AltaGas

NEWS RELEASE
ALTAGAS DELIVERS $166 MILLION IN NORMALIZED SECOND QUARTER 2018 EBITDA AND MAINTAINS 2018 OUTLOOK

Key Projects, Capital Plan and Integration of WGL on Track

Calgary, Alberta (August 1, 2018)

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

- Second quarter 2018 normalized EBITDA[1] of $166 million and normalized Funds from Operations[1] of $121 million were consistent with 2017 and in line with expectations;
- Outlook for 2018 maintained with normalized EBITDA expected to grow 25 to 30 per cent and normalized funds from operations growing 15 to 20 per cent, including WGL Holdings Inc. (WGL);
- Net capital expenditures for 2018 expected to be $1.0 to $1.3 billion with Midstream and Utilities comprising over 85% of the total;
- Asset monetization strategy progresses and includes two key objectives: completion of the funding for the acquisition of WGL Holdings, Inc. (WGL Acquisition) and the refinement of AltaGas' asset mix to realize its long-term vision and drive continued growth;
- Central Penn Pipeline expected to be in service in Q3 2018, and Mountain Valley Pipeline expected on-line in Q1 2019;
- Ridley Island Propane Export Terminal (RIPET) construction activities advancing on schedule for start-up in Q1 2019, with approximately 75% of supply secured and the balance progressing as expected;
- On July 31, 2018, Washington Gas filed an application with the Commonwealth of Virginia's State Corporation Commission to increase its base rates for natural gas service;
- Integration activities well underway after closing of WGL Acquisition;
- AltaGas being led by interim co-CEO's David Cornhill and Phillip Knoll – strategy and vision for company remains unchanged; and
- Combined company a North American leader in the new clean energy economy.

AltaGas Ltd. (AltaGas) (TSX:ALA) today reported results in line with its expectations and remains firmly focused on achieving its operational and financial objectives for 2018. With normalized EBITDA of $166 million, and normalized funds from operations of $121 million, AltaGas remains well positioned to fund its capital program through internally generated cash flow, its dividend reinvestment program, and normal course borrowings under its credit facilities. AltaGas' net income applicable to common shares for the quarter was $1 million ($0.01 per share), with normalized net income of $23 million or $0.13 per share. WGL also filed its third quarter consolidated financial results today, which are available through SEDAR at www.sedar.com.

"Our solid second quarter results illustrate the strength of AltaGas' "standalone" business," stated David Cornhill, Chairman and interim co-Chief Executive Officer of AltaGas. "With the closing of the WGL Acquisition, we completed the first phase of our business transformation, creating a leading North American clean energy infrastructure company."

"We are linking and aligning our vision for our business, our asset sale strategy and our capital investments," continued Mr. Cornhill. "As we move through the divestment of assets, we will not only fund a significant proportion of the WGL Acquisition, but also realign our asset base to support the long-term vision for AltaGas," said Mr. Cornhill.

1. Non-GAAP measure; see discussion in the advisories of this news release

Financial & Operational Results

Normalized EBITDA	Three Months Ended June 30		Six Months Ended June 30	
($ millions)	**2018**	2017	**2018**	2017
Gas	**$ 48**	$ 41	**$ 119**	$ 108
Power	**75**	77	**116**	127
Utilities	**50**	55	**162**	170
Sub-total: Operating Segments	**173**	173	**397**	405
Corporate	**(7)**	(7)	**(9)**	(11)
	$ 166	$ 166	**$ 388**	$ 394

In the second quarter of 2018, AltaGas' Gas segment recorded normalized EBITDA of $48 million, an increase of 17 percent over the same period last year. The increase was driven by higher realized frac spread and volumes, as well as contributions from AltaGas' Townsend 2A and North Pine facilities which came into service in the fourth quarter of 2017.

In the second quarter of 2018, AltaGas' Power segment achieved normalized EBITDA of $75 million, in line with the second quarter of 2017, while its Utilities segment achieved normalized EBITDA of $50 million, a decrease of approximately $5 million compared to the second quarter of 2017. Positive growth in the Utilities' customer base, and colder than normal weather at SEMCO and AltaGas Utilities, were partially offset by U.S. tax reform which impacted both SEMCO and Enstar. The Utilities segment also had one-time positive impacts in the second quarter of 2017 due to an insurance settlement and an early termination payment from one of SEMCO's non-regulated customers. The Power and Utility segments were also impacted by the stronger Canadian dollar.

Commencing in the third quarter of 2018, and effective as of the close of the WGL Acquisition, WGL's activities will continue to be carried out through three business segments: Gas, Power, and Utilities, and will be reflected in each of AltaGas' segments, respectively.

AltaGas' 2018 capital expenditure plan is expected to be $1.0 billion to $1.3 billion. This reflects the original $500 to $600 million of capital investments for AltaGas' business, and $500 to $700 million of additional capital related to WGL investments. Approximately 40 - 45 percent of the total capital is expected to be spent in AltaGas' Gas segment, on key projects including RIPET, and the Central Penn and Mountain Valley Pipelines. Approximately 45 - 50 percent is expected to be spent in the Utilities segment on approved system betterment across AltaGas' utilities, as well as on accelerated pipe replacement programs in Virginia, Maryland and Washington D.C. There is also some initial capital being spent to advance the Marquette Connector Pipeline in Michigan.

Power will account for the remainder of the capital primarily driven through investments in distributed generation projects across the United States.

"AltaGas has significant opportunities in our Gas and U.S. utilities businesses over the next few years," stated Mr. Cornhill, "The majority of our capital is being deployed in these two businesses. With significant investments in two of North America's most prolific gas plays – the Montney and Marcellus/Utica – through infrastructure tied to energy exports, we are very well positioned for continued growth well into the future. Our utilities are also in excellent jurisdictions with strong regulatory relationships and growing customer demand providing us with great opportunities to provide clean energy and play a significant role in the new clean energy economy."

Asset Monetizations and Funding Strategy for WGL

During the second quarter, AltaGas made material progress on its asset monetization plans to align with the long-term vision for the business as well as advance the financing plans with respect to the WGL Acquisition.

The WGL Acquisition was financed through net proceeds of approximately $2.3 billion from the sale of subscription receipts, gross proceeds of approximately $922 million from the sale of a 35 percent minority interest in the Northwest British Columbia Hydro Electric Facilities and a US$2.3 billion draw on a fully committed acquisition credit facility and existing cash on hand.

Consistent with its previously articulated plans, AltaGas expects to rapidly repay the funds drawn on the bridge facility through the monetization of certain assets, as well as with the proceeds of term debt and hybrid securities offerings. To facilitate potential securities' offerings, a US $2 billion final short form base shelf prospectus for the issuance of both debt securities and preferred shares was filed in June.

Certain assets are currently under review for potential divestiture. With the greatest opportunities for growth lying in the Gas business and in U.S. utilities and AltaGas' current capital investments primarily targeted in those areas, AltaGas expects asset sales to further streamline its business, provide for business optimization and align with and support its vision for the corporation.

WGL Integration Activities are Advancing and are On Track

With the successful completion of the regulatory approval process and the close of the WGL Acquisition on July 6, 2018, the next steps in the integration process are underway, including: merger commitments tracking and reporting and the development of initiatives to realize merger-related savings.

Outlook

AltaGas' four-year capital plan drives growth across all three business segments, with approximately $6 billion of identified capital investments through 2021, including approximately $4.5 billion in secured growth and approximately $1.5 billion in growth opportunities:

High Quality Utility Assets

AltaGas' Utilities segment is expected to grow significantly, with rate base through 2021 increasing from approximately $5 billion in 2018 to approximately $7 billion in 2021. This reflects the addition of the utilities in WGL's service areas and is the result of exposure to higher growth markets with significant capital expenditures to support customer additions, general system betterment, and accelerated replacement programs.

Combined Midstream Business Provides Producers with Global Market Access

The Gas segment will benefit from continued growth through significant investments in the Central Penn and Mountain Valley Pipelines, expected to come online in the third quarter of 2018, and in the first quarter of 2019, respectively.

Construction of RIPET is also progressing on-time and on-budget and is slated to come online in the first quarter of 2019. Supply for approximately 75% of the total capacity has been secured, with the balance on schedule for start-up.

AltaGas is now positioned to actively participate in energy export projects on both coasts of North America and has a presence in the two most prolific gas plays – the Montney and Marcellus/Utica. Through RIPET, AltaGas is ideally positioned to move natural gas liquids to premium Asian markets. In the Marcellus/Utica, AltaGas connects low cost producers with high growth U.S. end-use markets and the Cove Point liquefied natural gas (LNG) terminal, which provides access for LNG exports off the east coast.

Generating Clean Energy with Natural Gas and Renewable Resources

Power will grow as well, although more modestly. AltaGas believes that with a clean power generation footprint that includes gas, hydroelectric, wind, small scale solar, biomass and energy storage, there will be longer-term opportunities for the power generation business throughout North America. AltaGas has identified a portfolio of development projects, which it continues to actively pursue and expects to continue to build out its distributed generation business.

Expectations for 2018

The WGL Acquisition closed on July 6, 2018. As a combined entity, AltaGas expects normalized EBITDA to increase by approximately 25 to 30 percent and normalized funds from operations to increase by approximately 15 to 20 percent. This includes the impact of certain contemplated asset monetizations and other financing initiatives as part of the long-term financing plan.

“For 2018 our outlook and expectations are unchanged. We see significant growth in normalized EBITDA and funds from operations. We remain committed to balancing funding growth opportunities with maintaining visible dividend growth to maximize total shareholder return and the long-term sustainability and growth in all three businesses,” concluded Mr. Cornhill.

The expected increase to EBITDA and funds from operations in 2018 compared to 2017 for the combined entity is mainly as a result of contributions from the WGL Acquisition in all three segments as well as positive contributions from:

- Higher realized frac spread mainly due to higher hedged price;
- Full year contributions from Townsend 2A and the first train of the North Pine facility;
- Higher expected earnings from the Northwest Hydro facilities due to contractual price increases and continued efficiency improvements;
- Higher volumes at Blythe;
- Higher Alberta power prices; and
- Colder weather and rate base and customer growth at certain of the utilities.

These positive contributions are expected to be partially offset by:

- The impact of U.S. tax reform;
- A weaker U.S. dollar on reported results of the U.S. assets;
- Planned turnarounds at the Harmattan, Joffre Ethane Extraction Plant (JEEP) and Pembina Empress Extraction Plant (PEEP) facilities; and
- The expiry of the PPA at the Ripon facility in the second quarter of 2018 (partially offset by the new Resource Adequacy (RA) contracts, which run from the second quarter of 2018 until year-end 2018, and is expected to be renewed on a yearly basis thereafter.

AltaGas’ current outlook reflects the factors and assumptions which are fully noted in the MD&A.

WGL Files Third Quarter Consolidated Financial Results
WGL also filed its third quarter consolidated financial results today, which are available through SEDAR at www.sedar.com.

Monthly Common Share Dividend and Quarterly Preferred Share Dividends

- The Board of Directors approved a dividend of $0.1825 per common share. The dividend will be paid on September 17, 2018, to common shareholders of record on August 27, 2018. The ex-dividend date is August 24, 2018. 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 June 30, 2018 and ending September 29, 2018, on AltaGas' outstanding Series A Preferred Shares. The dividend will be paid on September 28, 2018 to shareholders of record on September 14, 2018. The ex-dividend date is September 13, 2018;
- The Board of Directors approved a dividend of $0.24953 per share for the period commencing June 30, 2018 and ending September 29, 2018, on AltaGas' outstanding Series B Preferred Shares. The dividend will be paid on September 28, 2018 to shareholders of record on September 14, 2018. The ex-dividend date is September 13, 2018;
- The Board of Directors approved a dividend of US$0.330625 per share for the period commencing June 30, 2018 and ending September 29, 2018, on AltaGas' outstanding Series C Preferred Shares. The dividend will be paid on September 28, 2018 to shareholders of record on September 14, 2018. The ex-dividend date is September 13, 2018;
- The Board of Directors approved a dividend of $0.3125 per share for the period commencing June 30, 2018, and ending September 29, 2018, on AltaGas' outstanding Series E Preferred Shares. The dividend will be paid on September 28, 2018 to shareholders of record on September 14, 2018. The ex-dividend date is September 13, 2018;

- The Board of Directors approved a dividend of $0.296875 per share for the period commencing June 30, 2018, and ending September 29, 2018, on AltaGas' outstanding Series G Preferred Shares. The dividend will be paid on September 28, 2018 to shareholders of record on September 14, 2018. The ex-dividend date is September 13, 2018;
- The Board of Directors approved a dividend of $0.328125 per share for the period commencing June 30, 2018, and ending September 29, 2018, on AltaGas' outstanding Series I Preferred Shares. The dividend will be paid on September 28, 2018 to shareholders of record on September 14, 2018. The ex-dividend date is September 13, 2018; and
- The Board of Directors approved a dividend of $0.3125 per share for the period commencing June 30, 2018, and ending September 29, 2018, on AltaGas' outstanding Series K Preferred Shares. The dividend will be paid on September 28, 2018 to shareholders of record on September 14, 2018. The ex-dividend date is September 13, 2018.

CONSOLIDATED FINANCIAL REVIEW

	Three Months Ended June 30		Six Months Ended June 30	
($ millions)	**2018**	2017	**2018**	2017
Revenue	**610**	539	**1,488**	1,310
Normalized EBITDA(1)	**166**	166	**388**	394
Net income (loss) applicable to common shares	**1**	(8)	**50**	24
Normalized net income(1)	**23**	28	**93**	93
Total assets	**10,876**	10,099	**10,876**	10,099
Total long-term liabilities	**4,602**	4,670	**4,602**	4,670
Net additions to property, plant and equipment	**124**	125	**190**	127
Dividends declared(2)	**98**	89	**195**	178
Normalized funds from operations(1)	**121**	123	**290**	294

	Three Months Ended June 30		Six Months Ended June 30	
($ per share, except shares outstanding)	**2018**	2017	**2018**	2017
Net income (loss) per common share – basic	**0.01**	(0.05)	**0.28**	0.14
Net income (loss) per common share – diluted	**0.01**	(0.05)	**0.28**	0.14
Normalized net income - basic(1)	**0.13**	0.17	**0.52**	0.55
Dividends declared(2)	**0.55**	0.53	**1.10**	1.05
Normalized funds from operations(1)	**0.67**	0.72	**1.63**	1.74
Shares outstanding - basic (millions)				
During the period(3)	**179**	170	**178**	169
End of period	**181**	171	**181**	171

(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, and $0.1825 beginning on November 27, 2017.

(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 second quarter results, progress on construction projects 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 12:00 p.m. MT (2:00 p.m. ET) on August 1, 2018 by dialing 403-451-9481 or toll free 1-855-859-2056. The passcode is 3989973. The replay will expire at 9:59 p.m. MT (11:59 p.m. ET) on August 8, 2018.

Additional information relating to AltaGas' results can be found in the Management's Discussion and Analysis and unaudited condensed interim consolidated financial statements for the three and six months ended June 30, 2018 available through AltaGas' website at www.altagas.ca or through SEDAR at www.sedar.com.

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

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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", "outlook", "vision", "opportunity" and similar expressions suggesting future events or future performance, as they relate to AltaGas or any affiliate of the AltaGas, 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: the implementation and success of AltaGas' strategy for the corporation as a whole and each of its business segments; shareholder returns; expected normalized EBITDA and FFO growth; expected capital expenditures, companywide, by segment and by project; expected asset sales and associated strategy; expected components and timing of the WGL acquisition financing plan, including the repayment of the draw on the bridge facility through potential asset sales and securities offerings; expected secured growth capital expenditures and growth opportunities; expected rate base growth; expected in service dates of the Marcellus pipeline investments; expected timing of RIPET; expected benefits of RIPET and Cove Point LNG to producers; stability of AltaGas' business; and potential opportunities for the business segments. 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; and the outcomes of significant commercial contract negotiations.*

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 Aboriginal 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; the Harmattan Rep agreements; 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; risks associated with the financing of the WGL Acquisition and the underlying business of WGL; and the other factors discussed under the heading "Risk Factors" in the Corporation's AIF for the year ended December 31, 2017.

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, expected, projected or targeted 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.

This news release contains references to certain financial measures that do not have a standardized meaning prescribed by GAAP and may not be comparable to similar measures presented by other entities. The non-GAAP measures and their reconciliation to GAAP financial measures are shown in AltaGas' Management's Discussion and Analysis (MD&A) as at and for the three months ended June 30, 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. The specific rationale for and incremental information associated with each non-GAAP measure is discussed in AltaGas' MD&A as at and for the three months ended June 30, 2018. 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.

Normalized 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 expense. Normalized EBITDA includes additional adjustments for unrealized gains (losses) on risk management contracts, realized loss on foreign exchange derivatives, losses on investments, transaction costs related to acquisitions, gains (losses) on the sale of assets, provisions on assets, development costs, accretion expenses related to asset retirement obligations and the Northwest Transmission Line liability, and foreign *exchange gains. 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 applicable to common shares adjusted for the after-tax impact of unrealized gains (losses) on risk management contracts, realized loss on foreign exchange derivatives, losses on investments, transaction costs related to acquisitions, gains (losses) on the sale of assets, provisions on assets, and financing costs associated with the bridge facility for the WGL Acquisition. 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 transaction and financing costs related to acquisitions. 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) dated July 31, 2018 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 three and six months ended June 30, 2018. This MD&A should be read in conjunction with the accompanying unaudited condensed interim Consolidated Financial Statements and notes thereto of AltaGas as at and for the three and six months ended June 30, 2018 and the audited Consolidated Financial Statements and MD&A as at and for the year ended December 31, 2017.

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

Abbreviations, acronyms and capitalized terms used in this MD&A without express definition shall have the same meanings given to those terms in the MD&A as at and for the year ended December 31, 2017 or the Annual Information Form.

This MD&A contains forward-looking information (forward-looking statements). Words such as "may", "can", "would", "could", "should", "will", "intend", "plan", "anticipate", "believe", "aim", "seek", "propose", "contemplate", "estimate", "focus", "strive", "forecast", "expect", "project", "target", "potential", "objective", "continue", "outlook", "vision", "opportunity" and similar expressions suggesting future events or future performance, as they relate to the Corporation or any affiliate of the Corporation, are intended to identify forward-looking statements. In particular, this MD&A contains forward-looking statements with respect to, among other things, business objectives, expected growth, results of operations, performance, business projects and opportunities and financial results.

