitken Creek

On September 26, 2018, AltaGas announced that it entered into a definitive agreement with Black Swan to acquire 50 percent ownership in certain existing and future natural gas processing plants of Black Swan, including 50 percent ownership in the Aitken Creek North gas processing facility (Plant 1) currently in operation, and 50 percent ownership in the Nig Creek gas processing facility (Plant 2), which is currently under construction. AltaGas and Black Swan will also enter into long term processing, transportation and marketing agreements that include new AltaGas liquids handling infrastructure, strengthening AltaGas' Northeast British Columbia value proposition and connecting producers with additional options for energy exports. The total capital investment by AltaGas is expected to be approximately $230 million and the transaction closed on October 2, 2018. Plant 2 is expected to be on stream in the fourth quarter of 2019.

North Pine

The additional natural gas liquids from the Townsend 2B and Aitken Creek expansion projects will increase utilization in AltaGas' existing liquids pipelines and facilities, resulting in the need for an expansion of the North Pine fractionator, and will provide additional propane supply to RIPET. The North Pine expansion project will add 10,000 Bbl/d of fractionation capacity, optimize the existing 10,000 Bbl/d fractionation train, add rail storage, and optimize the rail yard and rail operation. The project is estimated to cost approximately $58 million and is expected to be on stream in the first quarter of 2020.

Alton Natural Gas Storage Project

Development of the Alton Natural Gas Storage Project, located near Truro, Nova Scotia is focusing on regulatory and construction planning, environmental study, and community engagement. This includes an application to the Nova Scotia Utility and Review Board (NSUARB) to extend the Alton Approval to Construct for the cavern site. The application is currently before the NSUARB for decision. In addition, Alton is progressing the permitting and planning for the natural gas pipeline with provincial authorities. The start-date for solution mining for cavern development is being determined. The Nova Scotia Minister of Environment is expected to make a decision on the Industrial Approval (IA) appeal by Sipekne'katik First Nation in due course. In the meantime, the IA remains in effect for the project. AltaGas continues to work constructively with governments, regulators, and the Mi'kmaq of Nova Scotia. The Alton Natural Gas Storage Project is expected to provide up to 10 Bcf of natural gas storage capacity. The first phase of storage service for two caverns, consisting of approximately 4 Bcf of storage capacity, is expected to commence in 2022.

Utility Projects

Accelerated Utility Pipe Replacement Plans

Accelerated pipe replacement programs are in place in all three of Washington Gas' utility jurisdictions. These are long-term programs with 17 to 35 remaining years, subject to both changing conditions and regulatory review and approval in five year increments. The anticipated expenditures over the next five years are approximately US$1 billion, with future increments projected to include significant expenditures as well. Washington Gas is accelerating pipe replacement in order to further enhance the safety and reliability of the pipeline system. In contrast to the traditional rate-making approach to capital investments, Washington Gas begins recovering the cost, including a return, for these investments immediately through approved surcharges for each accelerated pipe replacement program. Once new base rates are put into effect in a given jurisdiction, expenditures previously being recovered through the accelerated pipe replacement surcharge will be collected through the new base rates.

In the District of Columbia, the construction activities related to an accelerated replacement program targeting vintage mechanically coupled pipe began in 2009 and were completed in January 2017, with restoration and paving continuing into 2017. In 2013, Washington Gas filed PROJECTpipes in which Washington Gas proposed to replace bare and/or unprotected steel services, bare and targeted unprotected steel main, and cast iron main in its distribution system in the District of Columbia. In 2015, the Public Service Commission of the District of Columbia (PSC of DC) approved the settlement agreement for PROJECTpipes, authorizing the recovery, through a surcharge, of total project costs not to exceed US$110 million through the end of September 2019. In December 2018, Washington Gas submitted the next phase of PROJECTpipes to the PSC of DC. The second phase spans the next five years and enables Washington Gas to continue to proactively replace its pipelines on an accelerated basis, proposing to replace approximately 22 miles of pipe and over 8,000 service lines from October 1, 2019 to December 31, 2024. If approved by the PSC of DC, Washington Gas will spend approximately US$305 million on the second phase over five years, which would be recovered through the surcharge billing mechanism previously approved by the PSC of DC.

In 2014, pursuant to the Strategic Infrastructure Development and Enhancement (STRIDE) law in Maryland, the Maryland Public Service Commission (PSC of MD) approved Washington Gas' initial STRIDE Plan to recover the reasonable and prudent costs associated with qualifying infrastructure replacements through monthly surcharges. The PSC of MD approved replacement of bare and/or unprotected steel services and targeted copper and/or pre-1975 plastic services, bare and targeted unprotected steel main, mechanically coupled pipe main and service, and cast iron main in Washington Gas' Maryland distribution system at an estimated five-year cost of US$200 million, including cost of removal, through 2018. In 2015, the PSC of MD approved one additional program applicable to gas distribution system replacements and three of the four requested additional programs applicable to gas transmission system replacements at an incremental cost of US$19 million, including cost of removal, in eligible infrastructure replacements over the remaining four years of the initial STRIDE Plan. In June 2018, Washington Gas filed a request for a second five-year plan (STRIDE 2.0) with the PSC of MD at an estimated cost of approximately US$394 million starting January 2019. In December 2018, the PSC of MD approved the request but lowered the authorized budget from US$394 million to US$350 million.

On April 21, 2011, the Commonwealth of Virginia State Corporation Commission (SCC of VA), pursuant to a new law to advance Virginia's Steps to Advance Virginia's Energy Plan (SAVE), approved Washington Gas' initial SAVE plan for accelerated replacement of infrastructure facilities and a SAVE rider to recover eligible costs associated with those replacement programs. Subsequently, the SCC of VA approved three amendments to Washington Gas' SAVE plan, increasing the overall investment, the scope of approved programs and new facilities replacement programs. Washington Gas' approved SAVE plan encompasses eight ongoing programs: (i) bare and/or unprotected steel service replacement program, (ii) bare and unprotected steel main replacement program, (iii) mechanically coupled pipe replacement, (iv) copper services replacement program, (v) black plastic services replacement program, (vi) cast iron mains replacement program, (vii) meter set and piping remediation/replacement program and (viii) transmission programs. Washington Gas was authorized to invest US$256 million, including cost of removal, over the five-year calendar period through 2017. In November 2017, the SCC of VA approved Washington Gas' application to amend and extend its SAVE plan (SAVE 2.0). SAVE 2.0 authorizes Washington Gas to invest approximately US$500 million over a five-year period, to continue work on both previously approved and new distribution and transmission system accelerated replacement programs.

Marquette Connector Pipeline

On August 23, 2017, the Michigan Public Service Commission (MPSC) approved SEMCO Gas' application to construct, own, and operate the MCP. The MCP is a proposed new pipeline that will connect the Great Lakes Gas Transmission Pipeline to the

Northern Natural Gas Pipeline in Marquette, Michigan, which will provide system redundancy and increase deliverability, reliability and diversity of supply to SEMCO Gas' approximately 35,000 customers in Michigan's Western Upper Peninsula.

The Company received approval for all environmental permits in September 2018 and the completed Archeological Assessment has been submitted to the state's Historical Preservation Officer. The construction bid package has been tentatively awarded. Construction is expected to begin in 2019, with clearing and mobilization scheduled to begin in the first quarter of 2019 and an anticipated in-service date near the end of the fourth quarter of 2019.

New Customer Growth

The Utility business actively markets and adds new customers through both capital expenditures and different rate mechanisms aimed at bringing the benefits of natural gas, including lower energy bills and reduced carbon emissions, to more residents in its territories. In 2019, Washington Gas, SEMCO and ENSTAR expect new customer growth of 1.0 percent, 0.8 percent, and 0.9 percent, respectively, supported by additional capital and rate base. Adding new customers directly drives earnings growth through additional distribution revenues.

Power Projects

Distributed Generation Investments

WGL currently owns and manages distributed generation projects with approximately 325 MW of gross capacity across 20 states and the District of Columbia in the United States. The power output from these projects is generally contracted directly with end-user customers under long-term service agreements, providing clean energy solutions to a variety of commercial, government, institutional, and residential customers. For certain investments, WGL, along with a tax equity partner, has formed several tax equity funds to acquire, own, and operate distributed generation projects. These funds have invested approximately US$223 million in distributed generation projects since 2016, of which WGL's share was approximately US$145 million. WGL is the managing member of these funds and invested cash equal to the purchase price of the distributed generation projects less any contributions from the tax-equity partner for projects sold by WGL into the funds. WGL is the operations and maintenance provider, and was the developer of these projects.

One of the tax equity partnerships, SFGF II, LLC, remains open to acquire new solar projects. To date, SFGF II, LLC has invested a total of US$122 million in new projects since June 30, 2017 and there is US$28 million remaining for additional acquisitions through March 31, 2019. As of December 31, 2018, WGL has contributed US$74 million into SFGF II, LLC. The estimated total contribution by WGL to this fund is expected to be approximately US$95 million by the end of the commitment period.

The Company continues to consider additional energy storage and renewables opportunities.

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. AltaGas' previously owned Canadian utilities, which served end-users in Alberta, British Columbia, Nova Scotia and Inuvik, were sold to AltaGas Canada Inc. in 2018. AltaGas' remaining utility businesses in the United States serve over 1.6 million customers and have a rate base of approximately US$3.7 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;
- 65 percent interest in Cook Inlet Natural Gas Storage Alaska LLC (CINGSA) in Alaska; and
- An approximate 37 percent interest in AltaGas Canada Inc.

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 the effects of variance in customer usage caused by weather and other factors such as conservation.

<u>Washington Gas</u>

Washington Gas is a regulated public utility acquired as part of the WGL Acquisition that 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 2018, Washington Gas had approximately 1.2 million customers. Of these customers, approximately 94 percent are residential. The rate base at year end was approximately US$2.8 billion. At the end of 2018, the approved regulated ROE for Washington Gas in its various jurisdictions ranged from 9.25 percent to 9.7 percent based on an equity ratio ranging from 51.7 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' customers are eligible to purchase their natural gas from unregulated third-party marketers through natural gas unbundling. As at December 31, 2018, approximately 15 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, 2018, it had service agreements with four pipeline companies that provided firm transportation and storage services with contract expiration dates ranging from 2019 to 2044. Washington Gas has also contracted with various interstate pipeline and storage companies to add to its storage and transportation capacity.

In early 2018, Washington Gas filed applications in all three of its jurisdictions for approval of a reduction of distribution rates to reflect the impact of the Tax Cuts and Jobs Act (TCJA). For the period from close of the WGL Acquisition to December 31, 2018, the impact of these filings and subsequent responses from the regulatory commissions was a reduction in base rates of approximately US$6 million in Maryland, US$3 million in the District of Columbia, and US$6 million in Virginia.

On May 15, 2018, Washington Gas filed an application with the PSC of MD to increase its base rates for natural gas service for approximately US$56 million including approximately US$15 million in annual surcharges currently paid by customers for system upgrades. On December 11, 2018, the PSC of MD approved Washington Gas' US$29 million in new revenues and increased the return on equity to 9.7 percent. On January 10, 2019, Washington Gas requested a rehearing, alleging two errors in the agency's final order. A PSC of MD decision on the application for rehearing is expected late in first or second quarter of 2019.

On June 15, 2018, Washington Gas filed an application with the PSC of MD for approval of the second phase of its accelerated natural gas pipeline initiative. The application requested approval of approximately US$394 million in accelerated infrastructure replacements for the 2019 to 2023 period. On December 11, 2018, the PSC of MD approved a US$350 million five-year program. On January 9, 2019, Washington Gas applied to supplement its 2019 project list with an additional annual spend of approximately US$65 million. On January 25, 2019, the PSC of MD approved the 2019 revised project list and affirmed the annual spend of approximately US$65 million.

On July 31, 2018, Washington Gas filed an application with the SCC of VA to increase its base rates for natural gas service. This base rate increase, if granted, would be approximately US$38 million, of which approximately US$15 million relates to costs being collected through the monthly SAVE surcharges for accelerated pipeline replacement. The new interim rates are effective, subject to refund, in January 2019. Hearings are scheduled for April 2019 with a decision expected in the second half of 2019.

On August 31, 2018, Washington Gas filed the 2019 SAVE capital expenditure application with the SCC of VA seeking approval for approximately US$70 million of SAVE capital expenditures in 2019. The SAVE application for 2019 was approved and implemented beginning January 2019.

On December 7, 2018, Washington Gas filed an application with the PSC of DC for the phase 2 PROJECTpipes program requesting approval of approximately US$305 million in accelerated infrastructure replacement in the District of Columbia during the 2019 to 2024 period.

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 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 under the name SEMCO Gas and has an interest in a regulated natural gas storage facility in Michigan. At the end of 2018, SEMCO Gas had approximately 303,000 customers. Of these customers, approximately 84 percent are residential. In 2018, 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$472 million. In 2018, the approved regulated ROE for SEMCO Gas was 10.35 percent with an approved capital structure based on 49 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 a 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. The anticipated annual average capital spending over the final five year period is approximately US$10 million.

SEMCO Gas is required by Michigan law to establish an Energy Optimization Program (an EO plan) for their customers and to implement and fund various energy efficiency and conservation matters. The costs of the measures offered through the EO program are recovered through surcharges imposed on all customers of SEMCO Gas. EO plans and reconciliations are subject to review and approval by the MPSC. SEMCO Gas also has the ability to earn a performance incentive if certain EO goals and objectives are met annually. During 2018, the MPSC issued an order for SEMCO Gas to collect US$1 million for the 2017 EO plan year performance incentive.

In December 2016, SEMCO Gas filed an application with the MPSC seeking approval to construct, own, and operate the Marquette Connector Pipeline. In August 2017, the MPSC approved SEMCO's application. Construction is expected to be completed in 2019, with an in-service date during the fourth quarter of 2019. Please refer to the *Growth Capital* section of this MD&A for further information.

As required by an order issued by the MPSC in September 2012, SEMCO Gas filed a depreciation study with the MPSC in September 2017, using 2016 data. On April 9, 2018, the MPSC issued an order approving the settlement agreement and new depreciation rates. The new rates reflect a US$1.9 million upward adjustment to depreciation expense when compared to the current rates and are effective on January 1, 2019. SEMCO Gas is required to file a new depreciation case and updated depreciation study with the MPSC no later than September 30, 2022, using 2021 data.

On December 27, 2017, the MPSC issued an order instructing all regulated utilities in Michigan to track the impact of the TCJA effective January 1, 2018. On February 22, 2018, the MPSC issued an order requiring utilities in Michigan to follow a 3-step approach for computing and implementing bill credits to reflect the reduction in revenue requirements as a result of the TCJA. The first step was to establish a credit (Credit A) through a contested case. Credit A is a forward looking tax credit that will refund the annual tax savings relating to the reduction of the corporate tax rate from 35 percent to 21 percent on a prospective basis. SEMCO Gas submitted its Credit A filing on March 29, 2018, reflecting a revenue reduction of approximately US$5.9 million on an annual basis. On April 20, 2018, SEMCO Gas supplemented its Credit A filing with a proposal to reduce its Main Replacement Program (MRP) surcharges to reflect the impact of the TCJA on its MRP annual revenue requirement. On May 30, 2018, the MPSC issued an order approving a settlement in SEMCO Gas' Credit A filing reflecting a reduction in revenues of approximately US$5.9 million and a reduction to the annual MRP revenue requirement of approximately US$0.6 million, effective July 1, 2018. Credit A will remain in place until new rates are set in the next general rate case. The second step was to establish another credit (Credit B) through a contested case. Credit B is a backward-looking tax credit to reflect the reduction of the corporate tax rate of 35 percent to 21 percent, for the period January 1, 2018 through the date Credit A is established. On July 27, 2018, SEMCO Gas filed its proposal for Credit B to address the impacts of federal corporate tax reduction arising from the TCJA on its natural gas rates from January 1, 2018 until June 30, 2018. On September 28, 2018, the MPSC issued an order approving the settlement in SEMCO Gas' Credit B filing. SEMCO Gas will refund approximately US$4.7 million to customers volumetrically via bill credits for three months beginning with the first billing cycle in October 2018. The third and final step was to file an application to establish the calculation for all of the remaining impacts of the TCJA (Calculation C), which is primarily the remeasurement of deferred taxes and how the amounts deferred as regulatory liabilities will flow back to ratepayers. On October 1, 2018, SEMCO Gas filed its application to address the Calculation C effects of the TCJA, which is currently ongoing.

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 2018, ENSTAR had approximately 145,000 customers including residential, commercial and transportation and of these customers, approximately 91 percent are residential. In 2018, 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$291 million for ENSTAR and US$77 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 measureable changes in their application for new rates.

On March 23, 2018, the RCA sent a letter to several investor-owned utilities in Alaska, asking for the utilities' proposed response to the 2017 Tax Cut and Jobs Act. On April 26, 2018, ENSTAR filed its proposed reduction in rates with the RCA, reflecting a US$5.1 million decrease from the annual revenue requirement that was determined in October 2017. On May 29, 2018, the RCA approved ENSTAR's proposed rate decrease and the reduced rates went into effect on June 1, 2018. ENSTAR anticipates addressing excess deferred income taxes in its next rate case, which is required to be filed no later than June 1, 2021, with a test year of 2020.

In April 2018, CINGSA filed a request for an advanced ruling on a redundancy project for approximately US$41 million of capital expenditures and an annual revenue requirement of approximately US$6 million. Reply testimony was filed in September 2018 and a hearing occurred in October 2018, with a decision expected in the second quarter of 2019.

The CINGSA rate case was filed in April 2018 based on a 2017 historical test year, reducing rates by US$4 million due to a lower rate base, lower returns on equity (ROE) and lower federal income tax. The rate case hearing is scheduled for April 2019 with a decision expected in the third quarter of 2019.

AltaGas Canada Inc.

In the fourth quarter of 2018, the IPO of ACI, a previously wholly owned subsidiary of AltaGas, was completed. As of December 31, 2018, AltaGas had an approximate 37 percent equity interest in ACI. ACI holds certain assets formerly held by AltaGas, including rate regulated distribution utility 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 equity interest in the Northwest Hydro facilities. ACI's utilities purchased from AltaGas include AltaGas Utilities Inc. (AUI), serving approximately 80,400 customers in Alberta, Pacific Northern Gas Ltd. (PNG), serving approximately 41,900 customers in British Columbia, and Heritage Gas Ltd. (HGL), serving approximately 7,300 customers in Nova Scotia. For the period prior to IPO close on October 25, 2018, the results of all ACI entities were consolidated within AltaGas' results. Subsequent to the IPO close, AltaGas' interest in ACI is accounted for as an equity investment.

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:

- Maximize use of existing infrastructure and increase market penetration in order to maintain cost-effective rates;
- Invest in the safety and reliability of existing infrastructure, including delivery system upgrade programs;
- Expand infrastructure to new markets to bring the economic and environmental benefits of gas to new customers, without unduly burdening existing customers;
- Maintain strong relationships with local communities, Indigenous peoples, governments, and regulatory bodies;
- Maintain strong community and regulatory relationships while ensuring fair returns to shareholders; and
- Acquire new franchises when the opportunities arise.

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' U.S. utilities have 168 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, prudent investments in current areas of operations, and the addition of new customers. Customer growth rates for AltaGas' U.S. utilities are moderate, as is typical with mature utilities, with growth rates generally tied closely to the economic growth of the respective franchise regions.

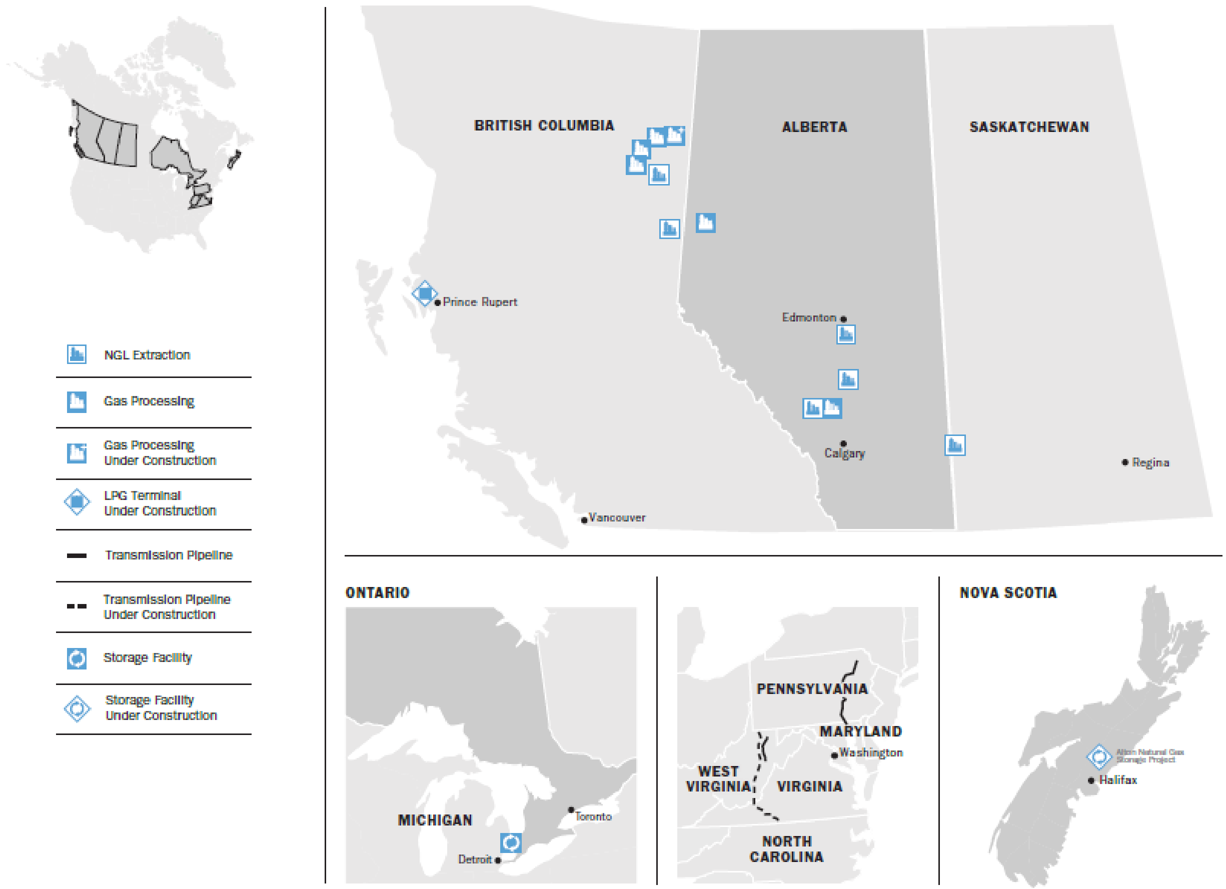
MIDSTREAM

Description of Assets

AltaGas' Midstream segment serves customers primarily in the Western Canada Sedimentary Basin (WCSB) and, subsequent to the disposition of the non-core midstream assets in Canada which closed in February 2019, transacts more than 1.5 Bcf/d of natural gas including natural gas gathering and processing, NGL extraction and fractionation, transmission, storage and natural gas and NGL marketing. 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 owns approximately 1.5 Bcf/d of extraction processing capacity and approximately 0.7 Bcf/d of raw field gas processing capacity. The Midstream segment also includes an equity investment in Petrogas through AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP).

Transmission pipelines deliver natural gas to distribution systems, end-users or other downstream pipelines. AltaGas uses its market knowledge and expertise to create value by buying and reselling natural gas; providing gas transportation, storage, and gas and NGL marketing for producers; and sourcing gas supply for some of the Corporation's processing assets. The Midstream segment also includes expansion and greenfield projects under development or construction, including RIPET and the Alton Natural Gas Storage Project discussed under the *Growth Capital* section of this MD&A.

With the acquisition of WGL, the Midstream segment also includes WGL's investments in four pipelines in the northeastern United States, including Stonewall, Central Penn, Mountain Valley, and the proposed Constitution Pipeline (Constitution), as well as the retail gas marketing business of WGL Energy Services, Inc. (WGL Energy Services).



Specifically, subsequent to the sale of non-core midstream assets in Canada, the Midstream segment includes:

- Interests in five NGL extraction plants with net licensed inlet capacity of 1.5 Bcf/d. The extraction assets provide stable fixed-fee or cost-of-service type revenues and margin based revenues. The natural gas supply to AltaGas' extraction plants, with the exception of the Younger extraction plant (Younger), 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;
- The first train of the North Pine facility near Fort St. John, British Columbia with capacity to fractionate 10,000 Bbls/d of propane plus NGL mix, and 6,000 Bbls/d of condensate terminaling capacity and two eight inch diameter NGL supply pipelines, each approximately 40 km in length;
- Gathering and processing facilities in Western Canada and a network of gathering and sales lines that gather natural gas upstream of processing facilities and deliver natural gas into downstream pipeline systems that feed North American natural gas markets. The field 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;
- A 15-year strategic alliance between AltaGas and Painted Pony Energy Ltd. (Painted Pony) for the development of processing infrastructure and marketing services for natural gas and NGL. Since the formation of the strategic alliance in 2014, AltaGas completed the 198 Mmcf/d shallow-cut gas processing facility (the Townsend facility) including the related egress pipelines and truck terminal, and the 99 Mmcf/d Townsend 2A facility (collectively the Townsend facilities). AltaGas is the operator of these facilities and is also the marketer for Painted Pony's gas and NGL;
- 50 percent ownership of the 5.3 Bcf Sarnia natural gas storage facility connected to the Dawn Hub in Eastern Canada;
- The Alton Natural Gas Storage Project under construction;

- Natural gas and NGL marketing and gas transportation services to optimize the value of the infrastructure assets and meet customer needs. WGL Midstream 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. WGL Midstream also contracts for storage and pipeline capacity in its trading activities through both long term contracts and short term transportation releases;
- 50 percent ownership in AIJVLP, with the remaining 50 percent owned by Idemitsu Kosan Co., Ltd.;
- AIJVLP holds a two-thirds ownership interest in Petrogas, a leading North American integrated midstream company, with an extensive logistics network consisting of over 2,500 rail cars and 27 rail, truck and storage terminals providing key infrastructure, supply logistics and marketing expertise. Petrogas also owns and operates the Ferndale Terminal;
- The Ridley Island Propane Export Terminal in British Columbia under construction, which has an expected in-service date of early in the second quarter of 2019;
- WGL's retail gas marketing business, which sells natural gas directly to residential, commercial and industrial customers in Maryland, Virginia, Delaware, Pennsylvania and the District of Columbia;
- A 21 percent net equity interest in Central Penn, a regulated 185 mile pipeline that has the capacity to transport and deliver up to approximately 1.7 Bcf/d of natural gas. Central Penn began operations on October 6, 2018;
- A 10 percent equity interest in Mountain Valley. The proposed pipeline will transport approximately 2.0 Bcf/d of natural gas. Mountain Valley is expected to be placed in service in the fourth quarter of 2019. In April 2018, WGL Midstream 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 in service in late 2020;
- A 30 percent equity interest in Stonewall, which has the capacity to gather up to 1.4 billion cubic feet of natural gas per day from the Marcellus production region in West Virginia and connects with an interstate pipeline system that serves markets in the mid-Atlantic region; and
- A 10 percent interest in the proposed Constitution Pipeline through a 10 percent equity investment in Constitution Pipeline Company, LLC. The natural gas pipeline venture is proposed to transport natural gas from the Marcellus region in northern Pennsylvania to major northeastern markets.

Capitalize on Opportunities

AltaGas plans to grow its Midstream business by expanding and optimizing strategically-located assets and by adding new assets to serve customers by providing access to new markets, including Asia. New infrastructure is expected to be larger scale facilities supporting the vast reserves in North America. 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:

- Develop high quality assets that enhance the integrated midstream offering and connect producers to market;
- Consolidate its position in key markets to deliver optimal growth over the long-term;
- Provide a fully-integrated midstream service offering including gas and NGL gathering and processing, fractionation, and transportation facilities, and logistics and marketing services to its customers across the energy value chain, with higher producer netbacks resulting from export access to higher value markets, including Asia;
- Maintain strong relationships with local communities, Indigenous peoples, governments, and regulatory bodies;
- Maximize profitability of existing facilities by increasing capacity, utilization and efficiency;
- Mitigate volume risk through contractual structures, redeployment of equipment and expansion of geographic reach;
- Coordinate between facilities, business segments and product lines to improve efficiencies and maximize profits; and
- Continue to develop the Northeast U.S. natural gas value chain strategy which complements AltaGas' existing business and investments.

In recent years, the WCSB has changed from a maturing basin to one capable of sustainable long-term growth through new low cost gas formations such as the Montney. The emergence of unconventional gas plays in the WCSB such as the Montney, as well as increased focus on horizontal multi-fracturing and completions technology, have resulted in abundant natural gas supply and associated liquids. Market demand, including the demand generated from the LPG and potential LNG export projects on the west coast of North America, provides significant long-term growth opportunities for the Corporation's Midstream segment. AltaGas expects to capitalize on these opportunities by increasing throughput at facilities, by increasing working interests in existing plants, and by acquiring and constructing new facilities such as liquefaction, refrigeration, natural gas processing, extraction, fractionation, storage and transmission pipelines. AltaGas' 15-year strategic alliance with Painted Pony, and, more recently, the agreements with Black Swan and Kelt, are examples of the Corporation's ability to partner with producers to provide a fully-integrated service offering.

The Corporation also expects there to be opportunities to increase volumes by tying in new wells and building or purchasing adjoining facilities and systems to create larger integrated processing infrastructure to capture operating synergies and enhance its competitive advantage. The strategic location of some of its existing gas processing infrastructure is expected to benefit from growing natural gas production in northeastern British Columbia and western Alberta, in response to the development of unconventional sources of gas, such as the Montney Deep Basin and Duvernay resource plays. The Townsend facilities and the related infrastructure, as well as the recent agreements with Kelt and Black Swan are examples of AltaGas' ability to capitalize on energy infrastructure growth opportunities. The first train of the North Pine facility entered commercial operation in 2017, which provides NGL processing capacity to producers in the area and is connected to the Townsend facilities through pipelines. The combined commitments from Black Swan and Kelt will trigger the expansion of the North Pine C3+ fractionation capacity from the current 10,000 Bbl/d to the permitted and approved 20,000 Bbl/d. The North Pine facility is well connected by rail to Canada's west coast including RIPET. Through the Townsend facilities, the North Pine facility and RIPET currently under construction, AltaGas is well positioned to provide a fully integrated midstream service offering while also providing access to higher netback markets for producer NGL. The Gordondale facility and the Blair Creek facility are also meeting liquids extraction needs in the Montney area as producers seek to increase netbacks by capitalizing on liquids-rich gas in this prolific area. Overall, the diverse nature of AltaGas' natural gas and NGL infrastructure is expected to provide ongoing opportunities for AltaGas to increase throughput, utilization and profitability.

