AltaGas Canada

News Release

FOR IMMEDIATE RELEASE

ALTAGAS CANADA INC. ANNOUNCES THIRD QUARTER 2018 RESULTS AND DECLARES ITS FIRST DIVIDEND

Calgary, Alberta (October 31, 2018) – AltaGas Canada Inc. ("ACI") (TSX: ACI) today announced third quarter 2018 financial results for the period ended September 30, 2018.

Highlights:

- With the completion of ACI's Initial Public Offering ("IPO"), ACI is set to deliver on continued rate base growth at its Utilities;
- ACI expects to deliver a compound annual growth rate of five percent on net income to its shareholders from 2019 through to 2023;
- Combined Utilities rate base grew to approximately $850 million as at September 30, 2018. ACI has a robust growth capital program in place for the remainder of 2018 with approximately $330 million planned between 2019 - 2023;
- By 2023, ACI expects its combined Utility rate base will grow to over $1 billion; and
- The Board of Directors declared its first dividend of $0.1744 for the period of October 25, 2018 to December 31, 2018, which on an annualized basis would yield $0.95 per common share.

In the third quarter of 2018, normalized EBITDA[1] was $15.9 million compared to $16.5 million for the same period in 2017. Third quarter 2018 net income after taxes was $0.5 million compared to $1.9 million for the same period in 2017. The results were driven primarily by ACI's Utilities which delivered rate base and customer growth and also benefitted from colder weather, offset by lower wind generation at the Bear Mountain Wind Park and lower results from the Northwest Hydro Facilities due to unseasonably cool, dry weather.

ACI completed its initial public offering on October 25, 2018 and as such, these results are attributable to AltaGas Ltd. and may not be directly comparable to future results primarily due to the change in ACI's capital structure.

"With the IPO successfully completed and a solid asset base in place, we are focused on bringing value to our shareholders," said Jared Green, President and Chief Executive Officer of ACI. "As we look forward to the next five years, we are confident in our ability to deliver a five percent compound annual growth rate on net income. We are also pleased to announce that the Board of Directors declared our very first dividend."

2018 Capital Program

For nine months ended September 30, 2018, ACI's net invested capital was $47.5 million. For the full year 2018 ACI expects to spend approximately $80 million across its Utilities.

Between 2019 and 2023, ACI expects to spend approximately $330 million at its Utilities and expects to grow rate base to over $1 billion. ACI expects to fund this capital program utilizing internally generated cash flow and a small amount of incremental debt.

ACI Dividend Declaration

The Board of Directors of ACI declared a dividend of $0.1744 per common share, payable on December 31, 2018 to shareholders of record at the close of business on or about November 30, 2018. This dividend is an eligible dividend for Canadian income tax purposes.

About ACI

ACI is a Canadian company with natural gas distribution utilities and renewable power generation assets. ACI serves approximately 130,000 customers, delivering low carbon energy, safely and reliably. For more information visit: www.altagascanada.ca.

FOOTNOTES

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

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", "expect", "project", "target", "potential", "objective", "continue", "outlook", "opportunity" and similar expressions suggesting future events or future performance, as they relate to ACI or any affiliate of ACI, 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: continued rate base growth at ACI's Utilities; expected compound annual growth rate; expected rate base growth; expected growth capital spending; and expected funding sources for the capital program.

ACI's forward-looking statements are subject to certain risks and uncertainties which could cause results or events to differ from current expectations, including, without limitation: legislative and regulatory environment; demand for natural gas; access to and use of capital markets; market value of ACI's securities; ACI's ability to pay dividends; ACI's ability refinance its debt; prevailing economic conditions; the potential for service interruptions and physical damage to infrastructure; natural gas supply; ability of the company to maintain, replace and expand its regulated assets; and impact of labour relations and reliance on key personnel. Applicable risk factors are discussed more fully under the heading "Risk Factors" in ACI's prospectus dated October 18, 2018.

Many factors could cause ACI'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, 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 ACI's 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. ACI 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 ACI's Management's Discussion and Analysis (MD&A) as at and for the nine months ended September 30, 2018. These non-GAAP measures provide additional information that management believes is meaningful regarding ACI's operational performance, liquidity and capacity to fund dividends, capital expenditures, and other investing activities. The specific rationale for and incremental information associated with non-GAAP measures are discussed in ACI's most recent MD&A. 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 ACI's operating profitability prior to how business activities are financed, assets are amortized, or earnings are taxed. Normalized EBITDA is calculated using net income adjusted for pre-tax depreciation and amortization, interest expense, and income tax expense, accretion expenses, and foreign exchange gains (losses). 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 EBITDA should not be viewed as an alternative to net income after taxes or other measures of income calculated in accordance with U.S. GAAP as an indicator of performance.