Specifically, such forward-looking statements included in this document include, but are not limited to, statements with respect to the following: the implementation and success of AltaGas' strategy for the Corporation as a whole and each of its business segments; that abundant natural gas and demand for clean energy will provide opportunities for sustained growth across all three business segments; the aim to maintain a long-term balanced mix of energy infrastructure assets across AltaGas' business segments; the expected benefits of AltaGas' export-related infrastructure assets; AltaGas' ability to take advantage of the demand for clean energy through its clean energy assets; the expected benefits of the WGL Acquisition to each segment, including increases in EBITDA; the expected timing and components of repayment of the acquisition credit facility, including assets sales and securities offerings; expected timing, scale and cost of WGL's investments in the Marcellus, including Central Penn, Mountain Valley and the MVP Southgate; expected increase in normalized EBITDA and FFO to the WGL Acquisition; the expected growth in rate base and growth due to capital investments in the Utilities segment; the expected impacts of the US tax reform; planned turnarounds; expected capital expenditures for AltaGas, for the combined company, by segment, and by project; expected maintenance capital; expected funding of the committed capital program; expected timing and capacity of the Alton natural gas storage project; expected solar investments and the potential value of certain solar projects; expected timing and expenditures of Washington Gas' accelerated utility pipe replacement programs; expected cost, timing, size, and capacity and tolling arrangements for RIPET; expectation that RIPET will be the first propane export facility on the West Coast; potential growth of AltaGas' energy export business; expected cost, scale and timing of the MCP; and expected maintenance of the Corporation's investment grade credit rating. 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 negotiations; and financing of the WGL Acquisition.

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 Aboriginal 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; the Harmattan Rep agreements; 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; risks associated with the acquisition of WGL, the financing of the WGL Acquisition and the underlying business of WGL; and the other factors discussed under the heading "Risk Factors" in the Corporation's AIF for the year ended December 31, 2017 and set out in AltaGas' other continuous disclosure documents.

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

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

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

RECENT DEVELOPMENTS

Acquisition of WGL Holdings, Inc. (WGL)

Following the receipt of all required federal, state, and local regulatory approvals, on July 6, 2018 the Corporation acquired WGL Holdings, Inc. (the WGL Acquisition), creating a North American leader in the clean energy economy and enhancing AltaGas' position as a leading North American clean energy infrastructure company. The aggregate purchase price was 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. The WGL Acquisition will benefit all three business segments: Gas, Power and Utilities. In the Gas segment, the combined midstream business will provide producers with global market access; in the Power segment, a clean power generation footprint covering hydroelectric, wind, small scale solar, biomass, and energy storage will expand AltaGas' clean energy offerings; and in the Utility segment, the high quality utility assets will be underpinned by regulated, low risk cash flow.

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, gross proceeds of approximately $922 million from the sale of a 35 percent minority interest in the Northwest British Columbia Hydro Electric Facilities (see *Minority Interest Sale of Northwest Hydro Facilities* section below), draws on the fully committed acquisition credit facility of $3.0 billion (US$2.3 billion) and existing cash on hand. The total funding included additional amounts for the payment of fees and regulatory commitments related to the WGL Acquisition. The acquisition credit facility could remain in place for up to 12 to 18 months after closing of the WGL Acquisition. The sale of the subscription receipts was completed in the first quarter of 2017 (see *Subscription Receipts* section below) and upon closing of the WGL Acquisition, the subscription receipts were exchanged into approximately 84.5 million common shares of AltaGas.

WGL is a diversified energy infrastructure company and the sole common shareholder of Washington Gas Light Company (Washington Gas), a regulated natural gas utility headquartered in Washington, D.C., serving approximately 1.2 million customers in Virginia, Maryland, and the District of Columbia. WGL has a growing midstream business with investments in natural gas gathering infrastructure and regulated gas pipelines in the Marcellus/Utica gas formation located in the northeastern United States. WGL's midstream business has interstate transportation and storage contracts as well as marine-based energy export capabilities via the North American Atlantic coast through WGL's access to the Cove Point LNG Terminal in Maryland which was developed by a third party and recently began exporting LNG. WGL also owns contracted clean power assets, with a focus on solar distributed generation and energy efficiency assets throughout the United States. In addition, WGL has a retail gas and power marketing business with approximately 214,000 customers in Maryland, Virginia, Delaware, Pennsylvania and the District of Columbia. With the close of the WGL Acquisition, AltaGas has over $23 billion of assets and approximately 1.8 million rate regulated gas customers.

Subsequent to transaction close, WGL's activities will continue to be carried out through AltaGas' three business segments: Gas, Power, and Utilities. Specifically,

- AltaGas' Gas segment will include WGL Midstream, Inc.'s (WGL Midstream) interest in four pipelines in the northeastern United States. This includes 30 percent ownership in Stonewall, which is currently in service and designed to gather 1.4 Bcf/d from West Virginia; 21 percent ownership in Central Penn, which is designed to transport 1.7 Bcf/d in Pennsylvania and is expected to be operational in the third quarter of 2018; 10 percent ownership in Mountain Valley, which is designed to transport 2.0 Bcf/d from West Virginia to Virginia with an expected in-service date in the first quarter of 2019; and 10 percent ownership in the proposed Constitution Pipeline. In addition, AltaGas' Gas segment will include the results from the retail gas marketing business of WGL Energy Services, Inc. (WGL Energy Services).
- AltaGas' Power segment will include the results from WGL Energy Systems, Inc. (WGL Energy Systems), which provides clean and energy-efficient solutions including distributed generation (commercial solar, fuel cells, combined heat and power and other distributed generation solutions) and energy efficiency projects to government and commercial clients, as well as the operations of WGSW Inc. (WGSW), a holding company formed to invest in alternative energy assets. In addition, AltaGas' Power segment will include the results from WGL Energy Services' retail power marketing business.
- AltaGas' Utilities segment will include the results from the operations of Washington Gas and Hampshire Gas Company (Hampshire). Washington Gas provides regulated gas distribution services (including the sale and delivery of natural gas) to end-use customers. Hampshire provides regulated interstate natural gas storage services to Washington Gas.

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 subsequently been delisted from the TSX.

Minority Interest Sale of Northwest Hydro Facilities

On June 22, 2018, AltaGas successfully completed the sale of a 35 percent indirect equity interest in the Northwest British Columbia Hydro Electric Facilities (Northwest Hydro) for gross proceeds of approximately $922 million. The purchase price implies a 2017 EBITDA multiple of approximately 27 times and a total value of $2.6 billion on a 100 percent basis. 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. AltaGas remains the majority holder of the Northwest Hydro facilities and will continue to provide all operational, maintenance and management functions. The sale of the interest in the Northwest Hydro facilities is part of the larger funding strategy related to the WGL Acquisition and represents almost half of the approximately $2 billion in asset sales expected to be raised. AltaGas remains confident in completing its long-term financing plan over the next number of months and continues to advance discussions for the monetization of certain additional assets.

Base Shelf Prospectus and Other Asset Sales

AltaGas expects to rapidly repay the funds drawn on the bridge facility through the monetization of certain assets, as well as with the proceeds of term debt and hybrid securities offerings. To facilitate potential securities' offerings, a US$2 billion final short form base shelf prospectus for the issuance of both debt securities and preferred shares was filed in June.

Certain assets are currently under review for potential divestiture. With the greatest opportunities for growth lying in the Gas business and in U.S. utilities and AltaGas' current capital investments primarily targeted in those areas, AltaGas expects asset sales to further streamline its business, provide for business optimization and align with and support its vision for the Corporation.

ALTAGAS ORGANIZATION

The businesses of AltaGas are operated by AltaGas and a number of its subsidiaries including, without limitation, AltaGas Services (U.S.) Inc.; in regards to the gas business, AltaGas Extraction and Transmission Limited Partnership, AltaGas Pipeline Partnership, AltaGas Processing Partnership, AltaGas Northwest Processing Limited Partnership and Harmattan Gas Processing Limited Partnership; in regards to the power business, Coast Mountain Hydro Limited Partnership, Blythe Energy Inc. (Blythe), and AltaGas San Joaquin Energy Inc.; and, in regards to the utility business, AltaGas Utilities Inc. (AUI), Heritage Gas Limited (Heritage Gas), Pacific Northern Gas Ltd. (PNG), 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).

Effective upon close of the WGL Acquisition on July 6, 2018, AltaGas' subsidiaries also include: in regards to the gas business, WGL Midstream and the retail gas marketing business of WGL Energy Services; in regards to the power business, WGSW, WGL Energy Systems, and the retail power marketing business of WGL Energy Services; and, in regards to the utility business, Washington Gas and Hampshire.

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 and maintain a long-term, balanced mix of energy infrastructure assets across its Gas, Power and Utility business segments. AltaGas' business strategy is underpinned by the growing demand for clean energy with natural gas as a key fuel source. AltaGas has three business segments:

- Gas, which transacts more than 3 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;
- Power, which includes 2,033 MW of gross capacity from natural gas-fired, hydro, wind, biomass, solar, other distributed generation and energy storage assets located in 20 provinces and states across North America. The Power business also includes energy efficiency contracting and WGL's retail power marketing business; and
- Utilities, serving almost 1.8 million customers with a rate base of approximately $5 billion through ownership of regulated natural gas distribution utilities across 8 jurisdictions in North America, and a regulated natural gas storage utility 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, delivering clean and affordable natural gas to homes and businesses.

SECOND QUARTER 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.)

- On June 28, 2018, AltaGas received a conditional final regulatory approval from the Public Service Commission of the District of Columbia (PSC of DC) for the WGL Acquisition. AltaGas and WGL accepted the conditions on July 2, 2018. All necessary approvals for the WGL transaction have now been obtained and the transaction closed on July 6, 2018;
- On June 13, 2018, AltaGas announced that it has 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 June 4, 2018, a US$2 billion preliminary short form base shelf prospectus for the issuance of both debt securities and preferred shares was filed in Alberta. The final short form base shelf prospectus was filed on June 13, 2018 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 May 8, 2018, AltaGas signed a unanimous settlement agreement with the key stakeholders in the Washington, D.C. regulatory proceedings with respect to the WGL Acquisition;
- On April 4, 2018, AltaGas received regulatory approval from the Maryland Public Service Commission (PSC of MD) for the WGL Acquisition;
- 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;
- Effective upon the expiry of the Power Purchase Arrangement (PPA) at the Ripon gas-fired electricity generation facility (Ripon), in the second quarter of 2018 AltaGas signed Resource Adequacy (RA) contracts for June through December 2018;
- Normalized EBITDA was $166 million, consistent with $166 million in the second quarter of 2017;
- Normalized funds from operations were $121 million ($0.67 per share) compared to $123 million ($0.72 per share) in the second quarter of 2017;
- Net income applicable to common shares was $1 million ($0.01 per share) compared to net loss applicable to common shares of $8 million ($0.05 per share) in the second quarter of 2017;
- Normalized net income was $23 million ($0.13 per share) compared to $28 million ($0.17 per share) in the second quarter of 2017;
- Net debt was $2.7 billion as at June 30, 2018, compared to $3.6 billion on December 31, 2017; and
- Net debt-to-total capitalization ratio was 33 percent as at June 30, 2018, compared to 44 percent as at December 31, 2017.

HIGHLIGHTS SUBSEQUENT TO QUARTER END

- On July 6, 2018, AltaGas completed the acquisition of WGL 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 of 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 veteran and Board Member, will act as interim co-CEOs until a replacement is found. The key strategic priorities, financing plan for WGL and business operations remain unchanged and on track; and
- 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.

CONSOLIDATED FINANCIAL REVIEW

($ millions)	Three Months Ended June 30 **2018**	2017	Six Months Ended June 30 **2018**	2017
Revenue	**610**	539	**1,488**	1,310
Normalized EBITDA[(1)]	**166**	166	**388**	394
Net income (loss) applicable to common shares	**1**	(8)	**50**	24
Normalized net income[(1)]	**23**	28	**93**	93
Total assets	**10,876**	10,099	**10,876**	10,099
Total long-term liabilities	**4,602**	4,670	**4,602**	4,670
Net additions to property, plant and equipment	**124**	125	**190**	127
Dividends declared[(2)]	**98**	89	**195**	178
Normalized funds from operations[(1)]	**121**	123	**290**	294

($ per share, except shares outstanding)	Three Months Ended June 30 **2018**	2017	Six Months Ended June 30 **2018**	2017
Net income (loss) per common share - basic	**0.01**	(0.05)	**0.28**	0.14
Net income (loss) per common share - diluted	**0.01**	(0.05)	**0.28**	0.14
Normalized net income - basic[(1)]	**0.13**	0.17	**0.52**	0.55
Dividends declared[(2)]	**0.55**	0.53	**1.10**	1.05
Normalized funds from operations[(1)]	**0.67**	0.72	**1.63**	1.74
Shares outstanding - basic (millions)				
During the period[(3)]	**179**	170	**178**	169
End of period	**181**	171	**181**	171

(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, and $0.1825 beginning on November 27, 2017.

(3) Weighted average.

Three Months Ended June 30

Normalized EBITDA for the second quarter of 2018 was $166 million, consistent with $166 million for the same quarter in 2017. Factors positively impacting normalized EBITDA included higher realized frac spread, colder weather experienced at certain of the utilities, contributions from the Townsend 2A and North Pine facilities which commenced commercial operations in the fourth quarter of 2017, and impacts related to Pembina assuming operatorship of the Younger extraction facility (Younger). These were offset by the impact from the weaker U.S. dollar on reported results from U.S. assets, the absence of one-time impacts in 2017 related to insurance proceeds received by SEMCO's non-regulated operations and an early termination payment from one of SEMCO's non-regulated customers moving from a fixed fee to a volumetric based contract, higher expenses at the U.S. utilities mainly related to consulting and support services, decreased revenue from SEMCO due to U.S. tax reform, and expiry of the Power Purchase Arrangement (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 is in place until the end of 2018). For the three months ended June 30, 2018, the average Canadian/U.S. dollar exchange rate decreased to 1.29 from an average of 1.34 in the same quarter of 2017, resulting in a decrease in normalized EBITDA of approximately $4 million.

Normalized funds from operations for the second quarter of 2018 were $121 million ($0.67 per share), compared to $123 million ($0.72 per share) for the same quarter in 2017. The decrease was mainly due to the same drivers as normalized EBITDA and higher interest expense. In the second quarter of 2018, AltaGas received $3 million of dividend income from the Petrogas Preferred Shares (2017 - $3 million) and $1 million of common share dividends from Petrogas (2017 - $1 million).

Operating and administrative expenses for the second quarter of 2018 were $146 million, compared to $136 million for the same quarter in 2017. The increase was mainly due to higher transaction costs on acquisitions (primarily related to the WGL

Acquisition) of $7 million in the second quarter of 2018 compared to $5 million in the same quarter in 2017, higher expenses at the U.S. utilities mainly related to consulting and support services, and expenses related to the planned turnaround at the Harmattan facility (Harmattan). Depreciation and amortization expense for the second quarter of 2018 was $73 million, compared to $71 million for the same quarter in 2017. The increase was mainly due to new assets placed into service. Interest expense for the second quarter of 2018 was $43 million, compared to $41 million for the same quarter in 2017. The increase was predominantly due to higher average interest rates, partially offset by lower average outstanding debt balances.

AltaGas recorded income tax expense of $2 million for the second quarter of 2018 compared to $8 million in the same quarter of 2017. The decrease was mainly due to the recently enacted change in the U.S. Federal tax rate from 35 percent to 21 percent.

Net income applicable to common shares for the second quarter of 2018 was $1 million ($0.01 per share), compared to a net loss of $8 million ($0.05 per share) for the same quarter in 2017. The increase was mainly due to lower unrealized losses recognized on risk management contracts, lower losses on investments, lower income tax expense, and the same previously referenced factors impacting normalized EBITDA, partially offset by higher transaction costs incurred on the WGL Acquisition, realized losses on foreign exchange derivatives, higher interest expense, higher depreciation and amortization expense, and higher preferred share dividends.

Normalized net income was $23 million ($0.13 per share) for the second quarter of 2018, compared to $28 million ($0.17 per share) reported for the same quarter in 2017. The decrease was mainly due to higher interest expense, depreciation and amortization expense, and preferred share dividends, partially offset by lower income tax expense, and the same previously referenced factors impacting normalized EBITDA. Normalizing items in the second quarter of 2018 included after-tax amounts related to transaction costs on acquisitions, unrealized gains on risk management contracts, amortization of financing costs associated with the bridge facility of $2 million, realized losses on foreign exchange derivatives, and losses on investments. In the second quarter of 2017, normalizing items included after-tax amounts related to transaction costs on acquisitions, unrealized losses on risk management contracts and long-term investments, gain on sale of assets, provision on assets, and financing costs associated with the bridge facility for the WGL Acquisition of $3 million.

Six Months Ended June 30

Normalized EBITDA for the first half of 2018 was $388 million, compared to $394 million for the same period in 2017. The decrease was mainly due to the impact from the weaker U.S. dollar on reported results from U.S. assets, decreased revenue from SEMCO due to U.S. tax reform, lower natural gas storage margins, expenses related to the planned and unplanned outages at Blythe, higher expenses at the utilities primarily due to consulting and support services, the expiry of the Ripon PPA in May 2018 (partially offset by the new RA contract which began in the second quarter of 2018 and is in place until the end of 2018), and the absence of one-time impacts in 2017 related to insurance proceeds received by SEMCO's non-regulated operations and an early termination payment from one of SEMCO's non-regulated customers moving from a fixed fee to a volumetric based contract. These increases were partially offset by higher realized frac spread and frac exposed volumes, contributions from the Townsend 2A and North Pine facilities which commenced commercial operations in the fourth quarter of 2017, colder weather experienced at certain of the utilities and impacts related to Pembina assuming operatorship of Younger. For the six months ended June 30, 2018, the average Canadian/U.S. dollar exchange rate decreased to 1.28 from an average of 1.33 in the same period of 2017, resulting in a decrease in normalized EBITDA of approximately $10 million.

Normalized funds from operations for the first half of 2018 were $290 million ($1.63 per share), compared to $294 million ($1.74 per share) for the same period in 2017, reflecting the same drivers as normalized EBITDA and lower income tax expense. In the first half of 2018, AltaGas received $6 million of dividend income from the Petrogas Preferred Shares (2017 - $6 million) and $2 million of common share dividends from Petrogas (2017 - $2 million).

Operating and administrative expenses for the first half of 2018 were $287 million, compared to $296 million in the first half of 2017, primarily due to lower transaction costs on acquisition (primarily related to the WGL Acquisition) of $17 million in the first half of 2018 compared to $41 million in the first half of 2017, partially offset by expenses related to the planned and unplanned outages at Blythe and the planned turnaround at Harmattan and higher expenses at the utilities, primarily due to consulting and support services. Depreciation and amortization expense for the first half of 2018 was $145 million, compared to $142 million for the same period in 2017. The increase was mainly due to new assets placed into service. Interest expense for the first half of 2018 was $86 million, compared to $87 million for the same period in 2017. The decrease was mainly due to lower average debt outstanding partially offset by higher average interest rates.

AltaGas recorded income tax expense of $21 million for the first half of 2018 compared to $29 million in the same period of 2017. The decrease was mainly due to the recently enacted change in the U.S. Federal tax rate from 35 percent to 21 percent.

Net income applicable to common shares for the first half of 2018 was $50 million ($0.28 per share) compared to $24 million ($0.14 per share) for the same period in 2017. The increase was mainly due to lower transaction costs incurred on the WGL Acquisition, lower unrealized losses recognized on risk management contracts, lower income tax expense, and lower losses on sale of assets, partially offset by higher depreciation and amortization expense, a realized loss on foreign exchange derivatives, higher preferred share dividends, and the same previously referenced factors impacting normalized EBITDA.