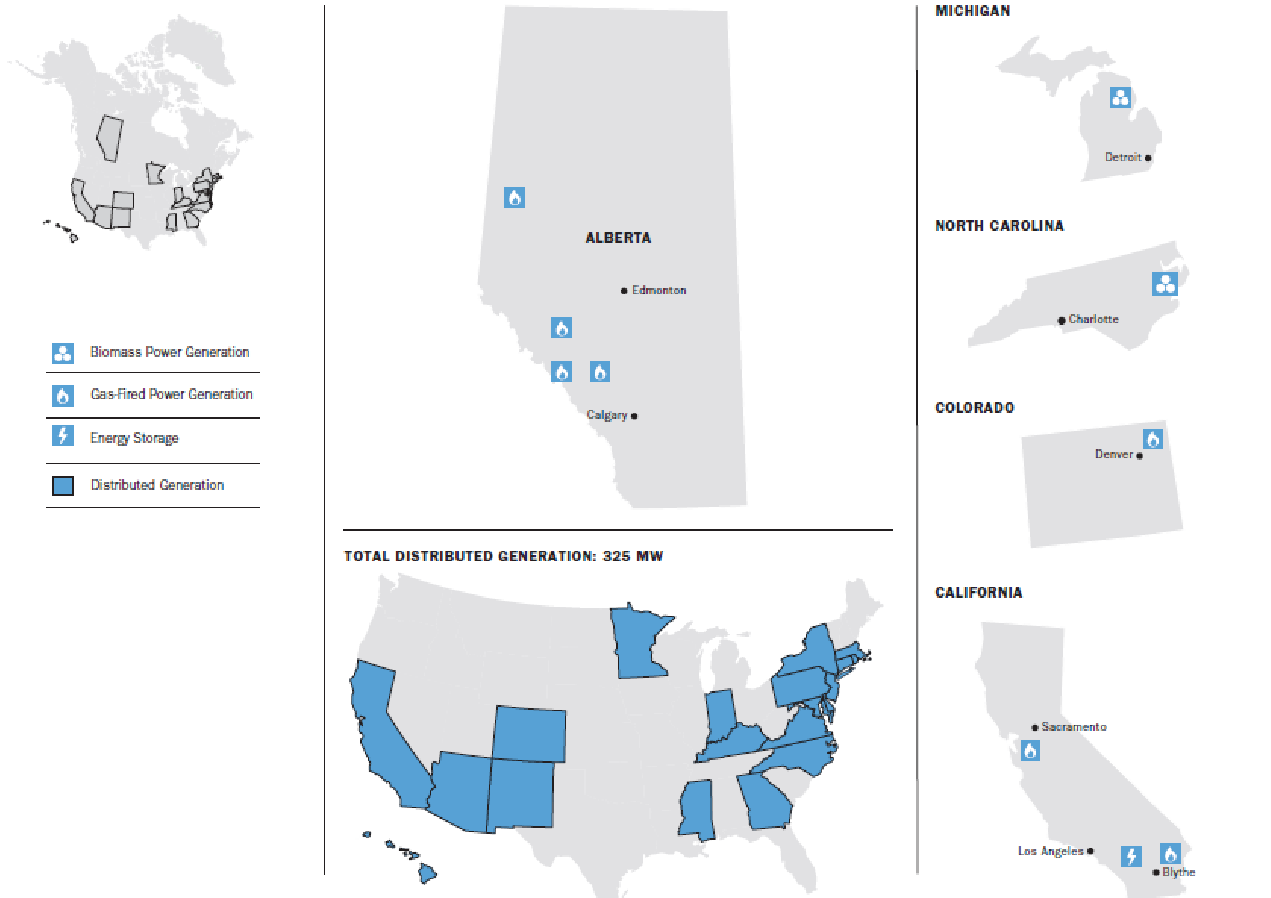
Due to the integrated nature of AltaGas' gas gathering and processing assets, transmission services are often offered in combination with gathering and processing, natural gas marketing and extraction services. AltaGas is uniquely positioned to work with producers providing services across the integrated value chain, from wellhead to the coast and on to export markets. This is particularly the case with producers in the vast Montney, Deep Basin, and Duvernay resource plays under development in northeastern British Columbia and western Alberta. With RIPET near Prince Rupert, British Columbia currently under construction and the Petrogas Ferndale Terminal in the state of Washington, AltaGas can provide multiple outlets for producers to deliver their products to the highest value markets, including Asia. AltaGas also pursues additional opportunities to enhance the value of its infrastructure through services ancillary to its infrastructure based businesses. These include maintaining the cost effective flow of gas through extraction plants and increasing services provided to producers. AltaGas is also reviewing plant optimization opportunities which will generate another source of cash flow and improve customer netbacks. AltaGas has significant gas market knowledge, which it employs across all its assets to enhance returns along the energy value chain and more effectively serve customers' needs.

POWER

Description of Assets

AltaGas' Power segment is engaged in the generation and sale of capacity, electricity, and ancillary services and related products through power facilities in Alberta, California, Colorado, Michigan, and North Carolina, as well as distributed generation assets including solar photovoltaic (PV) and fuel cells across the United States. AltaGas continues to pursue the demand for clean energy sources, while increasing earnings, cash flow stability, and predictability under a capital-light power strategy.

Subsequent to the sale of the non-core Canadian power assets which closed in February 2019, and the sale of the remaining 55 percent interest in the Northwest Hydro facilities which closed in January 2019, the Power segment includes 1,105 MW of operational gross power generation capacity from gas-fired, distributed energy, solar, biomass, and energy storage, as well as a number of opportunities for additional energy storage assets currently under development.



Specifically, subsequent to the sale of non-core power assets in Canada and the remaining 55 percent interest in the Northwest Hydro facilities, 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 and Brush are under Power Purchase Arrangements (PPAs) with creditworthy utilities;
- 45 MW of cogeneration and 3 MW of gas-fired peaking plant capacity in Alberta;
- 85 MW of gross biomass generation in the United States. The Grayling facility is under a long-term PPA with CMS Energy through 2027 while the Craven facility is contracted through 2027 with Duke Energy;
- 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 natural gas directly to residential, commercial and industrial customers in Maryland, Virginia, Delaware, Pennsylvania and the District of Columbia; and
- 325 MW of distributed generation capacity acquired in the WGL Acquisition, including solar PV and natural gas fuel cells across the United States. Generation is sold under long-term power purchase agreements with customers.

On November 13, 2018, AltaGas sold three northern California natural gas-fired power assets (Tracy, Hanford and Henrietta) with total generating capacity of 523 MW, located in the San Joaquin Valley (the San Joaquin facilities). Also, in December 2018, AltaGas sold the Busch Ranch 15 MW wind generation facility in Colorado.

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 through 2018 and for the majority of 2019. AltaGas retains the rights to the energy and ancillary service attributes of the facility, which are sold on a merchant basis into the California Independent System Operator (CAISO).

In southern California, the existing 507 MW Blythe Energy Center is currently operating under a PPA with SCE until July 31, 2020, serving the CAISO market. 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 pipeline connection as a second supply source, and interconnects to SCE and CAISO via its 67-mile transmission line.

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.

At December 31, 2018, AltaGas operated the Northwest Hydro facilities in northwest British Columbia with total generation capacity of 277 MW. In the second quarter of 2018, AltaGas sold an indirect 35 percent of its interest in these facilities to a third party, and in the fourth quarter of 2018, AltaGas sold an additional 10 percent interest to ACI. On December 13, 2018, AltaGas announced that it had reached an agreement for the sale of its remaining indirect equity interest of approximately 55 percent in these facilities for expected proceeds of approximately $1.37 billion. The sale closed in January 2019.

With the close of the WGL Acquisition, the Power segment now includes WGL's Power assets with commercial energy systems and U.S. electricity retail. The commercial energy systems include 325 MW of distributed generation assets (solar PV systems and natural gas fuel cells). Through WGL, AltaGas also operates as general contractor to upgrade mechanical, electrical, water and energy-related infrastructure of large governmental and commercial facilities by implementing both traditional and alternative energy technologies. The sale of energy is under long term power purchase agreements with a general duration of 20 years.

The U.S. power retail business sells power to end users in Maryland, Virginia, Delaware, Pennsylvania 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 2020 has been entered into with Shell Energy North America (US) LP for the majority of electricity requirements to service end users, which also reduces credit requirements.

AltaGas also owns biomass assets including a 30 percent working interest in a 37 MW wood biomass power facility in Grayling, Michigan and a 50 percent working interest in a 48 MW wood biomass power facility in Craven County, North Carolina. The Grayling facility is contracted under a long term PPA through 2027 with CMS Energy and the Craven facility is contracted through 2027 with Duke Energy.

Capitalize on Opportunities

AltaGas' strategy is to develop, build, own and operate long-life, low-risk infrastructure assets to deliver strong, stable returns for investors. Growth in the Power business involves a capital-light strategy that is focused on strong and stable returns from renewable sources of clean energy and energy storage, as the Corporation seeks to capitalize on the increasing demand for clean power while reducing its carbon footprint.

The demand for clean energy continues to be strong across North America as the industry addresses climate change legislation and utilities are faced with the renewable portfolio standards. Utilities' reliance on coal is lessening as its market share continues to decrease for environmental and economic reasons, with low cost natural gas and increasing renewables providing a cost competitive option for fuel on a marginal cost basis in many parts of North America.

CONSOLIDATED FINANCIAL REVIEW

($ millions)	Three Months Ended December 31 2018	2017	Year Ended December 31 2018	2017
Revenue	**1,727**	745	**4,257**	2,556
Normalized EBITDA(1)	**394**	213	**1,009**	797
Net income (loss) applicable to common shares	**174**	(11)	**(502)**	30
Normalized net income(1)	**120**	63	**195**	204
Total assets	**23,488**	10,032	**23,488**	10,032
Total long-term liabilities	**11,746**	4,578	**11,746**	4,578
Net additions to property, plant and equipment	**16**	114	**573**	388
Dividends declared(2)	**121**	94	**463**	362
Normalized funds from operations(1)	**255**	179	**657**	615

($ per share, except shares outstanding)	Three Months Ended December 31 2018	2017	Year Ended December 31 2018	2017
Net income (loss) per common share - basic	**0.64**	(0.06)	**(2.25)**	0.18
Net income (loss) per common share - diluted	**0.64**	(0.06)	**(2.25)**	0.18
Normalized net income - basic(1)	**0.44**	0.36	**0.88**	1.19
Dividends declared(2)	**0.45**	0.54	**2.09**	2.12
Normalized funds from operations(1)	**0.94**	1.03	**2.95**	3.60
Shares outstanding - basic (millions)				
During the period(3)	**272**	174	**223**	171
End of period	**275**	175	**275**	175

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

(2) Dividends declared per common share per month: $0.175 beginning on August 25, 2016, $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 2018 was $394 million, compared to $213 million for the same quarter in 2017. The increase was primarily due to contributions from WGL, AltaGas' share of ACI earnings subsequent to IPO close on October 25, 2018, the impact from the stronger U.S. dollar on reported results from U.S. assets, contributions from the acquisition of a 50 percent interest in the Black Swan gas processing facilities, higher SEMCO rates and growth, and higher Harmattan fee for service revenue. These were partially offset by the impact of the ACI IPO, the impact of the sale of the San Joaquin facilities, lower river flows at the Northwest Hydro facilities, and decreased revenue from SEMCO due to the TCJA. For the three months ended December 31, 2018, the average Canadian/U.S. dollar exchange rate increased to 1.32 from an average of 1.27 in the same quarter of 2017, resulting in an increase in normalized EBITDA of approximately $5 million.

Normalized funds from operations for the fourth quarter of 2018 were $255 million ($0.94 per share), compared to $179 million ($1.03 per share) for the same quarter in 2017, reflecting the same drivers as normalized EBITDA, partially offset by lower income tax recoveries and higher interest expense. The decrease in per share amounts is due to a higher number of shares outstanding in 2018 compared to 2017. In the fourth quarter of 2018, AltaGas received $3 million of dividend income from the Petrogas Preferred Shares (2017 - $3 million) and $2 million of common share dividends from Petrogas (2017 - $1 million).

Operating and administrative expenses for the fourth quarter of 2018 were $346 million, compared to $151 million for the same quarter in 2017. The increase was mainly due to the inclusion of WGL's operating and administrative expenses, partially offset by the exclusion of ACI's operating and administrative expenses subsequent to IPO close on October 25, 2018, and lower transaction costs of $12 million in the fourth quarter of 2018 compared to $15 million in the same quarter in 2017.

Depreciation and amortization expense for the fourth quarter of 2018 was $126 million, compared to $71 million for the same quarter in 2017. The increase was mainly due to depreciation and amortization expense for assets acquired in the WGL Acquisition, partially offset by the exclusion of depreciation and amortization expense for assets sold to ACI subsequent to the IPO close on October 25, 2018 and the sale of the San Joaquin facilities on November 13, 2018. Interest expense for the fourth quarter of 2018 was $110 million, compared to $44 million for the same quarter in 2017. The increase was mainly due to interest on the bridge facility, interest on debt assumed in the WGL Acquisition and higher average debt balances.

AltaGas recorded an income tax recovery of $63 million for the fourth quarter of 2018 compared to an income tax recovery of $76 million in the same quarter of 2017. The lower income tax recovery was mainly due to the absence of tax recoveries related to the TCJA and provisions on assets in the fourth quarter of 2017, partially offset by a tax recovery on assets classified as held for sale in the fourth quarter of 2018.

Net income applicable to common shares for the fourth quarter of 2018 was $174 million ($0.64 per share) compared to a net loss applicable to common shares of $11 million ($0.06 per share) for the same quarter in 2017. The increase was mainly due to the same previously referenced factors resulting in the increase in normalized EBITDA, lower provisions on assets, higher unrealized gains on risk management contracts, lower transaction costs related to the WGL Acquisition, and changes in the fair value of natural gas optimization inventory. These increases were partially offset by lower income tax recovery, higher interest expense, higher depreciation and amortization expense, higher net income applicable to non-controlling interests, provisions on equity investments, higher losses on sale of assets, and higher losses on investments.

Normalized net income was $120 million ($0.44 per share) for the fourth quarter of 2018, compared to $63 million ($0.36 per share) reported for the same quarter in 2017. The increase was mainly due to the same previously referenced factors resulting in the increase in normalized EBITDA, partially offset by lower income tax recoveries, higher interest expense and higher depreciation and amortization expense. Normalizing items in the fourth quarter of 2018 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. In the fourth quarter of 2017, normalizing items included after-tax amounts related to transaction costs on acquisitions, unrealized losses on risk management contracts, gains on long-term investments, provisions on assets, development costs, financing costs associated with the bridge facility for the WGL Acquisition of $3 million, and the impact of the TCJA.

Year Ended December 31

Normalized EBITDA for the year ended December 31, 2018 was $1,009 million, compared to $797 million in 2017. The increase was primarily due to contributions from WGL for the period subsequent to transaction close on July 6, 2018, higher commodity margins as a result of higher realized frac spread and higher frac exposed volumes, contributions from the Townsend 2A and North Pine facilities which commenced operations in the fourth quarter of 2017, AltaGas' share of ACI earnings subsequent to the IPO close on October 25, 2018, higher rates and customer growth at certain utilities, colder weather primarily at SEMCO, and higher interest income. These increases were partially offset by the impact of the ACI IPO, lower river flows at the Northwest Hydro facilities, decreased revenue from SEMCO due to the TCJA, the impact of the sale of the San Joaquin facilities, the expiry of the PPA at the Ripon gas-fired electricity generation facility in May 2018 (partially offset by the new RA contract which began in the second quarter of 2018 and was in place for the remainder of 2018), lower natural gas storage margins, and the impact of the weaker U.S. dollar on reported results from U.S. assets. For the years ended December 31, 2018 and 2017, the average Canadian/U.S. dollar exchange rate was approximately 1.30. Fluctuations in the rate throughout the year resulted in a decrease in normalized EBITDA of approximately $2 million for the year ended December 31, 2018.

Normalized funds from operations for the year ended December 31, 2018 were $657 million ($2.95 per share), compared to $615 million ($3.60 per share) in 2017 reflecting the same drivers as normalized EBITDA and higher tax recoveries, partially offset by higher interest expense. The decrease in per share amounts is due to a higher number of shares outstanding in 2018 compared to 2017. Previously, AltaGas estimated that normalized funds from operations for the year would increase by approximately 10 percent in 2018 compared to 2017. The actual increase in normalized funds from operations in 2018 of 7 percent was lower than expected, due to lower Northwest Hydro river flows and the delay of cash distribution receipts from equity investments to early 2019. For the year ended December 31, 2018, AltaGas received $13 million of dividend income from Petrogas Preferred Shares (2017 - $13 million) and $5 million in common share dividends from Petrogas (2017 - $5 million).

In 2018, AltaGas recorded pre-tax provisions of approximately $729 million (after-tax $562 million). These provisions were primarily related to the San Joaquin Power assets in California comprised of the Tracy, Hanford and Henrietta plants, non-core Midstream and Power assets in Canada which are currently classified as held for sale, certain assets included in the IPO of ACI, and certain Power assets in the United States. In addition, pre-tax provisions of $37 million and $2 million were recorded on certain remaining gas assets and the Pomona Gas Repowering project respectively, and $6 million was recorded on a WGL Energy Systems financing receivable that was classified as held for sale at December 31, 2018. In 2017, AltaGas recorded pre-tax provisions on assets of $133 million (after-tax $80 million) related to the Hanford and Henrietta gas-fired peaking facilities in California and certain non-core development stage projects in the Power segment. In addition, in 2017, AltaGas recorded a pre-tax provision of $7 million (after-tax $5 million) related to a non-core gas processing facility that has been classified as held for sale in the Midstream segment.

Operating and administrative expenses for the year ended December 31, 2018 were $1,129 million, compared to $572 million in 2017. The increase was mainly due to WGL merger commitment costs of $182 million and the inclusion of WGL's operating and administrative expenses for the period since transaction close on July 6, 2018, partially offset by the exclusion of ACI's operating and administrative expenses subsequent to transaction close on October 25, 2018 and lower transaction costs (primarily related to the WGL Acquisition) of $63 million in 2018 compared to $66 million in 2017. Depreciation and amortization expense for the year ended December 31, 2018 was $394 million, compared to $282 million in 2017. The increase was mainly due to depreciation and amortization expense on assets acquired in the WGL Acquisition, partially offset by the exclusion of depreciation and amortization expense on assets sold to ACI subsequent to transaction close on October 25, 2018 and the sale of the San Joaquin facilities as of November 13, 2018. Interest expense for the year ended December 31, 2018 was $309 million, compared to $170 million in 2017. The increase was mainly due to interest on the bridge facility, interest on debt assumed in the WGL Acquisition and higher average debt balances.

AltaGas recorded an income tax recovery of $263 million for the year ended December 31, 2018 compared to $34 million in 2017. The increase in income tax recovery was primarily due to tax recoveries booked on asset provisions and WGL transaction and merger commitment costs, as well as a tax recovery on assets classified as held for sale.

Net loss applicable to common shares for the year ended December 31, 2018 was $502 million ($2.25 per share) compared to net income of $30 million ($0.18 per share) in 2017. The decrease was mainly due to provisions on assets recognized during 2018 as discussed above, merger commitment costs related to the WGL Acquisition, higher depreciation and amortization expense, higher interest expense, realized losses on foreign exchange derivatives, higher net income applicable to non-controlling interests, provisions on equity investments, and higher losses on the sale of assets, partially offset by the same previously referenced factors impacting normalized EBITDA, higher income tax recoveries, changes in the fair value of natural gas optimization inventory, higher unrealized gains on risk management contracts, and lower transaction costs related to the WGL Acquisition.

Normalized net income for the year ended December 31, 2018 was $195 million ($0.88 per share), compared to $204 million ($1.19 per share) in 2017. The decrease was due to higher depreciation and amortization expense, higher interest expense and higher preferred share dividends, partially offset by higher income tax recoveries and the same previously referenced factors impacting normalized EBITDA. Normalizing items for the year ended December 31, 2018 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. For the year ended December 31, 2017, normalizing items included after-tax amounts related to unrealized losses on risk management contracts, the impact of the TCJA, transaction costs on acquisitions and dispositions, financing costs of $14 million associated with the bridge facility for the WGL Acquisition, losses on sale of assets, provisions on assets, gains on investments, and development costs.

Total assets and total long-term liabilities as at December 31, 2018 have both increased significantly compared to December 31, 2017, primarily due to the WGL Acquisition. Total assets increased by approximately $13.5 billion during 2018, mainly due to the addition of WGL's assets as well as goodwill of approximately $3.2 billion recorded upon acquisition. Long-term liabilities increased by approximately $7.2 billion during 2018, mainly due to the addition of WGL's long-term liabilities as well as additional debt used to finance the WGL Acquisition.

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, 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)	**2018**	2017	**2018**	2017
Normalized EBITDA	**$ 394**	$ 213	**$ 1,009**	$ 797
Add (deduct):				
Transaction costs related to acquisitions and dispositions	**(12)**	(15)	**(63)**	(66)
Merger commitment costs	**—**	—	**(182)**	—
Unrealized gains (losses) on risk management contracts	**44**	(16)	**56**	(63)
Changes in fair value of natural gas optimization inventory	**12**	—	**15**	—
Non-controlling interest related to HLBV investments	**(22)**	—	**(39)**	—
Realized losses on foreign exchange derivatives	**—**	—	**(35)**	—
Gains (losses) on investments	**(10)**	7	**(10)**	4
Losses on sale of assets	**(12)**	—	**(10)**	(3)
Provisions on assets	**(31)**	(138)	**(729)**	(140)
Provisions on investments accounted for by the equity method	**(15)**	—	**(15)**	—
Development costs	**—**	(1)	**—**	(2)
Investment tax credits related to distributed generation assets	**(2)**	—	**(5)**	—
Accretion expenses	**(3)**	(3)	**(11)**	(11)
Foreign exchange gains	**1**	—	**5**	2
EBITDA	**$ 344**	$ 47	**$ (14)**	$ 518
Add (deduct):				
Depreciation and amortization	**(126)**	(71)	**(394)**	(282)
Interest expense	**(110)**	(44)	**(309)**	(170)
Income tax recovery	**63**	76	**263**	34
Net income (loss) after taxes (GAAP financial measure)	**$ 171**	$ 8	**$ (454)**	$ 100

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 Statement of Income using net income adjusted for pre-tax depreciation and amortization, interest expense, and income tax recovery.

Normalized EBITDA includes additional adjustments for unrealized gains (losses) on certain risk management contracts, realized losses on foreign exchange derivatives, gains (losses) on investments, transaction costs related to acquisitions and dispositions, merger commitment costs, losses on the sale of assets, provisions on assets, provisions on equity investments, accretion expenses related to asset retirement obligations and the Northwest Transmission Line liability, foreign exchange gains, development costs, 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)	**2018**	2017	**2018**	2017
Normalized net income	**$ 120**	$ 63	**$ 195**	$ 204
Add (deduct) after-tax:				
Transaction costs related to acquisitions and dispositions	**(9)**	(14)	**(50)**	(53)
Merger commitment costs	**—**	—	**(135)**	—
Unrealized gains (losses) on risk management contracts	**30**	(12)	**34**	(55)
Changes in fair value of natural gas optimization inventory	**12**	—	**15**	—
Realized loss on foreign exchange derivatives	**—**	—	**(35)**	—
Gains (losses) on investments	**(10)**	6	**(1)**	3
Losses on sale of assets	**(36)**	—	**(35)**	(3)
Provisions on investments accounted for by the equity method	**(11)**	—	**(11)**	—
Provisions on assets	**(23)**	(84)	**(562)**	(85)
Tax adjustment on assets held for sale	**104**	—	**104**	—
Development costs	**—**	(1)	**—**	(1)
Impact of the TCJA	**—**	34	**—**	34
Financing costs associated with the bridge facility	**(3)**	(3)	**(21)**	(14)
Net income (loss) applicable to common shares (GAAP financial measure)	**$ 174**	$ (11)	**$ (502)**	$ 30

Normalized net income represents net income (loss) applicable to common shares adjusted for the after-tax impact of unrealized gains (losses) on certain risk management contracts, realized loss on foreign exchange derivatives, gains (losses) on investments, merger commitment costs, transaction costs related to acquisitions and dispositions, losses on the sale of assets, provisions on assets, provisions on equity investments, a tax recovery as a result of the Northwest Hydro facilities being held for sale, financing costs associated with the bridge facility for the WGL Acquisition, development costs, the impact of the TCJA, 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

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2018**	2017	**2018**	2017
Normalized funds from operations	**$ 255**	$ 180	**$ 657**	$ 615
Add (deduct):				
Development costs	**—**	(1)	**—**	(1)
Transaction and financing costs related to acquisitions and dispositions	**(12)**	(17)	**(63)**	(71)
Merger commitment costs	**—**	—	**(182)**	—
Funds from operations	**243**	162	**412**	543
Add (deduct):				
Net change in operating assets and liabilities	**(301)**	(10)	**(487)**	2
Asset retirement obligations settled	**(2)**	(1)	**(4)**	(4)
Cash from (used by) operations (GAAP financial measure)	**$ (60)**	$ 151	**$ (79)**	$ 541

Normalized funds from operations is used to assist management and investors in analyzing the liquidity of the Corporation without regard to changes in operating assets and liabilities in the period and non-operating related expenses (net of current taxes) such as development costs and transaction and financing costs related to acquisitions and dispositions.

Funds from operations are calculated from the Consolidated Statement of Cash Flows and are defined as cash from operations before net changes in operating assets and liabilities and expenditures incurred to settle asset retirement obligations. Management uses this measure to understand the ability to generate funds for capital investments, debt repayment, dividend payments and other investing activities.

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

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, 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 section *Capital Resources* of this MD&A.

RESULTS OF OPERATIONS BY REPORTING SEGMENT

Normalized EBITDA [1]	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2018**	2017	**2018**	2017
Utilities	**$ 232**	$ 90	**$ 426**	$ 298
Midstream	**93**	61	**277**	221
Power	**76**	72	**320**	303
Sub-total: Operating Segments	**401**	223	**1,023**	822
Corporate	**(7)**	(10)	**(14)**	(25)
	$ 394	$ 213	**$ 1,009**	$ 797

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

Revenue	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2018**	2017	**2018**	2017
Utilities	**$ 818**	$ 353	**$ 1,766**	$ 1,127
Midstream	**489**	267	**1,435**	1,008
Power	**412**	164	**1,171**	632
Sub-total: Operating Segments	**1,719**	784	**4,372**	2,767
Corporate	**28**	(14)	**(2)**	(58)
Intersegment eliminations	**(20)**	(25)	**(113)**	(153)
	$ 1,727	$ 745	**$ 4,257**	$ 2,556

UTILITIES

OPERATING STATISTICS

	Three Months Ended December 31		Year Ended December 31	
	2018	2017	**2018**	2017
U.S. utilities				
Natural gas deliveries - end-use (Bcf)(1)	**58.5**	24.3	**107.3**	70.8
Natural gas deliveries - transportation (Bcf)(1)	**52.0**	14.2	**89.2**	52.0
Service sites (2)	**1,642,523**	581,518	**1,642,523**	581,518
Degree day variance from normal - SEMCO Gas (%) (3)	**7.5**	4.8	**5.6**	(5.3)
Degree day variance from normal - ENSTAR (%) (3)	**(19.6)**	(8.3)	**(11.5)**	(1.6)
Degree day variance from normal - Washington Gas (%) (3) (4)	**0.4**	—	**(0.7)**	—

(1) Petajoule (PJ) is one million gigajoules. Bcf is one billion cubic feet.

(2) Service sites reflect all of the service sites of the U.S. utilities, including transportation and non-regulated business lines.

(3) A degree day for U.S. utilities 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 which 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 it 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	**2018**	2017
Approved ROE (%)		
Canadian utilities (average) (4)	**—**	9.7
U.S. utilities (average)	**10.6**	11.6
Approved return on debt (%)		
Canadian utilities (average) (4)	**—**	5.0
U.S. utilities (average)	**5.4**	6.0
Rate base *($ millions)*(1)		
Canadian utilities (4)	**—**	833
U.S. utilities(2)(3)	**3,684**	847

(1) 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.

(2) In U.S. dollars.

(3) Reflects AltaGas' 65 percent interest in Cook Inlet Natural Gas Storage Alaska LLC.

(4) The Canadian utilities were sold to ACI in the fourth quarter of 2018.

During the fourth quarter of 2018, AltaGas' Utilities segment experienced colder weather, primarily at SEMCO, compared to the same quarter of 2017. The 2018 increase in customers and transportation represents the addition of WGL natural gas deliveries.

For the year ended December 31, 2018, AltaGas' Utilities segment experienced overall colder weather compared to 2017. This was mainly driven by 6 percent colder than normal weather at SEMCO and 13 percent colder than normal weather at AUI (for the period prior to the ACI IPO), partially offset by 12 percent warmer than normal weather at ENSTAR. Overall colder weather resulted in increased natural gas deliveries to end-use customers. The 2018 increase in customers and transportation represents the addition of WGL natural gas deliveries.

Service sites increased by approximately 1.1 million sites in 2018 compared to 2017 due to the addition of WGL customers and growth in customer base, partially offset by decreases due to the sale of the Canadian utilities to ACI.

Three Months Ended December 31

The Utilities segment reported normalized EBITDA of $232 million in the fourth quarter of 2018, compared to $90 million in the same quarter in 2017. The increase was mainly due to the impact of the WGL Acquisition of $159 million, the favorable impact of the stronger U.S. dollar, higher rates, growth in customer base, higher customer usage, and colder weather in Michigan. The increase was partially offset by the impact of the ACI IPO in the fourth quarter of 2018, the 2018 impact related to the federal tax reduction at the U.S. utilities, and warmer weather in Alaska.