MANAGEMENT'S DISCUSSION AND ANALYSIS

GENERAL

AltaGas Canada Inc. ("the Company") was incorporated under the Canada Business Corporations Act on October 27, 2011 as AltaGas Utility Holdings (Pacific) Inc., a wholly owned subsidiary of AltaGas Ltd. ("AltaGas"). Prior to the transactions described in the *Subsequent Events* section below, the Company owned rate-regulated natural gas distribution utility assets in British Columbia through its subsidiary, Pacific Northern Gas Ltd. On September 5, 2018, the name of the Company was changed to AltaGas Canada Inc. Subsequent to the transactions described in the *Subsequent Events* section below, the Company is a reporting issuer listed on the Toronto Stock Exchange with ownership interests in rate-regulated natural gas distribution utilities and renewable power assets.

This Management's Discussion and Analysis (MD&A) dated October 30, 2018 is provided to enable readers to assess the results of operations and liquidity and capital resources of the Company. This MD&A should be read in conjunction with the accompanying unaudited condensed interim combined financial statements as at and for the three and nine months ended September 30, 2018 (the Interim Financial Statements) and the audited combined financial statements and notes thereto of the Business (comprising the Company and the Acquired Assets) as at December 31, 2017 and December 31, 2016, and for the three years ended, December 31, 2017 (Annual Financial Statements) included as Appendix FS to the Company's long form prospectus dated October 18, 2018.

The Interim 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.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This MD&A contains certain forward-looking information and statements within the meaning of applicable securities laws. The use of any of the words ''expect'', ''anticipate'', ''continue'', ''estimate'', ''objective'', ''ongoing'', ''may'', ''will'', ''should'', ''believe'', ''plan'', "would", "could", "focus", "forecast", "opportunity" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this MD&A contains forward-looking information and statements pertaining to the following: expected use of proceeds of the Offering; expected customer growth; estimated timing for the Heritage Gas Limited Customer Retention Program; the expected accumulation of Heritage Gas Limited's revenue deficiency account; expected transition of Inuvik Gas to the Town of Inuvik; anticipated sources of indebtedness; expected funding of the Company's capital program; planned expenditures under the approved capital budget; expected business environment and operational factors contributing to the Company's performance; and anticipated statutory tax rates.

The forward-looking information and statements contained in this MD&A reflect several material factors, expectations and assumptions of the Company including, without limitation: that the Company will continue to conduct its operations in a manner consistent with past operations; the general continuance of current or, where applicable, assumed industry conditions; the continuance of existing regulatory regimes; that there will be no material defaults by the counterparties to agreements with the Company and such agreements will not be terminated prior to their scheduled expiry; and the Company will continue to have access to wind and water resources in amounts consistent with the amounts expected by the Company. The Company believes the material factors, expectations and assumption reflected in the forward-looking information and statements are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information and statements included in this MD&A are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information and statements, including, without limitation: changes in the demand for or supply of the Company's services; unanticipated operating results; changes in regulatory matters; limited, unfavourable or a lack of access to capital markets; increased costs; the impact of competitors; attracting and retaining skilled personnel and certain other risks (including, without limitation, those risks identified elsewhere in this MD&A).

The forward-looking information and statements contained in this MD&A speak only as of the date of this MD&A, and none of the Company or its subsidiaries assumes any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable laws. The reader is cautioned not to place undue reliance on forward-looking information and statements.

SUBSEQUENT EVENTS

Subsequent events have been reviewed through October 30, 2018, the date on which the Interim Financial Statements were approved for issue by the Board of Directors.

Acquired Assets and Acquired Indebtedness (collectively, the Acquisition)

On October 18, 2018 (the Acquisition Date), the Company acquired, pursuant to a Purchase and Sale Agreement, the business conducted by AltaGas using direct and indirect interests in the following assets (the Acquired Assets):

- Rate-regulated natural gas distribution utility assets in Alberta and Nova Scotia owned by AltaGas Utility Group Inc. (AUGI) via its operating subsidiaries AltaGas Utilities Inc. (AUI) and Heritage Gas Limited (HGL);
- Minority interests in entities (Inuvik Gas Ltd. and Ikhil Joint Venture) providing natural gas to the Town of Inuvik, Northwest Territories;
- Fully contracted 102 MW wind power park located near Dawson Creek, British Columbia owned by Bear Mountain Wind Limited Partnership (Bear Mountain); and
- Approximately 10 percent indirect equity interest in the capital of Northwest Hydro Limited Partnership (Coast LP) which indirectly owns three fully contracted 277 MW run-of-river hydroelectric power generation assets in northwest British Columbia (Northwest Hydro Facilities).