Normalized net income was $93 million ($0.52 per share) for the first half of 2018, consistent with $93 million ($0.55 per share) reported for the same period in 2017. Variances from 2017 included higher depreciation and amortization expense and higher preferred share dividends, partially offset by lower income tax expense, lower interest, and the same previously referenced factors impacting normalized EBITDA. Normalizing items in the first half of 2018 included after-tax amounts related to transaction costs on acquisitions, losses on investments, amortization of financing costs associated with the bridge facility of $5 million, unrealized gains on risk management contracts, realized loss on foreign exchange derivatives, and gains on sale of assets. In the first half of 2017, normalizing items included after-tax amounts related to transaction costs on acquisitions, unrealized losses on risk management contracts and long-term investments, losses on sale of assets, provision on assets, and financing costs associated with the bridge facility for the WGL Acquisition of $6 million.

2018 OUTLOOK

The WGL Acquisition closed on July 6, 2018. As a combined entity, AltaGas expects normalized EBITDA to increase by approximately 25 to 30 percent and normalized funds from operations to increase by approximately 15 to 20 percent compared to prior year.

The WGL Acquisition will drive growth in all three business segments. The combined Utilities segment is expected to have the largest contribution to EBITDA, followed by the Power and Gas segments. Specifically for Utilities, the combined segment is expected to have an overall rate base of approximately $5 billion and is expected to grow through planned capital investments in 2018, particularly for the U.S. utilities. The WGL Acquisition will also increase the number of utility customers by approximately 1.2 million. The Power segment is expected to benefit from the addition of WGL's commercial energy systems and retail marketing business, both of which are expected to provide ongoing growth opportunities. Finally, the Gas segment is expected to benefit from the addition of WGL's pipeline investments in the prolific Marcellus/Utica gas resource regions as well as a gas supply agreement associated with the Cove Point LNG Terminal which began exporting LNG this year. WGL's investment in the Stonewall Gas Gathering System is currently in-service and WGL expects the Central Penn pipeline to be operational in the third quarter of 2018 and the Mountain Valley pipeline to be operational in the first quarter of 2019. For further information on the WGL Acquisition see the *Recent Developments* section of this MD&A.

The expected increase to EBITDA and funds from operations in 2018 compared to 2017 for the combined entity is mainly as a result of contributions from the WGL Acquisition in all three segments, as well as higher realized frac spread mainly due to higher hedged prices, full year contributions from Townsend 2A and the first train of the North Pine facility, higher expected earnings from the Northwest Hydro facilities due to contractual price increases and continued efficiency improvements, higher volumes at Blythe, and colder weather and rate base and customer growth at certain of the utilities. These increases may be partially offset by the impact of a weaker U.S. dollar on reported results of the U.S. assets, the impact of planned turnarounds at the Harmattan, Joffre Ethane Extraction Plant (JEEP) and Pembina Express Extraction Plant (PEEP) facilities, higher repair and maintenance expenses at Blythe, and the expiry of the PPA at the Ripon facility in the second quarter of 2018 (partially offset by the new RA contract which began in the second quarter of 2018 and is in place until the end of 2018). U.S. tax reform is expected to be negative to normalized EBITDA and funds from operations for AltaGas' U.S. businesses while, on a net income basis, the impact of U.S. tax reform is expected to be positive.

The overall forecasted normalized EBITDA and funds from operations for the combined business include assumptions around the U.S./Canadian dollar exchange rate, the impact of certain contemplated asset monetizations and other financing initiatives as part of the WGL financing plan, and the impact of U.S. tax reform. Any variance from AltaGas' current assumptions could impact the forecasted increase to normalized EBITDA and funds from operations.

AltaGas estimates an average of approximately 10,300 Bbls/d will be exposed to frac spreads prior to hedging activities. For 2018, AltaGas has frac hedges in place for approximately 7,500 Bbls/d at an average price of approximately $33/Bbl excluding basis differentials.

GROWTH CAPITAL

Based on projects currently under review, development or construction, and including the WGL capital program for the period subsequent to close, AltaGas expects net invested capital expenditures for the combined entity in the range of $1.0 to $1.3 billion, of which approximately $500 to $600 million relates to AltaGas excluding WGL. For the combined entity, the Gas segment will account for approximately 40 to 45 percent of total capital expenditures, while the Utilities segment will account for approximately 45 to 50 percent and the Power segment will account for the remainder. Gas and Power maintenance capital is expected to be approximately $25 to $35 million of the total capital expenditures in 2018. The majority of AltaGas' capital expenditures is focused on the continued construction at the Ridley Island Propane Export Terminal (RIPET), maintaining and growing rate base at the Utilities, WGL's investments in the Central Penn and Mountain Valley gas pipeline developments in the Marcellus/Utica gas formation, pre-construction design, engineering, and right-of-way procurement for the Marquette Connector Pipeline (MCP), and growth capital associated with the tie-in of incremental third party gas volumes in the Western Canadian Basin. The Corporation continues to focus on enhancing productivity and streamlining businesses, including the disposition of smaller assets.

AltaGas' 2018 committed capital program is expected to be funded through internally-generated cash flow, the Premium Dividend™, Dividend Reinvestment and Optional Cash Purchase Plan (DRIP) and normal course borrowings on existing committed credit facilities.

<u>Gas Projects</u>

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).

Construction of RIPET commenced during the second quarter of 2017. The LPG storage tank, rail infrastructure, and balance of plant construction remain on track to meet the expected commercial operation date of the first quarter of 2019. With the inner tank floor and final roof pours complete, the LPG storage tank is advancing on schedule. Rail and marine infrastructure is also progressing, with construction of the rail retaining wall advancing, earthworks and grading for rail offloading underway, and the first marine jetty modules scheduled to arrive this summer. The team is simultaneously continuing construction of the balance of plant, with detailed site preparation and grading underway. The site construction management team and project support teams have successfully hit all critical milestones to date on the RIPET master schedule.

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In 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 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.

Based on production from its existing facilities and forecasts from new plants under construction and in active development, AltaGas anticipates having physical volumes equal to approximately 50 percent of the expected capacity of 1.2 million tonnes per annum. The remaining 50 percent is expected to be supplied by producers and other suppliers. Currently, the supply for approximately 75 percent of the total capacity has been secured with the balance progressing as expected. Based on negotiations with a number of producers and other suppliers, AltaGas expects to underpin approximately 40 percent of RIPET's annual expected capacity under tolling arrangements.

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 discussions with Astomos and several third party off-takers for further capacity commitments are proceeding.

Central Penn Pipeline

Central Penn is a proposed 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). 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 will have 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. On February 3, 2017, the Federal Energy Regulatory Commission (FERC) issued an order granting Certificate of Public Convenience and Necessity, subject to certain conditions. On September 15, 2017, the FERC granted authorization to proceed with the construction of the Central Penn pipeline. Currently, Central Penn is under construction and is expected to be placed in service in the third quarter of 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 plans to invest an estimated US$450 million for a 55 percent interest in Meade (21 percent indirect interest in Central Penn). As of June 30, 2018, WGL Midstream has spent approximately US$415 million on Meade.

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 will be released to WGL Midstream.

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 EQT Midstream Partners, LP (EQT) and developed, constructed, and owned by Mountain Valley (a venture of EQT and other entities), will transport approximately 2.0 Bcf/d and will extend EQT Corporation's Equitrans 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. On June 21, 2018, the 4th U.S. Circuit Court of Appeals granted a stay of permit for certain construction activities in West Virginia, while the court considers challenging a federal permit. Construction activities in Virginia were put on hold to remediate erosion controls affected by recent weather events. Construction activities resumed for certain segments of the pipeline in the first week of July. On July 27, 2018, the Court of Appeals set aside the U.S. Forest Service and Bureau of Land Management's decisions granting a right-of-way for a 3.5 mile segment of the pipeline. Mountain Valley is working with the appropriate agencies on the renewed decision process. Mountain Valley has modified its construction schedule and the pipeline is targeted to be placed in-service during the first quarter of 2019.

WGL Midstream expects to invest approximately US$350 million through the in-service date of the pipeline based on scheduled capital contributions and its pro rata share of project costs. As of June 30, 2018, WGL Midstream's investment in the pipeline is US$121 million. 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 EQT to acquire a 5 percent equity interest in a project to build a lateral interstate natural gas pipeline (the MVP Southgate project). The proposed lateral pipeline will receive gas from the Mountain Valley Pipeline mainline in Pittsylvania County, Virginia and extend approximately 70 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$17.0 million and the lateral pipeline is expected to be placed into service in late 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. 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 (SFN) in due course. In the meantime, the IA remains in effect for the project. AltaGas continues to work constructively with governments, regulators, and 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 Recovery 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 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 and encapsulation 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 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 2019.

In 2014, pursuant to the Strategic Infrastructure Development and Enhancement (STRIDE) law in Maryland, the PSC of Maryland approved Washington Gas' initial STRIDE Plan to recover the reasonable and prudent costs associated with qualifying infrastructure replacements through monthly surcharges. The Commission 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 Maryland 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 Maryland at an estimated cost of approximately US$394 million starting January 2019. The STRIDE 2.0 request is pending PSC of Maryland approval.

On April 21, 2011, the Commonwealth of Virginia State Corporation Commission (SCC of VA), pursuant to a new law to advance Virginia's Energy Plan (SAVE Act), 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 Commission 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 Commission 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 MCP is estimated to cost between US$135 to $140 million.

The construction plans and specifications were completed during the second quarter of 2018 and approximately half of the property rights that traverse the planned pipeline route were secured. The application for all environmental permits has been submitted and final approval is expected to be received by the end of August 2018. Additionally, the Phase I archeological assessment is also expected to be completed by the end of August 2018. 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.

Power Projects

Distributed Generation Investments

WGL currently owns and manages distributed generation projects with approximately 325 MW of gross capacity across 20 states in the United States. The power output from these projects is generally contracted directly with end-user customers under long-term service agreements, providing green energy solutions to a variety of commercial, government, institutional, and residential customers. For certain investments, WGL, along with its tax equity partners, has recently formed several tax equity funds to acquire, own, and operate distributed generation projects. These funds have invested approximately US$155 million in distributed generation projects since 2016, of which WGL's share was approximately US$100 million. WGL is the managing member of these funds and provided 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, is currently acquiring new solar projects. To date, SFGF II, LLC has invested a total of US$73 million in new projects since June 30, 2017 and there is US$77 million remaining for additional acquisitions through March 31, 2019. As of June 30, 2018, WGL has contributed US$48 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.

On March 28, 2018, WGL entered into a new arrangement whereby WGL develops renewable solar projects after signing long-term power service agreements with customers and then sells the completed solar projects to a financing partner who will lease the project back to WGL, allowing the investor to retain the tax benefits of the projects. This optimizes the tax attributes associated with the projects, lowering the financing cost for WGL. WGL has until September 28, 2019 to sell the commercial distributed generation projects under the arrangement to the investor and it could lease each project back over a period of up to 25 years. The total value of these solar projects could be up to US$75 million, none of which has been committed to date.

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 June 30		Six Months Ended June 30	
($ millions)	**2018**	2017	**2018**	2017
Normalized EBITDA	**$ 166**	$ 166	**$ 388**	$ 394
Add (deduct):				
Transaction costs related to acquisitions	**(7)**	(5)	**(17)**	(41)
Unrealized gains (losses) on risk management contracts	**22**	(22)	**23**	(21)
Realized loss on foreign exchange derivatives	**(36)**	—	**(36)**	—
Losses on investments	**(5)**	(7)	**(15)**	(8)
Gains (losses) on sale of assets	**—**	1	**1**	(3)
Provision on assets	**—**	(1)	**—**	(1)
Development costs	**—**	—	**1**	—
Accretion expenses	**(3)**	(3)	**(6)**	(6)
Foreign exchange gains	**1**	1	**1**	1
EBITDA	**$ 138**	$ 130	**$ 340**	$ 315
Add (deduct):				
Depreciation and amortization	**(73)**	(71)	**(145)**	(142)
Interest expense	**(43)**	(41)	**(86)**	(87)
Income tax expense	**(2)**	(8)	**(21)**	(29)
Net income after taxes (GAAP financial measure)	**$ 20**	$ 10	**$ 88**	$ 57

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 expense.

Normalized EBITDA includes additional adjustments for unrealized gains (losses) on risk management contracts, realized loss on foreign exchange derivatives, losses on investments, transaction costs related to acquisitions, gains (losses) on the sale of assets, provisions on assets, development costs, accretion expenses related to asset retirement obligations and the Northwest Transmission Line liability, and foreign exchange gains. 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

($ millions)	Three Months Ended June 30 2018	Three Months Ended June 30 2017	Six Months Ended June 30 2018	Six Months Ended June 30 2017
Normalized net income	**$ 23**	$ 28	**$ 93**	$ 93
Add (deduct) after-tax:				
Transaction costs related to acquisitions	**(5)**	(4)	**(16)**	(29)
Unrealized gains (losses) on risk management contracts	**26**	(22)	**26**	(22)
Realized loss on foreign exchange derivatives	**(36)**	—	**(36)**	—
Losses on investments	**(5)**	(7)	**(13)**	(8)
Gains (losses) on sale of assets	**—**	1	**1**	(3)
Provision on assets	**—**	(1)	**—**	(1)
Financing costs associated with the bridge facility	**(2)**	(3)	**(5)**	(6)
Net income (loss) applicable to common shares (GAAP financial measure)	**$ 1**	$ (8)	**$ 50**	$ 24

Normalized net income represents net income applicable to common shares adjusted for the after-tax impact of unrealized gains (losses) on risk management contracts, realized loss on foreign exchange derivatives, losses on investments, transaction costs related to acquisitions, gains (losses) on the sale of assets, provisions on assets, and financing costs associated with the bridge facility for the WGL Acquisition. 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

($ millions)	Three Months Ended June 30 2018	Three Months Ended June 30 2017	Six Months Ended June 30 2018	Six Months Ended June 30 2017
Normalized funds from operations	**$ 121**	$ 123	**$ 290**	$ 294
Add (deduct):				
Transaction and financing costs related to acquisitions	**(7)**	(7)	**(20)**	(43)
Funds from operations	**114**	116	**270**	251
Add (deduct):				
Net change in operating assets and liabilities	**34**	(12)	**68**	54
Asset retirement obligations settled	**(1)**	(2)	**(2)**	(3)
Cash from operations (GAAP financial measure)	**$ 147**	$ 102	**$ 336**	$ 302

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 transaction and financing costs related to acquisitions.

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 June 30		Six Months Ended June 30	
($ millions)	**2018**	2017	**2018**	2017
Gas	**$ 48**	$ 41	**$ 119**	$ 108
Power	**75**	77	**116**	127
Utilities	**50**	55	**162**	170
Sub-total: Operating Segments	**173**	173	**397**	405
Corporate	**(7)**	(7)	**(9)**	(11)
	$ 166	$ 166	**$ 388**	$ 394

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

GAS

OPERATING STATISTICS

	Three Months Ended June 30		Six Months Ended June 30	
	2018	2017	**2018**	2017
Extraction inlet gas processed (Mmcf/d)[1]	**769**	921	**926**	977
FG&P inlet gas processed (Mmcf/d)[1]	**458**	379	**463**	375
Total inlet gas processed (Mmcf/d)[1]	**1,227**	1,300	**1,389**	1,352
Extraction ethane volumes (Bbls/d)[1]	**16,527**	23,023	**20,955**	28,323
Extraction NGL volumes (Bbls/d)[1] [2]	**33,201**	35,862	**38,354**	37,062
Total extraction volumes (Bbls/d)[1] [3]	**49,728**	58,885	**59,309**	65,385
Frac spread - realized ($/Bbl)[1] [4]	**14.98**	9.06	**17.20**	9.77
Frac spread - average spot price ($/Bbl)[1] [5]	**22.19**	10.98	**22.22**	13.96

(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, divided by the respective frac exposed volumes for the period.

Inlet gas volumes processed at the extraction facilities for the three months ended June 30, 2018 decreased by 152 Mmcf/d, compared to the same period in 2017. The decrease was primarily due to planned turnarounds at Harmattan and PEEP, and reduced ownership interest at the Younger facility effective April 2018, partially offset by higher inlet volumes at EEEP due to higher available gas flows and a turnaround in the second quarter of 2017, and higher inlet volumes at JEEP despite a turnaround in the second quarter of 2018. Inlet gas volumes processed at the field gathering and processing (FG&P) facilities for the three months ended June 30, 2018 increased by 79 Mmcf/d primarily due to volumes received at Townsend and the recently constructed Townsend 2A facilities, 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 six months ended June 30, 2018 decreased by 51 Mmcf/d, compared to the same period in 2017. The decrease was primarily due to planned turnarounds at Harmattan and PEEP in the second quarter of 2018, and reduced ownership interest at Younger effective April 2018, partially offset by higher inlet volumes at EEEP due to higher available gas flows and a turnaround in the second quarter of 2017. Inlet gas volumes processed at the FG&P facilities for the six months ended June 30, 2018 increased by 88 Mmcf/d primarily due to volumes received at Townsend and the recently constructed Townsend 2A facilities, and higher volumes at Gordondale, partially offset by the disposition of certain non-core facilities in the first quarter of 2018.

Average ethane volumes for the three months ended June 30, 2018 decreased by 6,496 Bbls/d, while average NGL volumes decreased by 2,661 Bbls/d, compared to the same period in 2017. Lower ethane volumes were a result of rejecting production at Younger due to uneconomic pricing and lower ethane volumes at Harmattan due to a planned turnaround, partially offset by higher production at EEEP. Lower NGL volumes were a result of the planned turnaround at Harmattan, and a lower ownership interest at Younger, partially offset by higher production at Townsend and Gordondale.

Average ethane volumes for the six months ended June 30, 2018 decreased by 7,368 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 quarter of 2018 and at PEEP in the first quarter of 2018, and lower ethane volumes at Harmattan due to the planned turnaround, partially offset by higher production at EEEP. Average NGL volumes increased by 1,292 Bbls/d compared to the same period in 2017. Higher NGL volumes were primarily due to increased volumes produced at the Townsend and newly constructed Townsend 2A facilities, Gordondale, and EEEP facilities, partially offset by the planned turnaround at Harmattan and reduced ownership interest at Younger.

Three Months Ended June 30

The Gas segment reported normalized EBITDA of $48 million in the second quarter of 2018, compared to $41 million in the same quarter of 2017. The increase in normalized EBITDA was due to higher realized frac spread and frac exposed volumes, contributions from the Townsend 2A and North Pine facilities which commenced commercial operations in the fourth quarter of 2017, and a one-time payment related to Pembina assuming operatorship of Younger, partially offset by the planned turnaround at Harmattan and lower rates at Blair Creek due to contractual arrangements with producers. During the second quarter of 2018, AltaGas recorded equity earnings of $1 million from Petrogas, compared to $2 million in the same quarter of 2017. The decrease in Petrogas earnings was due to unrealized mark to market losses on hedges.