Year Ended December 31

The Utilities segment reported normalized EBITDA of $426 million for the year ended December 31, 2018, compared to $298 million in 2017. The increase was mainly due to the impact of the WGL Acquisition for the period since transaction close of $153 million, colder weather in Michigan, higher rates, and growth in customer base. The increase was partially offset by the impact of the ACI IPO, the 2018 revenue impact related to the federal tax reduction at the U.S. utilities, one-time impacts in 2017 related to insurance proceeds received by SEMCO's non-regulated operations of approximately $2 million and an early termination payment of approximately $2 million from one of SEMCO's non-regulated customers moving from a fixed fee to a volumetric based contract, the impact of the stronger Canadian dollar, and warmer weather in Alaska.

MIDSTREAM

OPERATING STATISTICS

	Three Months Ended December 31		Year Ended December 31	
	2018	2017	**2018**	2017
Extraction inlet gas processed (Mmcf/d)(1)	**934**	983	**912**	970
FG&P inlet gas processed (Mmcf/d)(1)	**479**	441	**466**	392
Total inlet gas processed (Mmcf/d)(1)	**1,413**	1,424	**1,378**	1,362
Extraction ethane volumes (Bbls/d)(1)	**25,448**	26,125	**24,346**	27,493
Extraction NGL volumes (Bbls/d)(1) (2)	**39,074**	42,181	**38,128**	37,850
Total extraction volumes (Bbls/d)(1) (3)	**64,522**	68,306	**62,474**	65,343
Frac spread - realized ($/Bbl)(1) (4)	**15.84**	18.02	**16.49**	13.40
Frac spread - average spot price ($/Bbl)(1) (5)	**21.00**	30.66	**22.79**	20.50
Natural gas optimization inventory (Bcf)	**35.9**	2.7	**35.9**	2.7
WGL retail energy marketing - gas sales volumes (Mmcf)	**20,750**	—	**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.

Inlet gas volumes processed at the extraction facilities for the three months ended December 31, 2018 decreased by 49 Mmcf/d, compared to the same period in 2017. The decrease was primarily due to reduced ownership at Younger effective April 2018, partially offset by higher inlet volumes at the Joffre Ethane Extraction Plant (JEEP) and Harmattan due to higher available gas flows. Inlet gas volumes processed at the field gathering and processing (FG&P) facilities for the three months ended December 31, 2018 increased by 38 Mmcf/d primarily due to volumes received at the Townsend facilities and the recently acquired Aitken Creek North facility, partially offset by the disposition of certain non-core facilities in the first quarter of 2018.

Inlet gas volumes processed at the extraction facilities for the year ended December 31, 2018 decreased by 58 Mmcf/d, compared to the same period in 2017. The decrease was mainly due to reduced ownership at Younger effective April 2018, partially offset by higher inlet volumes at JEEP and Edmonton Ethane Extraction Plant (EEEP) due to higher available gas flows. Inlet gas volumes processed at the FG&P facilities for the year ended December 31, 2018 increased by 74 Mmcf/d primarily due to volumes received at the Townsend facilities and higher volumes at Gordondale, partially offset by the disposition of certain non-core assets in the first quarter of 2018.

Average ethane volumes for the three months ended December 31, 2018 decreased by 677 Bbls/d, while average NGL volumes decreased by 3,107 Bbls/d compared to the same period in 2017. Lower ethane volumes were a result of rejecting production at Younger due to uneconomic pricing, partially offset by higher ethane production at Pembina Empress Extraction Plant (PEEP), EEEP and Harmattan. Lower NGL volumes were a result of a lower ownership interest at Younger and lower volumes at Gordondale, partially offset by higher NGL production at the North Pine facility due to additional volumes available from the Townsend facilities.

Average ethane volumes for the year ended December 31, 2018 decreased by 3,147 Bbls/d compared to the same period in 2017. Lower ethane volumes were primarily due to rejecting production due to uneconomic pricing at Younger in the second, third and fourth quarters of 2018, and lower ethane volumes at Harmattan due to a planned turnaround in the second quarter, partially offset by higher production at EEEP, JEEP and PEEP. Average NGL volumes for the year ended December 31, 2018 increased by 278 Bbls/d compared to the same period in 2017. Higher NGL volumes were primarily due to increased volumes produced at the Townsend, North Pine and Gordondale facilities partially offset by reduced ownership at Younger and the planned turnaround at Harmattan.

With the addition of WGL, for the period from transaction close to December 31, 2018, U.S. retail sales volumes were 28,906 Mmcf.

Three Months Ended December 31

The Midstream segment reported normalized EBITDA of $93 million in the fourth quarter of 2018, compared to $61 million for the same quarter of 2017. The increase was mainly due to contributions from WGL Midstream assets of $31 million, the acquisition of 50 percent ownership in Black Swan's Aitken Creek North gas processing facility in the fourth quarter of 2018, and higher revenues at Harmattan due to increased NGL activities, partly offset by lower frac exposed volumes at Younger due to reduced ownership and lower frac spreads, and lower NGL marketing margins.

During the fourth quarter of 2018, AltaGas recorded equity earnings of $6 million from Petrogas, comparable to the same quarter of 2017.

During the fourth quarter of 2018, AltaGas hedged approximately 7,500 Bbls/d of NGL volumes at an average price of $33/Bbl excluding basis differentials. During the fourth quarter of 2017, AltaGas hedged 6,500Bbls/d of NGL at an average price of $24/Bbl, excluding basis differentials. The average indicative spot NGL frac spread for the fourth quarter of 2018 was approximately $21/Bbl, compared to $31/Bbl in the same quarter of 2017 inclusive of basis differentials. The realized frac spread of approximately $16/Bbl in the fourth quarter of 2018 (2017 - $18/Bbl) was comparable to the same period in 2017.

During the fourth quarter of 2018, the Midstream segment recognized an additional pre-tax provision of $2 million on certain non-core midstream assets classified as held for sale. In the fourth quarter of 2017, the Midstream segment recognized a pre-tax provision on assets of $7 million related to a non-core gas processing facility in Alberta which was classified as held for sale at December 31, 2017.

Year Ended December 31

The Midstream segment reported normalized EBITDA of $277 million for the year ended December 31, 2018, compared to $221 million in 2017. The increase was mainly due to contributions from WGL for the period after transaction close on July 6, 2018 of $38 million, higher realized frac spread and frac exposed volumes primarily at EEEP, contributions from the North Pine and Townsend 2A facilities which commenced commercial operations in the fourth quarter of 2017, impacts from the acquisition of 50 percent ownership in the Aitken Creek North facility in the fourth quarter of 2018, higher revenues at Harmattan due to increased NGL activities and higher ethane revenues at EEEP, partially offset by lower natural gas storage and marketing margins, the impact of the sale of the EDS and JFP transmission assets in the first quarter of 2017, and the planned turnaround at the Harmattan facility.

For the year ended December 31, 2018, AltaGas recorded equity earnings of $19 million from Petrogas as compared to $25 million in 2017. The decrease in Petrogas earnings was due to a planned turnaround at the Ferndale Terminal in the first quarter of 2018 and unrealized mark to market losses on hedges. In addition, AltaGas had lower Tidewater dividends from Tidewater due to the sale of the shares in the third quarter of 2018.

During the year-ended December 31, 2018, AltaGas recognized pre-tax provisions of $117 million on certain non-core midstream assets 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. During the year ended December 31, 2017, AltaGas recognized a pre-tax provision of $7 million related to a non-core gas processing facility that was classified as held for sale at December 31, 2017.

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, while in the same period of 2017, AltaGas recognized a pre-tax loss of $3 million on the sale of the EDS and JFP transmission assets.

During the year ended December 31, 2018, AltaGas sold 43.7 million shares of Tidewater Midstream and Infrastructure Inc. For the year ended December 31, 2018, AltaGas recorded an unrealized loss of $1 million and a realized loss of $2 million relating to the sale of these shares.

For the year ended December 31, 2018, AltaGas hedged approximately 7,500 Bbls/d of NGL volumes at an average price of $33/Bbl, excluding basis differentials. For the year ended December 31, 2017 AltaGas hedged 5,800 Bbls/d of NGL at an average price of $23/Bbl, excluding basis differentials. The average indicative spot NGL frac spread for the year ended December 31, 2018 was approximately $23/Bbl compared to $21/Bbl in the same period of 2017. The realized frac spread of $16/Bbl for the year ended December 31, 2018 (2017 - $13/Bbl) was higher than the same period in 2017 due to improved commodity prices.

On April 3, 2018, AltaGas entered into a long-term natural gas processing arrangement (the Processing Arrangement) with Birchcliff Energy Ltd. at AltaGas' deep-cut sour gas processing facility located in Gordondale, Alberta (the Gordondale facility). Under the Processing Arrangement, Birchcliff is provided with up to 120 MMcf/d of natural gas processing on a firm-service basis, and Birchcliff's take-or-pay obligation is 100 MMcf/d. The Processing Arrangement provides stable long-term cash flow by filling the existing operational capacity of 120 Mmcf/d at the Gordondale facility and significantly enhances the potential to flow third-party volumes through the facility and to grow those volumes to bring the operating capacity up to 150 Mmcf/d. Growing propane volumes from Gordondale will be dedicated to RIPET as part of the commercial arrangements. The new Processing Arrangement was effective as of January 1, 2018 and replaces the parties' existing Gordondale processing arrangement.

On August 27, 2018, AltaGas announced that it entered into definitive agreements with Kelt to provide an energy infrastructure solution for the liquids-rich Inga Montney development located in British Columbia. These agreements underpin the expansion of AltaGas' Townsend complex including the addition of a 198 MMcf per day C3+ deep cut gas processing facility and provides Kelt with firm processing of 75 MMcf per day of raw gas under an initial 10 year take-or-pay agreement. Under the terms of the agreement, Kelt has the option during the first three years of the initial take-or-pay term to commit to additional firm processing up to a total of 198 MMcf per day for a term of its choice, with an additional minimum take-or-pay commitment of ten years.

On September 26, 2018, AltaGas announced that it has entered into a definitive agreement with Black Swan to acquire 50 percent ownership in certain existing and future natural gas processing plants of Black Swan in British Columbia. As part of the arrangement, AltaGas and Black Swan have also entered into long term processing, transportation and marketing agreements that include new integrated AltaGas liquids handling infrastructure, thereby strengthening AltaGas' Northeast B.C. value proposition and connecting producers with additional options for energy exports. The total capital investment by AltaGas will be approximately $230 million and the transaction closed on October 2, 2018.

POWER

OPERATING STATISTICS

	Three Months Ended December 31		Year Ended December 31	
	2018	2017	**2018**	2017
Renewable power sold (GWh)	**233**	301	**1,551**	1,629
Conventional power sold (GWh)	**985**	1,059	**3,728**	2,844
Renewable capacity factor (%)	**14.6**	27.5	**29.7**	39.6
Contracted conventional equivalent availability factor (%) (1)	**97.4**	96.3	**97.2**	98.1
WGL retail energy marketing - electricity sales volumes (GWh)	**2,911**	—	**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 2018, the volume of renewable power sold decreased by 68 GWh and the volume of conventional power sold decreased by 74 GWh, compared to the same quarter in 2017. The decrease in renewable volumes was due to continued dry and cool weather at the Northwest Hydro facilities, the October 2018 sale of the Bear Mountain wind facility to ACI, and decreased generation at the Craven facility due to an extended planned outage, partially offset by the addition of WGL power generation. The decrease in conventional volumes sold was due to the November 2018 sale of the San Joaquin facilities, partially offset by increased dispatch at Blythe under its power purchase agreement due to greater operational and fuel flexibility.

For the year ended December 31, 2018, the volume of renewable power sold decreased by 78 GWh and the volume of conventional power sold increased by 884 GWh compared to 2017. The decrease in renewable volumes was due to lower generation at the Northwest Hydro facilities, lower wind generation at the Bear Mountain wind facility and the October 2018 sale to ACI, and lower generation at Craven, partially offset by the addition of WGL power generation for the period since transaction close. The increase in conventional volumes was due to higher dispatch at Blythe due to greater operational and fuel flexibility, partially offset by the November 2018 sale of the San Joaquin facilities.

The contracted conventional equivalent availability factor was higher for the three months ended December 31, 2018 as a result of Blythe requiring maintenance in the fourth quarter of 2017 due to increased dispatch. The contracted conventional equivalent availability factor was lower for the year ended December 31, 2018 due to a longer planned outage and increased unplanned outages at Blythe.

The renewable capacity factor during the fourth quarter of 2018 was lower due to lower generation at the Northwest Hydro facilities and lower Bear Mountain wind generation due to the sale of Bear Mountain to ACI in October 2018. The renewable capacity factor for the year ended December 31, 2018 was lower than 2017 due to the same factors impacting the fourth quarter of 2018.

With the addition of WGL, for the period from transaction close to December 31, 2018, U.S. retail sales volumes were 5,906 GWh.

Three Months Ended December 31

The Power segment reported normalized EBITDA of $76 million in the fourth quarter of 2018, compared to $72 million in the same quarter of 2017. Normalized EBITDA increased as a result of earnings from WGL's power assets of $33 million, partially offset by lower river flows at the Northwest Hydro facilities, the impact of the sale of the San Joaquin facilities in November 2018, the impact of the ACI IPO, expiry of the Ripon PPA on May 31, 2018, and lower contributions from Craven due to an extended planned outage and new contract terms.

In the fourth quarter of 2018, AltaGas sold the Bear Mountain wind facility as well as an approximate 10 percent interest in the Northwest Hydro facilities to AltaGas Canada Inc. Subsequent to the IPO, AltaGas has retained an equity interest in ACI of approximately 37 percent. In addition, on November 13, 2018, the Power segment closed the sale of the San Joaquin facilities to Middle River Power III for a gross purchase price of approximately US$299 million resulting in a pre-tax loss of $14 million, and on December 11, 2018, the Busch Ranch wind asset in the United States was sold for a purchase price of approximately US$16 million resulting in a pre-tax gain of $3 million.

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. During the fourth quarter of 2017, the Power segment recorded pre-tax provisions on assets of $131 million related to the Hanford and Henrietta gas-fired peaking facilities and a non-core development stage peaking project in California. In addition, during the fourth quarter of 2018, a provision on equity investments of $15 million was recorded related to investments in biomass assets in the U.S.

Year Ended December 31

The Power segment reported normalized EBITDA of $320 million for the year ended December 31, 2018, compared to $303 million in 2017. Normalized EBITDA increased as compared to the same period in 2017 as a result of earnings from WGL's power assets for the period since transaction close of $64 million, and higher energy sales at the Pomona Energy Storage facility, partially offset by lower 2018 river flows and higher operating costs at the Northwest Hydro facilities, the impact of the sale of the San Joaquin facilities in November 2018, the expiry of the Ripon PPA on May 31, 2018, the impact of the ACI IPO, and lower contributions from Craven due to unplanned outages and new contract terms.

In June 2018, the Power segment closed the sale of a 35 percent indirect equity interest in the Northwest Hydro facilities for cash proceeds of approximately $922 million. The sale of the minority interest in the Northwest Hydro facilities is to a joint venture company that is indirectly owned by Axium Infrastructure Inc., as manager of Axium Infrastructure Canada II Limited Partnership, and Manulife Financial Corporation. On December 13, 2018, AltaGas announced that it reached an agreement for the sale of its remaining interest of approximately 55 percent in these facilities for total proceeds of approximately $1.37 billion. The assets were classified as held for sale at December 31, 2018 and the sale closed in January 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 to be sold to Birch Hill, $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. In addition, a pre-tax provision of $2 million was recorded relating 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. During the year ended December 31, 2017, the Power segment recorded pre-tax provisions on assets of approximately $133 million related to the Hanford and Henrietta gas-fired peaking facilities and certain non-core development stage gas-fired peaking assets in California and Alberta.

For the year ended December 31, 2018, the Power segment was also impacted by the previously mentioned asset sales recorded in the fourth quarter of 2018. During the year ended December 31, 2017, the Power segment disposed of certain non-core development stage wind assets for a pre-tax gain of $1 million.

CORPORATE

Three Months Ended December 31

In the Corporate segment, normalized EBITDA for the fourth quarter of 2018 was a loss of $7 million, compared to a loss of $10 million in the same period of 2017. The decreased loss was mainly due to higher interest income and lower employee benefit expenses.

Year Ended December 31

In the Corporate segment, normalized EBITDA for the year ended December 31, 2018 was a loss of $14 million, compared to a loss of $25 million for the year ended December 31, 2017. The decreased loss was mainly due to interest income earned on funds that were held in escrow for the WGL Acquisition and lower employee benefit expenses, partly offset by increases to professional and consulting fees and information technology related costs.

INVESTED CAPITAL

					Three Months Ended December 31, 2018
($ millions)	**Utilities**	**Midstream**	**Power**	**Corporate**	**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**

					Three Months Ended December 31, 2017
($ millions)	Utilities	Midstream	Power	Corporate	Total
Invested capital:					
Property, plant and equipment	$ 46	$ 65	$ 3	$ —	$ 114
Intangible assets	1	2	—	1	4
Contributions from non-controlling interest	—	(5)	—	—	(5)
Invested capital	47	62	3	1	113
Disposals:					
Property, plant and equipment	—	—	—	—	—
Net invested capital	$ 47	$ 62	$ 3	$ 1	$ 113

During the fourth quarter of 2018, AltaGas' invested capital was $569 million, compared to $113 million in the same quarter of 2017. The increase in expenditures was primarily due to capital spending at Washington Gas of approximately $150 million, expenditures related to the construction of RIPET, and contributions to WGL's investment in the Mountain Valley Pipeline.

The invested capital in the fourth quarter of 2018 included maintenance capital of $2 million (2017 - $2 million) in the Midstream segment and $2 million (2017 - $2 million) in the Power segment.

					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**

					Year Ended December 31, 2017
($ millions)	Utilities	Midstream	Power	Corporate	Total
Invested capital:					
Property, plant and equipment	$ 125	$ 312	$ 19	$ 2	$ 458
Intangible assets	2	3	13	2	20
Long-term investments	—	17	—	—	17
Contributions from non-controlling interest	—	(17)	—	—	(17)
Invested capital	127	315	32	4	478
Disposals:					
Property, plant and equipment	(1)	(67)	(2)	—	(70)
Net invested capital	$ 126	$ 248	$ 30	$ 4	$ 408

For the year ended December 31, 2018, AltaGas' invested capital was approximately $7.1 billion, compared to $478 million in 2017. The increase in invested capital in 2018 was primarily due to cash paid for the WGL Acquisition of $5.9 billion, higher additions to property, plant and equipment, higher contributions to AIJVLP, and contributions to WGL's investments in the Central Penn Pipeline and Mountain Valley Pipeline, partially offset by higher contributions from non-controlling interest (representing Vopak's share of construction costs related to RIPET).

The increase in additions to property, plant and equipment in 2018 was mainly due to capital expenditures related to system betterment and accelerated pipeline replacement programs at Washington Gas, construction costs at RIPET, capital expenditures related to WGL's distributed generation projects, and the purchase of an office building at SEMCO. The disposals of property, plant and equipment in 2018 primarily related to the San Joaquin facilities in California, the Busch Ranch wind farm in Colorado, a development stage wind asset in the Power segment, and certain other non-core facilities in the Midstream segment. In 2017, the disposals of property, plant and equipment related to the sale of the EDS and JFP transmission assets.

The invested capital for the year ended December 31, 2018 included maintenance capital of $17 million (2017 - $10 million) in the Midstream segment and $13 million (2017 - $9 million) in the Power segment. The maintenance capital for the Midstream segment was mainly related to the costs incurred for the Harmattan facility turnaround, while the maintenance capital for the Power segment mainly related to maintenance at the Northwest Hydro facilities.

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, 2018 and December 31, 2017, the fair values of the Corporation's derivatives were as follows:

($ millions)		**December 31, 2018**		December 31, 2017
Natural gas	**$**	**(137)**	$	6
NGL frac spread		**16**		(24)
Power		**(9)**		(1)
Foreign exchange		**(1)**		2
Net derivative liability	**$**	**(131)**	$	(17)

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 in the period in which the change occurs. For the Utility segment, changes in the fair value of derivative instruments recoverable or refundable to customers are recorded to regulatory assets or regulatory liabilities on the Consolidated Balance Sheets, while changes in the fair value of derivative instruments not affected by rate regulation are recorded in the Consolidated Statements of Income in the period in which the change occurs.

The Midstream segment also executes fixed-for-floating NGL frac spread swaps to manage exposure to frac spreads as the financial results of several extraction plants are affected by fluctuations in NGL frac spreads. The average indicative spot NGL frac spread for the year ended December 31, 2018 was approximately $23/Bbl (2017 - $21/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, 2018 was approximately $16/Bbl (2017 - $13/Bbl). For 2019, AltaGas currently has frac hedges in place to hedge approximately 6,200 Bbls/d at an average price of $40/Bbl, excluding basis differentials. 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 managed transportation and storage assets on behalf of third parties. To serve retail gas customers, AltaGas enters into retail sales contracts that contain optionality as well as physical and financial contracts which qualify as derivative instruments.

The Utility 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.

Foreign Exchange

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, 2018, Management designated $1.5 billion of outstanding U.S. denominated long-term debt to hedge against the currency translation effect of its foreign investments (December 31, 2017 - $nil). This designation has the effect of mitigating volatility on net income by offsetting foreign exchange gains and losses on U.S. dollar denominated long-term debt and foreign net investment. For the year ended December 31, 2018, AltaGas incurred an after-tax unrealized loss of $80 million arising from the translation of debt in other comprehensive income (2017 – after-tax unrealized gain of $7 million).

To mitigate the foreign exchange risks associated with the cash purchase price of WGL, AltaGas entered into foreign currency option contracts with an aggregate notional value of approximately US$1.2 billion which expired in May 2018. These foreign currency option contracts did not qualify for hedge accounting. Therefore, all changes in fair value were recognized in net income. For the year ended December 31, 2018, an unrealized gain of $35 million and a realized loss of $36 million were recognized in revenue in relation to these contracts (2017 - unrealized losses of $34 million). In the second quarter of 2018, AltaGas entered into foreign exchange forward contracts with an aggregate notional value of $3.2 billion intended to minimize the foreign exchange risk of the WGL Acquisition, which settled in the third quarter of 2018. These foreign exchange derivatives did not qualify for hedge accounting. Therefore, all changes in fair value were recognized in net income. For the year ended December 31, 2018, a realized gain of $1 million was recognized in income in relation to these forward contracts (2017 - $nil).

Weather

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 period from close of the WGL Acquisition to December 31, 2018, pre-tax losses of $1 million were recorded related to these instruments (2017 - $nil).

The Effects of Derivative Instruments on the Consolidated Statements of Income

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

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2018**	2017	**2018**	2017
Natural gas	**$ 13**	$ 6	**$ (2)**	$ 2
Storage optimization	**—**	—	**—**	3
NGL frac spread	**45**	(11)	**40**	(12)
Power	**12**	(9)	**9**	(21)
Foreign exchange	**(1)**	(2)	**34**	(35)
	$ 69	$ (16)	**$ 81**	$ (63)

Please refer to Note 22 of the 2018 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
Operational	• Accelerated replacement of aging pipeline and infrastructure within Washington Gas' system • Acquire large working interests to control and optimize operations and maximize efficiencies • 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, safety and environmental programs • Purchase property and business interruption insurance • Fixed price operating and maintenance contracts with equipment manufacturers • Hedging strategy used to balance price and operating risk
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
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 liquidity needs through a variety of sources including internally-generated cash flows, asset sales, DRIP, access to credit facilities, and long-term debt and equity issuances • 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 • Maintain financial flexibility and access to multiple credit facilities and continually monitor covenant compliance • 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
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
Volume of power generated	• PPAs for the Blythe and Brush facilities include 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 • Diversification of fuel sources and geography • Hedging strategy to balance price and operating risk • Undertake extensive studies to support investment decisions

Risks	Strategies and Organizational Capability to Mitigate Risks
Commodity price	• Contracting terms, 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 with hedge targets approved by the Board of Directors • Matching natural gas and electricity purchase obligations with sales commitments in terms of volume and pricing • Regulatory recovery mechanisms for gas purchases to serve utility customers • Monitor hedge transactions through Risk Management Committee • AltaGas' Commodity Risk Policy prohibits transactions for speculative purposes • Employ hedging practices to reduce exposure to commodity prices and volatility and lock in margins when the opportunity arises to increase profitability and reduce earnings volatility • Employ strong systems and processes for monitoring and reporting compliance with the Commodity Risk Policy • Use a system designed to manage and provide controls for marketing and risk management processes for the NGL business • 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
Regulatory and Stakeholder	• Regulatory and commercial personnel monitor and manage regulatory issues • Utilities seek rate recovery through rate cases with regulatory commissions and agencies • Proactive regulatory and government relations group, strong working relationships with regulators, Indigenous peoples, and other stakeholders • Build risk mitigation into contracts where appropriate • Skilled regulatory department retained • Use of expert third parties when needed
Environment and safety	• Strong safety and environmental management systems • Accelerated replacement of mature pipeline infrastructure within Washington Gas' system • Preventative and remedial measures to address increased leak rates within Washington Gas' distribution system • Continuous process improvement strategy employed • Focus on mitigating the impact of climate change regulations • Zero tolerance safety policies for staff and contractors and reviews of past safety practices for contractors • Purchase and maintain general liability and business interruption insurance • Pipeline and asset integrity programs are in place
Labour relations	• Maintain access to strong labour markets to attract qualified talent • Positive employee relations to retain existing talent and maintain strong relations with unions
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

Risks	Strategies and Organizational Capability to Mitigate Risks
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
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
Legislative	• Ongoing identification of public policy issues to determine risks to 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
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
External stakeholder relations	• Proactive stakeholder relations and communications groups, strong working relationships with Indigenous peoples, stakeholders, and regulators • Strong commitment to creating social value • Comprehensive safety and environmental management systems
Risks related to the integration of WGL	• AltaGas has established a cross-functional WGL integration team focused on effectively integrating WGL into AltaGas operations, while eliminating duplicative costs and realizing other efficiencies

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.

		Year Ended December 31
($ millions)	**2018**	2017
Cash from (used in) operations	**$ (79)**	$ 541
Investing activities	**(5,834)**	(495)
Financing activities	**5,987**	(38)
Increase in cash and cash equivalents	**$ 74**	$ 8

Cash from Operations

Cash from operations decreased by $620 million for the year ended December 31, 2018 compared to 2017 primarily due to lower net income after taxes and an unfavorable variance in net change in operating assets and liabilities. The unfavorable variance in net change in operating assets and liabilities was primarily due to the addition of WGL's operating assets and liabilities.

Working Capital

($ millions except current ratio)		**December 31, 2018**		December 31, 2017
Current assets	**$**	**4,033**	$	702
Current liabilities		**4,102**		815
Working deficiency	**$**	**(69)**	$	(113)
Working capital ratio		**0.98**		0.86

The increase in the working capital ratio was primarily due to an increase in assets held for sale, accounts receivable, inventory, and prepaid expenses, partially offset by an increase in the current portion of long-term debt, increased short-term debt, an increase in accounts payable and accrued liabilities, and an increase in liabilities held for sale of $171 million. AltaGas’ working capital will fluctuate in the normal course of business.

Investing Activities

Cash used in investing activities for the year ended December 31, 2018 was $5.8 billion, compared to cash used in investing activities of $495 million in 2017. 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). Investing activities for the year ended December 31, 2017 primarily included expenditures of approximately $473 million for property, plant, and equipment and $20 million for intangible assets, approximately $36 million for derivative contracts, approximately $17 million of contributions to AltaGas’ equity investments, and a $13 million loan to Petrogas under the $100 million interest bearing secured loan facility provided to Petrogas, partially offset by cash proceeds of approximately $71 million, net of transaction costs, primarily from the sale of the EDS and JFP transmission assets.

Financing Activities

Cash from financing activities for the year ended December 31, 2018 was $6.0 billion, compared to cash used in financing activities of $38 million in 2017. Financing activities for the year ended December 31, 2018 were primarily comprised of net short and long-term debt issuances of $2.4 billion, net proceeds from the issuance of common shares of $2.6 billion, net borrowings under bankers’ acceptances of $554 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. Financing activities for the year ended December 31, 2017 were primarily comprised of repayments of long-term debt and short-term debt of $862 million and $74 million, respectively, and dividends of $421 million, partially offset by net proceeds from the issuance of preferred shares of $293 million and common shares of $242 million (mainly from common shares issued through DRIP), net proceeds from the issuance of medium term notes (MTNs) of $447 million, borrowings under the credit facilities of $311 million, and proceeds from the sale of a non-controlling interest in RIPET to Vopak of $24 million. Total dividends paid to common and preferred shareholders of AltaGas for the year ended December 31, 2018 were $540 million (2017 - $421 million), of which $326 million was reinvested through the DRIP (2017 - $236 million). The increase in dividends paid was due to more common shares and preferred shares outstanding and dividend increases on common shares declared in the fourth quarter of 2017.

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 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, 2018**	December 31, 2017
Short-term debt	**$ 1,210**	$ 47
Current portion of long-term debt	**890**	189
Long-term debt[1]	**8,067**	3,437
Total debt	**10,167**	3,673
Less: cash and cash equivalents	**(102)**	(27)
Net debt	**$ 10,065**	$ 3,646
Shareholders' equity	**7,020**	4,573
Non-controlling interests	**621**	66
Total capitalization	**$ 17,706**	$ 8,285
Net debt-to-total capitalization (%)	**57**	44

(1) Net of debt issuance costs of $35 million as at December 31, 2018 (December 31, 2017 - $14 million).

As at December 31, 2018, AltaGas' total debt primarily consisted of outstanding MTNs of $2.7 billion (December 31, 2017 - $2.9 billion), WGL and Washington Gas long-term debt of $2.7 billion, reflecting fair value adjustments on acquisition (December 31, 2017 - $nil), SEMCO long-term debt of $496 million (December 31, 2017 - $462 million) and $3.0 billion drawn under the bank credit facilities (December 31, 2017 - $260 million). In addition, AltaGas had $271 million of letters of credit (December 31, 2017 - $120 million) outstanding.

As at December 31, 2018, AltaGas' total market capitalization was approximately $3.8 billion based on approximately 275 million common shares outstanding and a closing trading price on December 31, 2018 of $13.90 per common share.

AltaGas' earnings interest coverage for the rolling 12 months ended December 31, 2018 was (1.2) times (12 months ended December 31, 2017 – 1.3 times).