Since AltaGas controlled the Company at the Acquisition Date, the business conducted using the Acquired Assets was transferred at its carrying value.

On the same date, the Company acquired the indebtedness that AUGI and PNG had with AltaGas and certain of its subsidiaries (the Acquired Indebtedness) in the amount of $481.6 million.

The Company acquired the Acquired Assets and Acquired Indebtedness from AltaGas for $889.1 million which was satisfied by issuing to AltaGas:

- 5,912,857 common shares;
- An unsecured promissory note bearing interest at 4.5 percent per annum in the principal amount of $316.3 million to be repaid upon closing of the Initial Public Offering described below;
- An unsecured promissory note bearing interest at 3.3 percent per annum in the principal amount of $35.9 million to be repaid no later than 30 days after closing of the Initial Public Offering; and
- An unsecured promissory note bearing interest at 4.5 percent per annum in the principal amount of $351.2 million with a term of 30 months, the interest to be increased by 0.25 percent on the 18 and 24 month anniversaries of the issuance date.

Prior to the Acquisition:

- The Company paid an eligible dividend of $31.0 million to AltaGas;
- Bear Mountain distributed cash of $64.6 million to AltaGas; and
- AUGI repaid indebtedness of $28.4 million to AltaGas.

Initial Public Offering of Common Shares

On October 18, 2018, the Company filed a final long form prospectus in connection with its offering of 16,500,000 common shares (the Offering) issued pursuant to the terms of an Underwriting Agreement at a price of $14.50 per common share (the Offering Price).

On October 25, 2018, the Company completed the Offering and issued 16,500,000 common shares at the Offering Price for gross proceeds of $239.3 million.

The Company has granted to the Underwriters an option (the Over-Allotment Option), exercisable at the Underwriters' discretion at any time, in whole or in part, until 30 days after the closing of the Offering to purchase at the Offering Price up to an additional 2,475,000 common shares (representing 15 percent of the common shares offered) to cover over-allotments.

Upon closing of the Offering and the exercise or otherwise of the Over-Allotment Option, 30,000,000 common shares will be issued and outstanding. AltaGas will own 45 percent of the outstanding common shares, assuming no exercise of the Over-Allotment Option and the resulting conversion of indebtedness, and 36.8 percent of the outstanding common shares if the Over-Allotment Option is exercised in full.

The net proceeds of the Offering were $223.7 million after deducting the Underwriters' fee of $12.6 million and other expenses of the Offering, estimated to be $3.0 million. If the Over-Allotment Option is exercised in full, the net proceeds are expected to be approximately $257.7 million after deducting the Underwriters' fee of $14.4 million and other expenses of the Offering, estimated to be $3.0 million**.**

Pursuant to the Purchase and Sale Agreement, the Company used the net proceeds of the Offering (excluding any proceeds from the Over-Allotment Option) to:

- Repay in full a note issued to AltaGas bearing interest at 5.0 percent per annum in the principal amount of $157.4 million which resulted from a return on capital on the Company's common shares prior to the Acquisition;
- Repay a portion of the unsecured promissory note bearing interest at 4.5 percent per annum issued to AltaGas in the principal amount of $316.3 million.

The Company intends to use the net proceeds, if any, from the exercise of the Over-Allotment Option to repay all or a portion of the unsecured promissory note bearing interest at 3.3 percent per annum issued to AltaGas in the principal amount of $35.9 million.

On October 25, 2018, the Company and a syndicate of lenders executed a $200 million Extendible Revolving Term Credit Facility, a $250 million Term Credit Facility and a $35 million Demand Revolving Operating Facility, which are described in the *Liquidity and Capital Resources* section of this MD&A

Transition Services Agreement

On October 18, 2018, the Company entered into a Transition Services Agreement with AltaGas pursuant to which AltaGas will provide certain day-to-day services required by the Company, to include: (a) general administrative and corporate services, including accounting, tax, finance, legal and regulatory, payroll, corporate human resources and pension management, environmental, health and safety administration, procurement, enterprise resource planning and information technology; (b) credit support services; and (c) accounting, budgeting and engineering services in respect of the Ikhil Joint Venture. AltaGas will provide the services on a cost recovery basis only. The Transition Services Agreement will operate until June 30, 2020, subject to earlier termination in certain circumstances, and is extendable by mutual agreement of the parties.

OVERVIEW OF THE BUSINESS

Utilities segment

AUI

AUI owns and operates a regulated natural gas distribution utility in Alberta. At the end of September 2018, AUI served approximately 80,000 customers. AUI’s customers are primarily residential and small commercial consumers located in smaller population centers or rural areas of Alberta. AUI's rate base at September 30, 2018 was approximately $330 million. For 2017, the Alberta Utilities Commission (AUC) approved a Return on Equity (ROE) of 8.5 percent on 41 percent equity. On August 2, 2018, the AUC approved an ROE of 8.5 percent on 39 percent equity for AUI for 2018, 2019 and 2020.