During the second quarter of 2018, AltaGas hedged approximately 7,500 Bbls/d of NGL at an average frac spread of $33/Bbl excluding basis differentials. During the second quarter of 2017, AltaGas hedged 5,500 Bbls/d of NGL at an average price of $23/Bbl, excluding basis differentials. The average indicative spot NGL frac spread in the second quarter of 2018 was approximately $22/Bbl, compared to $11/Bbl in the second quarter of 2017 inclusive of basis differentials. The realized frac spread (based on average spot price and realized hedge price inclusive of basis differentials) of approximately $15/Bbl in the second quarter of 2018 (2017 - $9/Bbl) was higher than the same quarter in 2017 due to improved commodity prices and higher hedged prices.

Six Months Ended June 30

The Gas segment reported normalized EBITDA of $119 million in the first half of 2018, compared to $108 million in the same period of 2017. The increase in normalized EBITDA was due to higher realized frac spread and frac exposed volumes, contributions from the North Pine and Townsend 2A facilities which commenced commercial operations in the fourth quarter of 2017, and a one-time payment related to the change in operatorship of Younger, partially offset by lower natural gas storage margins, the impact of the sale of the EDS and JFP transmission assets in the first quarter of 2017, the planned turnaround at Harmattan, and lower rates at Blair Creek due to contractual arrangements with producers. During the first half of 2018, AltaGas recorded equity earnings of $11 million from Petrogas, compared to $13 million in the same period 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.

During the first half of 2018, AltaGas hedged approximately 7,500 Bbls/d of NGL at an average frac spread of $33/Bbl, excluding basis differentials. During the first half of 2017, AltaGas hedged 5,400 Bbls/d of NGL at an average price of $22/Bbl, excluding basis differentials. The average indicative spot NGL frac spread for first half of 2018 was approximately $22/Bbl compared to $14/Bbl in the same period of 2017 inclusive of basis differentials. The realized frac spread (based on average spot price and realized hedge price inclusive of basis differentials) of approximately $17/Bbl in the first half of 2018 (2017 - $10/Bbl) was higher than the same period in 2017 due to improved commodity prices and higher hedged prices.

During the first half of 2018, AltaGas recognized a pre-tax gain of $1 million on the sale of a non-core gas processing facility while in the first half of 2017, AltaGas recognized a pre-tax loss of $3 million on the sale of the EDS and JFP transmission assets.

On April 3, 2018, AltaGas entered into a long-term natural gas processing arrangement (the Processing Arrangement) with Birchcliff Energy Ltd. (Birchcliff) 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.

POWER

OPERATING STATISTICS

	Three Months Ended June 30		Six Months Ended June 30	
	2018	2017	**2018**	2017
Renewable power sold (GWh)	**504**	499	**630**	647
Conventional power sold (GWh)	**642**	409	**1,484**	793
Renewable capacity factor (%)	**51.7**	50.7	**30.0**	30.1
Contracted conventional equivalent availability factor (%) (1)	**97.7**	99.9	**96.6**	98.2

(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 second quarter of 2018, the volume of renewable power sold was comparable to the same quarter in 2017. The volume of conventional power sold increased by 233 GWh, a 57 percent increase compared to the same quarter of 2017. The significant increase in conventional volumes was due to increased run time at Blythe due to greater operational and fuel flexibility.

The renewable capacity factor for the second quarter of 2018 increased due to higher river flow at the Forrest Kerr Hydro facility and favorable wind conditions at Bear Mountain in the second quarter of 2018 compared to the second quarter of 2017. The contracted conventional equivalent availability factor was lower in the second quarter of 2018 as a result of unplanned outages at Blythe.

During the first half of 2018, the volume of renewable power sold decreased by 17 GWh and the volume of conventional power sold increased by 691 GWh, an 87 percent increase compared to the same period in 2017. The renewable power volume decrease was due to lower generation at the Northwest Hydro facilities, lower generation at the Craven biomass facility (Craven) and weaker wind generation at the Bear Mountain wind facility. The significant increase in conventional volumes was due to higher dispatch at Blythe, due to greater operational and fuel flexibility.

The variances related to the renewable capacity factor for the first half of 2018 decreased due to lower river flows at the Northwest Hydro Facilities and unfavorable wind conditions at Bear Mountain during the early part of 2018. The contracted conventional availability factor was lower for the first half of 2018 due to a longer planned outage and increased unplanned outages at Blythe.

Three Months Ended June 30

The Power segment reported normalized EBITDA of $75 million in the second quarter of 2018, compared to $77 million in the same period of 2017. Normalized EBITDA decreased as a result of the weaker U.S. dollar, higher operating costs at the

Northwest Hydro facilities, and the expiry of the Ripon PPA on May 30, 2018 (partially offset by the new RA contract which began in the second quarter of 2018 and is in place until the end of 2018), partially offset by the timing of the Craven spring outage which occurred in the first quarter of 2018 compared to the second quarter of 2017, and a higher contribution from the Grayling biomass facility due to lower operating costs. Normalized EBITDA from Canadian conventional assets was also higher, due to higher generation and higher Alberta power prices, partially offset by lower hedge gains.

On June 22, 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. AltaGas will continue to consolidate the entities that hold the Northwest Hydro facilities. In the second quarter of 2017, the Power segment disposed of certain non-core development stage wind assets in Alberta for proceeds of approximately $1 million, resulting in a pre-tax gain on disposition of approximately $1 million. This was largely offset by a pre-tax provision of $1 million taken on certain non-core development stage gas-fired peaking assets in Alberta.

Six Months Ended June 30

The Power segment reported normalized EBITDA of $116 million in the first half of 2018, compared to $127 million in the same period of 2017. Normalized EBITDA decreased as a result of the weaker U.S. dollar, expenses related to the outages at Blythe, the expiry of the Ripon PPA on May 30, 2018 (partially offset by the new RA contract which began in the second quarter of 2018 and is in place until the end of 2018), lower contributions from Craven due to unplanned outages and lower contract terms, and lower early spring river flows and higher operating costs at the Northwest Hydro facilities due to minor repair work completed during the planned outage.

UTILITIES

OPERATING STATISTICS

	Three Months Ended June 30		Six Months Ended June 30	
	2018	2017	**2018**	2017
Canadian utilities				
Natural gas deliveries - end-use (PJ)[(1)]	**5.6**	4.8	**19.6**	18.4
Natural gas deliveries - transportation (PJ)[(1)]	**1.4**	1.5	**3.2**	3.4
U.S. utilities				
Natural gas deliveries - end-use (Bcf)[(1)]	**12.0**	10.3	**43.0**	40.5
Natural gas deliveries - transportation (Bcf)[(1)]	**10.9**	11.5	**24.3**	26.9
Service sites [(2)]	**580,526**	575,084	**580,526**	575,084
Degree day variance from normal - AUI (%) [(3)]	**3.9**	(7.4)	**8.9**	(3.3)
Degree day variance from normal - Heritage Gas (%) [(3)]	**6.7**	(4.3)	**(5.9)**	(2.5)
Degree day variance from normal - SEMCO Gas (%) [(4)]	**14.8**	(8.4)	**5.5**	(11.1)
Degree day variance from normal - ENSTAR (%) [(4)]	**(6.1)**	(5.4)	**(3.0)**	5.2

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

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

(3) A degree day for AUI and Heritage Gas is the cumulative extent to which the daily mean temperature falls below 15 degrees Celsius at AUI and 18 degrees Celsius at Heritage Gas. Normal degree days are based on a 20-year rolling average. Positive variances from normal lead to increased delivery volumes from normal expectations. Degree day variances do not materially affect the results of PNG, as the BCUC has approved a rate stabilization mechanism for its residential and small commercial customers.

(4) 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 and during the prior 10 years for ENSTAR.

During the second quarter of 2018, AltaGas' Utilities segment experienced colder weather compared to the same quarter of 2017. This was mainly driven by 15 percent colder than normal weather at SEMCO and 4 percent colder than normal weather at AUI, partially offset by 6 percent warmer than normal weather at ENSTAR. Overall colder weather resulted in increased natural gas deliveries to end-use customers in both Canada and the U.S.

During the first half of 2018, AltaGas' Utilities segment experienced colder weather compared to the same period of 2017. This was mainly driven by 6 percent colder than normal weather at SEMCO and 9 percent colder than normal weather at AUI, partially offset by 6 percent warmer than normal weather at Heritage Gas and 3 percent warmer than normal weather at ENSTAR. Overall colder weather resulted in increased natural gas deliveries to end-use customers in both Canada and the U.S.

Service sites at June 30, 2018 increased by approximately 5,400 sites compared to June 30, 2017 due to growth in the customer base at all of the utilities.

Three Months Ended June 30

The Utilities segment reported normalized EBITDA of $50 million in the second quarter of 2018, compared to $55 million in the same quarter of 2017. The decrease was mainly due to 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 2018 revenue impact related to the federal tax reduction at SEMCO and ENSTAR of approximately $4 million, higher expenses, and the unfavorable impact of the stronger Canadian dollar. The decrease was partially offset by colder weather and higher volumes in Alberta and Michigan, and higher rates in Alberta, Michigan and Alaska.

Six Months Ended June 30

The Utilities segment reported normalized EBITDA of $162 million in the first half of 2018, compared to $170 million in the same period of 2017. The decrease was mainly due to 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 2018 revenue impact related to the federal tax reduction at SEMCO and ENSTAR of approximately $7 million, the impact of the stronger Canadian dollar, and lower expenses in 2017 primarily due to favorable pension true-ups at the U.S. utilities. Also contributing to the decrease is lower customer usage at AUI and warmer weather in Nova Scotia and Alaska. The decrease was partially offset by colder weather in Michigan and Alberta and higher interruptible storage service revenue at CINGSA.

Washington Gas Rate Cases

On May 15, 2018, Washington Gas filed an application with the PSC of MD to increase its base rates for natural gas service, generating approximately US$41 million of additional revenue. The revenue increase includes an increase in base rates of approximately US$56 million partially offset by a reduction of approximately US$15 million in annual surcharges currently paid by customers for system upgrades. A PSC of MD decision is expected in mid-December 2018.

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 asks for approval of approximately US$394 million in accelerated infrastructure replacements for the 2019 to 2023 period. A prehearing conference was held in late July 2018 and a PSC of MD decision is expected in mid-December 2018.

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.

CORPORATE

Three Months Ended June 30

In the Corporate segment, normalized EBITDA for the second quarter of 2018 and 2017 was a loss of $7 million. Increases to professional and consulting fees and information technology related costs were fully offset by decreases to regulatory compliance and corporate promotion expenses.

Six Months Ended June 30

In the Corporate segment, normalized EBITDA for the first half of 2018 was a loss of $9 million, compared to a loss of $11 million in the same period of 2017. The decrease was a result of a number of factors including lower regulatory compliance, corporate promotion, and information technology related costs, partially offset by higher professional and consulting fees.

INVESTED CAPITAL

					Three Months Ended June 30, 2018
($ millions)	**Gas**	**Power**	**Utilities**	**Corporate**	**Total**
Invested capital:					
Property, plant and equipment	**$ 61**	**$ 9**	**$ 54**	**$ 1**	**$ 125**
Intangible assets	**2**	**—**	**1**	**1**	**4**
Contributions from non-controlling interest	**(9)**	**—**	**—**	**—**	**(9)**
Invested capital	**54**	**9**	**55**	**2**	**120**
Disposals:					
Property, plant and equipment	**(1)**	**—**	**—**	**—**	**(1)**
Net invested capital	**$ 53**	**$ 9**	**$ 55**	**$ 2**	**$ 119**

					Three Months Ended June 30, 2017
($ millions)	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	$ 89	$ 6	$ 31	$ —	$ 126
Intangible assets	—	1	1	1	3
Contributions from non-controlling interest	(6)	—	—	—	(6)
Invested capital	83	7	32	1	123
Disposals:					
Property, plant and equipment	—	(1)	—	—	(1)
Net invested capital	$ 83	$ 6	$ 32	$ 1	$ 122

During the second quarter of 2018, AltaGas' invested capital was $120 million, compared to $123 million in the same quarter of 2017. The decrease in invested capital was primarily due to higher contributions from non-controlling interest (representing Vopak's share of construction costs related to RIPET) as well as lower additions to property, plant and equipment for the three months ended June 30, 2018 compared to the same period of 2017. The decrease in additions to property, plant and equipment in the second quarter of 2018 was primarily due to the absence of costs incurred in the second quarter of 2017 related to the construction of the Townsend 2A and North Pine facilities, partially offset by the purchase of an office building at SEMCO and costs related to the construction of RIPET.

The invested capital in the second quarter of 2018 included maintenance capital of $10 million (2017 - $2 million) in the Gas segment and $7 million (2017 - $3 million) in the Power segment. The increase in maintenance capital for the Gas segment was primarily due to the planned turnaround at Harmattan in the second quarter of 2018, and in the Power segment was due to costs of approximately $5 million incurred during a planned outage at the Northwest Hydro facilities in the second quarter of 2018.

($ millions)		Gas		Power		Utilities		Corporate		Six Months Ended June 30, 2018 Total
Invested capital:										
Property, plant and equipment	**$**	**115**	**$**	**13**	**$**	**71**	**$**	**1**	**$**	**200**
Intangible assets		**2**		**1**		**1**		**2**		**6**
Long-term investments		**19**		**—**		**—**		**—**		**19**
Contributions from non-controlling interest		**(23)**		**—**		**—**		**—**		**(23)**
Invested capital		**113**		**14**		**72**		**3**		**202**
Disposals:										
Property, plant and equipment		**(8)**		**(2)**		**—**		**—**		**(10)**
Net invested capital	**$**	**105**	**$**	**12**	**$**	**72**	**$**	**3**	**$**	**192**

($ millions)		Gas		Power		Utilities		Corporate		Six Months Ended June 30, 2017 Total
Invested capital:										
Property, plant and equipment	$	134	$	15	$	47	$	1	$	197
Intangible assets		1		1		1		2		5
Long-term investments		14		—		—		—		14
Contributions from non-controlling interest		(6)		—		—		—		(6)
Invested capital		143		16		48		3		210
Disposals:										
Property, plant and equipment		(67)		(2)		(1)		—		(70)
Net invested capital	$	76	$	14	$	47	$	3	$	140

During the first half of 2018, AltaGas' invested capital was $202 million, compared to $210 million in the same period of 2017. The decrease in invested capital in the first half of 2018 was mainly due to higher contributions from non-controlling interest (representing Vopak's share of construction costs related to RIPET), partially offset by a higher contribution to long-term investments (AIJVLP) and higher additions to property, plant and equipment.

The increase in additions to property, plant and equipment in the first half of 2018 was mainly due to costs related to the construction of RIPET and SEMCO's purchase of its office building, partially offset by costs incurred in the first half of 2017 related to the construction of the Townsend 2A and North Pine facilities. The disposals of property, plant and equipment in the first half of 2018 primarily related to non-core facilities in the Gas segment and a development stage wind asset in the Power segment, while in the first half of 2017 the disposals of property, plant and equipment related to the sale of the EDS and JFP transmission assets.

The invested capital in the first half of 2018 included maintenance capital of $13 million (2017 - $2 million) in the Gas segment and $9 million (2017 - $6 million) in the Power segment. The increase in maintenance capital for the first half of 2018 was primarily due to the same factors impacting the increased maintenance capital in the second quarter of 2018.

RISK MANAGEMENT

AltaGas is exposed to various market risks in the normal course of operations that could impact earnings and cash flows. At times, AltaGas will enter into financial derivative contracts to manage exposure to fluctuations in commodity prices and foreign exchange rates. The Board of Directors of AltaGas has established a risk management policy for the Corporation establishing AltaGas' risk management control framework. Financial derivative instruments are governed under, and subject to, this policy. As at June 30, 2018 and December 31, 2017, the fair values of the Corporation's derivatives were as follows:

($ millions)		**June 30, 2018**		December 31, 2017
Natural gas	**$**	**(6)**	$	6
NGL frac spread		**(21)**		(24)
Power		**(9)**		(1)
Foreign exchange		**2**		2
Net derivative liability	**$**	**(34)**	$	(17)

Commodity Price Contracts

From time to time, the Corporation executes gas, power, and other commodity contracts to manage its asset portfolio and lock in margins from back-to-back purchase and sale agreements. The fair value of power, natural gas, and NGL derivatives was calculated using estimated forward prices from published sources for the relevant period. AltaGas has not elected hedge accounting for any of its derivative contracts currently in place. Changes in the fair value of these derivative contracts are recorded in the Consolidated Statement of Income in the period in which the change occurs.

The Power segment has various fixed price power purchase and sale contracts in the Alberta market, which are expected to be settled over the next five years.

The Corporation also executes fixed-for-floating NGL frac spread swaps to manage its 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 six months ended June 30, 2018 was approximately $22/Bbl (2017 – $14/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 six months ended June 30, 2018 was approximately $17/Bbl inclusive of basis differentials (2017 - $10/Bbl). For the remainder of 2018, AltaGas currently has frac hedges in place to hedge approximately 7,500 Bbls/d at an average price of $33/Bbl, excluding basis differentials.

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 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 June 30, 2018 and December 31, 2017, management has not designated any outstanding U.S. dollar denominated long-term debt to hedge against the currency translation effect of its foreign investments. Designation of U.S. dollar denominated long-term debt 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 three and six months ended June 30, 2018, AltaGas incurred after-tax unrealized gains of $nil arising from the translation of debt in other comprehensive income (three and six months ended June 30, 2017 - after-tax unrealized gains of $6 million and $7 million, respectively).

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 three and six months ended June 30, 2018, unrealized gains of $35 million and $34 million, respectively, and a realized loss of $36 million were recognized in revenue in relation to these contracts (2017 - unrealized losses of $16 million and $22 million, respectively). 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. These foreign exchange derivatives do not qualify for hedge accounting. Therefore, all changes in fair value are recognized in net income. For the three and six months ended June 30, 2018, unrealized gains of $2 million were recognized in revenue in relation to these forward contracts (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 June 30		Six Months Ended June 30	
($ millions)	**2018**	2017	**2018**	2017
Natural gas	**$ (5)**	$ —	**$ (11)**	$ (2)
Storage optimization	**—**	1	**—**	3
NGL frac spread	**(8)**	2	**3**	10
Power	**(2)**	(9)	**(5)**	(9)
Foreign exchange	**37**	(16)	**36**	(23)
	$ 22	$ (22)	**$ 23**	$ (21)

Please refer to Note 20 of the 2017 Annual Consolidated Financial Statements and Note 12 of the unaudited condensed interim Consolidated Financial Statements as at and for the three and six months ended June 30, 2018 for further details regarding AltaGas' risk management activities.