Credit Facilities

($ millions)	Borrowing capacity	**Drawn at December 31, 2018**	Drawn at December 31, 2017
Demand credit facilities [1] [2]	$ 378	**$ 153**	$ 75
Extendible revolving letter of credit facilities [2]	559	**117**	41
PNG operating facility	—	**—**	13
AltaGas Ltd. revolving credit facility [1]	1,400	**965**	219
AltaGas Ltd. revolving US$300 million credit facility [1] [2]	409	**288**	—
Bridge facility [1] [2] [3]	113	**113**	—
Syndicated US$1,200 million facility [1] [2]	1,637	**1,637**	—
SEMCO Energy US$150 million unsecured credit facility [1] [2]	205	**1**	32
WGL US$650 million unsecured revolving credit facility [2]	887	**—**	—
Washington Gas US$350 million unsecured revolving credit facility [2] [4]	477	**—**	—
	$ 6,065	**$ 3,274**	$ 380

(1) Amount drawn at December 31, 2018 converted at the month-end rate of 1 U.S. dollar = 1.3642 Canadian dollar (December 31, 2017 - 1 U.S. dollar = 1.2545 Canadian dollar).

(2) Borrowing capacity was converted at the December 31, 2018 U.S./Canadian dollar month-end exchange rate.

(3) The acquisition credit facility was mostly repaid in the fourth quarter of 2018.

(4) Washington Gas has the right to request additional borrowings of up to US$100 million with the bank's approval, for a total of US$450 million.

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. At December 31, 2018, commercial paper outstanding totaled US$840 million for WGL and Washington Gas.

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.

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, 2018**
Bank debt-to-capitalization[(1)]	not greater than 65 percent	56.5%
Bank EBITDA-to-interest expense [(1)] [(2)]	not less than 2.5x	2.9
Bank debt-to-capitalization (SEMCO)[(3)]	not greater than 60 percent	36.1%
Bank EBITDA-to-interest expense (SEMCO)[(3)]	not less than 2.25x	7.3
Bank debt-to-capitalization (WGL)[(4)]	not greater than 65 percent	59.4%
Bank debt-to-capitalization (Washington Gas)[(4)]	not greater than 65 percent	46.6%

(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 7, 2017, a $5 billion base shelf prospectus was filed. The purpose of the base shelf prospectus is to facilitate timely offerings of certain types of future public debt and/or equity issuances during the 25-month period that the base shelf prospectus remains effective. As at December 31, 2018, approximately $4.6 billion was available under the base shelf prospectus.

On June 4, 2018, a US$2 billion preliminary short form prospectus for the issuance of both debt securities and preferred shares was filed in Alberta. AltaGas filed a final short form base shelf prospectus on June 13, 2018 both in 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. As at December 31, 2018, US$2.0 billion was available under the base shelf prospectus.

CONTRACTUAL OBLIGATIONS

December 31, 2018	Payments Due by Period				
($ millions)	Total	Less than 1 year	1 - 3 years	4 - 5 years	After 5 years
Short-term debt [(1)]	$ 1,210	$ 1,210	$ —	$ —	$ —
Long-term debt [(1)]	8,904	889	3,063	1,593	3,359
Operating leases	302	24	59	54	165
Purchase obligations	54,127	4,626	7,847	6,531	35,123
Capital project commitments	119	119	—	—	—
Pension plan and retiree benefits [(2)]	42	42	—	—	—
Merger commitments [(3)]	183	29	54	38	62
Other liabilities	13	11	2	—	—
Total contractual obligations [(4)]	$ 64,900	$ 6,950	$ 11,025	$ 8,216	$ 38,709

(1) Excludes interest payments and deferred financing costs.

(2) Assumes only required payments will be made into the pension plans in 2019. Contributions are made in accordance with independent actuarial valuations.

(3) Relates to merger commitments arising from the WGL Acquisition.

(4) U.S. dollar commitments have been converted to Canadian dollar using the December 31, 2018 exchange rate.

AltaGas expects to fund its obligations through internally-generated cash flow, asset sales, the Dividend Reinvestment and Optional Cash Purchase Plan, proceeds from hybrid securities and preferred share offerings, 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 2018 Annual Consolidated Financial Statements for the amounts due to or from related parties on the Consolidated Balance Sheets and the classification of revenue, income, and expenses in the Consolidated Statements of Income.

CREDIT RATINGS

On December 19, 2018, Standard & Poor's (S&P) downgraded AltaGas' issuer rating and senior unsecured MTN rating from BBB with a Negative Outlook to BBB- with a Negative Outlook and downgraded AltaGas' Preferred Shares rating from P-3(high) to P-3. On December 21, 2018, DBRS Limited (DBRS) downgraded AltaGas' rating from BBB Under Review with Developing Implications to BBB(low) with a Stable Outlook and downgraded AltaGas' Preferred Shares from Pfd-3 to Pfd-3(low). On July 27, 2018, Fitch assigned a first time rating of BBB to AltaGas and a first time rating of BB+ to AltaGas' Preferred Shares. On December 17, 2018, Fitch affirmed the rating of BBB for AltaGas and BB+ for AltaGas' Preferred Shares.

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.

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

Subscription Receipts

In 2017, the Corporation issued approximately 84.5 million subscription receipts pursuant to a private placement and public offering to partially fund the WGL Acquisition at a price of $31 each for total gross proceeds of approximately $2.6 billion. Each subscription receipt entitled the holder to automatically receive one common share upon closing of the WGL Acquisition. During the time the subscription receipts were outstanding, holders received cash payments (Dividend Equivalent Payments) per subscription receipt that were equal to dividends declared on each common share. The funds were released from escrow on July 5, 2018. Upon closing, the subscription receipts were automatically exchanged for AltaGas common shares in accordance with the terms of the subscription receipt agreement and have been delisted from the TSX.

	As at February 22, 2019
Issued and outstanding	
Common shares	275,576,772
Preferred Shares	
Series A	5,511,220
Series B	2,488,780
Series C	8,000,000
Series E	8,000,000
Series G	8,000,000
Series I	8,000,000
Series K	12,000,000
WGL $4.25 series	150,000
WGL $4.80 series	70,600
WGL $5.00 series	60,000
Issued	
Share options	5,964,758
Share options exercisable	2,593,473

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.

On December 12, 2018, the Board of Directors approved a decrease in the monthly dividend by $0.1025 per common share to $0.08 per common share ($0.96 per common share annualized) effective for the January 2019 dividend.

The following table summarizes AltaGas' dividend declaration history:

Dividends
Year ended December 31

($ per common share)	**2018**	2017
First quarter	**$ 0.547500**	$ 0.525000
Second quarter	**0.547500**	0.525000
Third quarter	**0.547500**	0.525000
Fourth quarter	**0.445000**	0.540000
Total	**$ 2.087500**	$ 2.115000

Series A Preferred Share Dividends

Year ended December 31

($ per preferred share)		**2018**		2017
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)		**2018**		2017
First quarter	**$**	**0.217600**	$	0.195410
Second quarter		**0.238720**		0.195710
Third quarter		**0.249530**		0.201010
Fourth quarter		**0.262770**		0.214250
Total	**$**	**0.968620**	$	0.806380

Series C Preferred Share Dividends

Year ended December 31

(US$ per preferred share)		**2018**		2017
First quarter	**$**	**0.330625**	$	0.275000
Second quarter		**0.330625**		0.275000
Third quarter		**0.330625**		0.275000
Fourth quarter		**0.330625**		0.330625
Total	**$**	**1.322500**	$	1.155625

Series E Preferred Share Dividends

Year ended December 31

($ per preferred share)		**2018**		2017
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

Series G Preferred Share Dividends

Year ended December 31

($ per preferred share)		**2018**		2017
First quarter	**$**	**0.296875**	$	0.296875
Second quarter		**0.296875**		0.296875
Third quarter		**0.296875**		0.296875
Fourth quarter		**0.296875**		0.296875
Total	**$**	**1.187500**	$	1.187500

Series I Preferred Share Dividends

Year ended December 31

($ per preferred share)		**2018**		2017
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)		**2018**		2017
First quarter	**$**	**0.312500**	$	—
Second quarter		**0.312500**		0.438400
Third quarter		**0.312500**		0.312500
Fourth quarter		**0.312500**		0.312500
Total	**$**	**1.250000**	$	1.063400

In connection with the WGL Acquisition, AltaGas assumed Washington Gas' preferred stock. Washington Gas has three series of cumulative preferred stock outstanding. Dividends declared from the period from closing of the WGL Acquisition to December 31, 2018 were as follows:

$4.25 series Preferred Share Dividends
Year ended December 31

(US$ per preferred share)		**2018**		2017
First quarter	**$**	**—**	$	—
Second quarter		**—**		—
Third quarter		**1.062500**		—
Fourth quarter		**1.062500**		—
Total	**$**	**2.125000**	$	—

$4.80 series Preferred Share Dividends
Year ended December 31

(US$ per preferred share)		**2018**		2017
First quarter	**$**	**—**	$	—
Second quarter		**—**		—
Third quarter		**1.200000**		—
Fourth quarter		**1.200000**		—
Total	**$**	**2.400000**	$	—

$5.00 series Preferred Share Dividends
Year ended December 31

(US$ per preferred share)		**2018**		2017
First quarter	**$**	**—**	$	—
Second quarter		**—**		—
Third quarter		**1.250000**		—
Fourth quarter		**1.250000**		—
Total	**$**	**2.500000**	$	—

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 2018 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 and intangible assets with 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, 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, 2018 and determined that no write-down was required, with the exception of certain goodwill impairments recorded in the third quarter of 2018 as a result of assets held for sale.

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 19 of the 2018 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, and the expected rate of compensation increase. 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 2018 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 judgement 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, 2018, no 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, 2018, AltaGas adopted the following Financial Accounting Standards Board (FASB) issued Accounting Standards Updates (ASU):

- ASU No. 2014-09 “Revenue from Contracts with Customers” and all related amendments (collectively “ASC 606”). AltaGas adopted ASC 606 using the modified retrospective method to contracts that have not been completed as at January 1, 2018. Under the modified retrospective method, the comparative information is not adjusted. The adoption of ASC 606 impacted the timing of revenue recognition in relation to contracts with take-or-pay or minimum volume commitments whereby the customers have make up rights for deficiency quantities. However, on adoption, no cumulative adjustments to opening retained earnings were required for this change in revenue recognition pattern as none of the customers had material deficiency quantities. Please also refer to Note 23 of the Consolidated Financial Statements as at and for the year ended December 31, 2018 for further details. The application of ASC 606 did not have a material impact on AltaGas’ consolidated financial statements in 2018;

- ASU No. 2016-01 “Recognition and Measurement of Financial Assets and Financial Liabilities” which revised an entity’s accounting related to (1) the classification and measurement of investments in equity securities and (2) the presentation of certain fair value changes for financial liabilities measured at fair value. It also amended certain disclosure requirements associated with the fair value of financial instruments. Upon adoption, AltaGas reclassified its equity securities with readily determinable fair values from available-for-sale to held for trading. Changes in fair value for equity securities with readily determinable fair values are now recognized through earnings instead of other comprehensive income. As a result, a cumulative-effect adjustment to retained earnings of approximately $7 million was recognized as at January 1, 2018. The remaining provisions of this ASU did not have a material impact on AltaGas’ consolidated financial statements;

- ASU No. 2016-15 “Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments*”.* The amendments in this ASU clarified the classification of certain cash flow transactions on the statement of cash flow. The adoption of this ASU did not have a material impact on AltaGas’ consolidated financial statements;

- ASU No. 2016-16 “Income Taxes: Intra-Entity Transfers of Assets Other Than Inventory”. The amendments in this ASU revised the accounting for income tax consequences on intra-entity transfers of assets by requiring an entity to recognize current and deferred tax on intra-entity transfers of assets other than inventory when the transfer occurs. The adoption of this ASU did not have a material impact on AltaGas’ consolidated financial statements;

- ASU No. 2016-18 “Statement of Cash Flows: Restricted Cash”. The amendments in this ASU required those amounts deemed to be restricted cash and restricted cash equivalents to be included in the cash and cash equivalents balance on the statement of cash flows. The change in presentation of the restricted cash balance on the statement of cash flows was applied on a retrospective basis;

- ASU No. 2017-01 “Business Combinations: Clarifying the Definition of a Business”. The amendments in this ASU changed the definition of a business to assist entities with evaluating when a set of transferred assets and activities is a business. AltaGas will apply the amendments to this ASU prospectively;

- ASU No. 2017-04 “Intangibles – Goodwill and Other: Simplifying the Test for Goodwill Impairment”. The amendments in this ASU removed Step 2 of the goodwill impairment test, eliminating the requirement to determine the fair value of individual assets and liabilities of a reporting unit to measure the goodwill impairment. AltaGas early adopted this ASU and will apply the amendments to this ASU prospectively. The adoption of this ASU did not have a material impact on AltaGas’ consolidated financial statements;

- ASU No. 2017-05 “Other Income – Gains and Losses from the De-recognition of Nonfinancial Assets: Clarifying the Scope of Asset De-recognition Guidance and Accounting for Partial Sales of Nonfinancial Assets”. The amendments in this ASU clarified the scope of ASC 610-20 as well as the accounting for partial sales of nonfinancial assets. The adoption of this ASU did not have a material impact on AltaGas’ consolidated financial statements;

- ASU No. 2017-07 “Compensation – Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost”. The amendments in this ASU revised the presentation of net periodic pension cost and net periodic postretirement benefit cost on the income statement and limited the components that are eligible for capitalization in assets to only the service cost component. AltaGas applied the change in presentation of the current service cost and other components of net benefit cost on the income statement retrospectively. As a result, $1.6 million of net benefit cost associated with other components was reclassified from the line item "Operating and administrative" to "other income" on the Consolidated Statements of Income for the year ended December 31, 2017. AltaGas applied the change related to the capitalization of the service cost prospectively. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements;

- ASU No. 2017-09 "Compensation – Stock Compensation: Scope of Modifications Accounting". The amendments in this ASU provided guidance on the types of changes to the terms or conditions of share-based payment arrangements to which an entity would be required to apply modification accounting. The guidance was applied prospectively and did not have a material impact on AltaGas' consolidated financial statements;

- ASU No. 2017-12 "Derivatives and Hedging – Targeted Improvements to Accounting for Hedging Activities". The amendments in this ASU improved the financial reporting of hedging relationships to better portray the economic results of an entity's risk management activities in its financial statements and made certain targeted improvements to simplify the application of hedge accounting. AltaGas early adopted this ASU. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements;

- ASU No. 2018-02 "Income Statement – Reporting Comprehensive Income: Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income". The amendments in this ASU allow a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the TCJA. AltaGas early adopted this ASU. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements; and

- ASU No. 2018-03 "Technical Corrections and Improvements to Financial Instruments – Overall". The amendments in this ASU clarified certain aspects of the guidance issued in ASU No. 2016-01. AltaGas early adopted this ASU. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements.

FUTURE CHANGES IN ACCOUNTING PRINCIPLES

In February 2016, FASB issued ASU No. 2016-02 "Leases", which requires lessees to recognize on the balance sheet a right-of-use asset and a lease liability. Lessor accounting remains substantially unchanged, however, the ASU modifies what qualifies as a sales-type and direct financing lease and eliminates the real estate-specific provisions included in ASC 840. The ASU also requires additional disclosures regarding leasing arrangements. In January 2018, FASB issued ASU 2018-01 "Land Easement Practical Expedient for Transition to Topic 842", providing entities with an optional election not to evaluate existing and expired land easements not previously accounted for as leases under ASC 840 using the provisions of ASC 842. In July 2018, FASB issued ASU 2018-11 "Targeted Improvements", allowing entities to report the comparative periods presented in the period of adoption under the previous lease standard (ASC 840), and recognize a cumulative-effect adjustment to the opening balance of retained earnings as of January 1, 2019. The ASU also provides a practical expedient under which lessors are not required to separate out lease and non-lease components of a contract, provided certain conditions are met. In December 2018, FASB issued ASU 2018-20 "Narrow-Scope Improvement for Lessors", allowing lessors to include and exclude certain costs from variable payments. The ASU also require lessors to allocate certain variable payments to the lease and non-lease components when the changes in facts and circumstances on which the variable payment is based occur. The amendments to the new lease standard are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. AltaGas is in the final stages of evaluating the impact of adopting ASC 842 on its consolidated financial statements. Leases, except as noted below, for which AltaGas is the lessee will be reflected on the balance sheet upon adoption by recording an increase to long-term assets and an increase to long-term liabilities net of the current portion that is recorded in current liabilities. The increases are expected to be less than 1 percent of total assets. AltaGas will utilize the transition practical expedients which allow entities to not have to reassess whether an arrangement contains a lease under the provisions of ASC 842, as well as the transition practical expedients related to land easements and not separating out lease and non-lease components of a contract for certain classes of assets. As a result of the transition practical expedients, AltaGas expects to have primarily operating leases on transition consistent with its current conclusions under ASC 840. AltaGas will also elect to exclude leases with terms of 12 months or less from the calculation of lease liabilities and right of use assets under the short term lease exemption.

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. In November 2018, FASB issued ASU No. 2018-19 "Codification Improvements to Topic 326 – Financial Instruments: Credit Losses". The amendments in the Update align the implementation date for nonpublic entities annual financial statements with the implementation date for their interim financial statements and clarify the scope of the guidance in the amendments in Update 2016-13. The effective date for the amendments in this Update is the same as the effective date in Update 2016-13. AltaGas is currently assessing the impact of this ASU on its consolidated financial statements.

In June 2018, FASB issued 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 amendments in this update are effective for fiscal years beginning after December 15, 2018, 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 June 2018, FASB issued 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 Update clarify whether a transfer of assets is a contribution or an exchange transaction. The amendments in this update are effective for fiscal years beginning after December 15, 2018, 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. 2018-13 "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 postretirement plans. The amendments in this update 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 August 2018, FASB issued 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 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 and AltaGas will early adopt this ASU on January 1, 2019. 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. 2018-16 "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 amendments in this update should be adopted concurrently with ASU 2017-12. AltaGas early adopted ASU 2017-12 on January 1, 2018 and therefore will adopt this update on January 1, 2019. An entity should apply the amendments prospectively for any qualifying new or re-designated cash flow hedging relationships. 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 Update 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 update 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.

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, is 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 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, 2018 and concluded that as at December 31, 2018, AltaGas' DCP and ICFR were effective.

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).

The Chief Executive Officer and Chief Financial Officer of AltaGas have limited the scope of the design of ICFR evaluation to exclude controls, policies, and procedures of all entities acquired in the WGL Acquisition that closed on July 6, 2018, as it has not been possible to conduct an assessment of WGL's ICFR between such closing and the date of this report. This limitation of scope is in accordance with section 3.3(1)(b) of National Instrument 52-109 as well as relevant SEC guidance, which allows an issuer to limit its assessment of ICFR to exclude controls, policies and procedures of a business that the issuer acquired for a maximum period of 365 days from the end of the financial period in which the acquisition occurred. Summary financial information of WGL included in the audited Consolidated Financial Statements as at and for the year ended December 31, 2018, includes total assets of approximately $14 billion and revenues of approximately $1 billion.

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)	**Q4-18**	Q3-18	Q2-18	Q1-18	Q4-17	Q3-17	Q2-17	Q1-17
Total revenue	**1,727**	1,041	610	878	745	502	539	771
Normalized EBITDA[(2)]	**394**	226	166	223	213	190	166	228
Net income (loss) applicable to common shares	**174**	(726)	1	49	(11)	18	(8)	32
($ per share)	**Q4-18**	Q3-18	Q2-18	Q1-18	Q4-17	Q3-17	Q2-17	Q1-17
Net income (loss) per common share								
Basic	**0.64**	(2.78)	0.01	0.28	(0.06)	0.10	(0.05)	0.19
Diluted	**0.64**	(2.78)	0.01	0.28	(0.06)	0.10	(0.05)	0.19
Dividends declared	**0.45**	0.55	0.55	0.55	0.54	0.53	0.53	0.53

(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:

- The improved NGL commodity prices in 2017 and 2018;
- The weak Alberta power pool prices throughout 2017;
- The weaker U.S. dollar in the second half of 2017 and the first half of 2018 on translated results of the U.S. assets;
- The seasonally colder weather experienced at several of the utilities in the fourth quarter of 2017 and during 2018;
- The closing of the sale of the EDS and the JFP transmission assets to Nova Chemicals in March of 2017;
- The commencement of commercial operations on October 1, 2017 at Townsend 2A;
- The commencement of commercial operations at the first train of the North Pine Facility on December 1, 2017;
- Losses on risk management contracts recorded in 2017 and 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 negative impact on revenue of the TCJA at the U.S. utilities throughout 2018;
- Revenue from WGL after the acquisition closed in the third quarter of 2018;
- Revenue from AltaGas' 50 percent ownership in Black Swan's Aitken Creek North gas processing facility beginning in the fourth quarter of 2018;
- Lower volumes at the Northwest Hydro facilities during 2018;
- The impact of the sale of non-core U.S. power assets in the fourth quarter of 2018; and
- The impact of the sale of the Canadian utilities to ACI in the fourth quarter of 2018.

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, provision 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. For these reasons, the 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:

- Higher depreciation and amortization expense due to new assets placed into service;
- Higher interest expense since the first quarter of 2017 mainly due to higher financing costs associated with the bridge facility;
- The unrealized loss of approximately $8 million recognized upon ceasing to account for the Tidewater investment using the equity method in the second quarter of 2017;
- After-tax provisions totaling $84 million recognized in the fourth quarter of 2017 related to the Hanford and Henrietta gas-fired peaking facilities, a non-core gas processing facility in Alberta, and a non-core development stage peaking project in California;
- Impact of the TCJA resulting in a decrease in tax expense of approximately $34 million in the fourth quarter of 2017;
- After-tax transaction costs incurred throughout 2017 (totaling $53 million) and 2018 ($50 million) 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;
- The impact of WGL income for the period after the close of the acquisition on July 6, 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; and
- The impact of the sale of the Canadian utilities to ACI in the fourth quarter of 2018.

SELECTED ANNUAL FINANCIAL INFORMATION

($ millions, except where noted)	**2018**	2017	2016
Revenue	**4,257**	2,556	2,190
Net income (loss) applicable to common shares	**(502)**	30	155
Basic ($ per share)	**(2.25)**	0.18	0.99
Diluted ($ per share)	**(2.25)**	0.18	0.99
Total assets	**23,488**	10,032	10,201
Total long-term financial liabilities	**8,282**	3,596	3,532
Weighted average number of common shares outstanding (millions)	**223**	171	157
Dividends declared per common share ($ per share)	**2.087500**	2.115000	2.030000
Preferred share dividends declared ($ per share)			
Series A	**0.845000**	0.845000	0.845000
Series B	**0.968620**	0.806380	0.786920
Series C	**1.322500**	1.155625	1.100000
Series E	**1.250000**	1.250000	1.250000
Series G	**1.187500**	1.187500	1.187500
Series I	**1.312500**	1.312500	1.448245
Series K	**1.250000**	1.063400	—
Washington Gas $4.80 series (US$)	**2.400000**	—	—
Washington Gas $4.25 series (US$)	**2.125000**	—	—
Washington Gas $5.00 series (US$)	**2.500000**	—	—

Management's Responsibility for Consolidated Financial Statements

The Consolidated Financial Statements and Management's Discussion and Analysis (MD&A) of AltaGas Ltd. (AltaGas or the Corporation) are the responsibility of Management and have been approved by the Board of Directors of the Corporation. 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.

Management is responsible for establishing and maintaining adequate internal controls over financial reporting (ICFR) for the Corporation. Management has designed and maintains a system of internal controls over financial reporting, including a program of internal audits to carry out its responsibility. Management believes these controls provide reasonable assurance that financial records are reliable and form a proper basis for the preparation of financial statements. Management undertakes communication to employees of policies that govern ethical business conduct. The Chief Executive Officer and Chief Financial Officer of AltaGas have limited the scope of the design of ICFR evaluation to exclude controls, policies, and procedures of all entities acquired in the WGL Acquisition that closed on July 6, 2018, as it has not been possible to conduct an assessment of WGL's ICFR between such closing and the date of this report. This limitation of scope is in accordance with section 3.3(1)(b) of National Instrument 52-109 as well as relevant SEC guidance, which allows an issuer to limit its assessment of ICFR to exclude controls, policies and procedures of a business that the issuer acquired for a maximum period of 365 days from the end of the financial period in which the acquisition occurred. Summary financial information of WGL included in the audited Consolidated Financial Statements as at and for the year ended December 31, 2018, includes total assets of approximately $14 billion and revenues of approximately $1 billion.

The MD&A and Consolidated Financial Statements are approved by the Board of Directors after considering the recommendation of the Audit Committee. The Audit Committee of the Board of Directors 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 Audit Committee's responsibilities include overseeing Management's performance in carrying out its financial reporting responsibilities and reviewing the Consolidated Financial Statements and MD&A, before these documents are submitted to the Board of Directors for approval. The internal and independent external auditors have access to the Audit Committee without obtaining prior Management approval.

The Audit Committee approves the terms of engagement of the independent external auditors and reviews the annual audit plan, the Auditors' Report and the results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the shareholders.

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. 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) *"Tim Watson"*

TIM WATSON
Executive Vice President and
Chief Financial Officer of
AltaGas Ltd.

February 27, 2019

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., which comprise the consolidated balance sheets as at December 31, 2018 and 2017, and the consolidated statements of income, 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 the Company as at December 31, 2018 and 2017, 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.

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, 2019

Consolidated Balance Sheets

As at *($ millions)*	**December 31, 2018**	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents *(note 31)*	**$ 101.6**	$ 27.3
Accounts receivable, net of allowances *(note 22)*	**1,547.5**	382.9
Inventory *(note 6)*	**515.9**	201.1
Restricted cash holdings from customers *(note 31)*	**4.1**	8.9
Regulatory assets *(note 20)*	**21.0**	1.1
Risk management assets *(note 22)*	**114.1**	38.6
Prepaid expenses and other current assets *(notes 28 and 31)*	**199.9**	36.0
Assets held for sale *(note 5)*	**1,528.9**	6.0
	4,033.0	701.9
Property, plant and equipment *(note 7)*	**10,929.6**	6,689.8
Intangible assets *(note 8)*	**711.9**	588.8
Goodwill *(note 9)*	**4,068.2**	817.3
Regulatory assets *(note 20)*	**663.0**	328.6
Risk management assets *(note 22)*	**57.7**	15.9
Deferred income taxes *(note 19)*	**—**	2.8
Restricted cash holdings from customers *(note 31)*	**6.1**	7.5
Prepaid post-retirement benefits *(note 28)*	**342.7**	—
Long-term investments and other assets *(notes 11, 22, 28 and 31)*	**283.1**	312.6
Investments accounted for by the equity method *(note 13)*	**2,392.4**	567.0
	$ 23,487.7	$ 10,032.2
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities *(notes 17 and 22)*	**$ 1,488.2**	$ 415.3
Dividends payable *(note 22)*	**22.0**	32.0
Short-term debt *(notes 14 and 22)*	**1,209.9**	46.8
Current portion of long-term debt *(notes 15 and 22)*	**890.2**	188.9
Customer deposits	**98.0**	30.8
Regulatory liabilities *(note 20)*	**114.9**	10.9
Risk management liabilities *(note 22)*	**89.3**	57.6
Other current liabilities *(note 22)*	**18.1**	32.6
Liabilities associated with assets held for sale *(note 5)*	**171.4**	0.3
	4,102.0	815.2
Long-term debt *(notes 15 and 22)*	**8,066.9**	3,436.5
Asset retirement obligations *(note 16)*	**500.6**	88.3
Unamortized investment tax credits *(note 19)*	**190.1**	—
Deferred income taxes *(note 19)*	**957.9**	444.2
Regulatory liabilities *(note 20)*	**1,392.8**	268.6
Risk management liabilities *(note 22)*	**213.0**	13.8
Other long-term liabilities *(notes 17, 18 and 22)*	**122.0**	201.9
Future employee obligations *(note 28)*	**302.2**	124.5
	$ 15,847.5	$ 5,393.0

As at *($ millions)*	**December 31, 2018**	December 31, 2017
Shareholders' equity		
Common shares, no par values, unlimited shares authorized; 2018 - 275.2 million and 2017 - 175.3 million issued and outstanding *(note 24)*	**$ 6,653.9**	$ 4,007.9
Preferred shares *(note 24)*	**1,318.8**	1,277.7
Contributed surplus	**373.2**	22.3
Accumulated deficit	**(1,905.3)**	(933.6)
Accumulated other comprehensive income (AOCI) *(note 21)*	**579.0**	199.1
Total shareholders' equity	**7,019.6**	4,573.4
Non-controlling interests	**620.6**	65.8
Total equity	**7,640.2**	4,639.2
	$ 23,487.7	$ 10,032.2

Variable interest entities (note 12).
Commitments, contingencies and guarantees (note 29).
Subsequent events (note 33).

See accompanying notes to the Consolidated Financial Statements.

Approved by the Board of Directors of AltaGas Ltd.