AUI is currently operating under a revenue cap per customer formula under Performance-Based Regulation (PBR) plans. The first generation PBR plan was implemented for all Alberta electric and natural gas distribution companies, and was effective for AUI as of January 1, 2013 with an initial term of five years. The PBR framework is intended to incentivize utilities to be more efficient. Under this model, rates are adjusted annually by formula based on a customer growth factor and inflation factor less expected productivity improvements. Provisions within the first generation PBR formula also included recovery of costs determined to flow through directly to customers and related to material exogenous events and incremental capital funding for major capital projects not otherwise encompassed within the PBR formula.

Effective January 1, 2018, the AUC approved a second PBR term from 2018 to 2022. Under the second generation PBR plan, rates continue to be set under a revenue cap per customer formula with annual adjustments for customer growth and inflation less expected productivity improvements. In addition, the PBR mechanism continues to allow for recovery of costs determined to flow through directly to customers and related to material exogenous events. Incremental capital funding continues to be available, however, it is now largely established under a formula based on historical capital additions rather than for applied-for projects and programs.

PNG

PNG operates a transmission and distribution system in the west central portion of northern British Columbia (PNG West) and in the areas of Fort St. John and Dawson Creek (FSJ/DC) and Tumbler Ridge (TR) in northeastern British Columbia (PNG(N.E.)). At the end of September 2018, PNG served approximately 42,000 customers. Approximately 87 percent of PNG’s total customers are residential. The allowed ROE for PNG West and PNG(N.E.) TR is 9.50 percent and for PNG(N.E.) FSJ/DC is 9.25 percent. The approved common equity ratio for PNG West and PNG(N.E.) TR is 46.5 percent and for PNG(N.E.) FSJ/DC is 41 percent. PNG’s rate base at September 30, 2018 was approximately $212 million.

PNG operates under a cost of service regulatory model whereby customer rates are set based on revenues that allow for the recovery of forecast costs plus an established rate of return on deemed common equity of PNG.

In November 2017, PNG submitted Revenue Requirements Applications with the British Columbia Utilities Commission (BCUC) for 2018 and 2019 and received approvals for interim and refundable delivery rate increases effective January 1, 2018. The BCUC issued its decisions in August 2018 and approved permanent delivery rate decreases of approximately 1.8 percent for each of 2018 and 2019 for customers in PNG West, permanent delivery rate increases of approximately 6 percent for each of 2018 and 2019 for customers in the FSJ/DC service areas, as well as permanent delivery rate increase of approximately 18 percent for each of 2018 and 2019 for customers in the TR service area, compared to 2017 rates. The BCUC also directed PNG to include a provision for negative salvage in its depreciation expense commencing in 2019. PNG has requested a transition period for the inclusion of negative salvage accounting. The delivery rate increases noted do not include the impact of negative salvage accounting.

On October 9, 2018, PNG published a request for expressions of interest in a multi-lateral process, in which PNG is seeking interested parties who require firm transportation service on its existing pipeline system for natural gas deliveries from Station 4a on the Enbridge Westcoast Energy Inc. southern mainline near Summit Lake, British Columbia to the Terrace, Kitimat, and Prince Rupert areas, as well as a proposed expansion of its pipeline system from Summit Lake to Kitimat (the PNG Pipeline Looping Project). Non-binding expressions of interest were accepted until October 26, 2018. Following review of the non-binding expressions of interest, PNG will invite interested parties to continue to participate in its multi-lateral process and execute binding agreements, which will include the payment of option fees to reserve existing PNG transportation capacity, as well as support agreements, for a pro-rata share of the project development costs to assess feasibility. Through the project development phase, option holders will be required to backstop PNG's ongoing pipeline development costs, on a pro-rata basis, until such time transportation service agreements have been executed on an unconditional basis.

HGL

HGL has the exclusive rights to distribute natural gas through its distribution system to all or part of seven counties in Nova Scotia, including the Halifax Regional Municipality. As of September 30, 2018, HGL's customer base is approximately 7,100 customers. HGL has a mix of residential, small commercial, large commercial and industrial customers. For 2018 and 2017, HGL's approved regulated ROE is 11 percent with an approved deemed capital structure of 45 percent equity. HGL's rate base at September 30, 2018 was approximately $307 million.