LIQUIDITY

	Three Months Ended June 30		Six Months Ended June 30	
($ millions)	**2018**	2017	**2018**	2017
Cash from operations	**$ 147**	$ 102	**$ 336**	$ 302
Investing activities	**(107)**	(129)	**(196)**	(176)
Financing activities	**642**	150	**609**	7
Increase in cash and cash equivalents	**$ 682**	$ 123	**$ 749**	$ 133

Cash from Operations

Cash from operations increased by $34 million for the six months ended June 30, 2018, compared to the same period in 2017, primarily due to higher net income after taxes and a favorable variance in net change in operating assets and liabilities. The favorable variance in net change in operating assets and liabilities was primarily due to the absence of prepayments on long-term service agreements related to RIPET in the first half of 2018, a reduction in the deferred lease receivable relating to Townsend and a reduction in non-utility inventory, partially offset by non-utility timing of receivables, lower pre-payments from a customer and the recognition of a contract asset in the first half of 2018. The contract asset is related to Accounting Standard Update No. 2014-09 "Revenue from Contracts with Customers" which was adopted in 2018. Please refer to Note 11 of the unaudited condensed interim Consolidated Financial Statements for additional details.

Working Capital

($ millions except current ratio)		June 30, 2018		December 31, 2017
Current assets	**$**	**1,284**	$	702
Current liabilities		**769**		815
Working capital (deficiency)	**$**	**515**	$	(113)
Working capital ratio		**1.67**		0.86

The improvement in working capital ratio was primarily due to an increase of cash on hand due to the proceeds received from the minority sale of Northwest Hydro, a decrease in short-term debt, and a decrease in accounts payable and accrued liabilities, partially offset by a decrease in accounts receivable and inventory and an increase to the current portion of long-term debt. AltaGas' working capital will fluctuate in the normal course of business.

Investing Activities

Cash used in investing activities for the six months ended June 30, 2018 was $196 million, compared to $176 million in the same period in 2017. Investing activities for the six months ended June 30, 2018 primarily included expenditures of approximately $195 million for property, plant, and equipment, and approximately $19 million of contributions to AltaGas' equity investments, partially offset by cash proceeds of approximately $23 million, net of transaction costs, primarily from the sale of non-core gas facilities and a wind asset, as well as the sale of an investment. Investing activities for the six months ended June 30, 2017 primarily included expenditures of approximately $179 million for property, plant, and equipment, approximately $36 million for derivative contracts, and approximately $14 million of contributions to AltaGas' equity investments, partially offset by cash proceeds of approximately $70 million, net of transaction costs, primarily from the sale of the EDS and JFP transmission assets.

Financing Activities

Cash from financing activities for the six months ended June 30, 2018 was $609 million, compared to $7 million in the same period in 2017. Financing activities for the six months ended June 30, 2018 were primarily comprised of the proceeds from the sale of the non-controlling interest in the Northwest Hydro facilities of $921 million (net of transaction costs), net proceeds from the issuance of common shares of $135 million (mainly from common shares issued through the DRIP), contributions from non-controlling interests of $23 million and net borrowings under bankers' acceptances of $8 million, partially offset by repayments of long-term debt and short-term debt of $205 million and $48 million, respectively. Financing activities for the six months ended June 30, 2017 were primarily comprised of net proceeds from the issuance of preferred shares of $293 million and common shares of $121 million (mainly from common shares issued through the DRIP), net borrowings under bankers' acceptances of $344 million, issuance of long-term debt of $196 million, and proceeds from the sale of a non-controlling interest in RIPET to Vopak of $24 million, partially offset by repayments of long-term debt and short-term debt of $634 million and $125 million, respectively. Total dividends paid to common and preferred shareholders of AltaGas for the six months ended June 30, 2018 were $227 million (2017 - $207 million), of which $134 million was reinvested through the DRIP (2017 - $117 million). The increase in dividends paid was due to more common 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, maximize the profitability of its existing assets and grow its energy infrastructure to create long-term value and enhance returns for its investors. AltaGas' capital structure is comprised of shareholders' equity (including non-controlling interests), short-term and long-term debt (including the current portion) less cash and cash equivalents.

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

($ millions)		June 30, 2018		December 31, 2017
Short-term debt	**$**	**—**	$	47
Current portion of long-term debt		**214**		189
Long-term debt[1]		**3,249**		3,437
Total debt		**3,463**		3,673
Less: cash and cash equivalents		**(784)**		(27)
Net debt	**$**	**2,679**	$	3,646
Shareholders' equity		**5,035**		4,573
Non-controlling interests		**510**		66
Total capitalization	**$**	**8,224**	$	8,285
Net debt-to-total capitalization (%)		**33**		44

(1) Net of debt issuance costs of $14 million as at June 30, 2018 (December 31, 2017 - $14 million).

As at June 30, 2018, AltaGas' total debt primarily consisted of outstanding MTNs of $2.7 billion (December 31, 2017 - $2.9 billion), PNG debenture notes of $34 million (December 31, 2017 - $34 million), SEMCO long-term debt of $481 million (December 31, 2017 - $462 million) and $212 million drawn under the bank credit facilities (December 31, 2017 - $260 million). In addition, AltaGas had $210 million of letters of credit (December 31, 2017 - $120 million) outstanding.

As at June 30, 2018, AltaGas' total market capitalization was approximately $4.9 billion based on approximately 181 million common shares outstanding and a closing trading price on June 30, 2018 of $27.15 per common share.

AltaGas' earnings interest coverage for the rolling 12 months ended June 30, 2018 was 1.4 times (12 months ended June 30, 2017 – 2.2 times).

Credit Facilities

($ millions)		Borrowing capacity		Drawn at June 30, 2018		Drawn at December 31, 2017
Demand credit facilities	$	220	**$**	**164**	$	75
Extendible revolving letter of credit facility		150		**41**		41
PNG operating facility		25		**4**		13
PNG credit facility		25		**—**		—
AltaGas Ltd. revolving credit facility [1]		1,400		**212**		219
AltaGas Ltd. revolving US$300 million credit facility [1] [2]		395		**—**		—
SEMCO Energy US$150 million unsecured credit facility [1] [2]		198		**1**		32
	$	2,413	**$**	**422**	$	380

(1) Amount drawn at June 30, 2018 converted at the month-end rate of 1 U.S. dollar = 1.3168 Canadian dollar (December 31, 2017 - 1 U.S. dollar = 1.2545 Canadian dollar).

(2) Borrowing capacity was converted at the June 30, 2018 U.S./Canadian dollar month-end exchange rate.

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 June 30, 2018**
Bank debt-to-capitalization[(1)]	not greater than 65 percent	29.5%
Bank EBITDA-to-interest expense [(1) (2)]	not less than 2.5x	3.9
Bank debt-to-capitalization (SEMCO)[(3)]	not greater than 60 percent	36.9%
Bank EBITDA-to-interest expense (SEMCO)[(3)]	not less than 2.25x	7.5

(1) Calculated in accordance with the Corporation's credit facility agreement, which is available on SEDAR at www.sedar.com.

(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.

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 June 30, 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 June 30, 2018, US$2 billion was available under the base shelf prospectus.

RELATED PARTY TRANSACTIONS

In the normal course of business, AltaGas transacts with its subsidiaries, affiliates and joint ventures. There were no significant changes in the nature of the related party transactions described in Note 27 of the 2017 Annual Consolidated Financial Statements.

SHARE INFORMATION

	As at July 20, 2018
Issued and outstanding	
Common shares	266,087,547
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
Issued	
Share options	4,938,123
Share options exercisable	3,474,359

DIVIDENDS

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

The following table summarizes AltaGas' dividend declaration history:

Dividends

Year ended December 31 *($ per common share)*		**2018**		2017
First quarter	**$**	**0.547500**	$	0.525000
Second quarter		**0.547500**		0.525000
Third quarter		**—**		0.525000
Fourth quarter		**—**		0.540000
Total	**$**	**1.095000**	$	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
Fourth quarter		**—**		0.211250
Total	**$**	**0.422500**	$	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		**—**		0.201010
Fourth quarter		**—**		0.214250
Total	**$**	**0.456320**	$	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		**—**		0.275000
Fourth quarter		**—**		0.330625
Total	**$**	**0.661250**	$	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
Fourth quarter		**—**		0.312500
Total	**$**	**0.625000**	$	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
Fourth quarter		**—**		0.296875
Total	**$**	**0.593750**	$	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
Fourth quarter		**—**		0.328125
Total	**$**	**0.656250**	$	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
Fourth quarter		**—**		0.312500
Total	**$**	**0.625000**	$	1.063400

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. Other than as described below, AltaGas' significant accounting policies have remained unchanged and are contained in the notes to the 2017 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.

AltaGas' critical accounting estimates continue to be revenue recognition, financial instruments, depreciation and amortization expense, asset retirement obligations and other environmental costs, asset impairment assessments, income taxes, pension plans and post-retirement benefits, regulatory assets and liabilities, and contingencies. For a full discussion of these accounting estimates, refer to the 2017 Annual Consolidated Financial Statements and MD&A.

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 11 of the unaudited condensed interim Consolidated Financial Statements as at and for the three and six months ended June 30, 2018 for further details. AltaGas does not expect the application of ASC 606 to have a material impact on its 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, $0.4 million and $0.8 million of net benefit cost associated with other components were reclassified from the line item

"Operating and administrative" to "Other loss" on the Consolidated Statement of Income for the three and six months ended June 30, 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; 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 for all leases with lease terms greater than 12 months. 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 No. 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. The amendments to the new leases standard are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. In transition, lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. AltaGas is currently performing a scoping exercise by gathering a complete inventory of lease contracts in order to evaluate the impact of adopting ASC 842 on its consolidated financial statements, but expects that the new standard will have an impact on the Corporation's balance sheet as all operating leases will need to be reflected on the balance sheet upon adoption. In addition, AltaGas currently expects to 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.

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 February 2018, FASB issued 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. The amendments in this ASU are effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted and AltaGas plans to adopt this ASU effective July 1, 2018. 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. 2018-07 "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.

OFF-BALANCE SHEET ARRANGEMENTS

With the exception of the subscription receipts and the net proceeds thereof held in escrow as described under the *Developments Relating to the WGL Acquisition* section of this MD&A, AltaGas did not enter into any material off-balance sheet arrangements during the three and six months ended June 30, 2018. Reference should be made to the audited Consolidated Financial Statements and MD&A as at and for the year ended December 31, 2017 for information on off-balance sheet arrangements.

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

During the first half of 2018, there were no changes made to AltaGas' ICFR that materially affected, or are reasonably likely to materially affect, its ICFR.

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)	**Q2-18**	Q1-18	Q4-17	Q3-17	Q2-17	Q1-17	Q4-16	Q3-16
Total revenue	**610**	878	745	502	539	771	661	492
Normalized EBITDA(2)	**166**	223	213	190	166	228	194	176
Net income (loss) applicable to common shares	**1**	49	(11)	18	(8)	32	38	46
($ per share)	**Q2-18**	Q1-18	Q4-17	Q3-17	Q2-17	Q1-17	Q4-16	Q3-16
Net income (loss) per common share								
Basic	**0.01**	0.28	(0.06)	0.10	(0.05)	0.19	0.23	0.28
Diluted	**0.01**	0.28	(0.06)	0.10	(0.05)	0.19	0.23	0.28
Dividends declared	**0.55**	0.55	0.54	0.53	0.53	0.53	0.53	0.52

(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. The run-of-river hydroelectric facilities in British Columbia are also impacted by seasonal precipitation and snowpack melt, which create periods of high flow during the spring and summer months.

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

- The weak NGL commodity prices throughout 2016 and the improved NGL commodity prices in 2017 and the first half of 2018;
- The weak Alberta power pool prices throughout 2016 and 2017;
- The stronger U.S. dollar throughout 2016 and 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 the first half of 2018;
- The commencement of commercial operations early in the third quarter of 2016 at the integrated midstream complex at Townsend in northeast British Columbia, including the Townsend Facility, gas gathering line, NGL egress pipelines and truck terminal;
- The recovery of $7 million of development costs related to the PNG Pipeline Looping Project in the third quarter of 2016;
- The commissioning of the Pomona Energy Storage Facility on December 31, 2016;
- 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; and
- The negative impact on revenue of U.S. tax reform at the U.S. utilities in the first half 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 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 U.S. tax reform resulting in a decrease in tax expense of approximately $34 million in the fourth quarter of 2017; and
- After-tax transaction costs incurred throughout 2017 (totaling $53 million) and in the first half of 2018 ($16 million) predominantly due to the WGL Acquisition.

Consolidated Balance Sheets

(condensed and unaudited)

As at *($ millions)*	**June 30, 2018**	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents *(note 18)*	**$ 783.8**	$ 27.3
Accounts receivable, net of allowances	**262.9**	382.9
Inventory *(note 5)*	**178.2**	201.1
Restricted cash holdings from customers *(note 18)*	**4.0**	8.9
Regulatory assets	**1.5**	1.1
Risk management assets *(note 12)*	**26.5**	38.6
Prepaid expenses and other current assets	**26.8**	36.0
Assets held for sale *(note 4)*	**—**	6.0
	1,283.7	701.9
Property, plant and equipment	**6,883.6**	6,689.8
Intangible assets	**585.8**	588.8
Goodwill *(note 6)*	**844.4**	817.3
Regulatory assets	**333.5**	328.6
Risk management assets *(note 12)*	**13.9**	15.9
Deferred income taxes	**2.8**	2.8
Restricted cash holdings from customers *(note 18)*	**5.9**	7.5
Long-term investments and other assets *(note 7)*	**330.4**	312.6
Investments accounted for by the equity method	**592.1**	567.0
	$ 10,876.1	$ 10,032.2
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	**$ 389.3**	$ 415.3
Dividends payable	**33.0**	32.0
Short-term debt	**—**	46.8
Current portion of long-term debt *(notes 9 and 12)*	**214.1**	188.9
Customer deposits	**20.9**	30.8
Regulatory liabilities	**22.6**	10.9
Risk management liabilities *(note 12)*	**65.1**	57.6
Other current liabilities	**24.0**	32.6
Liabilities associated with assets held for sale *(note 4)*	**—**	0.3
	769.0	815.2
Long-term debt *(notes 9 and 12)*	**3,249.0**	3,436.5
Asset retirement obligations	**90.7**	88.3
Deferred income taxes	**601.8**	444.2
Regulatory liabilities	**280.4**	268.6
Risk management liabilities *(note 12)*	**9.0**	13.8
Other long-term liabilities	**208.4**	201.9
Future employee obligations	**123.1**	124.5
	$ 5,331.4	$ 5,393.0

As at *($ millions)*	**June 30, 2018**	December 31, 2017
Shareholders' equity		
Common shares, no par values, unlimited shares authorized; 2018 - 180.7 million and 2017 - 175.3 million issued and outstanding *(note 13)*	**$ 4,142.9**	$ 4,007.9
Preferred shares *(note 13)*	**1,277.7**	1,277.7
Contributed surplus	**357.9**	22.3
Accumulated deficit	**(1,085.7)**	(933.6)
Accumulated other comprehensive income (AOCI) *(note 10)*	**342.4**	199.1
Total shareholders' equity	**5,035.2**	4,573.4
Non-controlling interests	**509.5**	65.8
Total equity	**5,544.7**	4,639.2
	$ 10,876.1	$ 10,032.2

Variable interest entities (note 8).
Commitments, contingencies and guarantees (note 15).
Subsequent events (note 21).

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Income

(condensed and unaudited)

($ millions except per share amounts)	Three months ended June 30 2018	Three months ended June 30 2017	Six months ended June 30 2018	Six months ended June 30 2017
REVENUE *(note 11)*	**$ 609.8**	$ 538.8	**$ 1,488.2**	$ 1,310.0
EXPENSES				
Cost of sales, exclusive of items shown separately	**324.7**	271.3	**862.6**	705.5
Operating and administrative	**146.3**	136.0	**287.1**	295.7
Accretion expenses	**2.7**	2.7	**5.5**	5.5
Depreciation and amortization	**72.9**	70.7	**145.5**	142.1
Provisions on assets	**—**	1.3	**—**	1.3
	546.6	482.0	**1,300.7**	1,150.1
Income from equity investments	**2.7**	3.0	**12.8**	17.1
Other loss	**(1.3)**	(2.7)	**(6.6)**	(5.2)
Foreign exchange gains	**0.6**	1.1	**0.6**	1.4
Interest expense				
Short-term debt	**(0.4)**	(0.8)	**(1.2)**	(1.7)
Long-term debt	**(42.5)**	(40.0)	**(84.9)**	(85.3)
Income before income taxes	**22.3**	17.4	**108.2**	86.2
Income tax expense (recovery) *(note 17)*				
Current	**9.8**	10.3	**22.5**	21.6
Deferred	**(7.6)**	(2.7)	**(1.9)**	7.2
Net income after taxes	**20.1**	9.8	**87.6**	57.4
Net income applicable to non-controlling interests	**2.3**	1.9	**4.6**	4.2
Net income applicable to controlling interests	**17.8**	7.9	**83.0**	53.2
Preferred share dividends	**(16.4)**	(15.9)	**(32.8)**	(29.5)
Net income (loss) applicable to common shares	**$ 1.4**	$ (8.0)	**$ 50.2**	$ 23.7
Net income (loss) per common share *(note 14)*				
Basic	**$ 0.01**	$ (0.05)	**$ 0.28**	$ 0.14
Diluted	**$ 0.01**	$ (0.05)	**$ 0.28**	$ 0.14
Weighted average number of common shares outstanding (millions) *(note 14)*				
Basic	**179.3**	169.9	**177.9**	168.9
Diluted	**179.4**	169.9	**178.1**	169.2

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Comprehensive Income (Loss)

(condensed and unaudited)

($ millions)	Three months ended June 30 **2018**	Three months ended June 30 2017	Six months ended June 30 **2018**	Six months ended June 30 2017
Net income after taxes	**$ 20.1**	$ 9.8	**$ 87.6**	$ 57.4
Other comprehensive income (loss), net of taxes				
Gain (loss) on foreign currency translation	**58.3**	(70.1)	**131.5**	(94.3)
Unrealized gain on net investment hedge *(note 12)*	**—**	5.5	**—**	6.8
Reclassification of actuarial gains and prior service costs on defined benefit (DB) and post-retirement benefit plans (PRB) to net income *(note 16)*	**0.1**	0.2	**0.3**	0.4
Settlement of PRB plan	**—**	0.2	**—**	0.2
Curtailment of DB and PRB plan	**2.7**	—	**2.7**	—
Unrealized loss on available-for-sale assets	**—**	(0.1)	**—**	(17.5)
Adoption of ASU 2016-01 *(note 2)*	**—**	—	**7.1**	—
Other comprehensive income (loss) from equity investees	**0.4**	0.1	**1.7**	(1.1)
Total other comprehensive income (loss) (OCI), net of taxes *(note 10)*	**61.5**	(64.2)	**143.3**	(105.5)
Comprehensive income (loss) attributable to controlling interests and non-controlling interests, net of taxes	**$ 81.6**	$ (54.4)	**$ 230.9**	$ (48.1)
Comprehensive income (loss) attributable to:				
Non-controlling interests	**$ 2.3**	$ 1.9	**$ 4.6**	$ 4.2
Controlling interests	**79.3**	(56.3)	**226.3**	(52.3)
	$ 81.6	$ (54.4)	**$ 230.9**	$ (48.1)