(signed) *"David W. Cornhill"*

DAVID W. CORNHILL
Director

(signed) *"Robert B. Hodgins"*

ROBERT B. HODGINS
Director

Consolidated Statements of Income (Loss)

For the year ended December 31 ($ millions except per share amounts)		2018		2017
REVENUE *(note 23)*	**$**	**4,256.7**	$	2,556.2
EXPENSES				
Cost of sales, exclusive of items shown separately		**2,455.3**		1,357.1
Operating and administrative		**1,129.0**		572.2
Accretion expenses *(note 16)*		**10.9**		10.9
Depreciation and amortization *(notes 7 and 8)*		**394.0**		282.4
Provisions on assets *(note 10)*		**728.7**		139.6
		4,717.9		2,362.2
Income from equity investments *(note 13)*		**47.9**		31.4
Other income *(note 26)*		**0.9**		9.6
Foreign exchange gains		**4.5**		1.7
Interest expense				
Short-term debt		**(14.0)**		(3.7)
Long-term debt		**(295.0)**		(166.6)
Income (loss) before income taxes		**(716.9)**		66.4
Income tax expense (recovery) *(note 19)*				
Current		**24.4**		30.5
Deferred		**(287.6)**		(64.0)
Net income (loss) after taxes		**(453.7)**		99.9
Net income (loss) applicable to non-controlling interests		**(18.6)**		8.3
Net income (loss) applicable to controlling interests		**(435.1)**		91.6
Preferred share dividends		**(66.6)**		(61.3)
Net income (loss) applicable to common shares	**$**	**(501.7)**	$	30.3
Net income (loss) per common share *(note 25)*				
Basic	**$**	**(2.25)**	$	0.18
Diluted	**$**	**(2.25)**	$	0.18
Weighted average number of common shares outstanding (millions) *(note 25)*				
Basic		**222.6**		171.0
Diluted		**222.7**		171.3

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Comprehensive Income (Loss)

For the year ended December 31 ($ millions)		**2018**		2017
Net income (loss) after taxes	**$**	**(453.7)**	$	99.9
Other comprehensive income (loss), net of taxes				
Gain (loss) on foreign currency translation		**458.5**		(183.4)
Unrealized gain (loss) on net investment hedge *(note 22)*		**(80.2)**		6.6
Actuarial loss on pension plans and post-retirement benefit (PRB) plans (note 28)		**(10.8)**		(1.0)
Reclassification of actuarial gains and prior service costs on defined benefit (DB) and post-retirement benefit plans (PRB) to net income *(note 28)*		**0.5**		0.7
Settlement of PRB plan *(note 28)*		**—**		0.2
Curtailment of DB and PRB plan *(note 28)*		**2.7**		—
Unrealized loss on available-for-sale assets		**—**		(26.9)
Adoption of ASU 2016-01 *(note 2)*		**7.1**		—
Other comprehensive income (loss) from equity investees		**2.1**		(2.2)
Total other comprehensive income (loss) (OCI), net of taxes *(note 21)*		**379.9**		(206.0)
Comprehensive loss attributable to controlling interests and non-controlling interests, net of taxes	**$**	**(73.8)**	$	(106.1)
Comprehensive income (loss) attributable to:				
Non-controlling interests	**$**	**(18.6)**	$	8.3
Controlling interests		**(55.2)**		(114.4)
	$	**(73.8)**	$	(106.1)

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Equity

For the year ended December 31 ($ millions)		2018		2017
Common shares *(note 24)*				
Balance, beginning of year	**$**	**4,007.9**	$	3,773.4
Shares issued for cash on exercise of options		**1.3**		6.5
Shares issued under DRIP [(1)]		**325.8**		236.3
Deferred taxes on share issuance costs		**13.3**		(8.3)
Shares issued on conversion of subscription receipts, net of issuance costs		**2,305.6**		—
Balance, end of year	**$**	**6,653.9**	$	4,007.9
Preferred shares *(note 24)*				
Balance, beginning of year	**$**	**1,277.7**	$	985.1
Series K issued		**—**		293.4
Preferred shares acquired through WGL Acquisition *(note 24)*		**41.1**		—
Deferred taxes on share issuance costs		**—**		(0.8)
Balance, end of year	**$**	**1,318.8**	$	1,277.7
Contributed surplus				
Balance, beginning of year	**$**	**22.3**	$	17.4
Share options expense		**0.9**		1.4
Exercise of share options		**(0.1)**		(0.5)
Forfeiture of share options		**(0.1)**		(0.1)
Adoption of ASU No. 2016-09		**—**		1.1
Sale of non-controlling interest *(notes 4 and 12)*		**350.2**		3.0
Balance, end of year	**$**	**373.2**	$	22.3
Accumulated deficit				
Balance, beginning of year	**$**	**(933.6)**	$	(600.4)
Net income (loss) applicable to controlling interests		**(435.1)**		91.6
Common share dividends		**(462.9)**		(362.4)
Preferred share dividends		**(66.6)**		(61.3)
Adoption of ASU No. 2016-09		**—**		(1.1)
Adoption of ASU No. 2016-01 *(note 2)*		**(7.1)**		—
Balance, end of year	**$**	**(1,905.3)**	$	(933.6)
AOCI (*note 21*)				
Balance, beginning of year	**$**	**199.1**	$	405.1
Other comprehensive income (loss)		**379.9**		(206.0)
Balance, end of year	**$**	**579.0**	$	199.1
Total shareholders' equity	**$**	**7,019.6**	$	4,573.4
Non-controlling interests				
Balance, beginning of year	**$**	**65.8**	$	34.8
Net income (loss) applicable to non-controlling interests		**(18.6)**		8.3
Sale of non-controlling interest *(notes 4 and 12)*		**498.4**		20.0
Contributions from non-controlling interests to subsidiaries		**96.3**		11.0
Distributions by subsidiaries to non-controlling interests		**(30.3)**		(8.3)
Acquisition of non-controlling interest through WGL Acquisition *(note 3)*		**9.0**		—
Balance, end of year		**620.6**		65.8
Total equity	**$**	**7,640.2**	$	4,639.2

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

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Cash Flows

For the year ended December 31 ($ millions)	2018	2017
Cash from operations		
Net income (loss) after taxes	**$ (453.7)**	$ 99.9
Items not involving cash:		
Depreciation and amortization *(notes 7 and 8)*	**394.0**	282.4
Provisions on assets *(note 10)*	**728.7**	139.6
Accretion expenses *(note 16)*	**10.9**	10.9
Share-based compensation *(note 24)*	**0.8**	1.3
Deferred income tax recovery *(note 19)*	**(287.6)**	(64.0)
Losses on sale of assets *(notes 4 and 26)*	**10.6**	2.7
Income from equity investments *(note 13)*	**(47.9)**	(31.4)
Unrealized losses (gains) on risk management contracts *(note 22)*	**(80.8)**	62.5
Realized loss on expiry of foreign exchange options *(note 22)*	**36.0**	—
Losses (gains) on investments *(note 26)*	**10.1**	(3.6)
Amortization of deferred financing costs	**29.7**	16.9
Provision for doubtful accounts	**17.0**	—
Net change in pension and other post retirement benefits *(note 28)*	**(3.8)**	—
Other	**3.6**	(4.1)
Asset retirement obligations settled *(note 16)*	**(4.2)**	(4.0)
Distributions from equity investments	**44.5**	30.2
Changes in operating assets and liabilities *(note 31)*	**(486.5)**	1.9
	$ (78.6)	$ 541.2
Investing activities		
Business acquisitions, net of cash acquired *(note 3)*	**(5,931.0)**	—
Acquisition of property, plant and equipment	**(990.4)**	(473.0)
Acquisition of intangible assets	**(38.1)**	(20.3)
Acquisition of investment in a publicly traded entity	**—**	(7.0)
Contributions to equity investments	**(235.4)**	(16.8)
Loan to affiliate, net of repayment *(note 30)*	**30.0**	(12.5)
Financing receivable	**(8.7)**	—
Proceeds from disposition of investments *(note 11)*	**76.5**	—
Proceeds from IPO of ACI *(note 4)*	**858.9**	—
Payment for derivative contracts	**—**	(36.0)
Proceeds from disposition of assets, net of transaction costs *(note 4)*	**403.8**	70.6
	$ (5,834.4)	$ (495.0)
Financing activities		
Net issuance (repayment) of short-term debt	**497.7**	(74.2)
Issuance of long-term debt, net of debt issuance costs	**3,595.2**	758.1
Repayment of long-term debt	**(1,729.5)**	(861.6)
Net issuance of bankers' acceptances	**553.6**	—
Dividends - common shares	**(472.9)**	(359.6)
Dividends - preferred shares	**(66.6)**	(61.3)
Distributions to non-controlling interest	**(30.3)**	(8.3)
Contributions from non-controlling interests	**96.3**	11.0
Net proceeds from shares issued on exercise of options	**1.2**	6.0
Net proceeds from issuance of common shares	**2,633.7**	236.3
Net proceeds from issuance of preferred shares	**—**	293.4
Net proceeds from sale of non-controlling interest *(notes 4 and 12)*	**908.6**	24.1
Other	**—**	(1.9)
	$ 5,987.0	$ (38.0)
Change in cash, cash equivalents and restricted cash	**74.0**	8.2
Effect of exchange rate changes on cash, cash equivalents and restricted cash	**7.3**	1.4
Net change in cash classified within assets held for sale *(note 5)*	**(4.9)**	—
Restricted cash acquired *(note 31)*	**81.0**	—
Cash, cash equivalents, and restricted cash beginning of year	**43.7**	34.1
Cash, cash equivalents, and restricted cash end of year *(note 31)*	**$ 201.1**	$ 43.7

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., 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, and WGL Midstream Inc.; in regards to the Power business, AltaGas Power Holdings (U.S.) Inc., WGSW, Inc., WGL Energy Systems, Inc., and Blythe Energy Inc. (Blythe); and, in regards to the Utility business, Washington Gas Light Company, 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) and its Alaska natural gas distribution business under the name ENSTAR Natural Gas Company (ENSTAR).

AltaGas, a Canadian corporation, is a leading North American clean energy infrastructure company with strong growth opportunities and a focus on owning and operating assets to provide clean and affordable energy to its customers. The Corporation's long-term strategy is to grow in attractive areas across its Utility, Midstream, and Power 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 both coasts of North America via the Corporation's footprint in two of the most prolific gas plays – the Montney and Marcellus. To optimize capital deployment, the Corporation seeks to invest in U.S utilities located in strong growth markets with increasing construction to support customer additions, system improvement and accelerated replacement programs. In the Power business, AltaGas seeks to create innovative solutions with light capital investment utilizing the Corporation's clean energy expertise. AltaGas has three business segments:

- Utilities, which serves approximately 1.6 million customers with a rate base of approximately US$3.7 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, subsequent to the sale of non-core midstream assets in Canada that closed in February 2019, transacts more than 1.5 Bcf/d of natural gas and includes natural gas gathering and processing, natural gas liquids (NGL) extraction and fractionation, transmission, storage, natural gas and NGL marketing, the Corporation's 50 percent interest in AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP), an indirectly held one-third ownership investment in Petrogas Energy Corp. (Petrogas), through which AltaGas' interest in the Ferndale Terminal is held, an interest in four regulated pipelines in the Marcellus/Utica gas formation in northeast United States and WGL's retail gas marketing business; and
- Power, which, subsequent to the sale of non-core power assets in Canada that closed in February 2019, and the sale of the remaining 55 percent interest in the Northwest Hydro facilities which closed in January 2019, includes 1,105 MW of gross capacity from natural gas-fired, biomass, solar, other distributed generation and energy storage assets located in Alberta, Canada and 20 states and the District of Columbia in the United States. 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 over, but not control, are accounted for using the equity method.

Hypothetical Liquidation at Book Value (HLBV) methodology is used for certain WGL equity method investments as well as WGL 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.

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 and are presented separately in "net income applicable to non-controlling interests".

USE OF ESTIMATES AND MEASUREMENT UNCERTAINTY

The preparation of Consolidated Financial Statements in accordance with U.S. GAAP requires Management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenue and expenses during the period. Key areas where Management has made complex or subjective judgments, when matters are inherently uncertain, include but are not limited to: determining the nature and timing of satisfaction of performance obligations and determining the transaction price and amounts allocated to performance obligations for revenue recognition; depreciation and amortization rates, 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, 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 (collectively 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.

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 WGL executive and outside director retirement benefit plan obligations. As of December 31, 2018, the rabbi trust funds are invested in money market funds which are considered as 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, 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, where 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 U.S. 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.

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	3 - 80 years
Midstream assets	3 - 45 years
Power generation assets	2 - 120 years
Corporate assets	1 - 20 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 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 Statement of Income. Any difference between the cost and accumulated depreciation of the asset, net of salvage proceeds, is charged to accumulated depreciation or another regulatory asset or liability account. It is expected that any gain or loss that is charged to accumulated depreciation or another regulatory account will be reflected in future depreciation expense when it is refunded or collected in rates. When a non-regulated asset is retired or disposed of from PP&E, the original cost and related accumulated depreciation and amortization are derecognized and any gain or loss is recorded in the Consolidated Statement of Income.

Leases are classified as either capital or operating. Leases that transfer substantially all the benefits and risks of ownership of property to AltaGas are accounted for as capital leases.

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

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 Statement of Income.

Development Costs

AltaGas expenses development costs as incurred unless such development costs meet certain criteria related to technical, market, regulatory and financial feasibility for capitalization. Development costs are examined annually to ensure capitalization criteria continue to be met. When the criteria that previously justified the deferral of costs are no longer met, the unamortized balance is taken as a charge to income in the period when this determination is made. Development costs are amortized based on the expected period of benefit, beginning at the commencement of commercial operations.

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 Statement of Income.

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 Statement of Income under "other income".

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

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

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

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

Regulated Utility Operations

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

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 22 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.

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 U.S. 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 23.

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 Statement of Income. Non-monetary assets and liabilities are converted at the historical exchange rate in effect at the transaction date. Revenues and expenses are converted at the exchange rate applicable at the transaction date.

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

AltaGas may designate 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 medium-term incentive plan (MTIP) 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 or, at the election of AltaGas, its equivalent in common shares purchased from the market. The other portion of RU's and PSUs are valued at US$1 per unit. Upon vesting, the RUs and PSUs are paid in cash. All PUs are also subject to a performance multiplier ranging from 0 to 2 dependent on the Corporation's performance relative to performance targets agreed between the Corporation and the employees. 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, and the participant is entitled to payment at his or her termination date, 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 and expected health care costs. 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 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 9.6 years and 14.1 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 per Share

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

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

Contingencies

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

ADOPTION OF NEW ACCOUNTING STANDARDS

Effective January 1, 2018, AltaGas adopted the following Financial Accounting Standards Board (FASB) issued Accounting Standards Updates (ASU):

- ASU No. 2014-09 "Revenue from Contracts with Customers" and all related amendments (collectively "ASC 606"). AltaGas adopted ASC 606 using the modified retrospective method to contracts that have not been completed as at January 1, 2018. Under the modified retrospective method, the comparative information is not adjusted. The adoption of ASC 606 impacted the timing of revenue recognition in relation to contracts with take-or-pay or minimum volume commitments whereby the customers have make up rights for deficiency quantities. However, on adoption, no cumulative adjustments to opening retained earnings were required for this change in revenue recognition pattern as none of the customers had material deficiency quantities. Please also refer to Note 23 for further details. The application of ASC 606 did not have a material impact on AltaGas' consolidated financial statements in 2018;

- ASU No. 2016-01 "Recognition and Measurement of Financial Assets and Financial Liabilities" which revised an entity's accounting related to (1) the classification and measurement of investments in equity securities and (2) the presentation of certain fair value changes for financial liabilities measured at fair value. It also amended certain disclosure requirements associated with the fair value of financial instruments. Upon adoption, AltaGas reclassified its equity securities with readily determinable fair values from available-for-sale to held for trading. Changes in fair value for equity securities with readily determinable fair values are now recognized through earnings instead of other comprehensive income. As a result, a cumulative-effect adjustment to retained earnings of approximately $7 million was recognized as at January 1, 2018. The remaining provisions of this ASU did not have a material impact on AltaGas' consolidated financial statements;

- ASU No. 2016-15 "Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments*".* The amendments in this ASU clarified the classification of certain cash flow transactions on the statement of cash flow. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements;

- ASU No. 2016-16 "Income Taxes: Intra-Entity Transfers of Assets Other Than Inventory". The amendments in this ASU revised the accounting for income tax consequences on intra-entity transfers of assets by requiring an entity to recognize current and deferred tax on intra-entity transfers of assets other than inventory when the transfer occurs. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements;

- ASU No. 2016-18 "Statement of Cash Flows: Restricted Cash". The amendments in this ASU required those amounts deemed to be restricted cash and restricted cash equivalents to be included in the cash and cash equivalents balance on the statement of cash flows. The change in presentation of the restricted cash balance on the statement of cash flows was applied on a retrospective basis;

- ASU No. 2017-01 "Business Combinations: Clarifying the Definition of a Business". The amendments in this ASU changed the definition of a business to assist entities with evaluating when a set of transferred assets and activities is a business. AltaGas will apply the amendments to this ASU prospectively;

- ASU No. 2017-04 "Intangibles – Goodwill and Other: Simplifying the Test for Goodwill Impairment". The amendments in this ASU removed Step 2 of the goodwill impairment test, eliminating the requirement to determine the fair value of individual assets and liabilities of a reporting unit to measure the goodwill impairment. AltaGas early adopted this ASU. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements;

- ASU No. 2017-05 "Other Income – Gains and Losses from the De-recognition of Nonfinancial Assets: Clarifying the Scope of Asset De-recognition Guidance and Accounting for Partial Sales of Nonfinancial Assets". The amendments in this ASU clarified the scope of ASC 610-20 as well as the accounting for partial sales of nonfinancial assets. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements;

- ASU No. 2017-07 "Compensation – Retirement Benefits: Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost". The amendments in this ASU revised the presentation of net periodic pension cost and net periodic postretirement benefit cost on the income statement and limited the components that are eligible for capitalization in assets to only the service cost component. AltaGas applied the change in presentation of the current service cost and other components of net benefit cost on the income statement retrospectively. As a result, $1.6 million of net benefit cost associated with other components were reclassified from the line item "operating and administrative" to "other income" on the Consolidated Statements of Income for the year ended December 31, 2017. AltaGas applied the change related to the capitalization of the service cost prospectively. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements;

- ASU No. 2017-09 "Compensation – Stock Compensation: Scope of Modifications Accounting". The amendments in this ASU provided guidance on the types of changes to the terms or conditions of share-based payment arrangements to which an entity would be required to apply modification accounting. The guidance was applied prospectively and did not have a material impact on AltaGas' consolidated financial statements;

- ASU No. 2017-12 “Derivatives and Hedging – Targeted Improvements to Accounting for Hedging Activities”. The amendments in this ASU improved the financial reporting of hedging relationships to better portray the economic results of an entity’s risk management activities in its financial statements and made certain targeted improvements to simplify the application of hedge accounting. AltaGas early adopted this ASU. The adoption of this ASU did not have a material impact on AltaGas’ consolidated financial statements;

- ASU No. 2018-02 “Income Statement – Reporting Comprehensive Income: Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income”. The amendments in this ASU allow a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act (TCJA). AltaGas early adopted this ASU. The adoption of this ASU did not have a material impact on AltaGas’ consolidated financial statements; and

- ASU No. 2018-03 “Technical Corrections and Improvements to Financial Instruments – Overall”. The amendments in this ASU clarified certain aspects of the guidance issued in ASU No. 2016-01. AltaGas early adopted this ASU. The adoption of this ASU did not have a material impact on AltaGas’ consolidated financial statements.

FUTURE CHANGES IN ACCOUNTING PRINCIPLES

In February 2016, FASB issued ASU No. 2016-02 “Leases”, which requires lessees to recognize on the balance sheet a right-of-use asset and a lease liability. Lessor accounting remains substantially unchanged, however, the ASU modifies what qualifies as a sales-type and direct financing lease and eliminates the real estate-specific provisions included in ASC 840. The ASU also requires additional disclosures regarding leasing arrangements. In January 2018, FASB issued ASU 2018-01 “Land Easement Practical Expedient for Transition to Topic 842”, providing entities with an optional election not to evaluate existing and expired land easements not previously accounted for as leases under ASC 840 using the provisions of ASC 842. In July 2018, FASB issued ASU 2018-11 “Targeted Improvements”, allowing entities to report the comparative periods presented in the period of adoption under the previous lease standard (ASC 840), and recognize a cumulative-effect adjustment to the opening balance of retained earnings as of January 1, 2019. The ASU also provides a practical expedient under which lessors are not required to separate out lease and non-lease components of a contract, provided certain conditions are met. In December 2018, FASB issued ASU 2018-20 “Narrow-Scope Improvement for Lessors”, allowing lessors to include and exclude certain costs from variable payments. The ASU also require lessors to allocate certain variable payments to the lease and non-lease components when the changes in facts and circumstances on which the variable payment is based occur. The amendments to the new lease standard are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. AltaGas is in the final stages of evaluating the impact of adopting ASC 842 on its consolidated financial statements. Leases, except as noted below, for which AltaGas is the lessee will be reflected on the balance sheet upon adoption by recording an increase to long-term assets and an increase to long-term liabilities net of the current portion that is recorded in current liabilities. The increases are expected to be less than 1 percent of total assets. AltaGas will utilize the transition practical expedients which allow entities to not have to reassess whether an arrangement contains a lease under the provisions of ASC 842, as well as the transition practical expedients related to land easements and not separating out lease and non-lease components of a contract for certain classes of assets. As a result of the transition practical expedients, AltaGas expects to have primarily operating leases on transition consistent with its current conclusions under ASC 840. AltaGas will also elect to exclude leases with terms of 12 months or less from the calculation of lease liabilities and right of use assets under the short term lease exemption.

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 is currently assessing the impact of this ASU on its consolidated financial statements.

In June 2018, FASB issued 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 amendments in this update are effective for fiscal years beginning after December 15, 2018, 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 June 2018, FASB issued 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 Update clarify whether a transfer of assets is a contribution or an exchange transaction. The amendments in this update are effective for fiscal years beginning after December 15, 2018, 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. 2018-13 "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 postretirement plans. The amendments in this update 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 August 2018, FASB issued 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 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 and AltaGas will early adopt this ASU on January 1, 2019. 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. 2018-16 "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 amendments in this update should be adopted concurrently with ASU 2017-12. AltaGas early adopted ASU 2017-12 on January 1, 2018 and therefore will adopt this update on January 1, 2019. An entity should apply the amendments prospectively for any qualifying new or re-designated cash flow hedging relationships. 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 Update 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 update 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

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 for an aggregate purchase price of approximately $9.3 billion (US$7.1 billion), including the assumption of approximately $3.3 billion (US$2.5 billion) of debt and $41 million (US$31 million) of preferred shares.

Under the terms of the transaction, WGL shareholders received US$88.25 per common share. The net cash consideration was approximately $6.0 billion (US$4.6 billion). The WGL Acquisition was financed through net proceeds of approximately $2.3 billion from the sale of subscription receipts, draws on the fully committed acquisition credit facility of $3.0 billion (US$2.3 billion) and existing cash on hand. The draws on the acquisition credit facility included additional amounts for the payment of fees and regulatory commitments related to the WGL Acquisition. The sale of the subscription receipts was completed in the first quarter of 2017 and upon closing of the WGL Acquisition, the subscription receipts were exchanged into approximately 84.5 million common shares of AltaGas.

The WGL Acquisition is 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 is recognized as goodwill at the acquisition date.

The following table summarizes the 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 is provisional and reflects Management's current best estimate of the fair value of WGL's assets and liabilities based on the analysis of information obtained to date. Management is continuing to obtain specific information to support the evaluation of fixed assets, goodwill and deferred income taxes for certain elements of the acquired business. As the additional information becomes available, the purchase price allocation may differ from the preliminary purchase price allocation below. Any adjustments to the purchase price allocation will be made as soon as practicable but no later than one year from the date of acquisition.

The following table summarizes the estimated fair values that were assigned to the net assets of WGL at the date of acquisition:

Purchase consideration	**$**	**5,973**
Fair value assigned to net assets		
Current assets	$	1,187
Property, plant and equipment		5,943
Intangible assets		637
Regulatory assets		402
Long-term investments		1,411
Other long-term assets		449
Current liabilities		(1,798)
Long-term debt		(2,548)
Preferred shares		(41)
Regulatory liabilities		(1,125)
Deferred income taxes		(772)
Other long-term liabilities		(959)
Non-controlling interest		(9)
Fair value of net assets acquired	**$**	**2,777**
Goodwill	**$**	**3,196**

The fair value of property, plant and equipment was estimated using the valuation methodologies described in ASC 820, Fair Value Measurements and Disclosures, to value the property, plant and equipment purchased. The fair value of WGL's rate regulated property, plant and equipment is determined using a market participant perspective, which is equal to the carrying amount. The preliminary fair values of the remaining non-regulated property, plant and equipment is determined using both the income and cost approaches and resulted in an estimated fair value decrease relative to carrying value of approximately $92 million related to solar distributed generation assets.

Long-term investments include WGL's 55 percent equity investment in Meade Pipeline Co. LLC. (Meade), a 10 percent equity interest in Mountain Valley Pipeline LLC, and a 30 percent equity interest in Stonewall Gas Gathering Systems LLC. Meade owns 39 percent of Central Penn, and WGL owns a 21 percent indirect net interest in Central Penn. The preliminary fair value of these investments has been determined using an income approach, resulting in an estimated fair value increase of approximately $464 million.

Intangible assets consist of customer relationships, contracts relating to gas transportation capacity, and natural gas purchase and sale agreements for energy exports. The preliminary fair value of these assets is determined using an income approach, resulting in an estimated fair value of approximately $637 million.

The fair value of current assets and current liabilities approximate their carrying values due to their short-term nature.

The fair value of long-term debt was estimated based on the quoted market prices of the U.S. Treasury issues having a similar term to maturity, adjusted for the credit quality of the debt issuer, WGL or Washington Gas Light Company. This resulted in a fair value increase of approximately $87 million, with a corresponding regulatory offset.

Deferred income tax assets and liabilities have been applied on the cumulative amount of tax applicable to temporary differences between the accounting and tax values of assets and liabilities.

The preliminary purchase price allocation includes goodwill of approximately $3.2 billion. The goodwill is primarily related to the investment in low risk, long-life rate regulated assets, opportunities to grow the gas midstream business, expanded access to capital and greater financial flexibility as a result of increased scale, and earnings diversification. The goodwill recognized as part of this transaction is not deductible for income tax purposes, and as such, no deferred taxes have been recorded related to this goodwill.

Pre-tax acquisition expenses and merger commitment costs for the year ended December 31, 2018 of approximately $237.2 million were incurred and included in the Consolidated Statements of Income (2017 – $65.7 million).

Upon completion of the WGL Acquisition, AltaGas began consolidating WGL. Since the closing date through December 31, 2018, WGL has generated approximately $1,406 million in revenues and $113 million in net loss after tax. The loss was primarily due to the payment of various regulatory commitments as well as seasonality in certain of WGL's operating businesses.

The following supplemental unaudited, pro forma consolidated financial information for the years ended December 31, 2018 and 2017 gives effect to the WGL Acquisition as if it had closed on January 1, 2017. This pro forma information is presented for information purposes only and does not purport to be indicative of the results that would have occurred had the WGL Acquisition taken place at the beginning of 2017, nor is it indicative of the results that may be expected in future periods.

	Year ended December 31	
	2018	2017
Pro forma revenue	**$ 5,962**	$ 5,704
Pro forma net income (loss) after taxes	**$ (304)**	$ 450

Pro forma revenue excludes the gains and losses on foreign exchange contracts, as these contracts were used to mitigate the foreign exchange risks associated with the cash purchase price of WGL. As such, the gains and losses on these foreign exchange contracts are directly incremental to the WGL Acquisition and are non-recurring in nature. These adjustments increased pro forma revenue by $2 million for the year ended December 31, 2018, and increased pro forma revenue by $34 million for the year ended December 31, 2017.

Pro forma net income (loss) after taxes excludes all non-recurring acquisition-related expenses and merger commitment costs incurred by AltaGas and WGL and AltaGas' realized and unrealized gains and losses on foreign exchange contracts entered into to mitigate the foreign exchange risk associated with the WGL Acquisition. Pro forma net income (loss) after taxes was also adjusted to exclude financing costs associated with the bridge facility for the WGL Acquisition, and amortization of fair value adjustments relating to property, plant and equipment, intangible assets, and other long-term investments as well as tax impacts of all the previously noted adjustments. For the year ended December 31, 2018, the total after-tax pro forma adjustments increased net income (loss) after taxes by $132 million (2017 – $19 million).

4. SALE OF MINORITY INTEREST AND OTHER DISPOSITIONS

Northwest Hydro Facilities

On June 22, 2018, AltaGas completed the disposition of a 35 percent indirect equity interest in the Northwest Hydro facilities for gross cash proceeds of approximately $921.6 million. The disposition was completed through the sale of 35 percent of Northwest Hydro Limited Partnership (NW Hydro LP), a subsidiary of AltaGas which indirectly holds the Northwest Hydro facilities. At December 31, 2018, AltaGas continues to consolidate NW Hydro LP (Note 12). Upon close of the sale, AltaGas recognized a non-controlling interest of $420.4 million, a deferred income tax liability of $153.3 million and contributed surplus of $335.2 million on the Consolidated Balance Sheets, net of transaction costs. There was no impact to the Consolidated Statements of Income upon closing of this transaction.

On December 13, 2018, AltaGas announced that it reached an agreement for the sale of its remaining interest of approximately 55 percent in the Northwest Hydro facilities. The sale was completed in January 2019 (Notes 5 and 33).

Initial Public Offering of AltaGas Canada Inc.

On October 25, 2018, the initial public offering (IPO) of AltaGas Canada Inc. (ACI) was successfully completed, reflecting a final price of $14.50 per common share of ACI. The over-allotment option was exercised in full, and as a result, AltaGas holds approximately 37 percent of ACI common shares at December 31, 2018. Net proceeds to AltaGas (consisting of cash and debt) to AltaGas after the deduction of underwriting fees and expenses were approximately $892.2 million. ACI holds Canadian rate-regulated natural gas distribution utility assets and contracted wind power in Canada, as well as an approximate 10 percent indirect equity interest in the Northwest Hydro facilities.

In addition to a pre-tax provision of $193.7 million, AltaGas recognized a pre-tax loss on disposition of $0.5 million in the Consolidated Statement of Income under the line item “other income” for the year ended December 31, 2018.

Non-Core San Joaquin Power Assets in California

On November 13, 2018, AltaGas completed the disposition of the San Joaquin facilities for a sale price of approximately US$299.4 million. The assets comprise the Tracy, Hanford and Henrietta plants totaling 523 MW of capacity. In addition to a pre-tax provision of $340.6 million, AltaGas recognized a pre-tax loss on disposition of $14.4 million in the Consolidated Statements of Income under the line item “other income” for the year ended December 31, 2018.

Other U.S. Power Assets

On December 11, 2018, AltaGas completed the disposition of Busch Ranch, a wind asset in the United States, for a sale price of approximately US$16.3 million. AltaGas recognized a pre-tax gain on disposition of $3.2 million in the Consolidated Statements of Income under the line item “other income” for the year ended December 31, 2018.

Other Dispositions

In March 2018, AltaGas completed the disposition of the Acme and Shaunavon gas processing facilities in the Midstream segment for gross proceeds of approximately $7.0 million. As a result, AltaGas recognized a pre-tax gain on disposition of approximately $1.3 million in the Consolidated Statements of Income under the line item "other income" for the year ended December 31, 2018.

In March 2017, AltaGas completed the disposition of the Ethylene Delivery Systems (EDS) and the Joffre Feedstock Pipeline (JFP) transmission assets in the Midstream segment to Nova Chemicals Corporation for gross proceeds of approximately $67.0 million. AltaGas recognized a pre-tax loss on disposition of approximately $3.4 million in the Consolidated Statement of Income under the line item "other income" for the year ended December 31, 2017 related to this disposition.