HGL operates under cost-of-service regulation and is regulated by the Nova Scotia Utility and Review Board (NSUARB). In order to maintain competitive pricing and customer retention, HGL filed a Customer Retention Program application with the NSUARB in March 2016 requesting a decrease in distribution rates for commercial customers with consumption between 500 and 4,999 GJ per year and allowing for flexible rate increases from time to time for these customers up to their previously approved distribution rates while the Customer Retention Program is in place. HGL also requested a suspension of depreciation and a 50 percent capitalization rate for operating, maintenance and administrative expenses (approximately 25 percent more than HGL would capitalize under its capitalization policy) while the Customer Retention Program is in place. In September 2016, the NSUARB approved HGL's Customer Retention Program application. The approval included all of the items requested by HGL as well as a reduction to residential customer rates of $0.50 per GJ during the 2016 to 2017 and 2017 to 2018 winter seasons and a return on the deferred depreciation and operating expense balances arising from the Customer Retention Program of 4 percent.

The competitive position of natural gas pricing relative to propane improved in the Atlantic region throughout 2017 and into early 2018. Through enhanced gas procurement strategies and changes in market fundamentals, the average price of natural gas for HGL customers declined by over 20 percent in 2017 compared to 2016 and 2015, while the 2017 Sarnia benchmark price for propane increased by over 30 percent compared to 2016 and 40 percent compared to 2015. Accordingly, in November 2017 and in June 2018, HGL exercised the flexibility provided for in the Customer Retention Program to increase the rates which has partially restored the rates to previously approved cost of service levels. HGL estimates that the Customer Retention Program will be in place until the end of 2020.

For its regulated operations, HGL has approval from the NSUARB to use a Revenue Deficiency Account (RDA) until it is fully recovered, subject to a cap of $50 million, imposed in 2010 which may be increased subject to approval by the NSUARB. The RDA is revenue required to afford HGL the opportunity to earn the rates of return on its rate base, as approved by the NSUARB. In periods where the actual revenue billed is less than the revenue required to earn the approved rates of return, the RDA asset will accumulate. As the distribution network matures, the actual revenue billed is expected to exceed the revenue required to earn the approved rates of return and the RDA is drawn down.

Inuvik Gas Ltd. & Ikhil Joint Venture

The Company has an approximate one-third interest in Inuvik Gas and the Ikhil Joint Venture (Ikhil) natural gas reserves, which have historically supplied Inuvik Gas with natural gas for the Town of Inuvik. With the Ikhil natural gas reserves approaching the end of their life, a propane air mixture system producing synthetic natural gas was implemented as the main source of energy supply for Inuvik Gas with Ikhil serving as a back-up. In December 2016, Inuvik Gas notified the Town of Inuvik of its intention to terminate the gas distribution franchise agreement effective December 2018. Inuvik Gas is working with the Town of Inuvik over the course of the remaining term to transition ownership to the Town of Inuvik. Absent a purchase by the Town of Inuvik, Inuvik Gas will continue to provide natural gas services to its customers.

Renewable Energy segment

Bear Mountain

The Bear Mountain Wind Park near Dawson Creek, British Columbia is a 102 MW generating wind facility consisting of 34 turbines, a substation and transmission lines, which is connected to the BC Hydro transmission grid. All of the power from the Bear Mountain Wind Park is sold to BC Hydro under a 25-year power purchase agreement (PPAs) expiring in 2034 with escalation factor of 50 percent of BC Consumer Price Index.

Northwest Hydro Facilities

The Northwest Hydro Facilities, in which the Company has a 10 percent indirect equity interest, is located in Tahltan First Nation territory approximately 1,000 kilometers northwest of Vancouver, British Columbia, are comprised of the Forrest Kerr Hydroelectric Facility, the McLymont Creek Hydroelectric Facility, the Volcano Creek Hydroelectric Facility and a substation and transmission line and related facilities. The facilities have total generation capacity of 277 MW. These facilities are each underpinned by 60-year PPAs, fully indexed to the consumer price index for British Columbia, All Items (Not Seasonally Adjusted) as published by Statistics Canada (BC CPI). The PPA for Forrest Kerr and Volcano expires in 2074 and the PPA for McLymont expires in 2075. Impact benefit agreements are in place with the Tahltan First Nation for all three facilities, to facilitate a cooperative and mutually beneficial relationship.

SELECTED FINANCIAL INFORMATION

The Business' results of operations are presented on a combined basis. Some accounting policies require management to make estimates or assumptions that in some cases may relate to matters that are inherently uncertain. Some of the critical accounting policies and estimates include: revenue recognition, valuation and useful life of PP&E, financial instruments, decommissioning and restoration provisions and income taxes. See the *Critical Accounting Estimates* section of this MD&A for further discussion.