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Equity

(condensed and unaudited)

Six months ended June 30 ($ millions)		**2018**		2017
Balance, beginning of period	**$**	**4,007.9**	$	3,773.4
Shares issued for cash on exercise of options		**1.1**		3.7
Shares issued under DRIP [(1)]		**133.9**		117.4
Balance, end of period	**$**	**4,142.9**	$	3,894.5
Preferred shares *(note 13)*				
Balance, beginning of period	**$**	**1,277.7**	$	985.1
Series K Issued		**—**		293.4
Deferred taxes on share issuance costs		**—**		1.9
Balance, end of period	**$**	**1,277.7**	$	1,280.4
Contributed surplus				
Balance, beginning of period	**$**	**22.3**	$	17.4
Share options expense		**0.5**		0.7
Exercise of share options		**(0.1)**		(0.3)
Adoption of ASU No. 2016-09		**—**		1.1
Sale of non-controlling interest *(notes 4 and 8)*		**335.2**		3.0
Balance, end of period	**$**	**357.9**	$	21.9
Accumulated deficit				
Balance, beginning of period	**$**	**(933.6)**	$	(600.4)
Net income applicable to controlling interests		**83.0**		53.2
Common share dividends		**(195.2)**		(177.7)
Preferred share dividends		**(32.8)**		(29.5)
Adoption of ASU No. 2016-09		**—**		(1.1)
Adoption of ASU No. 2016-01 *(note 2)*		**(7.1)**		—
Balance, end of period	**$**	**(1,085.7)**	$	(755.5)
AOCI (*note 10*)				
Balance, beginning of period	**$**	**199.1**	$	405.1
Other comprehensive income (loss)		**143.3**		(105.5)
Balance, end of period	**$**	**342.4**	$	299.6
Total shareholders' equity	**$**	**5,035.2**	$	4,740.9
Non-controlling interests				
Balance, beginning of period	**$**	**65.8**	$	34.8
Net income applicable to non-controlling interests		**4.6**		4.2
Sale of non-controlling interest *(notes 4 and 8)*		**420.4**		20.0
Contributions from non-controlling interests to subsidiaries		**23.2**		—
Distributions by subsidiaries to non-controlling interests		**(4.5)**		(4.5)
Balance, end of period		**509.5**		54.5
Total equity	**$**	**5,544.7**	$	4,795.4

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

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Cash Flows

(condensed and unaudited)

($ millions)	Three months ended June 30 **2018**	Three months ended June 30 2017	Six months ended June 30 **2018**	Six months ended June 30 2017
Cash from operations				
Net income after taxes	**$ 20.1**	$ 9.8	**$ 87.6**	$ 57.4
Items not involving cash:				
Depreciation and amortization	**72.9**	70.7	**145.5**	142.1
Provisions on assets	**—**	1.3	**—**	1.3
Accretion expenses	**2.7**	2.7	**5.5**	5.5
Share-based compensation	**0.2**	0.4	**0.5**	0.7
Deferred income tax expense *(note 17)*	**(7.6)**	(2.7)	**(1.9)**	7.2
Losses (gains) on sale of assets *(note 4)*	**0.1**	(0.8)	**(1.2)**	2.6
Income from equity investments	**(2.7)**	(3.0)	**(12.8)**	(17.1)
Unrealized losses (gains) on risk management contracts *(note 12)*	**(21.9)**	22.2	**(22.5)**	21.2
Realized loss on expiry of foreign exchange options *(note 12)*	**36.0**	—	**36.0**	—
Losses on investments	**5.4**	7.2	**14.8**	7.7
Amortization of deferred financing costs	**3.2**	3.8	**6.3**	10.6
Other	**(0.4)**	(3.0)	**(0.2)**	(2.3)
Asset retirement obligations settled	**(0.9)**	(1.5)	**(1.6)**	(2.7)
Distributions from equity investments	**5.8**	7.0	**12.5**	13.6
Changes in operating assets and liabilities *(note 18)*	**34.0**	(11.9)	**67.8**	54.5
	$ 146.9	$ 102.2	**$ 336.3**	$ 302.3
Investing activities				
Acquisition of property, plant and equipment	**(112.9)**	(93.1)	**(195.2)**	(179.4)
Acquisition of intangible assets	**(3.1)**	(2.6)	**(4.7)**	(4.7)
Acquisition of investment in a publicly traded entity	**—**	(7.0)	**—**	(7.0)
Contributions to equity investments	**—**	—	**(19.4)**	(14.3)
Loan to affiliate, net of repayment	**—**	(12.5)	**—**	(5.0)
Proceeds from disposition of investment	**7.9**	—	**13.1**	—
Payment for derivative contracts	**—**	(15.0)	**—**	(36.0)
Proceeds from disposition of assets, net of transaction costs *(note 4)*	**0.9**	1.2	**10.0**	70.2
	$ (107.2)	$ (129.0)	**$ (196.2)**	$ (176.2)
Financing activities				
Net repayment of short-term debt	**(5.5)**	(1.8)	**(48.4)**	(124.5)
Issuance of long-term debt, net of debt issuance costs	**7.6**	182.3	**7.3**	195.8
Repayment of long-term debt	**(0.6)**	(407.6)	**(205.7)**	(633.8)
Net issuance (repayment) of bankers' acceptances	**(239.9)**	404.5	**8.3**	343.6
Dividends - common shares	**(97.9)**	(89.0)	**(194.2)**	(177.0)
Dividends - preferred shares	**(16.4)**	(17.4)	**(32.8)**	(29.5)
Distributions to non-controlling interest	**(3.0)**	(3.1)	**(4.5)**	(4.5)
Contributions from non-controlling interests	**8.7**	—	**23.2**	—
Net proceeds from shares issued on exercise of options	**0.5**	0.1	**1.0**	3.4
Net proceeds from issuance of common shares	**68.0**	59.0	**133.9**	117.4
Net proceeds from issuance of preferred shares	**—**	(0.2)	**—**	293.4
Net proceeds from sale of non-controlling interest *(notes 4 and 8)*	**921.0**	24.1	**921.0**	24.1
Other	**(0.2)**	(1.1)	**(0.5)**	(1.4)
	$ 642.3	$ 149.8	**$ 608.6**	$ 7.0
Change in cash, cash equivalents and restricted cash	**682.0**	123.0	**748.7**	133.1
Effect of exchange rate changes on cash, cash equivalents and restricted cash	**0.6**	0.4	**1.3**	0.6
Cash, cash equivalents, and restricted cash beginning of period	**111.1**	44.4	**43.7**	34.1
Cash, cash equivalents, and restricted cash end of period *(note 18)*	**$ 793.7**	$ 167.8	**$ 793.7**	$ 167.8

See accompanying notes to the Consolidated Financial Statements.

Notes to the Condensed Interim Consolidated Financial Statements (unaudited)

(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 Ltd. (AltaGas or the Corporation) are operated by AltaGas and a number of its subsidiaries including, without limitation, AltaGas Services (U.S.) Inc.; in regards to the gas business, AltaGas Extraction and Transmission Limited Partnership, AltaGas Pipeline Partnership, AltaGas Processing Partnership, AltaGas Northwest Processing Limited Partnership and Harmattan Gas Processing Limited Partnership; in regards to the power business, Coast Mountain Hydro Limited Partnership, Blythe Energy Inc. (Blythe), and AltaGas San Joaquin Energy Inc.; and, in regards to the utility business, AltaGas Utilities Inc. (AUI), Heritage Gas Limited (Heritage Gas), Pacific Northern Gas Ltd. (PNG), 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).

Effective upon close of the acquisition of WGL Holdings, Inc. (the WGL Acquisition) on July 6, 2018, AltaGas' subsidiaries also include: in regards to the gas business, WGL Midstream, Inc. (WGL Midstream) and the retail gas marketing business of WGL Energy Services, Inc.; in regards to the power business, WGSW Inc., WGL Energy Systems, Inc., and the retail power marketing business of WGL Energy Services, Inc.; and, in regards to the utility business, Washington Gas Light Company and Hampshire Gas Company.

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 and maintain a long-term, balanced mix of energy infrastructure assets across its Gas, Power and Utility business segments. AltaGas' business strategy is underpinned by the growing demand for clean energy with natural gas as a key fuel source. AltaGas has three business segments:

- Gas, which transacts more than 3 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;
- Power, which, subsequent to the WGL Acquisition includes 2,033 MW of gross capacity from natural gas-fired, hydro, wind, biomass, solar, other distributed generation and energy storage assets located in 20 provinces and states across North America. The Power business will also include energy efficiency contracting and WGL's retail power marketing business; and
- Utilities, which, subsequent to the WGL Acquisition serves almost 1.8 million customers with a rate base of approximately $5 billion through ownership of regulated natural gas distribution utilities across 8 jurisdictions in North America, and a regulated natural gas storage utility 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, delivering clean and affordable natural gas to homes and businesses.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PRESENTATION

These unaudited condensed interim Consolidated Financial Statements have been prepared by management in accordance with United States Generally Accepted Accounting Principles (U.S. GAAP). As a result, these unaudited condensed interim

Consolidated Financial Statements do not include all of the information and disclosures required in the annual Consolidated Financial Statements and should be read in conjunction with the Corporation's 2017 annual audited Consolidated Financial Statements prepared in accordance with U.S. GAAP. In management's opinion, these unaudited condensed interim Consolidated Financial Statements include all adjustments that are of a recurring nature and necessary to present fairly the financial position of the Corporation.

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 unaudited condensed interim 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.

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

Except as noted below, these unaudited condensed interim Consolidated Financial Statements have been prepared following the same accounting policies and methods as those used in preparing the Corporation's 2017 annual audited Consolidated Financial Statements.

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 11 for further details. AltaGas does not expect the application of ASC 606 to have a material impact on its 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, $0.4 million and $0.8 million of net benefit cost associated with other components were reclassified from the line item "Operating and administrative" to "Other loss" on the Consolidated Statement of Income for the three and six months ended June 30, 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; 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 for all leases with lease terms greater than 12 months. 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 No. 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. The amendments to the new leases standard are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. In transition, lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. AltaGas is currently performing a scoping exercise by gathering a complete inventory of lease contracts in order to evaluate the impact of adopting ASC 842 on its consolidated financial statements, but expects that the new standard will have an impact on the Corporation's balance sheet as all operating leases will need to be reflected on the balance sheet upon adoption. In addition, AltaGas currently expects to 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.

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 February 2018, FASB issued 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. The amendments in this ASU are effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. Early adoption is permitted and AltaGas plans to adopt this ASU effective July 1, 2018. 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. 2018-07 “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.

3. DEVELOPMENTS RELATING TO THE WGL ACQUISITION

Following the receipt of all required federal, state, and local regulatory approvals, on July 6, 2018, the Corporation acquired WGL Holdings, Inc. (WGL), creating a North American leader in the clean energy economy and enhancing AltaGas’ position as a leading North American clean energy infrastructure company. The aggregate purchase price was 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. The WGL Acquisition will benefit all three business segments: Gas, Power and Utilities. In the Gas segment, the combined midstream business will provide producers with global market access; in the Power segment, a clean power generation footprint covering hydroelectric, wind, small scale solar, biomass, and energy storage will expand clean energy offerings; and in the Utility segment, the high quality utility assets will be underpinned by regulated, low risk cash flow.

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, gross proceeds of approximately $922 million from the sale of a 35 percent minority interest in the Northwest British Columbia Hydro Electric Facilities (Note 4), draws on the fully committed acquisition credit facility of $3.0 billion (US$2.3 billion) and existing cash on hand. The total funding included additional amounts for the payment of fees and regulatory commitments related to the WGL Acquisition. The acquisition credit facility could remain in place for up to 12 to 18 months after closing. The sale of the subscription receipts was completed in the first quarter of 2017 (see *Subscription Receipts* section below) and upon closing of the WGL Acquisition, the subscription receipts were exchanged into approximately 84.5 million common shares of AltaGas.

WGL is a diversified energy infrastructure company and the sole common shareholder of Washington Gas Light Company (Washington Gas), a regulated natural gas utility headquartered in Washington, D.C., serving approximately 1.2 million customers in Virginia, Maryland, and the District of Columbia. WGL has a growing midstream business with investments in natural gas gathering infrastructure and regulated gas pipelines in the Marcellus/Utica gas formation located in the northeastern United States. WGL’s midstream business has interstate transportation and storage contracts as well as marine-based energy export capabilities via the North American Atlantic coast through WGL’s access to the Cove Point LNG Terminal in Maryland which was developed by a third party and recently began exporting LNG. WGL also owns contracted clean power assets, with a focus on solar distributed generation and energy efficiency assets throughout the United States. In addition, WGL has a retail gas and power marketing business with approximately 214,000 customers in Maryland, Virginia, Delaware, Pennsylvania and the District of Columbia. With the close of the WGL Acquisition, AltaGas has over $23 billion of assets and approximately 1.8 million rate regulated gas customers.

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 subsequently been delisted from the TSX.

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. AltaGas will continue to consolidate NW Hydro LP (Note 8). As a result 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 Sheet, net of transaction costs. There was no impact to the Consolidated Statement of Income upon closing of this transaction.

Other Dispositions

In March 2018, AltaGas completed the disposition of certain non-core facilities in the Gas 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 Statement of Income under the line item “Other loss” for the three and six months ended June 30, 2018.

5. INVENTORY

As at		**June 30, 2018**		December 31, 2017
Natural gas held in storage	**$**	**92.1**	$	133.9
Other inventory		**86.1**		67.2
	$	**178.2**	$	201.1

6. GOODWILL

As at		**June 30, 2018**		December 31, 2017
Balance, beginning of period	**$**	**817.3**	$	856.0
Foreign exchange translation		**27.1**		(38.4)
Reclassified to assets held for sale		**—**		(0.3)
Balance, end of period	**$**	**844.4**	$	817.3

7. LONG-TERM INVESTMENTS AND OTHER ASSETS

As at		**June 30, 2018**		December 31, 2017
Investments in publicly-traded entities	**$**	**67.1**	$	95.0
Loan to affiliate		**75.0**		75.0
Deferred lease receivable		**61.6**		29.0
Debt issuance costs associated with credit facilities		**17.6**		20.3
Refundable deposits		**15.6**		14.9
Prepayment on long-term service agreements		**74.4**		68.1
Subscription receipts issuance costs		**2.0**		1.7
Contract asset		**5.2**		—
Other		**11.9**		8.6
	$	**330.4**	$	312.6

8. VARIABLE INTEREST ENTITIES

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 $335.2 million.

The following table represents amounts included in the Consolidated Balance Sheet attributable to this VIE:

As at		**June 30, 2018**		December 31, 2017
Current assets	**$**	**55.0**	$	—
Property, plant and equipment		**1,101.1**		—
Intangible assets		**247.9**		—
Current liabilities		**(57.6)**		—
Other long term liabilities		**(145.3)**		—
Net assets	**$**	**1,201.1**	$	—

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 following table represents amounts included in the Consolidated Balance Sheet attributable to this VIE:

As at		June 30, 2018		December 31, 2017
Accounts receivable	$	1.6	$	1.4
Property, plant and equipment		163.5		84.3
Long-term investments and other assets		48.0		48.0
Net assets	$	213.1	$	133.7

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.

9. LONG-TERM DEBT

As at	Maturity date		June 30, 2018		December 31, 2017
Credit facilities					
$1,400 million unsecured extendible revolving[a]	15-May-2023	**$**	**212.0**	$	219.1
US$300 million unsecured extendible revolving[b]	15-May-2022		**—**		—
$25 million secured extendible revolving[c]	4-May-2023		**—**		—
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
SEMCO long-term debt					
US$300 million SEMCO Senior secured - 5.15 percent[d]	21-Apr-2020		**395.0**		376.4
US$82 million CINGSA Senior secured - 4.48 percent[e]	2-Mar-2032		**86.4**		85.2
Debenture notes					
PNG 2018 Series Debenture - 8.75 percent[c]	15-Nov-2018		**7.0**		7.0
PNG 2025 Series Debenture - 9.30 percent[c]	18-Jul-2025		**13.0**		13.0
PNG 2027 Series Debenture - 6.90 percent[c]	2-Dec-2027		**14.0**		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
		$	**3,477.6**	$	3,639.8
Less debt issuance costs			**(14.5)**		(14.4)
			3,463.1		3,625.4
Less current portion			**(214.1)**		(188.9)
		$	**3,249.0**	$	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.

10. 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	**—**	**—**	**—**	**131.5**	**1.7**	**133.2**
Amounts reclassified from OCI	**—**	**0.4**	**—**	**—**	**—**	**0.4**
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**	**4.6**	**—**	**131.5**	**1.7**	**144.9**
Income tax on amounts reclassified to earnings	**—**	**(0.1)**	**—**	**—**	**—**	**(0.1)**
Income tax on amounts related to curtailment of DB and PRB plan	**—**	**(1.5)**	**—**	**—**	**—**	**(1.5)**
Net current period OCI	**7.1**	**3.0**	**—**	**131.5**	**1.7**	**143.3**
Ending balance, June 30, 2018	**$ —**	**$ (8.4)**	**$ (129.0)**	**$ 474.4**	**$ 5.4**	**$ 342.4**
Opening balance, January 1, 2017	$ 19.8	$ (11.3)	$ (135.6)	$ 526.3	$ 5.9	$ 405.1
OCI before reclassification	(20.5)	—	6.8	(94.3)	(1.1)	(109.1)
Amounts reclassified from AOCI	—	0.5	—	—	—	0.5
Settlement of PRB plan	—	0.3	—	—	—	0.3
Current period OCI (pre-tax)	(20.5)	0.8	6.8	(94.3)	(1.1)	(108.3)
Income tax on amounts retained in AOCI	3.0	—	—	—	—	3.0
Income tax on amounts reclassified to earnings	—	(0.1)	—	—	—	(0.1)
Income tax on amounts related to settlement of PRB plan	—	(0.1)	—	—	—	(0.1)
Net current period OCI	(17.5)	0.6	6.8	(94.3)	(1.1)	(105.5)
Ending balance, June 30, 2017	$ 2.3	$ (10.7)	$ (128.8)	$ 432.0	$ 4.8	$ 299.6

Reclassification From Accumulated Other Comprehensive Income

AOCI components reclassified	Income statement line item	**Three months ended June 30, 2018**	**Six months ended June 30, 2018**
Defined benefit pension and PRB	Operating and administrative expense	**$ 0.2**	**$ 0.4**
Deferred income taxes	Income tax expenses – deferred	**(0.1)**	**(0.1)**
		$ 0.1	**$ 0.3**

AOCI components reclassified	Income statement line item	Three months ended June 30, 2017	Six months ended June 30, 2017
Defined benefit pension and PRB	Operating and administrative expense	$ 0.3	$ 0.5
Deferred income taxes	Income tax expenses – deferred	(0.1)	(0.1)
		$ 0.2	$ 0.4

11. REVENUE

The following table disaggregates revenue by major sources for the period ended June 30, 2018:

	Three months ended June 30, 2018				
	Gas	Power	Utilities	Corporate	Total
Revenue from contracts with customers					
Commodity sales contracts	$ 114.0	$ —	$ —	$ —	$ 114.0
Midstream service contracts	52.3	—	—	—	52.3
Gas sales and transportation services	—	—	197.3	—	197.3
Storage services	—	—	9.1	—	9.1
Other	—	—	2.4	—	2.4
Total revenue from contracts with customers	**$ 166.3**	**$ —**	**$ 208.8**	**$ —**	**$ 375.1**
Other sources of revenue					
Revenue from alternative revenue programs [(a)]	$ —	$ —	$ 0.6	$ —	$ 0.6
Leasing revenue [(b)]	23.7	97.3	0.1	—	121.1
Risk management activities [(c)]	57.5	63.4	(0.1)	(14.1)	106.7
Other	(0.1)	4.6	1.8	—	6.3
Total revenue from other sources	**$ 81.1**	**$ 165.3**	**$ 2.4**	**$ (14.1)**	**$ 234.7**
Total revenue	**$ 247.4**	**$ 165.3**	**$ 211.2**	**$ (14.1)**	**$ 609.8**

(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 are accounted for as operating leases. For the Power segment, the majority 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 gas and power segments is from the physical sale and delivery of natural gas and power to end users.