5. ASSETS HELD FOR SALE

As at		**December 31, 2018**		December 31, 2017
Assets held for sale				
Cash	**$**	**4.9**	$	—
Accounts receivable		**85.2**		0.3
Inventory		**0.5**		—
Property, plant and equipment		**1,189.6**		5.3
Intangible assets		**248.7**		0.1
Goodwill		**—**		0.3
	$	**1,528.9**	$	6.0
Liabilities associated with assets held for sale				
Accounts payable and accrued liabilities	**$**	**23.8**	$	—
Asset retirement obligations		**10.8**		0.3
Other long-term liabilities		**136.8**		—
	$	**171.4**	$	0.3

Non-Core Midstream and Power Assets in Canada

In the third quarter of 2018, AltaGas entered into definitive agreements for the sale of selected non-core smaller scale gas midstream and power assets in Canada, as well as AltaGas' commercial and industrial customer portfolio in Canada, for an aggregate purchase price of approximately $165.0 million. The transaction is subject to customary closing conditions and approvals, and was completed in February 2019. Accordingly, the carrying value of the assets and liabilities was classified as held for sale, which resulted in the reclassification of assets totaling $102.1 million to assets held for sale and liabilities totaling $10.8 million to liabilities associated with assets held for sale on the Consolidated Balance Sheets. Pre-tax provisions of $121.4 million on property, plant and equipment, $0.5 million on intangible assets, and $5.1 million on goodwill were recognized in 2018 due to the reduction of the carrying value of the assets to fair value less costs to sell. These assets are recorded in the Midstream and Power segments.

The transaction also includes the 43.7 million shares of Tidewater Midstream and Infrastructure Inc. previously held by AltaGas. This portion of the transaction was completed in September 2018 (Note 11).

Northwest Hydro Facilities

On December 13, 2018, AltaGas announced that it has reached an agreement for the sale of its remaining indirect equity interest of approximately 55 percent in the Northwest Hydro facilities for proceeds of approximately $1.37 billion. The transaction was completed in January 2019. Accordingly, the carrying value of the assets and liabilities was classified as held for sale, which resulted in the reclassification of $1,350.2 million of assets to assets held for sale and $160.6 million of liabilities to liabilities associated with assets held for sale on the Consolidated Balance Sheets. These assets are recorded in the Power segment.

Included within liabilities associated with assets held for sale is the Northwest Hydro NTL liability. In 2010, AltaGas entered into a 60-year CPI-indexed Electricity Purchase Agreement (EPA) and other related agreements with BC Hydro for the 195-MW Forrest Kerr run-of-river hydroelectric facility. As part of the related agreements, AltaGas agreed to pay BC Hydro annual payments of approximately $11.0 million per year, adjusted for inflation, in support of the construction and operation of the Northwest Transmission Line (NTL) until 2034. With the agreement for the sale of AltaGas' remaining indirect equity interest in the Northwest Hydro facilities, this liability has been reclassified to liabilities associated with assets held for sale.

Architect of the Capitol (AOC) Project

In the fourth quarter of 2018, WGL Energy Systems reached an agreement for the sale of a financing receivable related to the construction of an energy management services project. The transaction is subject to customary closing conditions, and is expected to be completed in the first quarter of 2019. Accordingly, the carrying value of the asset was classified as held for sale, which resulted in the reclassification of $76.6 million of accounts receivable to assets held for sale on the Consolidated Balance Sheets. A pre-tax provision of $6.0 million was recognized in 2018 due to the reduction of the carrying value of the receivable to fair value less costs to sell. This asset is recorded in the Power segment.

6. INVENTORY

As at	**December 31, 2018**	December 31, 2017
Natural gas held in storage	**$ 418.0**	$ 133.9
Materials and supplies	**53.3**	32.3
Renewable energy credits and emission compliance instruments	**38.2**	28.4
Other inventory	**6.4**	6.5
	$ 515.9	$ 201.1

7. PROPERTY, PLANT AND EQUIPMENT

As at	**December 31, 2018**			December 31, 2017		
	Cost	**Accumulated amortization**	**Net book value**	Cost	Accumulated amortization	Net book value
Utilities	**$ 7,090.5**	**$ (89.7)**	**$ 7,000.8**	$ 2,245.4	$ (226.1)	2,019.3
Midstream	**3,178.2**	**(845.7)**	**2,332.5**	2,801.4	(636.3)	$ 2,165.1
Power	**4,633.9**	**(1,858.3)**	**2,775.6**	2,874.8	(392.3)	2,482.5
Corporate	**49.4**	**(39.1)**	**10.3**	65.9	(37.7)	28.2
Reclassified to assets held for sale *(note 5)*	**(2,999.3)**	**1,809.7**	**(1,189.6)**	(16.7)	11.4	(5.3)
	$ 11,952.7	**$ (1,023.1)**	**$ 10,929.6**	$ 7,970.8	$ (1,281.0)	$ 6,689.8

Interest capitalized on long-term capital construction projects for the year ended December 31, 2018 was $12.6 million (2017 - $10.8 million).

As at December 31, 2018, the Corporation had approximately $872.7 million (December 31, 2017 - $269.5 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, 2018 was $324.3 million (2017 - $239.7 million).

8. INTANGIBLE ASSETS

As at	December 31, 2018			December 31, 2017		
	Cost	**Accumulated amortization**	**Net book value**	Cost	Accumulated amortization	Net book value
E&T contracts	**$ 26.6**	**$ (14.3)**	**$ 12.3**	$ 26.6	$ (13.4)	$ 13.2
Electricity service agreements	**269.5**	**(25.9)**	**243.6**	603.1	(108.5)	494.6
Energy services relationships	**176.1**	**(33.8)**	**142.3**	10.2	(8.1)	2.1
Software	**293.9**	**(77.7)**	**216.2**	126.8	(61.6)	65.2
Land rights	**1.4**	**(0.2)**	**1.2**	11.0	(2.4)	8.6
Commodity contracts	**346.3**	**(6.3)**	**340.0**	—	—	—
Franchises and consents	**5.0**	**—**	**5.0**	7.4	(2.2)	5.2
Reclassified to assets held for sale *(note 5)*	**(277.4)**	**28.7**	**(248.7)**	(0.1)	—	(0.1)
	$ 841.4	**$ (129.5)**	**$ 711.9**	$ 785.0	$ (196.2)	$ 588.8

Amortization expense related to intangible assets for the year ended December 31, 2018 was $69.7 million (2017 - $42.7 million).

As at December 31, 2018, the Corporation excluded $196.4 million (December 31, 2017 - $11.2 million) from the asset base subject to amortization. Items excluded related 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:

2019	$ **84.2**
2020	$ **82.5**
2021	$ **57.6**
2022	$ **132.3**
2023	$ **38.3**
Thereafter	$ **120.6**

9. GOODWILL

As at	**December 31, 2018**	December 31, 2017
Balance, beginning of year	**$ 817.3**	$ 856.0
Provisions on assets *(notes 5 and 10)*	**(124.2)**	—
Business acquisition *(note 3)*	**3,196.4**	—
Foreign exchange translation	**178.7**	(38.4)
Reclassified to assets held for sale	**—**	(0.3)
Balance, end of year	**$ 4,068.2**	$ 817.3

10. PROVISIONS ON ASSETS

Year ended December 31	**2018**	2017
Utilities	**$ 193.7**	$ —
Midstream	**153.7**	6.6
Power	**381.3**	133.0
	$ 728.7	$ 139.6

Utilities

In 2018, AltaGas recorded pre-tax provisions of $193.7 million related to certain rate-regulated natural gas distribution utility assets that were classified as held for sale in the third quarter of 2018. The pre-tax provision was comprised of $119.1 million on goodwill and $74.6 million on property, plant and equipment. No provisions on assets were recorded in 2017 for the Utilities segment.

Midstream

In 2018, AltaGas recorded pre-tax provisions totaling $153.7 million in the Midstream segment. The pre-tax provisions included $117.2 million related to certain non-core midstream assets that are classified as held for sale at December 31, 2018 (Note 5) and $36.5 million related to shut-in assets in the South, Cold Lake and Northwest operating areas. The total pre-tax provisions of $153.7 million were comprised of $148.1 million on property, plant, and equipment, $0.5 million on intangible assets, and $5.1 million on goodwill.

In 2017, AltaGas recorded a pre-tax provision on assets of $6.6 million on a non-core gas processing facility that was classified as held for sale (Note 5).

Power

In 2018, AltaGas recorded pre-tax provisions totaling $381.3 million in the Power segment. Of this, $340.6 million related to the Tracy, Hanford, and Henrietta gas-fired peaking plants in California that were disposed of in November 2018. The pre-tax provision on the California power assets was comprised of $221.3 million on property, plant, and equipment and $119.3 million on intangible assets. In addition, pre-tax provisions of $9.8 million were recorded on certain non-core power assets in Canada that are classified as held for sale at December 31, 2018 (Note 5), $23.1 million on a development project in the U.S., $1.8 million on the Pomona natural gas-fired co-generation facility in the United States, and $6.0 million on a WGL Energy Systems financing receivable that was classified as held for sale at December 31, 2018 (Note 5).

In 2017, AltaGas recognized pre-tax provisions on assets related to the Hanford and Henrietta gas-fired peaking plants in California, certain non-core development stage gas-fired peaking projects in California, and the Kent development project in Alberta of $133.0 million. The pre-tax provisions of $133.0 million were comprised of $48.5 million on intangible assets and $84.5 million on property, plant and equipment.

11. LONG-TERM INVESTMENTS AND OTHER ASSETS

As at	**December 31, 2018**	December 31, 2017
Investments in publicly-traded entities	**$ 8.4**	$ 95.0
Loan to affiliate *(note 30)*	**45.0**	75.0
Deferred lease receivable	**24.4**	29.0
Debt issuance costs associated with credit facilities	**7.9**	20.3
Refundable deposits	**16.2**	14.9
Prepayment on long-term service agreements	**82.5**	68.1
Subscription receipts issuance costs	**—**	1.7
Contract asset *(note 23)*	**11.5**	—
Rabbi trust *(note 28)*	**61.7**	—
Other	**25.5**	8.6
	$ 283.1	$ 312.6

In 2018, as part of the agreement for the sale of non-core midstream and power assets in Canada, AltaGas sold 43.7 million shares of Tidewater Midstream and Infrastructure Inc. for gross proceeds of $63.4 million. For the year ended December 31, 2018, a realized loss of $2.0 million was recognized in the Consolidated Statements of Income under the line item “other income” in relation to the sale of these shares.

12. 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:

Northwest Hydro Limited Partnership

On May 4, 2018, NW Hydro LP was formed to indirectly hold the assets of the Northwest Hydro facilities. On June 22, 2018, AltaGas closed the sale of a 35 percent indirect equity interest in its Northwest Hydro facilities through the sale of 35 percent of NW Hydro LP, and its general partner, Northwest Hydro GP Inc. (NW Hydro GP).

AltaGas has determined that NW Hydro 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 continued provision of all operational, maintenance and management functions for the Northwest Hydro facilities. In addition, AltaGas has the obligation to absorb the losses and the right to receive the benefits that could potentially be significant to the Northwest Hydro facilities. As such, AltaGas has consolidated NW Hydro LP and has recorded $420.4 million of the $921.6 million proceeds received as a non-controlling interest with the remainder of the proceeds, less deferred tax and transaction costs, recognized as contributed surplus in the amount of $334.6 million.

On December 13, 2018, AltaGas announced that it has reached an agreement for the sale of its remaining indirect equity interest of approximately 55 percent in the Northwest Hydro facilities (including NW Hydro LP) for proceeds of approximately $1.37 billion. The transaction was subject to customary closing conditions and approvals, and closed in January 2019. The assets and liabilities of NW Hydro LP have been classified as held for sale at December 31, 2018 (Note 5).

The assets of NW Hydro LP are the property of NW Hydro LP and are not available to AltaGas for any other purpose. NW Hydro LP's asset balances can only be used to settle its own obligations. The liabilities of NW Hydro 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.

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, which is estimated to be $450 to $500 million, will be 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 will provide construction and 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 construction, 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 and recorded $20.0 million of the $24.1 million proceeds received from Vopak on formation of RILE LP as a non-controlling interest with the remainder of the proceeds less deferred tax recognized as contributed surplus in the amount of $3.0 million.

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. Upon 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 operating costs by AltaGas LPG in accordance with the terms set out in the agreement.

Variable Interest Entities Acquired in WGL Acquisition

In connection with the WGL Acquisition (Note 3), AltaGas has acquired both consolidated and unconsolidated VIEs:

Consolidated VIE Investments

At December 31, 2018, WGSW Inc. (WGSW) was the primary beneficiary of SFGF LLC (SFGF), SFRC, LLC (SFRC), SFGF II, LLC (SFGF II), SFEE LLC (SFEE), and ASD Solar LP (ASD), 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. Accordingly, these VIEs have been consolidated:

SFGF, SFRC, and SFGF II

WGSW, along with its various tax equity partners, formed the tax equity partnerships SFGF, SFRC, and SFGF II to acquire, own, and operate distributed generation solar projects nationwide. WGSW is the managing member of these investments and will provide cash equal to the purchase price of the solar projects less any contributions from the tax-equity partner for projects sold into the partnerships. WGL Energy Systems is the developer of the projects and sells them to the partnerships, and is the operations and maintenance provider. Profits and losses are allocated between the partners under the HLBV method of accounting and the portion allocated to the tax equity partner is included in "net income (loss) attributable to non-controlling interest" on the accompanying Consolidated Statements of Income and is recorded to non-controlling interest on the accompanying Consolidated Balance Sheets.

SFEE

In 2016, WGSW and a tax equity partner formed SFEE to acquire distributed generation solar projects that were to be developed and sold by a third-party developer or WGL Energy Systems. New projects were to be designed and constructed under long-term power purchase agreements. SFEE is considered a VIE and is consolidated by WGSW.

ASD

WGSW is a limited partner in ASD, a limited partnership formed to own and operate a portfolio of residential solar projects, primarily rooftop photovoltaic power generation systems. SF ASD, a wholly-owned subsidiary of WGL Energy Systems, has management rights and control of ASD.

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

As at		**December 31, 2018**		December 31, 2017
Current assets	**$**	**1,383.5**	$	1.4
Property, plant and equipment		**619.2**		84.3
Long-term investments and other assets		**48.0**		48.0
Current liabilities		**(161.8)**		—
Asset retirement obligations		**(0.9)**		—
Deferred tax credits		**(3.0)**		—
Net assets	**$**	**1,885.0**	$	133.7

Unconsolidated VIE Investments

Meade Pipeline Co. LLC (Meade)

In 2014, WGL Midstream and certain partners entered into a limited liability company agreement and formed Meade, a Delaware limited liability company, to develop and own, jointly with Transcontinental Gas Pipe Line Company, LLC, a regulated pipeline, Central Penn Pipeline (Central Penn), a segment of the larger Atlantic Sunrise project. Central Penn is an approximately 185-mile pipeline originating in Susquehanna County, Pennsylvania and extending to Lancaster County, Pennsylvania with the capacity to transport and deliver up to approximately 1.7 Bcf per day of natural gas.

As at December 31, 2018, AltaGas held an equity investment in Meade with a carrying value of $666.9 million, inclusive of fair value adjustments on acquisition date (Note 3). WGL Midstream owns a 55 percent interest in Meade (21 percent indirect interest in Central Penn) and on a cash basis, as of December 31, 2018, WGL Midstream has spent approximately US$446 million as its share of the construction costs. Although WGL Midstream holds greater than a 50 percent interest in Meade, Meade is not consolidated by WGL Midstream and instead is accounted for under the equity method of accounting. WGL Midstream is not the primary beneficiary of Meade as it does not have the power to direct the activities most significant to the economic performance of Meade. WGL Midstream applies the HLBV equity method of accounting and any profits and losses are included in “income from equity investments” in the accompanying Consolidated Statements of Income and are added to or subtracted from the carrying amount of AltaGas’ investment balance.

The maximum financial exposure to loss as a result of the involvement with this VIE is equal to WGL Midstream's capital contributions.

13. INVESTMENTS ACCOUNTED FOR BY THE EQUITY METHOD

			Carrying value as at December 31		**Equity income (loss) for the year ended December 31**	
Description	**Location**	**Ownership Percentage**	**2018**	2017	**2018**	2017
AltaGas Canada Inc. (ACI)	Canada	36.75	**$ 112.5**	$ —	**$ 5.4**	$ —
AltaGas Idemitsu Joint Venture LP (AIJVLP)	Canada	50	**342.9**	323.3	**2.1**	6.6
Constitution Pipeline, LLC (Constitution)	United States	10	**—**	—	**(0.2)**	—
Craven County Wood Energy LP	United States	50	**7.8**	20.9	**(14.1)**	3.3
Eaton Rapids Gas Storage System	United States	50	**29.4**	26.4	**2.0**	2.5
Grayling Generating Station LP	United States	50	**29.0**	27.6	**3.6**	3.5
Inuvik Gas Ltd. (a)	Canada	33.333	**—**	—	**(0.2)**	—
Meade Pipeline Co. LLC (Meade) (b)	United States	55	**757.8**	—	**12.2**	—
Mountain Valley Pipeline, LLC (Mountain Valley)	United States	10	**532.5**	—	**11.5**	—
Sarnia Airport Storage Pool LP	Canada	50	**18.7**	18.8	**1.0**	1.0
Petrogas Preferred Shares	Canada	n/a	**150.0**	150.0	**12.8**	12.8
Tidewater Midstream and Infrastructure Ltd. (c)	Canada	n/a	**—**	—	**—**	1.7
Stonewall Gas Gathering Systems LLC	United States	30	**411.8**	—	**11.8**	—
			$ 2,392.4	$ 567.0	**$ 47.9**	$ 31.4

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

(b) Meade is a VIE (Note 12).

(c) AltaGas sold 43.7 million shares of Tidewater Midstream and Infrastructure Inc. in September 2018 (Note 11).

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

Year ended December 31		2018		2017
Revenues	**$**	**351.6**	$	110.6
Expenses		**(142.7)**		(74.2)
	$	**208.9**	$	36.4

As at December 31		2018		2017
Current assets	**$**	**1,204.6**	$	24.8
Property, plant and equipment	**$**	**7,602.5**	$	82.8
Intangible assets	**$**	**22.9**	$	5.6
Long-term investments and other assets	**$**	**1,326.6**	$	843.3
Current liabilities	**$**	**(1,015.2)**	$	(41.7)
Other long-term liabilities	**$**	**(949.6)**	$	(189.1)

Petrogas Preferred Shares

AltaGas, indirectly through its investment in AIJVLP, holds a one-third equity interest in Petrogas. In 2016, AltaGas directly invested $150.0 million to subscribe for 6,000,000 cumulative redeemable convertible preferred shares of Petrogas. These preferred shares form part of AltaGas' overall investment in Petrogas and entitle AltaGas to a fixed, cumulative, preferential cash dividend at a rate of 8.5 percent per annum payable quarterly. These preferred shares are, in the normal course, redeemable at any time on or after January 1, 2018 and convertible into a specified number of common shares at the option of either holder at any time on or after April 19, 2018. For the year ended December 31, 2018, AltaGas received dividend income of $12.8 million (2017 - $12.8 million) from the Petrogas preferred shares, which has been included in the Consolidated Statement of Income under the line item "income from equity investments".

AltaGas Canada Inc.

As at December 31, 2018, AltaGas owns an approximate 37 percent equity interest in ACI. On October 25, 2018, the ACI IPO was successfully completed reflecting a final price of $14.50 per common share of ACI (Note 4). ACI holds Canadian rate-regulated natural gas distribution utility assets and contracted wind power in Canada, as well as an approximate 10 percent interest in the Northwest Hydro facilities.

Equity Method Investments Acquired in WGL Acquisition

In connection with the WGL Acquisition (Note 3), AltaGas acquired the following investments accounted for by the equity method that are not considered VIEs:

Mountain Valley Pipeline, LLC (Mountain Valley)

WGL Midstream owns a 10 percent equity interest in Mountain Valley Pipeline, LLC. The proposed pipeline, which will be operated by EQM Gathering Opco, LLC (EQM) and developed, constructed, and owned by Mountain Valley (a venture of EQT Midstream Partners LP (EQT) and other entities), will transport approximately 2.0 Bcf of natural gas per day and will extend from Equitrans, LP's system in Wetzel County, West Virginia to Transcontinental Gas Pipe Line Company LLC's Station 165 in Pittsylvania County, Virginia. The pipeline is expected to span approximately 300 miles.

At December 31, 2018, AltaGas held an equity investment in Mountain Valley with a carrying value of $532.5 million, inclusive of fair value adjustments on acquisition date (Note 3). WGL Midstream expects to invest approximately US$350 million in scheduled capital contributions through the in-service date of the pipeline based on its contracted share of project costs. The equity method is considered appropriate because Mountain Valley is a Limited Liability Company (LLC) with specific ownership accounts and ownership between five and fifty percent resulting in WGL Midstream maintaining a more than minor influence over the partnership operating and financing policies. Profits and losses are allocated under the HLBV method of accounting and are included in income from equity investments in the accompanying Consolidated Statements of Income and are added to or subtracted from the carrying amount of AltaGas' investment balance.

In April 2018, WGL Midstream entered into a separate agreement with EQM to acquire a 5 percent equity interest in a project to build a lateral interstate natural gas pipeline connecting to the Mountain Valley Pipeline.

Stonewall Gas Gathering System (Stonewall)

WGL Midstream has a 30 percent equity interest in an entity that owns and operates certain assets known as the Stonewall Gas Gathering System. Stonewall has the capacity to gather up to 1.4 Bcf of natural gas per day from the Marcellus production region in West Virginia, and connects with an interstate pipeline system that serves markets in the mid-Atlantic region. As at December 31, 2018, the carrying value of the equity investment in Stonewall was $411.8 million, inclusive of fair value adjustments on acquisition date (Note 3). Profits and losses are allocated under the HLBV method of accounting and are included in income from equity investments in the accompanying Consolidated Statements of Income.

Constitution Pipeline Company, LLC (Constitution)

WGL Midstream has an investment in Constitution, owning a 10 percent equity interest in the proposed pipeline venture. At December 31, 2018, the carrying value of the equity investment in Constitution was $nil, reflecting AltaGas' fair value on acquisition date (Note 3). This natural gas pipeline venture is proposed to transport natural gas from the Marcellus region in northern Pennsylvania to major northeastern markets.

In addition to the above non-VIE equity investments acquired in the WGL Acquisition, the Company's investment in Meade (Note 12) is also accounted for using the equity method.

Provisions on investments accounted for by the equity method

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. No provisions were recorded for the year ended December 31, 2017.

14. SHORT-TERM DEBT

As at	**December 31, 2018**	December 31, 2017
Bank indebtedness [(a)]	**$ 0.2**	$ 6.2
US$150 million operating facility [(b)]	**—**	31.7
$25 million operating facility [(c)]	**—**	8.9
Commercial paper [(d)]	**1,145.2**	—
Project financing	**64.5**	—
	$ 1,209.9	$ 46.8

(a) Bank indebtedness bears interest at the lender's prime rate or at the interest rate applicable to bankers' acceptances. The prime lending rate at December 31, 2018 was 3.95 percent (December 31, 2017 – 3.2 percent).

(b) As at December 31, 2018, SEMCO held a US$150 million (December 31, 2017 - US$150.0 million) unsecured revolving operating credit facility with a Canadian chartered bank with a maturity date of December 20, 2023. Draws on the facility can be by way of U.S. base-rate loans, letters of credit and LIBOR loans. Letters of credit outstanding under this facility as at December 31, 2018 were $0.7 million (December 31, 2017 - $0.6 million).

(c) Upon completion of the ACI IPO, the operating facility was transferred to ACI.

(d) 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.

Other Credit Facilities

As at December 31, 2018, the Corporation held a $70.0 million (December 31, 2017 - $50.0 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, 2018 were $nil (December 31, 2017 - $nil).

As at December 31, 2018, AltaGas held a $150.0 million (December 31, 2017 - $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, 2018 were $117.0 million (December 31, 2017 - $40.8 million).

As at December 31, 2018, AltaGas held a US$200.0 million (December 31, 2017 - $150.0 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, 2018 were $147.3 million (December 31, 2017 - $71.3 million).

As at December 31, 2018, AltaGas held a $35.0 million (December 31, 2017 - $nil) 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, 2018 were $6.0 million (December 31, 2017 - $nil).

As at December 31, 2018, AltaGas held a US$300.0 million (December 31, 2017 - $nil) 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, 2018 were $nil (December 31, 2017 - $nil).

Credit Facilities Acquired in WGL Acquisition

As at December 31, 2018, WGL held a 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, 2018.

As at December 31, 2018, Washington Gas held a US$350.0 million (December 31, 2017 - $nil) 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, 2018.

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. At December 31, 2018, commercial paper outstanding totaled US$839.5 million for WGL and Washington Gas.

Project Financing

Washington Gas previously obtained third-party project financing on behalf of the United States federal government to provide funds during 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, Washington Gas assigns the ownership of the receivable 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. At December 31, 2018, draws related to project financing were $64.5 million (December 31, 2017 - $nil).

15. LONG-TERM DEBT

As at	Maturity date	**December 31, 2018**	December 31, 2017
Credit facilities			
$1,400 million unsecured extendible revolving[a]	15-May-2023	**$ 964.7**	$ 219.1
US$300 million unsecured extendible revolving[b]	15-May-2022	**287.8**	—
Acquisition credit facility	6-Jan-2020	**113.2**	—
US$1,200 million revolving credit facility[g]	28-Dec-2021	**1,637.0**	—
Medium-term notes (MTNs)			
$175 million Senior unsecured - 4.60 percent	15-Jan-2018	**—**	175.0
$200 million Senior unsecured - 4.55 percent	17-Jan-2019	**200.0**	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
$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	**299.9**	299.9
$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
$350 million Senior unsecured - 4.12 percent	7-Apr-2026	**349.8**	349.8
$200 million Senior unsecured - 3.98 percent	4-Oct-2027	**199.9**	199.9
$250 million Senior unsecured - 4.99 percent	4-Oct-2047	**250.0**	250.0
WGL and Washington Gas medium-term notes			
US$500 million Senior unsecured - 2.25 to 4.76 percent	Jan - Nov 2019	**682.1**	—
US$250 million Senior unsecured - 2.88 percent	12-Mar-2020	**341.1**	—
US$20 million Senior unsecured - 6.65 percent	20-Mar-2023	**27.3**	—
US$40.5 million Senior unsecured - 5.44 percent	11-Aug-2025	**55.3**	—
US$53 million Senior unsecured - 6.62 to 6.82 percent	Oct - 2026	**72.3**	—
US$72 million Senior unsecured - 6.40 to 6.57 percent	Feb - Sep 2027	**98.2**	—
US$52 million Senior unsecured - 6.57 to 6.85 percent	Jan - Mar 2028	**70.9**	—
US$8.5 million Senior unsecured - 7.50 percent	1-Apr-2030	**11.6**	—
US$50 million Senior unsecured - 5.70 to 5.78 percent	Jan - Mar 2036	**68.2**	—
US$75 million Senior unsecured - 5.21 percent	3-Dec-2040	**102.3**	—
US$75 million Senior unsecured - 5.00 percent	15-Dec-2043	**102.3**	—
US$300 million Senior unsecured - 4.22 to 4.60 percent	Sep - Dec 2044	**409.3**	—
US$450 million Senior unsecured - 3.80 percent	15-Sep-2046	**613.9**	—
SEMCO long-term debt			
US$300 million SEMCO Senior secured - 5.15 percent[d]	21-Apr-2020	**409.3**	376.4
US$82 million CINGSA Senior secured - 4.48 percent[e]	2-Mar-2032	**86.3**	85.2
Debenture notes			
PNG 2018 Series Debenture - 8.75 percent [c][f]	15-Nov-2018	**—**	7.0
PNG 2025 Series Debenture - 9.30 percent [c][f]	18-Jul-2025	**—**	13.0
PNG 2027 Series Debenture - 6.90 percent [c][f]	2-Dec-2027	**—**	14.0
CINGSA capital lease - 3.50 percent	1-May-2040	**0.6**	0.5
CINGSA capital lease - 4.48 percent	4-Jun-2068	**0.2**	0.2
Fair value adjustment on WGL Acquisition *(note 3)*		**89.0**	—
		$ 8,992.3	$ 3,639.8
Less debt issuance costs		**(35.2)**	(14.4)
		8,957.1	3,625.4
Less current portion		**(890.2)**	(188.9)
		$ 8,066.9	$ 3,436.5

(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) Collateral for the Secured Debentures and secured extendible revolving credit facility consisted of a specific first mortgage on substantially all of PNG's property, plant and equipment, and gas purchase and gas sales contracts, and a first floating charge on other property, assets and undertakings.

(d) Collateral for the US$ MTNs is certain SEMCO assets.

(e) 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.

(f) PNG debentures totaling $33.3 million have been sold to ACI (Note 4)

(g) Borrowings on the facility can be by way of U.S. base rate loans, U.S. prime loans, or LIBOR loans.

16. ASSET RETIREMENT OBLIGATIONS

As at		**December 31, 2018**		December 31, 2017
Balance, beginning of year	**$**	**88.3**	$	81.6
Obligations acquired *(note 3)*		**399.1**		—
New obligations		**3.3**		1.5
Obligations settled		**(4.2)**		(4.0)
Disposals		**(1.6)**		—
Revision in estimated cash flow		**3.8**		6.0
Accretion expense [(a)]		**12.3**		4.4
Foreign exchange translation		**20.3**		(0.9)
Reclassified to liabilities associated with assets held for sale *(note 5)*		**(10.8)**		(0.3)
Total		**510.5**		88.3
Less current portion (included in accounts payable and accrued liabilities)		**(9.9)**		—
Balance, end of year	**$**	**500.6**	$	88.3

(a) The majority of accretion expense is recorded through the Consolidated Statement of Income. Certain amounts relating to Washington Gas' Utility asset retirement obligations are recorded through regulatory liabilities on the Consolidated Balance Sheets due to regulatory treatment.

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, 2018 was $770.0 million (December 31, 2017 - $232.9 million).

The asset retirement obligations have been recorded in the Consolidated Financial Statements at estimated values discounted at rates between 1.5 and 8.5 percent and are expected to be incurred between 2019 and 2064. No assets have been legally restricted for settlement of the estimated liability.