The following tables summarize key financial results and operating data:

	Three months ended September 30		Nine months ended September 30	
($ millions)	**2018**	2017	**2018**	2017
Normalized EBITDA(1)	**15.9**	16.5	**70.1**	70.5
Net income after taxes	**0.5**	1.9	**24.4**	24.6
Normalized net income(1)	**0.8**	2.3	**23.6**	25.9
Net additions to property, plant and equipment	**21.8**	16.0	**45.5**	32.3
Normalized funds from operations(1)	**4.6**	3.8	**61.3**	40.6

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

Normalized EBITDA in the third quarter of 2018 was $15.9 million, a decrease of $0.6 million relative to the same period in 2017. Colder weather and utility customer growth were offset by lower wind generation in Bear Mountain and higher normal course operating and administrative expenses. Net income after taxes was impacted by an increase in interest expense following a debenture issuance to AltaGas in October 2017 and higher income taxes.

Normalized EBITDA in the nine months ended September 30, 2018 was $70.1 million, a decrease of $0.4 million relative to the same period in 2017, primarily due to lower wind generation in Bear Mountain, higher normal course operating and administrative expenses. Net income after taxes had lower realized losses on foreign exchange contracts in 2018, compared to 2017.

NORMALIZED EBITDA BY REPORTING SEGMENT [1]

($ millions)	Three months ended September 30 2018	Three months ended September 30 2017	Nine months ended September 30 2018	Nine months ended September 30 2017
Utilities	**11.2**	9.6	**59.9**	57.2
Renewable Energy	**$ 4.7**	$ 6.9	**$ 10.2**	$ 13.3
	$ 15.9	$ 16.5	**$ 70.1**	$ 70.5

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

NET INCOME AFTER TAXES BY REPORTING SEGMENT

($ millions)	Three months ended September 30 2018	Three months ended September 30 2017	Nine months ended September 30 2018	Nine months ended September 30 2017
Utilities [1]	**(2.1)**	(2.7)	**23.2**	20.5
Renewable Energy [1]	**$ 2.9**	$ 5.1	**$ 4.8**	$ 7.9
Sub-total: Operating Segments	**0.8**	2.4	**28.0**	28.4
Corporate [2]	**(0.3)**	(0.5)	**(3.6)**	(3.8)
	$ 0.5	$ 1.9	**$ 24.4**	$ 24.6

(1) Segment income before taxes

(2) Taxes and foreign exchange loss allocated to Corporate

UTILITIES SEGMENT REVIEW

Financial results

($ millions)	Three months ended September 30 2018	Three months ended September 30 2017	Nine months ended September 30 2018	Nine months ended September 30 2017
Revenue	**40.9**	41.0	**204.2**	207.6
Cost of sales	**(9.7)**	(11.3)	**(78.7)**	(89.3)
Net revenue	**31.2**	29.7	**125.5**	118.3
Operating and administrative expenses	**(20.2)**	(20.3)	**(64.6)**	(61.7)
Accretion expenses	**—**	—	**(0.1)**	—
Depreciation and amortization	**(5.8)**	(5.2)	**(16.6)**	(15.7)
Loss from equity investments	**(0.1)**	—	**(0.1)**	(0.1)
Other loss	**—**	(0.2)	**—**	(0.6)
Interest expense	**(7.2)**	(6.7)	**(20.9)**	(19.7)
Income (loss) before income taxes	**(2.1)**	(2.7)	**23.2**	20.5

Operating statistics

	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Canadian utilities				
Natural gas deliveries - end-use (PJ)[1]	**3.5**	3.8	**23.2**	22.4
Natural gas deliveries - transportation (PJ)[1]	**1.1**	1.6	**4.3**	5.4
Degree day variance from normal - AUI (%) [2]	**80.0**	(16.9)	**13.5**	(4.2)
Degree day variance from normal - HGL (%) [2]	**(16.5)**	(20.4)	**(4.6)**	(3.4)

(1) Petajoule (PJ) is one million gigajoules.

(2) A degree day for AUI and HGL is the cumulative extent to which the daily mean temperature falls below 15 degrees Celsius at AUI and 18 degrees Celsius at HGL. 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.

Management reviews the performance of the business in the Utilities segment by reference to 'Net revenue' which is defined in the 'Financial results' table above as revenue less cost of sales. The main component of cost of sales is commodity costs, and the period-on-period cost of sales variances are primarily due to changes in sales volumes and commodity prices. Since changes in commodity prices are recovered in rates approved by regulators, they do not have a significant impact on net revenue and income before income taxes. The commentary below therefore focuses on net revenue rather than on revenue and cost of sales independently.

Three month period ended September 30, 2018

Net revenue increased by $1.5 million primarily due to colder weather in Alberta than the prior year, higher customer rates and receipt of funds from AltaGas in connection with Part VI.1 tax transfers occurring in an earlier period, partially offset by lower cost of service requirements in 2018.