	Six months ended June 30, 2018				
	Gas	Power	Utilities	Corporate	Total
Revenue from contracts with customers					
Commodity sales contracts	$ 221.3	$ —	$ —	$ —	$ 221.3
Midstream service contracts	101.8	—	—	—	101.8
Gas sales and transportation services	—	—	607.6	—	607.6
Storage services	—	—	18.2	—	18.2
Other	0.6	—	5.3	—	5.9
Total revenue from contracts with customers	**$ 323.7**	**$ —**	**$ 631.1**	**$ —**	**$ 954.8**
Other sources of revenue					
Revenue from alternative revenue programs [(a)]	$ —	$ —	$ (4.5)	$ —	$ (4.5)
Leasing revenue [(b)]	47.7	164.5	0.1	—	212.3
Risk management activities [(c)]	188.0	139.2	1.1	(14.7)	313.6
Other	(0.2)	7.4	4.8	—	12.0
Total revenue from other sources	**$ 235.5**	**$ 311.1**	**$ 1.5**	**$ (14.7)**	**$ 533.4**
Total revenue	**$ 559.2**	**$ 311.1**	**$ 632.6**	**$ (14.7)**	**$ 1,488.2**

(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 are accounted for as operating leases. For the Power segment, the majority 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 gas and power segments is from the physical sale and delivery of natural gas and power to end users.

Revenue Recognition

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

Gas 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.

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 become 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, the majority 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.

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 have a term of one-month, 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.

Contract Balances

As at June 30, 2018, a contract asset of $5.2 million has been recorded within Long-term investments and other assets on the Consolidated Balance Sheet (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.

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 June 30, 2018:

	Remainder of 2018	2019	2020	2021	2022	> 2022	Total
Midstream service contracts	$ 20.1	$ 39.4	$ 39.8	$ 17.0	$ 16.6	$ 132.4	**$ 265.3**
Gas sales and transportation services	9.6	18.9	17.1	16.2	15.7	29.8	**107.3**
Storage services	13.8	26.9	26.6	26.6	26.6	246.4	**366.9**
Other	0.5	1.1	1.1	1.1	1.1	3.0	**7.9**
	$ 44.0	$ 86.3	$ 84.6	$ 60.9	$ 60.0	$ 411.6	**$ 747.4**

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.

12. 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 uses over-the-counter derivative instruments 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 from 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.

	June 30, 2018				
	Carrying Amount	**Level 1**	**Level 2**	**Level 3**	**Total Fair Value**
Financial assets					
Fair value through net income					
Risk management assets - current	**$ 26.5**	**$ —**	**$ 26.5**	**$ —**	**$ 26.5**
Risk management assets - non-current	**13.9**	**—**	**13.9**	**—**	**13.9**
Equity securities[(a)]	**67.1**	**67.1**	**—**	**—**	**67.1**
Amortized cost					
Loans and receivables [(a)]	**75.0**	**—**	**76.5**	**—**	**76.5**
	$ 182.5	**$ 67.1**	**$ 116.9**	**$ —**	**$ 184.0**
Financial liabilities					
Fair value through net income					
Risk management liabilities - current	**$ 65.1**	**$ —**	**$ 65.1**	**$ —**	**$ 65.1**
Risk management liabilities - non-current	**9.0**	**—**	**9.0**	**—**	**9.0**
Amortized cost					
Current portion of long-term debt	**214.1**	**—**	**217.0**	**—**	**217.0**
Long-term debt	**3,249.0**	**—**	**3,319.6**	**—**	**3,319.6**
Other current liabilities [(b)]	**16.6**	**—**	**16.7**	**—**	**16.7**
Other long-term liabilities [(b)]	**149.3**	**—**	**149.0**	**—**	**149.0**
	$ 3,703.1	**$ —**	**$ 3,776.4**	**$ —**	**$ 3,776.4**

(a) Included under the line items "Long-term investments and other assets" on the Consolidated Balance Sheet.

(b) 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 Sheet.

(b) Excludes non-financial liabilities.

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

	Three months ended June 30		Six months ended June 30	
	2018	2017	**2018**	2017
Natural gas	**$ (5.4)**	$ (0.3)	**$ (11.2)**	$ (2.0)
Storage optimization	**—**	0.5	**—**	2.8
NGL frac spread	**(8.2)**	2.0	**2.8**	9.6
Power	**(1.7)**	(8.7)	**(5.1)**	(9.1)
Foreign exchange	**37.2**	(15.7)	**36.0**	(22.5)
	$ 21.9	$ (22.2)	**$ 22.5**	$ (21.2)

Offsetting of Derivative Assets and Derivative Liabilities

Certain AltaGas risk management contracts are subject to master netting arrangements that create a legally enforceable right to offset by counterparty. The following is a summary of AltaGas' financial assets and financial liabilities that were subject to offsetting:

	June 30, 2018		
Risk management assets [(a)]	**Gross amounts of recognized assets/liabilities**	**Gross amounts offset in balance sheet**	**Net amounts presented in balance sheet**
Natural gas	**$ 20.6**	**$ (1.5)**	**$ 19.1**
NGL frac spread	**5.0**	**(3.2)**	**1.8**
Power	**18.1**	**(1.3)**	**16.8**
Foreign exchange	**29.0**	**(26.3)**	**2.7**
	$ 72.7	**$ (32.3)**	**$ 40.4**
Risk management liabilities [(b)]			
Natural gas	**$ 26.1**	**$ (1.5)**	**$ 24.6**
NGL frac spread	**26.4**	**(3.3)**	**23.1**
Power	**26.6**	**(1.2)**	**25.4**
Foreign exchange	**27.3**	**(26.3)**	**1.0**
	$ 106.4	**$ (32.3)**	**$ 74.1**

(a) Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $26.5 million and risk management assets (non-current) balance of $13.9 million.

(b) Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $65.1 million and risk management liabilities (non-current) balance of $9.0 million.

Risk management assets [a]	December 31, 2017 Gross amounts of recognized assets/liabilities	Gross amounts offset in balance sheet	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	18.2	(0.7)	17.5
	$ 78.6	$ (7.2)	$ 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.

Notional Summary

The following table presents the notional quantity outstanding related to the Corporation's commodity contracts:

	June 30, 2018	December 31, 2017
Natural Gas		
Sales	**112,840,107 GJ**	94,804,039 GJ
Purchases	**42,347,590 GJ**	61,980,315 GJ
Swaps	**3,769,166 GJ**	6,039,642 GJ
NGL Frac Spread		
Propane swaps	**2,417,477 Bbl**	1,992,927 Bbl
Butane swaps	**303,262 Bbl**	130,088 Bbl
Crude oil swaps	**503,082 Bbl**	518,665 Bbl
Natural gas swaps	**12,618,479 GJ**	11,428,515 GJ
Power		
Sales	**2,070,840 MWh**	2,169,321 MWh
Purchases	**286,964 MWh**	17,520 MWh
Swaps	**1,513,909 MWh**	1,563,160 MWh

Foreign Exchange

AltaGas may designate its U.S. dollar-denominated debt as a net investment hedge of its U.S. subsidiaries. As at June 30, 2018, AltaGas has not designated any outstanding debt as a net investment hedge. For the three and six months ended June 30, 2018, AltaGas incurred after-tax unrealized gains of $nil arising from the translation of debt in OCI (2017 - after-tax unrealized gains of $5.5 million and $6.8 million, respectively).

In addition, to mitigate the foreign exchange risks associated with the cash purchase price of WGL, AltaGas has entered into foreign currency option contracts with an aggregate notional value of 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 three and six months ended June 30, 2018, unrealized gains of $35.5 million and $34.3 million, respectively, and a realized loss of $36.0 million was recognized in revenue in relation to these contracts (2017 – unrealized losses of $15.5 million and $21.9 million, respectively). During the second quarter of 2018, AltaGas entered into foreign exchange forward contracts with an aggregate notional value of $3.2 billion. These foreign currency derivatives do not qualify for hedge accounting. For the three and six months ended June 30, 2018, unrealized gains of $1.7 million were recognized in revenue in relation to these forwards (2017 - $nil).

13. 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 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 for cash on exercise of options	46,775		1.1
Shares issued under DRIP	5,410,074		133.9
Issued and outstanding at June 30, 2018	**180,736,065**	**$**	**4,142.9**

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Preferred Shares

As at	June 30, 2018			December 31, 2017		
Issued and Outstanding	**Number of shares**		**Amount**	Number of shares		Amount
Series A	**5,511,220**	**$**	**137.8**	5,511,220	$	137.8
Series B	**2,488,780**		**62.2**	2,488,780		62.2
Series C	**8,000,000**		**205.6**	8,000,000		205.6
Series E	**8,000,000**		**200.0**	8,000,000		200.0
Series G	**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
Share issuance costs, net of taxes			**(27.9)**			(27.9)
	52,000,000	**$**	**1,277.7**	52,000,000	$	1,277.7

Share Option Plan

AltaGas has an employee share option plan under which employees and directors are eligible to receive grants. As at June 30, 2018, 13,114,671 shares were reserved for issuance under the plan. As at June 30, 2018, share options granted under the plan have a term between six and ten years until expiry and vest no longer than over a four-year period.

As at June 30, 2018, unexpensed fair value of share option compensation cost associated with future periods was $1.4 million (December 31, 2017 - $1.3 million).

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

As at	June 30, 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 period	**4,533,761**	**$**	**32.35**	4,119,386	$	32.39
Granted	**509,450**		**26.31**	848,000		30.80
Exercised	**(46,775)**		**22.13**	(240,125)		24.63
Forfeited	**(34,500)**		**32.14**	(193,500)		36.36
Expired	**(3,000)**		**26.23**	—		—
Share options outstanding, end of period	**4,958,936**	**$**	**31.83**	4,533,761	$	32.35
Share options exercisable, end of period	**3,502,547**	**$**	**32.19**	3,326,197	$	31.93

(a) Weighted average.

As at June 30, 2018, the aggregate intrinsic value of the total share options exercisable was $4.7 million (December 31, 2017 - $6.0 million), the total intrinsic value of share options outstanding was $5.1 million (December 31, 2017 - $6.0 million) and the total intrinsic value of share options exercised was $0.2 million (December 31, 2017 - $1.4 million).

The following table summarizes the employee share option plan as at June 30, 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	150,250	$	15.12	0.78	150,250	$	15.12	0.78
$18.01 to $25.08	444,700		20.75	2.33	444,700		20.75	2.33
$25.09 to $50.89	4,363,986		33.53	3.83	2,907,597		34.82	3.34
	4,958,936	**$**	**31.83**	**3.61**	**3,502,547**	**$**	**32.19**	**3.10**

Medium Term Incentive Plan (MTIP) and Deferred Share Unit Plan (DSUP)

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

PUs, RUs, and DSUs	**June 30, 2018**	December 31, 2017
(number of units)		
Balance, beginning of period	**564,549**	364,839
Granted	**130,254**	386,126
Additional units added by performance factor	**—**	24,301
Vested and paid out	**(44,031)**	(221,775)
Forfeited	**(39,079)**	(27,279)
Units in lieu of dividends	**23,342**	38,337
Outstanding, end of period	**635,035**	564,549

For the three and six months ended June 30, 2018, the compensation expense recorded for the MTIP and DSUP was $2.7 million and $2.9 million, respectively (2017 – $1.8 million and $3.2 million, respectively). As at June 30, 2018, the unrecognized compensation expense relating to the remaining vesting period for the MTIP was $9.2 million (December 31, 2017 - $8.4 million) and is expected to be recognized over the vesting period.

14. NET INCOME (LOSS) PER COMMON SHARE

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

	Three months ended June 30		Six months ended June 30	
	2018	2017	**2018**	2017
Numerator:				
Net income applicable to controlling interests	**$ 17.8**	$ 7.9	**$ 83.0**	$ 53.2
Less: Preferred share dividends	**(16.4)**	(15.9)	**(32.8)**	(29.5)
Net income (loss) applicable to common shares	**$ 1.4**	$ (8.0)	**$ 50.2**	$ 23.7
Denominator:				
(millions)				
Weighted average number of common shares outstanding	**179.3**	169.9	**177.9**	168.9
Dilutive equity instruments[(a)]	**0.1**	—	**0.2**	0.3
Weighted average number of common shares outstanding - diluted	**179.4**	169.9	**178.1**	169.2
Basic net income (loss) per common share	**$ 0.01**	$ (0.05)	**$ 0.28**	$ 0.14
Diluted net income (loss) per common share	**$ 0.01**	$ (0.05)	**$ 0.28**	$ 0.14

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

For the three and six months ended June 30, 2018, 3.9 million share options, respectively (2017 – 4.7 million and 2.1 million, respectively) were excluded from the diluted net income per share calculation as their effects were anti-dilutive.

15. COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

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

AltaGas enters into contracts to purchase natural gas and natural gas transportation and storage services from various suppliers for its utilities. These contracts, which have expiration dates that range from 2018 to 2034, 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.

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 $59.7 million over the term of the contract.

On October 4, 2017, Heritage Gas signed a Precedent Agreement (PA) with the intention of entering into a long-term (22 year) contract with Portland Natural Gas Transmission System (PNGTS) for natural gas transportation capacity from the Dawn Hub in Ontario to Nova Scotia on the Maritimes and Northeast Pipeline (M&NP) system. The PA with PNGTS was subject to Heritage Gas satisfying a condition precedent of obtaining regulatory approval by July 31, 2018 for the contract to proceed. On June 1, 2018, Heritage Gas received approval from the Nova Scotia Utility and Review Board (NSUARB) to enter into this contract and recover associated costs of the contract from its customers through regulated rates. The contract will commence on November 1, 2018.

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 Blythe. The term of the agreement is over 124,000 equivalent operating hours per CT, or 25 years, whichever comes first. As at June 30, 2018, approximately $204.3 million is expected to be paid over the next 18 years, of which $62.5 million is expected to be paid over the next five years.

In 2009, AltaGas entered into a 20-year storage agreement at the Dawn Hub in southwestern Ontario. AltaGas is obligated to pay approximately $3.5 million per annum over the term of the contract for storage services.

In 2007, AltaGas entered into a service and maintenance agreement with Enercon GmbH for the wind turbines for Bear Mountain. AltaGas has an obligation to pay a minimum of $7.9 million over the next four years.

Guarantees

In October 2014, Heritage Gas Limited, a wholly-owned subsidiary of AltaGas, entered into a throughput service contract with Enbridge Inc. (formerly Spectra Energy Corp.) for the use of the expansion of its Algonquin Gas Transmission and Maritimes & Northeast Pipeline systems (the Atlantic Bridge Project). The contract will commence upon completion of the construction of the pipelines and it will expire 15 years thereafter. AltaGas has two guarantees outstanding that total US$91.7 million to stand by all payment obligations under the transportation agreement.

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.

16. 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.

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

	Three months ended June 30, 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**	**$ 0.2**	**$ 2.5**	**$ 0.7**	**$ 4.9**	**$ 0.9**
Interest cost [b]	**1.3**	**0.1**	**3.6**	**1.0**	**4.9**	**1.1**
Expected return on plan assets [b]	**(1.5)**	**(0.1)**	**(6.0)**	**(1.7)**	**(7.5)**	**(1.8)**
Curtailment of plan [b]	**(1.0)**	**(0.2)**	**—**	**—**	**(1.0)**	**(0.2)**
Amortization of net actuarial loss [b]	**0.1**	**—**	**—**	**—**	**0.1**	**—**
Amortization of regulatory asset [b]	**0.4**	**—**	**1.9**	**—**	**2.3**	**—**
Net benefit cost recognized	**$ 1.7**	**$ —**	**$ 2.0**	**$ —**	**$ 3.7**	**$ —**

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

	Six months ended June 30, 2018					
	Canada		**United States**		**Total**	
	Defined Benefit	**Post-retirement Benefits**	**Defined Benefit**	**Post-retirement Benefits**	**Defined Benefit**	**Post-retirement Benefits**
Current service cost [a]	**$ 5.0**	**$ 0.4**	**$ 5.0**	**$ 1.4**	**$ 10.0**	**$ 1.8**
Interest cost [b]	**2.8**	**0.3**	**7.0**	**1.9**	**9.8**	**2.2**
Expected return on plan assets [b]	**(3.2)**	**(0.1)**	**(11.9)**	**(3.4)**	**(15.1)**	**(3.5)**
Curtailment of plan [b]	**(1.0)**	**(0.2)**	**—**	**—**	**(1.0)**	**(0.2)**
Amortization of net actuarial loss [b]	**0.4**	**—**	**—**	**—**	**0.4**	**—**
Amortization of regulatory asset [b]	**0.7**	**—**	**3.7**	**—**	**4.4**	**—**
Net benefit cost recognized	**$ 4.7**	**$ 0.4**	**$ 3.8**	**$ (0.1)**	**$ 8.5**	**$ 0.3**

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

	Three months ended June 30, 2017					
	Canada		United States		Total	
	Defined Benefit	Post-retirement Benefits	Defined Benefit	Post-retirement Benefits	Defined Benefit	Post-retirement Benefits
Current service cost [a]	$ 2.0	$ 0.2	$ 1.8	$ 0.4	$ 3.8	$ 0.6
Interest cost [b]	1.4	0.2	3.0	0.8	4.4	1.0
Expected return on plan assets [b]	(1.5)	(0.1)	(4.1)	(1.2)	(5.6)	(1.3)
Settlement of plan [b]	—	—	—	(0.1)	—	(0.1)
Amortization of net actuarial loss [b]	0.2	—	—	—	0.2	—
Amortization of regulatory asset/liability [b]	0.3	—	1.7	(0.1)	2.0	(0.1)
Net benefit cost recognized	$ 2.4	$ 0.3	$ 2.4	$ (0.2)	$ 4.8	$ 0.1

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

	Six months ended June 30, 2017											
	Canada				United States				Total			
		Defined Benefit		Post-retirement Benefits		Defined Benefit		Post-retirement Benefits		Defined Benefit		Post-retirement Benefits
Current service cost [a]	$	3.9	$	0.4	$	3.6	$	0.8	$	7.5	$	1.2
Interest cost [b]		2.9		0.3		5.9		1.5		8.8		1.8
Expected return on plan assets [b]		(3.0)		(0.1)		(8.2)		(2.4)		(11.2)		(2.5)
Settlement of plan [b]		—		—		—		(0.1)		—		(0.1)
Amortization of past service cost [b]		0.1		—		—		—		0.1		—
Amortization of net actuarial loss [b]		0.4		—		—		—		0.4		—
Amortization of regulatory asset/liability [b]		0.6		—		3.3		(0.1)		3.9		(0.1)
Net benefit cost (income) recognized	$	4.9	$	0.6	$	4.6	$	(0.3)	$	9.5	$	0.3

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

17. INCOME TAXES

The effective income tax rates for the three and six months ended June 30, 2018 were approximately 9.9 percent and 19.1 percent, respectively (2017 – 43.8 percent and 33.5 percent, respectively). The decrease in the effective tax rate for the three and six months ended June 30, 2018 was mainly due to the decrease in the U.S. Federal tax rate from 35 percent to 21 percent. In addition, a lower amount of the transaction costs incurred on the pending WGL Acquisition was non-deductible in the first half of 2018 than in the first half of 2017. This was partially offset by an increase to the uncertain tax provision in the first quarter of 2018.