17. 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.

At December 31, 2018, a liability of $15.4 million has been recorded on an undiscounted basis related to future environmental response costs (December 31, 2017 - $nil) 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. At December 31, 2018, AltaGas estimated the maximum liability associated with all of its sites to be approximately $40.1 million (December 31, 2017 - $nil). 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.

At December 31, 2018, AltaGas reported a regulatory asset of $19.9 million (December 31, 2017 - $13.9 million) for the portion of environmental response costs that are expected to be recoverable in future rates.

18. OTHER LONG-TERM LIABILITIES

As at	**December 31, 2018**	December 31, 2017
Deferred lease payable	**$ 13.1**	$ 2.4
Deferred revenue	**3.9**	3.8
Customer advances for construction	**58.6**	40.9
Sundance B PPA termination expense [a]	**2.0**	4.0
NTL liability [b]	**—**	142.0
Lease inducement	**2.7**	3.1
Merger commitments	**21.4**	—
Other long-term liabilities	**20.3**	5.7
	$ 122.0	$ 201.9

(a) On December 16, 2016, AltaGas Pipeline Partnership and the Government of Alberta reached a definitive settlement agreement regarding the termination of the Sundance B 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".

(b) The NTL liability has been reclassified as liabilities associated with assets held for sale (Note 5).

19. INCOME TAXES

Year ended December 31		2018		2017
Income (loss) before income taxes - consolidated	**$**	**(716.9)**	$	66.4
Statutory income tax rate (%)		**27.0**		27.0
Expected taxes at statutory rates	**$**	**(193.6)**	$	17.9
Add (deduct) the tax effect of:				
Permanent differences		**(1.0)**		9.5
Statutory and other rate differences		**(19.6)**		(30.5)
Rate adjustment for change in tax rates		**1.3**		(34.1)
Deferred income tax recovery on regulated assets		**(7.3)**		(7.4)
Tax differences on divestitures and transactions		**(32.3)**		6.9
Non-controlling interests		**4.7**		—
Change in valuation allowance		**(22.3)**		4.2
Other		**6.9**		—
	$	**(263.2)**	$	(33.5)
Income tax provision				
Current				
Canada		**23.7**		18.0
United States		**0.7**		12.5
	$	**24.4**	$	30.5
Deferred				
Canada		**(166.1)**		(7.4)
United States		**(121.5)**		(56.6)
	$	**(287.6)**	$	(64.0)
Effective income tax rate (%)		**36.7**		(50.5)

Net deferred income tax liabilities were composed of the following:

As at		December 31, 2018		December 31, 2017
PP&E and intangible assets	**$**	**1,764.6**	$	726.5
Regulatory assets		**(166.3)**		22.8
Tax pools, deferred financing and compensation		**(453.6)**		(302.3)
Other		**(209.9)**		(59.3)
Valuation allowance		**23.1**		53.7
	$	**957.9**	$	441.4

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 TCJA in the U.S. became law on December 22, 2017. The law includes significant changes to the U.S. corporate income tax system, including a federal corporate rate reduction from 35 percent to 21 percent beginning in 2018, changes to capital depreciation, limitations on the deductibility of interest expense and executive compensation, and the transition of U.S. international taxation from a worldwide tax system to a territorial tax system.

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

As at December 31, 2018, the Corporation had tax-effected non-capital losses of approximately $392.1 million, which will be available to offset future taxable income. If not used, these losses will expire between 2023 and 2038.

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 2017 remain subject to examination by taxation authorities. In the United States, both the federal and state tax returns filed for the years 2012 to 2017 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		**2018**		2017
Balance, beginning of year	**$**	**5.9**	$	2.2
Net changes during the year		**(3.7)**		3.7
Balance, end of year	**$**	**2.2**	$	5.9

20. 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 Statement of Income by a non-rate-regulated entity. These deferred regulatory assets and liabilities are included in the Consolidated Statement of Income in future periods when the amounts are reflected in customer rates. If an application is filed to modify customer rates with certain regulatory commissions, AltaGas is permitted to charge customers new rates, subject to refund, until the regulatory commission renders a final decision. During this interim period, a provision is recorded for a rate refund regulatory liability based on the difference between the amount collected in rates and the amount expected to be recovered from a final regulatory decision.

Management’s assessment of the probability of recovery or pass-through of regulatory assets and liabilities requires judgment and interpretation of laws and regulatory agency orders, rules, and rate-making conventions. The relevant regulatory bodies are the MPSC, 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 Statement of Income for the period in which the discontinuance of regulatory accounting occurs. Criteria that give rise to the discontinuance of regulatory accounting include: (i) increasing competition that restricts the ability of the Corporation to charge prices sufficient to recover specific costs, and (ii) a significant change in the manner in which rates are set by regulatory agencies from cost-based regulation to another form of regulation. The Corporation’s review of these criteria currently supports the continued application of regulatory accounting for all its utilities.

The following table summarizes the regulatory assets and liabilities recorded in the Consolidated Balance Sheets, as well as the remaining period, as of December 31, 2018 and 2017, over which the Corporation expects to realize or settle the assets or liabilities:

As at		December 31, 2018		December 31, 2017	Recovery Period
Regulatory assets - current					
Deferred cost of gas [a]	**$**	**20.4**	$	0.5	Less than one year
Deferred property taxes		**—**		0.3	Less than one year
Other		**0.6**		0.3	Less than one year
	$	**21.0**	$	1.1	
Regulatory assets - non-current					
Deferred regulatory costs and rate stabilization adjustment mechanism [a][b]	**$**	**215.5**	$	20.5	1 - 3 years
Pipeline rehabilitation costs		**—**		0.3	Various
Future recovery of pension and other retirement benefits [a]		**192.9**		113.9	Various
Future recovery of non-retirement employee benefits [a][c]		**21.3**		—	Various
Deferred pension costs [d]		**7.8**		—	1 years
Deferred environmental costs [a][e]		**19.9**		13.9	1 - 10 years
Deferred loss on reacquired debt [a][f]		**109.3**		2.5	1 - 15 years
Deferred depreciation and amortization		**—**		23.3	Various
Deferred future income taxes [a][g]		**67.0**		104.7	Various
Deferred customer retention program amortization		**—**		16.5	Various
Revenue deficiency account		**—**		31.0	Various
Other		**29.3**		2.0	Various
	$	**663.0**	$	328.6	
Regulatory liabilities - current					
Deferred cost of gas	**$**	**71.2**	$	9.0	Less than one year
Refundable tax credit [h]		**3.8**		1.9	Less than one year
Federal income tax rate change [i]		**26.2**		—	Less than one year
Other		**13.7**		—	Less than one year
	$	**114.9**	$	10.9	
Regulatory liabilities - non-current					
Option fees deferral [a]	**$**	**—**	$	4.3	Various
Refundable tax credit [h]		**6.1**		7.5	Various
Future expense of pension and other retirement benefits [a]		**166.7**		—	Various
Future removal and site restoration costs [j]		**514.7**		153.3	3 - 56 years
Deferred loss on reacquired debt		**1.8**		—	Various
Federal income tax rate change [a][i]		**698.4**		101.8	Various
Insurance recovery of environmental costs		**—**		0.3	2 years
Other		**5.1**		1.4	Various
	$	**1,392.8**	$	268.6	

(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) *Includes fair value of derivatives, which are not included in customer bills until settled.*

(c) *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.*

(d) *Relates to costs not recoverable through rates in the District of Columbia jurisdiction. However, Washington Gas is allowed to amortize these prior unrecovered pension and other post-retirement benefits through 2019.*

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

(f) *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. This also includes a fair value adjustment of $89 million recorded on the WGL Acquisition (Note 3).*

(g) *This regulatory asset reflects the amount of deferred income taxes expected to be refunded, or recovered from, customers in future rates.*

(h) *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.*

(i) *The TCJA was enacted on December 22, 2017, and required the Corporation to revalue its U.S. deferred tax assets and liabilities 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.*

(j) *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.*

21. 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, 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 OCI	**—**	**0.7**	**—**	**—**	**—**	**0.7**
Adoption of ASU No. 2016-01 *(note 2)*	**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**
Opening balance, January 1, 2017	$ 19.8	$ (11.3)	$ (135.6)	$ 526.3	$ 5.9	$ 405.1
OCI before reclassification	(30.3)	(1.3)	6.6	(183.4)	(2.2)	(210.6)
Amounts reclassified from AOCI	—	1.3	—	—	—	1.3
Current period OCI (pre-tax)	(30.3)	—	6.6	(183.4)	(2.2)	(209.3)
Income tax on amounts retained in AOCI	3.4	0.3	—	—	—	3.7
Income tax on amounts reclassified to earnings	—	(0.4)	—	—	—	(0.4)
Net current period OCI	(26.9)	(0.1)	6.6	(183.4)	(2.2)	(206.0)
Ending balance, December 31, 2017	$ (7.1)	$ (11.4)	$ (129.0)	$ 342.9	$ 3.7	$ 199.1

Reclassification From Accumulated Other Comprehensive Income

AOCI components reclassified	Income statement line item	Year ended December 31, 2018	Year ended December 31, 2017
Defined benefit pension and PRB plans	Operating and administrative	**$ 0.7**	$ 1.3
Deferred income taxes	Income tax expenses – deferred	**(0.2)**	(0.4)
		$ 0.5	$ 0.9

22. 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. The fair value of level 3 long term debt was determined by taking the present value of the debt securities' future cash flows discounted at interest rates that reflect market conditions as of the measurement date. The discount rate is based on the quoted market prices of the U.S. Treasury issues having a similar term to maturity, adjusted for the credit quality of the debt issuer.

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.

	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/liabilities [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 assets/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**	**—**	**6,027.6**	**2,012.7**	**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	**$ —**	**$ 6,984.8**	**$ 2,255.4**	**$ 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.

	December 31, 2017				
	Carrying Amount	Level 1	Level 2	Level 3	Total Fair Value
Financial assets					
Fair value through net income					
Risk management assets - current	$ 38.6	$ —	$ 38.6	$ —	$ 38.6
Risk management assets - non-current	15.9	—	15.9	—	15.9
Equity securities(a)	95.0	95.0	—	—	95.0
Amortized cost					
Loans and receivables (a)	75.0	—	85.6	—	85.6
	$ 224.5	$ 95.0	$ 140.1	$ —	$ 235.1
Financial liabilities					
Fair value through net income					
Risk management liabilities - current	$ 57.6	$ —	$ 57.6	$ —	$ 57.6
Risk management liabilities - non-current	13.8	—	13.8	—	13.8
Amortized cost					
Current portion of long-term debt	188.9	—	189.6	—	189.6
Long-term debt	3,436.5	—	3,568.3	—	3,568.3
Other current liabilities (b)	22.4	—	22.4	—	22.4
Other long-term liabilities (b)	146.0	—	147.7	—	147.7
	$ 3,865.2	$ —	$ 3,999.4	$ —	$ 3,999.4

(a) Included under the line item "long-term investments and other assets" on the Consolidated Balance Sheets.
(b) 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 at December 31, 2018:

	Net Fair Value	**Valuation Technique**	**Unobservable Inputs**	**Range**
Natural gas	$ (144.1)	Discounted Cash Flow	Natural Gas Basis Price (per dekatherm)	($1.40) - $7.28
Natural gas	$ (4.4)	Option Model	Natural Gas Basis Price (per dekatherm)	($1.37) - $5.07
			Annualized Volatility of Spot Market Natural Gas	37.46% - 900.98%
Electricity	$ (14.7)	Discounted Cash Flow	Electricity Congestion Price (per megawatt hour)	($8.28) - $84.44

The following table provides 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	**2018**			2017		
	Natural Gas	**Electricity**	**Total**	Natural Gas	Electricity	Total
Balance, beginning of year	**$ —**	**$ —**	**$ —**	$ **—**	$ **—**	$ **—**
Acquired *(note 3)*	**(136.1)**	**(10.6)**	**(146.7)**	**—**	**—**	**—**
Realized and unrealized losses:				**—**	**—**	**—**
Recorded in income	**(8.3)**	**(6.5)**	**(14.8)**			
Recorded in regulatory assets	**(5.9)**	**—**	**(5.9)**	**—**	**—**	**—**
Transfers out of Level 3	**7.3**	**—**	**7.3**	—	—	—
Purchases	**—**	**6.4**	**6.4**	—	—	—
Settlements	**0.3**	**(3.4)**	**(3.1)**	—	—	—
Foreign exchange translation	**(5.8)**	**(0.6)**	**(6.4)**			
Balance, end of year	**$ (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 year. Transfers out of Level 3 during the year ended December 31, 2018 were due to an increase in valuations using observable market inputs. Transfers into Level 3 during the year ended December 31, 2018 were due to an increase in unobservable market inputs used in valuations.

Realized and Unrealized Losses Recorded to Income for Level 3 Measurements

For the year ended December 31		2018		2017
Recorded to revenue				
Commodity contracts	**$**	**(11.1)**	$	—
Recorded to cost of sales				
Commodity contracts		**(3.7)**		—
	$	**(14.8)**	$	—

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

For the year ended December 31		2018		2017
Natural gas	**$**	**(2.2)**	$	2.2
Storage optimization		**—**		2.7
NGL frac spread		**40.0**		(11.7)
Power		**9.3**		(20.8)
Foreign exchange		**33.7**		(34.9)
	$	**80.8**	$	(62.5)

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.

	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.

Risk management assets [(a)]	December 31, 2017 Gross amounts of recognized assets/liabilities	Gross amounts offset in balance sheet	Netting of collateral	Net amounts presented in balance sheet
Natural gas	$ 41.0	$ (6.2)	$ —	$ 34.8
NGL frac spread	1.3	(0.3)	—	1.0
Power	17.7	(0.7)	—	17.0
Foreign exchange	1.7	—	—	1.7
	$ 61.7	$ (7.2)	$ —	$ 54.5
Risk management liabilities [(b)]				
Natural gas	$ 35.1	$ (6.2)	$ —	$ 28.9
NGL frac spread	25.3	(0.3)	—	25.0
Power	14.0	(0.7)	4.2	17.5
	$ 74.4	$ (7.2)	$ 4.2	$ 71.4

(a) *Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $38.6 million and risk management assets (non-current) balance of $15.9 million.*

(b) *Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $57.6 million and risk management liabilities (non-current) balance of $13.8 million.*

Cash Collateral

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

	December 31, 2018	December 31, 2017
Collateral posted with counterparties	**$ 27.6**	$ —
Cash collateral held representing an obligation	**$ 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, 2018 and 2017, AltaGas had not posted any collateral related to its derivative liabilities that contained credit-related contingent features. The following table shows the aggregate fair value of all derivative instruments with credit-related contingent features that are in a liability position, as well as the maximum amount of collateral that would be required if the most intrusive credit-risk-related contingent features underlying these agreements were triggered:

	December 31, 2018	December 31, 2017
Risk management liabilities with credit-risk-contingent features	**$ 14.7**	$ —
Maximum potential collateral requirements	**$ 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 2023. 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, 2018 and 2017:

December 31, 2018	**Fixed price (per GJ)**	**Period (months)**	**Notional volume (GJ)**	**Fair Value ($ millions)**
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**

December 31, 2017	Fixed price (per GJ)	Period (months)	Notional volume (GJ)	Fair Value ($ millions)
Sales	0.42 to 6.89	1-60	94,804,039	14.8
Purchases	0.52 to 6.40	1-48	61,980,315	(16.8)
Swaps	2.86 to 9.38	1-10	6,039,642	7.9

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, 2018 and 2017:

December 31, 2018	**Fixed price**	**Period (months)**	**Notional volume**	**Fair Value ($ millions)**
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)**

December 31, 2017	Fixed price	Period (months)	Notional volume	Fair Value ($ millions)
Propane swaps	$28.77 to $49.21 /Bbl	1-12	1,992,927 Bbl	(10.9)
Butane swaps	$47.83 to $54.67 /Bbl	1-12	130,088 Bbl	(0.3)
Crude oil swaps	$61.05 to $75.64 /Bbl	1-12	518,665 Bbl	(4.4)
Natural gas swaps	$0.42 to $2.27 /GJ	1-12	11,428,515 GJ	(8.4)

Power

AltaGas sells power to the Alberta Electric System Operator at market prices as well as to commercial and industrial users in Alberta at fixed 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 2023. As at December 31, 2018, 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, 2018 and 2017:

December 31, 2018	Fixed price (per MWh)	Period (months)	Notional volume (MWh)	Fair Value ($ millions)
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)**

December 31, 2017	Fixed price (per MWh)	Period (months)	Notional volume (MWh)	Fair Value ($ millions)
Power sales	38.20 to 95.03	1-60	2,169,321	(2.5)
Power purchases	58.50	1-12	17,520	(4.5)
Swap purchases	37.50 to 63.50	1-48	1,563,160	6.5

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, 2018:

Factor	Increase or decrease to forward prices	Increase or decrease to income before tax ($ millions)
Alberta power price	$1/MWh	0.3
PJM power price	$1/MWh	1.2
AECO natural gas price	$0.50/GJ	5.9
NYMEX natural gas price	$0.50/GJ	31.5
NGL frac spread:		
Propane	$1/Bbl	1.7
Butane	$1/Bbl	0.1
Western Texas Intermediate (WTI) crude oil	$1/Bbl	0.3
Natural gas	$0.50/GJ	4.7

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, 2018 and 2017, AltaGas did not have any outstanding foreign exchange forward contracts.

AltaGas may also designate its U.S. dollar-denominated debt as a net investment hedge of its U.S. subsidiaries. As at December 31, 2018, AltaGas designated US$1,494.0 million of outstanding debt as a net investment hedge (December 31, 2017 - $nil). For the year ended December 31, 2018, AltaGas incurred an after-tax unrealized loss of $80.2 million arising from the translation of debt in OCI (2017 - after-tax unrealized gain of $6.6 million).

To mitigate the foreign exchange risks associated with the cash purchase price of WGL, AltaGas entered into foreign currency option contracts with an aggregate notional value of approximately US$1.2 billion which expired in May 2018. These foreign currency option contracts do not qualify for hedge accounting. Therefore, all changes in fair value were recognized in net income. For the year ended December 31, 2018, an unrealized gain of $34.3 million and a realized loss of $36.0 million were recognized in revenue in relation to these contracts (2017 – unrealized losses of $34.3 million). During the second quarter of 2018, AltaGas entered into foreign exchange forward contracts with an aggregate notional value of $3.2 billion which settled in July 2018. These foreign currency derivatives do not qualify for hedge accounting. For the year ended December 31, 2018, a realized gain of $1.3 million was recognized in income in relation to these forwards (2017 - $nil).

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

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, 2018, 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 period from close of the WGL Acquisition to December 31, 2018, pre-tax losses of $1 million were recorded related to these instruments (2017 - $nil).

Accounts Receivable Past Due or Impaired

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

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**

As at December 31, 2017	Total	AR accruals	Receivables impaired	Less than 30 days	31 to 60 days	61 to 90 days	Over 90 days
Trade receivable	$ 383.0	$ 184.6	$ 2.4	$ 187.0	$ 7.9	$ 1.4	$ (0.3)
Other	2.3	—	—	2.3	—	—	—
Allowance for credit losses	(2.4)	—	(2.4)	—	—	—	—
	$ 382.9	$ 184.6	$ —	$ 189.3	$ 7.9	$ 1.4	$ (0.3)

Allowance for credit losses		**December 31, 2018**		December 31, 2017
Balance, beginning of year	**$**	**2.4**	$	2.5
Foreign exchange translation		**0.1**		(0.1)
New allowance [a]		**53.1**		0.4
Change in allowance		**(0.9)**		—
Allowance applied to uncollectible customer accounts		**—**		(0.4)
Balance, end of year	**$**	**54.7**	$	2.4

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

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, 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 and discounts

			Contractual maturities by period							
As at December 31, 2017		Total		Less than 1 year		1-3 years		4-5 years		After 5 years
Accounts payable and accrued liabilities	$	415.3	$	415.3	$	—	$	—	$	—
Dividends payable		32.0		32.0		—		—		—
Short-term debt		46.8		46.8		—		—		—
Other current liabilities [a]		22.4		22.4		—		—		—
Other long-term liabilities [a]		146.0		—		25.7		20.8		99.5
Risk management contract liabilities		71.4		57.6		11.1		2.7		—
Current portion of long-term debt [b]		188.9		188.9		—		—		—
Long-term debt [b]		3,450.9		—		1,009.1		363.8		2,078.0
	$	4,373.7	$	763.0	$	1,045.9	$	387.3	$	2,177.5

(a) Excludes non-financial liabilities

(b) Excludes deferred financing costs and discounts

23. REVENUE

The following table disaggregates revenue by major sources for the year ended December 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. 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 of $264.2 million associated with the GAIL Global (USA) LNG LLC (GAIL) contract, which are in scope of ASC 606, are reported in the 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 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 major sources of revenue from contracts with customers and segment.

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 also include gas sales to residential, commercial and industrial customers in certain states where WGL Energy Services is authorized as a competitive service provider. These commodity sales contracts have varying terms that generally range from one to five years. Customers are billed monthly based on the amount of gas delivered to the customer. Revenue is recognized based on the amount the Company 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 20 years. These long term purchase agreements provide stable cash flow by way of contracted prices for the underlying commodities. Commodity sales also include electricity sales to residential, commercial and industrial customers in certain states where WGL Energy Services is authorized as a competitive service provider. These commodity sales contracts have varying terms that generally range from one to five years. Customers are billed monthly based on meter readings or the amount of energy delivered to the customer. Revenue is recognized based on the amount the Company is entitled to invoice the customer.

Contract Balances

As at December 31, 2018, a contract asset of $11.5 million has been recorded within long-term investments and other assets on the Consolidated Balance Sheets (December 31, 2017 – $nil). 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, 2018 there is a contract asset of $47.3 million (December 31, 2017 - $nil) recorded within accounts receivable 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. In the fourth quarter of 2018, WGL Energy Systems reached an agreement for the sale of a financing receivable included in the contract asset. Accordingly, the receivable was reclassified as held for sale (Note 5) and a $6.0 million provision was recorded on the asset (Note 10). Contract liabilities of $2.2 million (2017 - $nil) have been recorded within other current 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.

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, 2018:

	2019	2020	2021	2022	2023	> 2023	Total
Midstream service contracts	$ 52.2	$ 55.7	$ 32.3	$ 31.9	$ 28.0	$ 192.4	**$ 392.5**
Gas sales and transportation services	0.6	0.6	0.6	0.6	0.6	3.2	**6.2**
Storage services	36.7	36.3	36.3	36.3	36.3	299.8	**481.7**
Other	37.0	10.5	1.6	0.8	0.8	3.2	**53.9**
Subtotals	$ 126.5	$ 103.1	$ 70.8	$ 69.6	$ 65.7	$ 498.6	**$ 934.3**

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.

24. SHAREHOLDERS' EQUITY

Authorization

AltaGas is authorized to issue an unlimited number of voting common shares. AltaGas is also authorized to issue preferred shares not to exceed 50 percent of the voting rights attached to the issued and outstanding common shares.

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

The Plan consists of three components: a Premium Dividend™ component, a Dividend Reinvestment component and an Optional Cash Purchase component. The Premium Dividend™ component of the plan was suspended effective December 18, 2018.

The Plan provides eligible holders of common shares with the opportunity to, at their election, either: (1) 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); or (2) 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) on the applicable dividend payment date and have these additional common shares of AltaGas exchanged for a cash payment equal to 101 percent of the reinvested amount (the Premium Dividend™ component of the Plan).

In addition, the Plan provides 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 are 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 are not entitled to participate in the Premium Dividend™ component of the Plan. 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, 2017	166,906,833	$	3,773.4
Shares issued for cash on exercise of options	240,125		6.5
Deferred taxes on share issuance cost	—		(8.3)
Shares issued under DRIP	8,132,258		236.3
December 31, 2017	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 costs	—		13.3
Shares issued under DRIP	15,377,575		325.8
Issued and outstanding at December 31, 2018	**275,224,066**	**$**	**6,653.9**

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Preferred Shares

As at	December 31, 2018			December 31, 2017		
Issued and Outstanding	**Number of**		**Amount**	Number of		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	**8,000,000**		**200.0**	8,000,000		200.0
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**	—		—
$5.00 series	**60,000**		**7.9**	—		—
Share issuance costs, net of taxes			**(27.9)**			(27.9)
Fair value adjustment on WGL Acquisition *(note 3)*			**4.1**			—
	52,280,600	**$**	**1,318.8**	52,000,000	$	1,277.7

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)]
AltaGas					
Series A [(e)]	3.38%	$0.845	$25	September 30, 2020	Series B
Series B [(f)]	Floating [(f)]	Floating [(f)]	$25	September 30, 2020 [(g)]	Series A
Series C [(h)]	5.29%	US$1.3225	US$25	September 30, 2022	Series D
Series E [(e)]	5.393%	$1.34825	$25	December 31, 2023	Series F
Series G [(e)]	4.75%	$1.1875	$25	September 30, 2019	Series H
Series I [(i)]	5.25%	$1.3125	$25	December 31, 2020	Series J
Series K [(j)]	5.00%	$1.25	$25	March 31, 2022	Series L
Washington Gas					
$4.80 series	4.27%	US$4.80	US$101	n/a	n/a
$4.25 series	4.27%	US$4.25	US$105	n/a	n/a
$5.00 series	4.27%	US$5.00	US$102	n/a	n/a

(a) The table above 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, Series H 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 H 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 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 H 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 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 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. 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, 2018, the floating quarterly dividend rate for Series B Shares is $0.26938 per share for the period starting December 31, 2018 to, but excluding, March 31, 2019.

(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.

(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 employees and directors are eligible to receive grants. As at December 31, 2018, 21,213,224 shares were reserved for issuance under the plan. As at December 31, 2018, 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, 2018, unexpensed fair value of share option compensation cost associated with future periods was $3.7 million (December 31, 2017 - $1.3 million).

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

As at	**December 31, 2018**			December 31, 2017		
	Options outstanding			Options outstanding		
	Number of options		**Exercise price[(a)]**	Number of options		Exercise price[(a)]
Share options outstanding, beginning of year	**4,533,761**	**$**	**32.35**	4,119,386	$	32.39
Granted	**2,811,460**		**16.69**	848,000		30.80
Exercised	**(57,275)**		**20.68**	(240,125)		24.63
Forfeited	**(878,013)**		**36.47**	(193,500)		36.36
Expired	**(100,750)**		**14.60**	—		—
Share options outstanding, end of year	**6,309,183**	**$**	**25.18**	4,533,761	$	32.35
Share options exercisable, end of year	**2,897,723**	**$**	**32.01**	3,326,197	$	31.93

(a) Weighted average.

As at December 31, 2018, the aggregate intrinsic value of the total options exercisable was $nil (December 31, 2017 - $6.0 million), the total intrinsic value of options outstanding was $nil (December 31, 2017 - $6.0 million) and the total intrinsic value of options exercised was $0.3 million (December 31, 2017 - $1.4 million).

The following table summarizes the employee share option plan as at December 31, 2018:

	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
$14.24 to $18.00	2,322,635	$	14.55	5.91	28,000	$	17.10	1.33
$18.01 to $25.08	425,000		20.76	1.83	425,000		20.76	1.83
$25.09 to $50.89	3,561,548		32.65	3.48	2,444,723		34.14	2.95
	6,309,183	**$**	**25.18**	**4.26**	**2,897,723**	**$**	**32.01**	**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	**2018**	2017
Fair value per option ($)	**1.27**	1.91
Risk-free interest rate (%)	**1.99**	1.31
Expected life (years)	**6**	6
Expected volatility (%)	**23.23**	21.05
Annual dividend per share ($) [(a)]	**1.18**	2.12
Forfeiture rate (%)	**—**	—

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

MTIP and DSUP

AltaGas has a MTIP for employees and executive officers, which includes RUs and PUs with vesting periods between 36 to 44 months from the grant date. In addition, AltaGas has a DSUP, which allows granting of DSUs to directors, officers and employees. DSUs granted under the DSUP vest immediately but settlement of the DSUs occurs when the individual ceases to be a director.

PUs, RUs, and DSUs	**December 31, 2018**	December 31, 2017
(number of units)		
Balance, beginning of year	**564,549**	364,839
Acquired (a)	**5,291,621**	—
Granted	**9,502,347**	386,126
Additional units added by performance factor	**—**	24,301
Vested and paid out	**(148,154)**	(221,775)
Forfeited	**(66,522)**	(27,279)
Units in lieu of dividends	**55,934**	38,337
Outstanding, end of year	**15,199,775**	564,549

(a) Upon close of the WGL Acquisition, AltaGas acquired WGL's PUs. These were converted to a fixed cash amount at a value of US$1.00 per unit.

For the year ended December 31, 2018, the compensation expense recorded for the MTIP and DSUP was $16.6 million (2017 - $9.1 million). As at December 31, 2018, the unrecognized compensation expense relating to the remaining vesting period for the MTIP was $26.9 million (December 31, 2017 - $8.4 million) and is expected to be recognized over the vesting period.

25. NET INCOME PER COMMON SHARE

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

		Year ended December 31		
		2018		2017
Numerator:				
Net income (loss) applicable to controlling interests	**$**	**(435.1)**	$	91.6
Less: Preferred share dividends		**(66.6)**		(61.3)
Net income (loss) applicable to common shares	**$**	**(501.7)**	$	30.3
Denominator:				
(millions)				
Weighted average number of common shares outstanding		**222.6**		171.0
Dilutive equity instruments(a)		**0.1**		0.3
Weighted average number of common shares outstanding - diluted		**222.7**		171.3
Basic net income (loss) per common share	**$**	**(2.25)**	$	0.18
Diluted net income (loss) per common share	**$**	**(2.25)**	$	0.18

(a) Includes all options that have a strike price lower than the share price of AltaGas' common shares as at December 31, 2018 and 2017.

For the year ended December 31, 2018, 4.0 million of share options (2017 – 2.8 million) were excluded from the diluted net income per share calculation as their effects were anti-dilutive.

26. OTHER INCOME

Year ended December 31		2018		2017
Losses from sale of assets	**$**	**(10.6)**	$	(2.7)
Other components of net benefit cost *(note 2)*		**18.9**		—
Interest income and other revenue		**2.7**		8.7
Gains (losses) on investments		**(10.1)**		3.6
	$	**0.9**	$	9.6

27. OPERATING LEASES

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. The carrying value of property, plant, and equipment associated with these leases was $2.5 billion as at December 31, 2018 (December 31, 2017 - $3.0 billion). For the year ended December 31, 2018, the total revenue earned from minimum lease payments was $285.1 million (2017 - $290.8 million) and from contingent rentals was $167.1 million (2017 - $175.6 million).