Operating and administrative expenses remained consistent as normal course inflation on costs was offset by lower maintenance costs resulting from the timing of maintenance activities.

Depreciation expense increased by $0.6 million partly due to a write down of unregulated plant assets held.

Interest expense increased by $0.5 million, largely as a result of a $30 million debenture issuance to AltaGas in October 2017.

Nine month period ended September 30, 2018

Net revenue increased by $7.2 million primarily due to colder weather in Alberta than the prior year, higher customer rates and receipt of funds from AltaGas in connection with Part VI.1 tax transfers occurring in an earlier period, partially offset by lower cost of service requirements in 2018.

Operating and administrative expenses increased by $2.9 million primarily due to higher wages and salaries as a result of filling vacant positions, higher pension costs, higher consulting fees and normal course inflation on costs.

Depreciation expense increased by $0.9 million as a result of additions to PP&E and a write down of unregulated plant assets held.

Interest expense increased by $1.2 million, largely as a result of a $30 million debenture issuance to AltaGas in October 2017.

RENEWABLE ENERGY SEGMENT REVIEW

Financial results

($ millions)	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Revenue	**2.9**	4.1	**10.4**	12.0
Cost of sales	**(0.1)**	(0.1)	**(0.2)**	(0.2)
Net revenue	**2.8**	4.0	**10.2**	11.8
Operating and administrative expenses	**(1.5)**	(1.4)	**(4.2)**	(3.8)
Depreciation and amortization	**(1.8)**	(1.8)	**(5.4)**	(5.4)
Income from equity investment	**3.4**	4.3	**4.2**	5.3
Income before income taxes	**2.9**	5.1	**4.8**	7.9

Operating statistics

	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Bear Mountain power sold (GWh)	**28.08**	40.22	**101.48**	116.01
Northwest Hydro power sold (GWh) (1)	**49.66**	56.45	**90.95**	97.91

(1) Representing 10% of the total power sold by the Northwest Hydro facilities, consistent with the Company's equity interest held.

Three month period ended September 30, 2018

Revenue decreased by $1.2 million primarily due to lower wind generation specifically in the month of September for electricity generated.

Operating and administrative expenses increased by $0.1 million primarily due to a higher maintenance charge as a result of an increase in the $/MWh charge and an unfavourable change in the foreign exchange rate arising from the Enercon maintenance contract which is denominated in Euros, partially offset by lower personnel costs as a result of a staff vacancy being unfilled.

Equity income from the Northwest Hydro investment decreased by $0.9 million due to the unseasonably cool and dry weather resulting in low river flows, partially offset by lower maintenance costs.

Nine month period ended September 30, 2018

Revenue decreased by $1.6 million primarily due to lower wind generation in the months of January and September 2018.

Operating and administrative expenses increased by $0.4 million primarily due to a higher maintenance charge as a result of an increase in the $/MWh charge and an unfavourable change in the foreign exchange rate arising from the Enercon maintenance contract, partially offset by lower personnel costs as a result of a staff vacancy being unfilled.

Equity income from the Northwest Hydro investment decreased by $1.1 million as a result of lower river flows and higher operating costs, partially offset by lower depreciation expense.

SELECTED QUARTERLY INFORMATION

The following table sets forth unaudited quarterly information for each of the eight quarters from the quarter ended December 31, 2016 to the quarter ended September 30, 2018. This information has been derived from the Business' Interim Financial Statements and its Annual Financial Statements.

($ millions)	**Q3-18**	Q2-18	Q1-18	Q4-17
Revenue	**43.8**	59.8	111.0	88.9
Normalized EBITDA	**15.9**	18.4	35.8	34.1
Net income after taxes	**0.5**	3.7	20.2	17.0

($ millions)	Q3-17	Q2-17	Q1-17	Q4-16
Revenue	45.1	58.9	115.6	90.6
Normalized EBITDA	16.5	17.3	36.7	29.2
Net income after taxes	1.9	3.5	19.2	14.3

Quarter-over-quarter financial results are impacted by seasonality, fluctuations in commodity prices, weather, planned and unplanned outages and timing of in-service dates of new projects.

Revenue for the Utilities segment 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 equity investment in the Northwest Hydro Facilities is impacted by seasonal precipitation and snowpack melt, which create periods of high river flow during the spring and summer months.