The effective tax rate for the three months ended June 30, 2018 decreased further due to tax recoveries on certain risk management contracts in the second quarter of 2018.

18. SUPPLEMENTAL CASH FLOW INFORMATION

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

	Three months ended June 30				Six months ended June 30			
		2018		2017		**2018**		2017
Source (use) of cash:								
Accounts receivable	**$**	**96.1**	$	80.2	**$**	**130.2**	$	97.3
Inventory		**(30.4)**		(37.2)		**38.6**		53.1
Other current assets		**3.3**		6.3		**10.5**		13.0
Regulatory assets (current)		**0.2**		0.9		**(0.4)**		(0.1)
Accounts payable and accrued liabilities		**(22.1)**		(24.4)		**(65.8)**		(29.3)
Customer deposits		**(0.3)**		(0.2)		**(11.0)**		(13.0)
Regulatory liabilities (current)		**14.1**		(1.1)		**11.3**		(8.3)
Other current liabilities		**2.7**		6.5		**(5.1)**		2.9
Other operating assets and liabilities		**(29.6)**		(42.9)		**(40.5)**		(61.1)
Changes in operating assets and liabilities	**$**	**34.0**	$	(11.9)	**$**	**67.8**	$	54.5

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

	Three months ended June 30		Six months ended June 30	
	2018	2017	**2018**	2017
Interest paid (net of capitalized interest)	**$ 41.8**	$ 35.8	**$ 82.5**	$ 88.2
Income taxes paid	**$ 9.4**	$ 12.3	**$ 21.0**	$ 23.6

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

As at June 30	**2018**	2017
Cash and cash equivalents	**$ 783.8**	$ 156.1
Restricted cash holdings from customers - current	**4.0**	3.9
Restricted cash holdings from customers - non-current	**5.9**	7.8
Cash, cash equivalents and restricted cash per consolidated statement of cash flow	**$ 793.7**	$ 167.8

19. SEASONALITY

The utility business is highly seasonal with the majority of natural gas deliveries occurring during the winter heating season. Gas sales increase during the winter resulting in stronger first and fourth quarter results and weaker second and third quarter results.

The power generation at the run-of-river hydro-facilities Forrest Kerr, Volcano Creek, and McLymont Creek occurs substantially from mid second quarter through early fourth quarter, resulting in weaker results in the first and fourth quarters.

20. 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:

Gas	– 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, including to commercial and industrial users; – natural gas storage facilities; – liquefied petroleum gas (LPG) terminal currently under construction; – natural gas and NGL marketing; and – equity investment in Petrogas, a North American entity engaged in the marketing, storage and distribution of NGL, drilling fluids, crude oil and condensate diluents.
Power	– natural gas-fired, wind, biomass and hydro power generation assets, whereby outputs are generally sold under long-term power purchase agreements, both operational and under development; – energy storage; and – sale of power to commercial and industrial users in Alberta.
Utilities	– rate-regulated natural gas distribution assets in Michigan, Alaska, Alberta, British Columbia and Nova Scotia; and – rate-regulated natural gas storage in Michigan and Alaska.
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 risk management contracts.

The following table provides a reconciliation of segment revenue to the disaggregated revenue table as disclosed under Note 11 of these unaudited condensed interim Consolidated Financial Statements:

	Three months ended June 30, 2018				
	Gas	**Power**	**Utilities**	**Corporate**	**Total**
External revenue *(note 11)*	**$ 247.4**	**$ 165.3**	**$ 211.2**	**$ (14.1)**	**$ 609.8**
Intersegment revenue	**14.2**	**1.9**	**0.4**	**(0.1)**	**16.4**
Segment revenue	**$ 261.6**	**$ 167.2**	**$ 211.6**	**$ (14.2)**	**$ 626.2**

	Six months ended June 30, 2018				
	Gas	**Power**	**Utilities**	**Corporate**	**Total**
External revenue *(note 11)*	**$ 559.2**	**$ 311.1**	**$ 632.6**	**$ (14.7)**	**$ 1,488.2**
Intersegment revenue	**73.5**	**3.8**	**1.3**	**-**	**78.6**
Segment revenue	**$ 632.7**	**$ 314.9**	**$ 633.9**	**$ (14.7)**	**$ 1,566.8**

The following tables show the composition by segment:

	Three months ended June 30, 2018					
	Gas	Power	Utilities	Corporate	Intersegment Elimination[(a)]	Total
Segment revenue	$ 261.6	$ 167.2	$ 211.6	$ (14.2)	$ (16.4)	$ 609.8
Cost of sales	(165.2)	(68.7)	(105.3)	—	14.5	(324.7)
Operating and administrative	(49.4)	(25.7)	(59.5)	(13.8)	2.1	(146.3)
Accretion expenses	(1.0)	(1.6)	(0.1)	—	—	(2.7)
Depreciation and amortization	(19.1)	(29.5)	(20.7)	(3.6)	—	(72.9)
Income from equity investments	0.4	1.9	0.4	—	—	2.7
Other income (loss)	(6.0)	—	2.4	2.5	(0.2)	(1.3)
Foreign exchange gains	0.1	—	—	0.5	—	0.6
Interest expense	—	—	—	(42.9)	—	(42.9)
Income (loss) before income taxes	$ 21.4	$ 43.6	$ 28.8	$ (71.5)	$ —	$ 22.3
Net additions (reductions) to:						
Property, plant and equipment[(b)]	$ 59.9	$ 8.9	$ 53.8	$ 0.9	$ —	$ 123.5
Intangible assets	$ 1.5	$ 0.6	$ 0.8	$ 0.7	$ —	$ 3.6

(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.

	Six months ended June 30, 2018					
	Gas	Power	Utilities	Corporate	Intersegment Elimination[(a)]	Total
Segment revenue	$ 632.7	$ 314.9	$ 633.9	$ (14.7)	$ (78.6)	$ 1,488.2
Cost of sales	(431.7)	(147.1)	(358.4)	—	74.6	(862.6)
Operating and administrative	(92.6)	(55.1)	(117.3)	(26.4)	4.3	(287.1)
Accretion expenses	(2.1)	(3.3)	(0.1)	—	—	(5.5)
Depreciation and amortization	(37.9)	(59.1)	(41.2)	(7.3)	—	(145.5)
Income from equity investments	9.6	2.5	0.7	—	—	12.8
Other income (loss)	(10.0)	—	3.8	(0.1)	(0.3)	(6.6)
Foreign exchange gains	—	—	—	0.6	—	0.6
Interest expense	—	—	—	(86.1)	—	(86.1)
Income (loss) before income taxes	$ 68.0	$ 52.8	$ 121.4	$ (134.0)	$ —	$ 108.2
Net additions (reductions) to:						
Property, plant and equipment[(b)]	$ 106.5	$ 10.8	$ 71.1	$ 1.2	$ —	$ 189.6
Intangible assets	$ 2.4	$ 0.6	$ 1.3	$ 1.6	$ —	$ 5.9

(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.

Three months ended June 30, 2017	Gas	Power	Utilities	Corporate	Intersegment Elimination[a]	Total
Segment revenue	$ 234.6	$ 151.3	$ 206.1	$ (21.1)	$ (32.1)	$ 538.8
Cost of sales	(151.0)	(52.0)	(98.5)	—	30.2	(271.3)
Operating and administrative	(44.8)	(23.7)	(56.0)	(13.6)	2.1	(136.0)
Accretion expenses	(1.0)	(1.7)	—	—	—	(2.7)
Depreciation and amortization	(16.7)	(30.8)	(21.0)	(2.2)	—	(70.7)
Provision on assets	—	(1.3)	—	—	—	(1.3)
Income from equity investments	1.6	0.9	0.5	—	—	3.0
Other income (loss)	(7.5)	0.8	2.6	1.6	(0.2)	(2.7)
Foreign exchange gains	—	—	—	1.1	—	1.1
Interest expense	—	—	—	(40.8)	—	(40.8)
Income (loss) before income taxes	$ 15.2	$ 43.5	$ 33.7	$ (75.0)	$ —	$ 17.4
Net additions (reductions) to:						
Property, plant and equipment[b]	$ 88.4	5.2	30.5	0.4	—	$ 124.5
Intangible assets	$ 0.4	1.3	0.5	0.6	—	$ 2.8

(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.

Six months ended June 30, 2017	Gas	Power	Utilities	Corporate	Intersegment Elimination[a]	Total
Segment revenue	$ 536.1	$ 283.5	$ 620.6	$ (19.0)	$ (111.2)	$ 1,310.0
Cost of sales	(355.1)	(113.8)	(343.5)	—	106.9	(705.5)
Operating and administrative	(86.6)	(46.9)	(112.2)	(54.6)	4.6	(295.7)
Accretion expenses	(2.0)	(3.5)	—	—	—	(5.5)
Depreciation and amortization	(33.2)	(61.6)	(41.7)	(5.6)	—	(142.1)
Provision on assets	—	(1.3)	—	—	—	(1.3)
Income from equity investments	12.7	3.2	1.2	—	—	17.1
Other income (loss)	(10.9)	0.8	3.2	2.0	(0.3)	(5.2)
Foreign exchange gains	—	—	—	1.4	—	1.4
Interest expense	—	—	—	(87.0)	—	(87.0)
Income (loss) before income taxes	$ 61.0	$ 60.4	$ 127.6	$ (162.8)	$ —	$ 86.2
Net additions (reductions) to:						
Property, plant and equipment[b]	$ 66.9	$ 12.4	$ 46.9	$ 0.6	$ —	$ 126.8
Intangible assets	$ 0.9	$ 1.4	$ 1.0	$ 1.6	$ —	$ 4.9

(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:

	Gas	Power	Utilities	Corporate	Total
As at June 30, 2018					
Goodwill	**$ 152.6**	**$ —**	**$ 691.8**	**$ —**	**$ 844.4**
Segmented assets	**$ 3,172.5**	**$ 3,298.7**	**$ 3,420.3**	**$ 984.6**	**$ 10,876.1**
As at December 31, 2017					
Goodwill	$ 152.6	$ —	$ 664.7	$ —	$ 817.3
Segmented assets	$ 3,096.8	$ 3,192.5	$ 3,460.2	$ 282.7	$ 10,032.2

21. SUBSEQUENT EVENTS

Subsequent events have been reviewed through July 31, 2018, the date on which these unaudited condensed interim Consolidated Financial Statements were issued.

Acquisition of WGL Holdings, Inc.

Following the receipt of all required federal and state 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 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 preliminary 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 preliminary purchase price allocation 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. As Management completes its analysis, the final purchase price allocation may differ materially from the preliminary purchase price allocation below.

Purchase consideration	**$**	**5,973**
Fair value assigned to net assets		
Current assets	$	1,246
Property, plant and equipment		6,104
Intangible assets		571
Regulatory assets (including current portion)		423
Long-term investments		1,245
Other long-term assets		468
Current liabilities		(1,872)
Long-term debt		(2,551)
Preferred shares		(41)
Regulatory liabilities (including current portion)		(1,125)
Other long-term liabilities		(1,875)
Non-controlling interest		(9)
Fair value of net assets acquired	**$**	**2,584**
Goodwill	**$**	**3,389**

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 of approximately $86 million.

Long-term investments include WGL's 55 percent equity investment in Meade Pipeline Co. LLC., a 10 percent equity interest in Mountain Valley Pipeline LLC, and a 30 percent equity interest in Stonewall Gas Gathering Systems LLC. The preliminary fair value of these investments has been determined using an income approach, resulting in an estimated fair value increase of approximately $297 million.

Intangible assets consist of customer relationships and various contracts relating to gas transportation capacity. The preliminary fair value of these assets is determined using an income approach, resulting in an estimated fair value of approximately $571 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 $3.4 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 for the three and six months ended June 30, 2018 of approximately $6.7 million and $16.6 million, respectively, were incurred and included in the Consolidated Statement of Income (2017 - $5.3 million and $40.8 million, respectively). AltaGas expects to recognize additional acquisition-related expenses in the third quarter of 2018 predominantly related to the fulfilment of various regulatory commitments.

Following the WGL Acquisition, AltaGas will consolidate WGL. The following supplemental unaudited, pro forma consolidated financial information for the three and six months ended June 30, 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.

	Three months ended June 30		Six months ended June 30	
	2018	2017	**2018**	2017
Pro forma revenue	**$ 1,156**	$ 1,192	**$ 3,162**	$ 3,088
Pro forma net income (loss) after taxes	**$ (71)**	$ 18	**$ 157**	$ 252

Pro forma revenue excludes the gains and losses on foreign exchange contracts used to mitigate the foreign exchange risks associated with the cash purchase price of WGL on the basis that the gains and losses are directly incremental to the WGL Acquisition and are non-recurring in nature. These adjustments decreased pro forma revenue by $1 million and $nil, respectively, for the three and six months ended June 30, 2018, and increased pro forma revenue by $16 million and $22 million, respectively, for the three and six months ended June 30, 2017.

Pro forma net income (loss) after taxes excludes all non-recurring acquisition-related expenses 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 after taxes was also adjusted for 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 three and six month periods ended June 30, 2018, the total after-tax pro forma adjustments reduced net income (loss) after taxes by $20 million and $28 million, respectively. For the three and six months ended June 30, 2017, the total after-tax pro forma adjustments increased net income (loss) after taxes by $3 million and $31 million, respectively.

Commitments and Contingencies

In connection with the WGL Acquisition, AltaGas and WGL have made commitments totaling approximately US$150.0 million related to the terms of the Public Service Commission of the District of Columbia settlement agreement and the conditions of approval from the Maryland Public Service Commission and the Commonwealth of Virginia State Corporation Commission. These commitments include US$56.4 million in rate credits distributable to both residential and non-residential customers, gas expansion and other programs in Maryland counties of approximately US$57.1 million, various public interest commitments totaling approximately US$33.3 million, safety programs of approximately US$2.8 million, and a renewable natural gas study of approximately US$0.4 million.

AltaGas also expects to make payments of approximately US$13 million for retention payments to senior executives and severance costs related to the retirement of senior executives following the WGL Acquisition, with the potential for additional payments in the future.

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$29.6 million to the end of June 2018. 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 granted Antero's motion to dismiss the case and the case is currently on appeal.

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. 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.

Silver Spring, Maryland Incident

In August 2016, there was an explosion and fire at an apartment complex on Arliss Street in Silver Spring, Maryland, the cause of which has not been determined. Washington Gas continues to support the investigation by the National Transportation and Safety Board (NTSB) and 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. An initial 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. 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 to help determine the cause of this incident.

Supplementary Quarterly Operating Information

(unaudited)

	Q2-18	Q1-18	Q4-17	Q3-17	Q2-17
OPERATING HIGHLIGHTS					
GAS					
Total inlet gas processed (Mmcf/d)[(1)]	1,227	1,553	1,424	1,322	1,300
Extraction volumes (Bbls/d)[(1)(2)]	49,728	74,786	68,306	64,026	58,885
Frac spread - realized ($/Bbl)[(1)(3)]	14.98	19.01	18.02	14.96	9.06
Frac spread - average spot price ($/Bbl)[(1)(4)]	22.19	22.25	30.66	21.28	10.98
POWER					
Renewable power sold (GWh)	504	126	301	681	499
Conventional power sold (GWh)	642	842	1,059	992	409
Renewable capacity factor (%)	51.7	8.1	27.5	70.3	50.7
Contracted conventional availability factor (%)[(5)]	97.7	94.5	96.3	99.6	99.9
UTILITIES					
Canadian utilities					
Natural gas deliveries - end-use (PJ)[(6)]	5.6	14.1	11.2	3.7	4.8
Natural gas deliveries - transportation (PJ)[(6)]	1.4	1.8	1.6	1.3	1.5
U.S. utilities					
Natural gas deliveries end use (Bcf) [(6)]	12.0	31.0	24.3	5.9	10.3
Natural gas deliveries transportation (Bcf)[(6)]	10.9	13.4	14.2	10.9	11.5
Service sites[(7)]	580,526	582,871	581,518	575,602	575,084
Degree day variance from normal - AUI (%)[(8)]	3.9	10.2	4.0	(16.9)	(7.4)
Degree day variance from normal - Heritage Gas (%)[(8)]	6.7	(8.1)	(4.6)	(20.4)	(4.3)
Degree day variance from normal - SEMCO Gas (%)[(9)]	14.8	3.0	4.8	5.7	(8.4)
Degree day variance from normal - ENSTAR (%)[(9)]	(6.1)	(1.7)	(8.3)	(16.6)	(5.4)

(1) Average for the period.

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

(3) 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.

(4) 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.

(5) 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.

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

(7) Service sites reflect all of the service sites of AUI, PNG, Heritage Gas, and U.S. Utilities, including transportation and non-regulated business lines.

(8) A degree day for AUI and Heritage Gas is the cumulative extent to which the daily mean temperature falls below 15 degrees Celsius at AUI and 18 degrees Celsius at Heritage Gas. Normal degree days are based on a 20-year rolling average. Positive variances from normal lead to increased delivery volumes from normal expectations. Degree day variances do not materially affect the results of PNG as the British Columbia Utilities Commission (BCUC) has approved a rate stabilization mechanism for its residential and small commercial customers.

(9) 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 and during the prior 10 years for ENSTAR.

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 natural gas, power and regulated utilities. The Corporation creates value by acquiring, growing and optimizing its energy infrastructure, including a focus on clean energy sources. For more information visit: www.altagas.ca.

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