The following table sets forth the future fixed minimum revenue related to the operating leases for the years ended December 31:

2019	194.4
2020	155.3
2021	111.9
2022	112.0
2023	104.2

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 who are not members of defined benefit plans. The pension cost recorded for the DC plan was $15.4 million for the year ended December 31, 2018 (2017 - $8.4 million).

Defined Benefit Plans

AltaGas has several defined benefit pension plans for unionized and non-unionized employees, including five in Canada and six in the United States. These benefit plans are partially funded except for three of the Canadian plans which are fully funded.

Supplemental Executive Retirement Plan (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. Security will be provided for the SERP benefits through a letter of credit within a retirement compensation arrangement trust account.

Post-Retirement Benefits

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 health insurance premiums. This benefit plan is not funded. Post-retirement benefit plans in the United States provide certain medical and prescription drug 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. Two of these benefit plans are partially funded and two of them are fully 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 is expected to be filed with the pension regulators in 2020. Actuarial valuations are required annually for AltaGas' U.S. defined benefit plans.

The following defined benefit and post-retirement benefit plans were acquired in connection with the acquisition of WGL:

Defined Benefit Plans:

- Qualified Pension Plan - Washington Gas maintains a qualified, trusteed, non-contributory defined benefit pension plan covering most active and vested former employees of Washington Gas and certain employees of WGL subsidiaries. The non-contributory defined benefit pension plan is closed to all employees hired on or after January 1, 2010.
- Supplemental Executive Retirement Plan (DB SERP) - several executive officers of Washington Gas participate in the non-funded DB SERP, a nonqualified pension plan. The DB SERP was closed to new entrants beginning January 1, 2010.
- Defined Benefit Restoration Plan (DB Restoration) - a non-funded defined benefit restoration plan for the purpose of providing supplemental pension and pension-related benefits to a select group of management employees of Washington Gas.

Post-retirement Benefit Plans:

- Life Plan - Washington Gas provides life insurance benefits for retired employees of Washington Gas and certain employees of WGL subsidiaries.
- Retiree Medical Plan – under this plan Washington Gas provides medical, prescription drug and dental benefits through Preferred Provider Organization (PPO) or Health Maintenance Organization (HMO) plans for eligible retirees and dependents not yet receiving Medicare benefits.
- Health Reimbursement Account (HRA) Plan – under this plan retirees age 65 and older and dependents receive an annual subsidy to help purchase supplemental medical, prescription drug and dental coverage in the marketplace.

Rabbi trusts have been funded to satisfy the employee benefit obligations associated with WGL's various pension plans for a total of $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:

	Canada		United States		Total	
Year ended December 31, 2018	**Defined Benefit**	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**
Accrued benefit obligation						
Balance, beginning of year	**$ 165.6**	**$ 15.8**	**$ 303.8**	**$ 82.7**	**$ 469.4**	**$ 98.5**
Plans disposed *(note 4)*	**(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 *(note 4)*	**(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**
Net amount recognized	**$ (20.5)**	**$ (1.9)**	**$ (281.2)**	**$ 333.2**	**$ (301.7)**	**$ 331.3**

Year ended December 31, 2017		Canada Defined Benefit		Canada Post-Retirement Benefits		United States Defined Benefit		United States Post-Retirement Benefits		Total Defined Benefit		Total Post-Retirement Benefits
Accrued benefit obligation												
Balance, beginning of year	$	150.0	$	16.4	$	290.5	$	72.7	$	440.5	$	89.1
Actuarial loss (gain)		8.3		(1.6)		23.2		14.4		31.5		12.8
Current service cost		7.9		0.7		8.0		1.8		15.9		2.5
Member contributions		0.2		—		—		—		0.2		—
Interest cost		5.8		0.6		11.7		2.9		17.5		3.5
Benefits paid		(6.3)		(0.3)		(8.6)		(3.2)		(14.9)		(3.5)
Expenses paid		(0.3)		—		(0.8)		(0.1)		(1.1)		(0.1)
Plan settlements		—		—		—		(0.5)		—		(0.5)
Foreign exchange translation		—		—		(20.2)		(5.3)		(20.2)		(5.3)
Balance, end of year	$	165.6	$	15.8	$	303.8	$	82.7	$	469.4	$	98.5
Plan assets												
Fair value, beginning of year	$	101.5	$	6.8	$	226.9	$	67.2	$	328.4	$	74.0
Actual return on plan assets		8.5		0.4		37.9		11.0		46.4		11.4
Employer contributions		11.6		1.2		9.5		0.6		21.1		1.8
Member contributions		0.2		—		—		—		0.2		—
Benefits paid		(6.3)		(0.3)		(8.6)		(3.2)		(14.9)		(3.5)
Expenses paid		(0.3)		—		(0.8)		(0.1)		(1.1)		(0.1)
Foreign exchange translation		—		—		(16.2)		(4.7)		(16.2)		(4.7)
Fair value, end of year	$	115.2	$	8.1	$	248.7	$	70.8	$	363.9	$	78.9
Net amount recognized	$	(50.4)	$	(7.7)	$	(55.1)	$	(11.9)	$	(105.5)	$	(19.6)

The following amounts were included in the Consolidated Balance Sheets:

		December 31, 2018 Defined Benefit		**December 31, 2018 Post-Retirement Benefits**		**December 31, 2018 Total**		December 31, 2017 Defined Benefit		December 31, 2017 Post-Retirement Benefits		December 31, 2017 Total
Prepaid post-retirement benefits	**$**	**—**	**$**	**341.4**	**$**	**341.4**	$	—	$	—	$	—
Accounts payable and accrued liabilities		**(27.6)**		**—**		**(27.6)**		(0.6)		—		(0.6)
Future employee obligations		**(273.9)**		**(10.3)**		**(284.2)**		(104.9)		(19.6)		(124.5)
	$	**(301.5)**	**$**	**331.1**	**$**	**29.6**	$	(105.5)	$	(19.6)	$	(125.1)

The funded status based on the accumulated benefit obligation for all defined benefit plans were:

		December 31, 2018 Canada		**December 31, 2018 United**		December 31, 2017 Canada		December 31, 2017 United States
Accumulated benefit obligation [(a)]	**$**	**(32.9)**	**$**	**(1,525.6)**	$	(143.9)	$	(274.2)
Fair value of plan assets		**13.8**		**1,354.1**		115.2		248.7
Funded status	**$**	**(19.1)**	**$**	**(171.5)**	$	(28.7)	$	(25.5)

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

The following amounts were not recognized in the net periodic benefit cost and recorded in the other comprehensive Income (losses):

	Canada		United States		Total	
Year ended December 31, 2018	**Defined Benefit**	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**
Past service 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)**

	Canada		United States		Total	
Year ended December 31, 2017	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Past service cost	$ (0.4)	$ —	$ —	$ —	$ (0.4)	$ —
Net actuarial loss	(13.9)	(1.3)	—	—	(13.9)	(1.3)
Recognized in AOCI pre-tax	$ (14.3)	$ (1.3)	$ —	$ —	$ (14.3)	$ (1.3)
Increase (decrease) by the amount included in deferred tax liabilities	4.0	0.3	(0.1)	—	3.9	0.3
Net amount in AOCI after-tax	$ (10.3)	$ (1.0)	$ (0.1)	$ —	$ (10.4)	$ (1.0)

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

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

	Canada		United States		Total	
Year ended December 31, 2017	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Past service cost	$ —	$ —	$ (1.2)	$ 5.6	$ (1.2)	$ 5.6
Net actuarial gain (loss)	(30.6)	0.4	(74.0)	(12.8)	(104.6)	(12.4)
Recognized in regulatory asset (liability)	$ (30.6)	$ 0.4	$ (75.2)	$ (7.2)	$ (105.8)	$ (6.8)

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 costs	$	0.1	$	0.2
Actuarial losses		0.5		—
Total	**$**	**0.6**	**$**	**0.2**

Amounts to be amortized in the next fiscal year from regulatory assets (liabilities)		Defined Benefit		Post-Retirement Benefits
Past service costs	$	0.2	$	(21.3)
Actuarial losses		9.1		0.1
Total	**$**	**9.3**	**$**	**(21.2)**

The net pension expense by plan for the period was as follows:

	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 [(b)]	**0.1**	**—**	**—**	**—**	**0.1**	**—**
Amortization of net actuarial loss [(b)]	**0.6**	**—**	**—**	**—**	**0.6**	**—**
Amortization of regulatory asset [(b)]	**—**	**—**	**7.8**	**(11.1)**	**7.8**	**(11.1)**
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.
(b) Recorded under the line item "Other Income" on the Consolidated Statements of Income.

	Year ended December 31, 2017					
	Canada		United States		Total	
	Defined Benefit	Post-retirement Benefits	Defined Benefit	Post-retirement Benefits	Defined Benefit	Post-retirement Benefits
Current service cost [(a)]	$ 7.9	$ 0.7	$ 8.0	$ 1.8	$ 15.9	$ 2.5
Interest cost [(b)]	5.8	0.6	11.7	2.9	17.5	3.5
Expected return on plan assets [(b)]	(5.9)	(0.2)	(16.9)	(4.7)	(22.8)	(4.9)
Settlement of plan [(b)]	—	—	—	0.2	—	0.2
Amortization of past service cost [(b)]	0.2	—	—	—	0.2	—
Amortization of net actuarial loss [(b)]	0.7	—	—	—	0.7	—
Amortization of regulatory asset/liability [(b)]	1.3	0.1	6.5	(0.3)	7.8	(0.2)
Net benefit cost (income) recognized	$ 10.0	$ 1.2	$ 9.3	$ (0.1)	$ 19.3	$ 1.1

(a) Recorded under the line item "Operating and administrative" expenses on the Consolidated Statements of Income.
(b) Recorded under the line item "Other Income" on the Consolidated Statements of Income.

The objective of the Corporation's investment policy is to maximize long-term total return while protecting the capital value of the fund from major market fluctuations through diversification and selection of investments.

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 has a target asset mix for the Canadian plans of 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 40 percent to 55 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, 2018:

Canada	**Fair value**	Level 1	Level 2	Percentage of Plan Assets (%)
Cash and short-term equivalents	**$ 1.7**	$ 1.7	$ —	12.3
Canadian equities	**3.7**	3.7	—	26.8
Foreign equities	**2.1**	2.1	—	15.2
Fixed income	**5.5**	5.5	—	39.9
Real estate	**0.8**	—	0.8	5.8
	$ 13.8	$ 13.0	$ 0.8	100.0

United States	**Fair value**	Level 1	Level 2	Percentage of Plan Assets (%)
Cash and short-term equivalents	**$ 6.3**	$ 6.3	$ —	0.3
Canadian equities	**2.1**	2.1	—	0.1
Foreign equities (a)	**273.2**	270.6	2.6	12.7
Fixed income	**850.1**	99.2	750.9	39.6
Derivatives	**9.3**	—	9.3	0.4
Other	**10.9**	—	10.9	0.5
Total investments in the fair value hierarchy	**$ 1,151.9**	378.2	773.7	53.6
Investments measured at net asset value using the NAV practical expedient (b)				
Commingled funds and pooled separate accounts (c)	**945.3**			44.2
Private Equity/Limited Partnership (d)	**48.2**			2.2
Total fair value of plan investments	**$ 2,145.4**			100.0
Net payable (e)	**(0.1)**			—
	$ 2,145.3			100.0

(a) Investments in foreign equities include U.S. and international securities.

(b) 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.

(c) As of December 31, 2018, investments in commingled funds and a pooled separate account consisted of approximately 89 percent common stock U.S. companies; 10 percent income producing properties located in the United States; and 1 percent short-term money market investments for WGL's defined benefit plans and 54 percent of common stock of large-cap U.S. companies, 20 percent of U.S. Government fixed income securities and 26 percent of corporate bonds for WGL's post-retirement benefit plans.

(d) At December 31, 2018, investments in a private equity/limited partnership consisted of common stock of international companies.

(e) At December 31, 2018, 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	$	**8.0**	$	8.0	$	—	0.4
Canadian equities		**5.8**		5.8		—	0.3
Foreign equities [(a)]		**275.3**		272.7		2.6	12.8
Fixed income		**855.6**		104.7		750.9	39.6
Derivatives		**9.3**		—		9.3	0.4
Real estate		**0.8**		—		—	—
Other		**10.9**		—		11.7	0.5
Total investments in the fair value hierarchy	$	**1,165.7**	$	391.2	$	774.5	54.0
Investments measured at net asset value using the NAV practical expedient [(b)]							
Commingled funds and pooled separate accounts [(c)]		**945.3**					43.8
Private Equity/Limited Partnership [(d)]		**48.2**					2.2
Total fair value of plan investments	$	**2,159.2**					100.0
Net payable [(e)]		**(0.1)**					—
	$	**2,159.1**					100.0

(a) Investments in foreign equities include U.S. and international securities.
(b) 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.
(c) As of December 31, 2018, investments in commingled funds and a pooled separate account consisted of approximately 89 percent common stock U.S. companies; 10 percent income producing properties located in the United States; and 1 percent short-term money market investments for WGL's defined benefit plans and 54 percent of common stock of large-cap U.S. companies, 20 percent of U.S. Government fixed income securities and 26 percent of corporate bonds for WGL's post-retirement benefit plans.
(d) At December 31, 2018, investments in a private equity/limited partnership consisted of common stock of international companies.
(e) At December 31, 2018, this net payable primarily represents pending trades for investments purchased net of pending trades for investments sold and interest receivable.

Significant actuarial assumptions used in measuring net benefit plan costs	**Defined Benefit**	**Post-Retirement Benefits**	Defined Benefit	Post-Retirement Benefits
Year ended December 31	**2018**		2017	
Discount rate (%)	**3.25 - 4.30**	**3.60 - 4.30**	2.65 - 4.20	4.00 - 4.20
Expected long-term rate of return on plan assets (%) [(a)]	**3.20 - 7.60**	**3.75 - 7.60**	6.18 - 7.30	3.10 - 7.30
Rate of compensation increase (%)	**2.75 - 4.10**	**4.10**	2.75 - 4.00	3.25
Average remaining service life of active employees (years)	**9.6**	**14.1**	12.7	13.5

(a) Only applicable for funded plans

Significant actuarial assumptions used in measuring benefit obligations	**Defined Benefit**	**Post-Retirement Benefits**	Defined Benefit	Post-Retirement Benefits
As at December 31	**2018**		2017	
Discount rate (%)	**3.60 - 4.40**	**3.90 - 4.50**	2.80 - 3.70	3.60 - 3.70
Rate of compensation increase (%)	**2.75 - 4.10**	**4.10**	2.75 - 4.00	3.25

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 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 rates used to measure the expected cost of benefits for the next year were between 6.4 and 6.5 percent. The health care cost trend rates were assumed to decline to between 2.1 and 5 percent by 2024.

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 2018:

	Increase	Decrease
Service and interest costs	$ 1.7	$ (1.3)
Accrued benefit obligation	$ 19.8	$ (16.0)

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:		
2019	$ 41.4	$ 0.1
Expected benefit payments:		
2019	$ 109.8	$ 25.3
2020	92.2	24.6
2021	95.3	25.0
2022	101.0	25.4
2023	99.4	25.5
2024 - 2028	$ 521.9	$ 130.9

29. COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

AltaGas has long-term natural gas purchase and transportation arrangements, electricity purchase arrangements, service agreements, storage contracts, environmental 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.

In connection with the WGL Acquisition, AltaGas and WGL have made commitments related to the terms of the PSC of DC settlement agreement and the conditions of approval from the PSC of MD and the SCC of VA. Among other things, these commitments include rate credits distributable to both residential and non-residential customers, gas expansion and other programs, various public interest commitments, and safety programs. The total amount expensed in 2018 was approximately US$140 million, of which US$111 million has been paid as of December 31, 2018. In addition, there are certain additional regulatory commitments which will be expensed when the costs are incurred in the future, including the hiring of damage prevention trainers, investment of US$70 million over a 10 year period to further extend natural gas service, and US$8 million for leak mitigation.

Future payments of these commitments at December 31, 2018 are estimated as follows:

	2019	2020	2021	2022	2023	2024 and beyond	**Total**
Gas purchase[a]	$ 3,157.1	$ 2,940.5	$ 2,639.3	$ 2,527.4	$ 2,349.9	$ 30,309.2	**$ 43,923.4**
Electricity purchase[c]	533.1	368.6	139.2	38.6	5.7	0.4	**1,085.6**
Service agreements[b][d]	74.3	48.2	30.9	17.3	14.8	168.0	**353.5**
Pipeline and storage services[e]	861.6	862.2	818.8	795.6	781.7	4,645.3	**8,765.2**
Capital projects[f]	119.2	—	—	—	—	—	**119.2**
Operating leases[g]	23.9	30.9	29.4	28.0	25.8	164.8	**302.8**
Environmental[h]	6.1	4.7	3.0	0.5	0.4	0.5	**15.2**
Merger commitments	29.3	30.8	22.8	19.2	19.2	62.1	**183.4**
	$ 4,804.6	$ 4,285.9	$ 3,683.4	$ 3,426.6	$ 3,197.5	$ 35,350.3	**$ 54,748.3**

(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) *In 2014, AltaGas' Blythe facility entered into a Long-Term Service Agreement with Siemens to complete various upgrade and maintenance services on the Combustion Turbines (CT) at the Blythe facility over 124,000 equivalent operating hour per CT, or 25 years, whichever comes first. The LTSA has fixed fees that will be incurred in the five years following December 31, 2014 and variable fees on a per equivalent operating hour basis. As at December 31, 2018, the total commitment was $190.9 million payable over the next 16 years, of which $59.6 million is expected to be paid over the next five years.*

(c) *AltaGas enters into contracts to purchase electricity from various suppliers for its utilities. Electricity purchase commitments are based on existing fixed price and fixed volume contracts, and include $44.1 million of commitments related to renewable energy credits.*

(d) *In 2017, AltaGas entered into a 12-year service agreement for tug services to support the marine operations of RIPET. AltaGas is obligated to pay fixed and variable fees of approximately $60.1 million over the term of the contract.*

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

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

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

(h) *Environmental commitments relate to future costs associated with sites where AltaGas or its predecessors may have operated manufactured gas plants.*

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, 2018, 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.

As a result of the WGL Acquisition, AltaGas has the following additional contingencies:

Antero Contract

Washington Gas and WGL Midstream contracted in June 2014 with Antero Resources Corporation (Antero) to buy gas from Antero at invoiced prices based on an index, and at a delivery point, specified in the contracts. Since deliveries began, however, the index price paid has been more than the fair market value at the same physical delivery point, resulting in losses within WGL entities of approximately US$40 million. Accordingly, Washington Gas and WGL Midstream notified Antero that it sought to apply a provision of the contracts that would permit a new index to be established. Antero objected, claiming that the contract provisions permitting re-pricing did not apply, unless Antero itself chose to sell gas at cheaper prices at the delivery point (which Antero claimed it had not). The dispute was arbitrated in January 2017, and the arbitral tribunal ruled in favor of Antero on the applicability of the re-pricing mechanism. However, the tribunal ruled that it lacked authority to determine whether Antero was in breach of its obligation to deliver gas to Washington Gas and WGL Midstream at a point where they could obtain the higher pricing. Accordingly, Washington Gas and WGL Midstream filed suit in state court in Colorado for a determination of this issue.

The state court initially granted Antero's motion to dismiss the case and WGL subsequently filed an appeal. In October 2018, the Court of Appeals reversed the state court's decision and remanded the lawsuit to the trial court.

Separately, Antero has initiated suit against Washington Gas and WGL Midstream, claiming that they have failed to purchase specified daily quantities of gas and seeking alleged cover damages exceeding US$100 million as of April 4, 2018 according to Antero's complaint. Washington Gas and WGL Midstream oppose both the validity and amount of Antero's claim. WGL believes the probability that Antero could succeed in collecting these penalties is remote therefore no accrual was made as of December 31, 2018. In December 2017, WGL Midstream amended its purchase contract with Antero and, effective February 1, 2018, is no longer obligated to purchase gas at the delivery point that is the subject of these disputes.

These two cases have been consolidated and a jury trial has been scheduled for June 10, 2019.

Silver Spring, Maryland Incident

Washington Gas has continually worked with the National Transportation and Safety Board (NTSB) to support its investigation of the August 2016 explosion and fire at an apartment complex on Arliss Street in Silver Spring, Maryland, the cause of which has not been determined. Additional information will be made available by the NTSB at the appropriate time. A total of 40 civil actions related to the incident have been filed against WGL and Washington Gas in the Circuit Court for Montgomery County, Maryland. All of these suits seek unspecified damages for personal injury and/or property damage. The one class action suit filed against WGL and Washington Gas was amended to assert property damage and loss of use claims. WGL maintains excess liability insurance coverage from highly-rated insurers, subject to a nominal self-insured retention and expects this coverage will be sufficient to cover any significant liability to it that may result from this incident. Management is unable to determine a range of potential losses that is reasonably possible of occurring and therefore has not recorded a reserve associated with this incident. Washington Gas was invited by the NTSB to be a party to the investigation and in that capacity, continues to work closely with the NTSB. The NTSB has scheduled a hearing for April 23, 2019 to determine the probable cause of the incident.

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, 2018**	December 31, 2017
Due from related parties		
Accounts receivable [(a)]	**$ 60.8**	$ 0.8
Long-term investments and other assets [(b)]	**45.0**	75.0
	$ 105.8	$ 75.8
Due to related parties		
Accounts payable [(c)]	**6.3**	3.2
Risk management liabilities - current [(d)]	**0.9**	—
	$ 7.2	$ 3.2

(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, 2018, Petrogas had drawn $45.0 million (December 31, 2017 - $75.0 million) under the facility.

(c) Payables to ACI and a joint venture.

(d) Foreign exchange hedge with ACI.

The following transactions with related parties have been recorded on the Consolidated Statements of Income for the year ended December 31, 2018 and 2017:

Year ended December 31		**2018**		2017
Revenue [(a)]	**$**	**68.4**	$	15.0
Cost of sales [(b)]	**$**	**(4.2)**	$	(6.5)
Operating and administrative expenses [(c)]	**$**	**1.3**	$	—
Other income [(d)]	**$**	**9.2**	$	4.4

(a) In the ordinary course of business, AltaGas sold natural gas and natural gas liquids to a joint venture and ACI. In addition, subsequent to the 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. Revenue also includes an unrealized loss on a foreign exchange hedge with ACI of $0.2 million in 2018 (2017 - $nil).

(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 2017, amount was offset by the expense associated with the forgiveness of a loan to an executive.

(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 the year. 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
		2018		2017
Source (use) of cash:				
Accounts receivable	**$**	**(526.9)**	$	(55.6)
Inventory		**(100.8)**		4.7
Other current assets		**12.5**		7.0
Regulatory assets (current)		**(15.8)**		(0.2)
Accounts payable and accrued liabilities		**237.9**		85.4
Customer deposits		**(13.3)**		(2.8)
Regulatory liabilities (current)		**69.2**		(4.8)
Other current liabilities		**(5.9)**		13.0
Other operating assets and liabilities		**(143.4)**		(44.8)
Changes in operating assets and liabilities	**$**	**(486.5)**	$	1.9

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

				Year ended December 31
		2018		2017
Interest paid (net of capitalized interest)	**$**	**288.9**	$	151.1
Income taxes paid	**$**	**36.9**	$	36.3

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

As at December 31		**2018**		2017
Cash and cash equivalents	**$**	**101.6**	$	27.3
Restricted cash holdings from customers - current		**4.1**		8.9
Restricted cash holdings from customers - non-current		**6.1**		7.5
Restricted cash included in prepaid expenses and other current assets[(a)]		**27.6**		—
Restricted cash included in long-term investments and other assets[(a)]		**61.7**		—
Cash, cash equivalents and restricted cash per consolidated statement of cash flow	**$**	**201.1**	$	43.7

(a) The restricted cash balances included in prepaid expenses and other current assets and long-term investments and other assets relates to Rabbi trusts associated with WGL's pension plans (Note 28). On the date of the WGL Acquisition, the restricted cash balances related to Rabbi trusts was $81.0 million.

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 currently under construction; – 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; – interests in four regulated gas pipelines in the Marcellus/Utica basins; and – sale of natural gas to residential, commercial and industrial customers in Washington D.C., Maryland, Virginia, Delaware, and Pennsylvania.
Power	– natural gas-fired, biomass, and solar power generation assets, 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, and Pennsylvania.
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 23:

	Year ended December 31, 2018				
	Utilities	**Midstream**	**Power**	**Corporate**	**Total**
External revenue *(note 23)*	**$ 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	2018	2017
Revenue[(a)]		
Canada	**$ 1,626.8**	$ 1,508.8
United States	**2,553.0**	1,109.9
Total	**$ 4,179.8**	$ 2,618.7

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

As at December 31	2018	2017
Property, plant and equipment		
Canada	**$ 2,348.2**	$ 4,320.5
United States	**8,581.4**	2,369.3
Total	**$ 10,929.6**	$ 6,689.8

The following tables show the composition by segment:

	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)**
Provisions on assets *(note 10)*	**(193.7)**	**(153.7)**	**(381.3)**	**—**	**—**	**(728.7)**
Income 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	**—**	**(0.2)**	**(0.1)**	**4.8**	**—**	**4.5**
Interest expense	**(103.9)**	**(10.6)**	**(8.9)**	**(185.6)**	**—**	**(309.0)**
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 Statement of Cash flow due to classification of business acquisition and foreign exchange changes on U.S. assets.

	Year ended December 31, 2017					
	Utilities	Midstream	Power	Corporate	Intersegment Elimination[a]	Total
Segment revenue	$ 1,126.7	$ 1,008.0	$ 631.7	$ (58.4)	$ (151.8)	$ 2,556.2
Cost of sales	(610.1)	(647.0)	(242.8)	—	142.8	(1,357.1)
Operating and administrative	(226.1)	(165.0)	(93.1)	(97.5)	9.5	(572.2)
Accretion expenses	(0.1)	(3.9)	(6.9)	—	—	(10.9)
Depreciation and amortization	(81.8)	(68.6)	(118.0)	(14.0)	—	(282.4)
Provision on assets	—	(6.6)	(133.0)	—	—	(139.6)
Income from equity investments	2.6	22.0	6.8	—	—	31.4
Other income (loss)	3.9	(0.9)	0.8	6.3	(0.5)	9.6
Foreign exchange gains	—	0.2	—	1.5	—	1.7
Interest expense	—	—	—	(170.3)	—	(170.3)
Income (loss) before income taxes	$ 215.1	$ 138.2	$ 45.5	$ (332.4)	$ —	$ 66.4
Net additions (reductions) to:						
Property, plant and equipment[b]	$ 124.3	$ 245.3	$ 16.5	$ 1.5	$ —	$ 387.6
Intangible assets	$ 2.1	$ 2.8	$ 13.2	$ 2.2	$ —	$ 20.3

(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 Statement of Cash flow 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, 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**
As at December 31, 2017					
Goodwill	$ 664.7	$ 152.6	$ —	$ —	$ 817.3
Segmented assets	$ 3,460.2	$ 3,096.8	$ 3,192.5	$ 282.7	$ 10,032.2

33. SUBSEQUENT EVENTS

Subsequent events have been reviewed through February 27, 2019, the date these Consolidated Financial Statements were issued. On January 31, 2019, AltaGas completed the sale of its remaining interest in the Northwest Hydro facilities for net proceeds of approximately $1.37 billion. On February 1, 2019, AltaGas completed the sale of non-core Midstream and Power assets in Canada.

Supplementary Quarterly Operating Information

	Q4-18	Q3-18	Q2-18	Q1-18	Q4-17
OPERATING HIGHLIGHTS					
UTILITIES					
U.S. Utilities					
Natural gas deliveries end use (Bcf) (1)	**58.5**	10.9	12.0	31.0	24.3
Natural gas deliveries transportation (Bcf)(1)	**52.0**	25.7	10.9	13.4	14.2
Service sites(2)	**1,642,523**	1,759,154	580,526	582,871	581,518
Degree day variance from normal - SEMCO Gas (%)(3)	**7.5**	(17.8)	14.8	3.0	4.8
Degree day variance from normal - ENSTAR (%)(3)	**(19.6)**	(31.2)	(6.1)	(1.7)	(8.3)
Degree day variance from normal - Washington Gas (%)(3)(4)	**0.4**	(4.1)	n/a	n/a	n/a
MIDSTREAM					
Total inlet gas processed (Mmcf/d)(5)	**1,413**	1,333	1,227	1,553	1,424
Extraction volumes (Bbls/d)(5)(6)	**64,522**	60,945	49,728	74,786	68,306
Frac spread - realized ($/Bbl)(5)(7)	**15.84**	15.60	14.98	19.01	18.02
Frac spread - average spot price ($/Bbl)(5)(8)	**21.00**	25.87	22.19	22.25	30.66
Natural gas optimization inventory (Bcf)	**35.9**	36.7	1.3	—	2.5
WGL retail energy marketing - gas sales volumes (Mmcf)	**20,750**	8,155	n/a	n/a	n/a
POWER					
Renewable power sold (GWh)	**233**	690	504	126	301
Conventional power sold (GWh)	**985**	1,255	642	842	1,059
Renewable capacity factor (%)	**14.6**	44.6	51.7	8.1	27.5
Contracted conventional availability factor (%)(9)	**97.4**	98.5	97.7	94.5	96.3
WGL retail energy marketing - electricity sales volumes (GWh)	**2,911**	3,000	n/a	n/a	n/a

(1) Petajoule (PJ) is one million gigajoules (GJ). Bcf is one billion cubic feet.

(2) Service sites reflect all service sites of the utilities, including transportation and non-regulated business lines.

(3) A degree day for U.S. Utilities 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 Energy Gas Company, 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 which 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 it 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) 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
MMBTU	million British thermal unit
PJ	petajoule
US$	United States dollar

ABOUT ALTAGAS

AltaGas is an energy infrastructure company with a focus on midstream, regulated utilities and power. 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.

For further information contact:

Investment Community
1-877-691-7199
investor.relations@altagas.ca

For investor relations inquiries contact:

Telephone: 403.691.7100
Toll-free: 1.877.691.7199

investor.relations@altagas.ca
1700, 355 - 4th Avenue SW
Calgary, Alberta T2P 0J1

altagas.ca