Other significant items that impacted quarter over quarter performance during the periods noted include (year-over-year comparison for the same quarter):

Impacting net revenue and net income after taxes

- Higher AUI revenue in the second and third quarters of 2018 as a result of colder weather and higher customer rates;
- Lower Bear Mountain revenue in the third quarter of 2018 due to lower wind generation specifically in the month of September;
- Lower AUI margins in the first quarter of 2018 primarily due to a one-time adjustment of fixed charges revenue (change in accrual methodology), together with lower PNG revenue primarily due to a rate refund adjustment resulting from anticipated rates being less than the 2018 interim rates previously recorded;
- Lower revenue in the third quarter of 2017 primarily due to lower PNG transport and industrial volumes due to warmer weather and lower customer rates;
- Lower gas prices in the fourth quarter of 2017 reflected in lower customer rates, partially offset by higher AUI customer usage and higher wind generation in Bear Mountain; and
- Variability in Bear Mountain volumes and average price quarter over quarter depending upon the amount and timing of wind generation.

Impacting net income after taxes

- Quarter-over-quarter seasonal variability in income from the equity investment in the Northwest Hydro Facilities, with higher river flow typically occurring during the second and third quarters of each year;

- Quarter-over-quarter variability in AUI and PNG operating and administrative expenses primarily due to the timing of vacant positions being filled and consulting fees;

- Quarter-over-quarter variability in HGL foreign exchange gains and losses arising from mark-to-market adjustments on US$ forward contracts with AltaGas; and

- Higher interest expense in the first three quarters of 2018 as a result of a $30 million debenture issuance to AltaGas in October 2017.

LIQUIDITY AND CAPITAL RESOURCES

		Three months ended September 30			Nine months ended September 30	
($ millions)		**2018**	2017		**2018**	2017
Cash from operations	**$**	**4.4**	$ 10.0	**$**	**63.5**	$ 48.1
Cash used in investing activities		**(21.5)**	(16.4)		**(40.0)**	(29.0)
Cash provided by (used in) financing activities		**17.1**	6.4		**(23.5)**	(19.1)
Increase in cash and cash equivalents	**$**	**—**	$ —	**$**	**—**	$ —

Cash from operations
During the nine months ended September 30, 2018, cash from operations increased by $15.4 million primarily due to a distribution of $20.3 million received from the Northwest Hydro equity investment in the second quarter of 2018**,** partially offset by an increase in payments of supplier invoices.

Investing activities
During the nine months ended September 30, 2018, cash used in investing activities included approximately $26 million of AUI system betterment, plant system updates and replacement of service lines and subdivision installations and PNG's $1.9 million of year-to-date spend on a pipeline to a propane export terminal on Ridley Island.

See also the *Invested Capital* section of this MD&A.

Financing activities
During the nine months ended September 30, 2018, cash used in financing activities increased by $4.4 million primarily due to a repayment of net parental investment facilitated by the Northwest Hydro distribution and repayments made on short-term advances due to AltaGas**.**

Capital Resources
The Company's objective for managing capital is to maintain its investment grade credit rating, ensure adequate liquidity, maximize the profitability of its existing assets and grow its energy infrastructure to create long-term value and enhance returns to investors. Its capital resources comprise short-term and long-term debt (including the current portion), and both short-term advances and long-term debt due to AltaGas. Short-term advances owed to AltaGas will be purchased by the Company in connection with the Acquisition.

Liquidity may be impacted by various internal and external factors including, but not limited to, weather, planned and unplanned outages, regulatory decisions, loss of customers and the general economic environment.

Credit Facilities

The Business funds its long and short term borrowing requirements with credit facilities as follows:

($ millions)	Borrowing capacity	**Drawn at September 30, 2018**	Drawn at December 31, 2017
AltaGas intercompany credit facility (1)	$ 70.0	**$ —**	$ 55.0
AltaGas term loan (1)	55.0	**55.0**	—
AltaGas intercompany credit facility (2)	30.0	**—**	—
PNG committed credit facility (2)	25.0	**—**	—
PNG operating credit facility (3)	25.0	**9.5**	12.8
AUGI demand operating facility (4)	20.0	**3.1**	3.5
	$ 225.0	**$ 67.6**	$ 71.3

(1) On May 4, 2018, PNG converted its $70 million intercompany revolving 5-year credit facility with AltaGas into a 4.15 percent $55 million intercompany term loan that matures on December 2, 2027. PNG has issued secured debentures for this new facility the collateral for which consists of a specific mortgage on substantially all of its PP&E and gas purchase and gas sales contracts, and a floating charge on other property, assets and undertakings. Interest and stand-by costs are due semi-annually and amounted to $0.9 million for the nine months ended September 30, 2018, and has been included in finance fees of which $0.6 million is outstanding and included in accrued liabilities. Optional repayments are allowed without penalty and there is no mandatory repayment prior to maturity;

(2) On May 4, 2018, PNG completed financing of $55 million of revolving five-year credit facilities, $30 million with AltaGas and $25 million with an external counterparty, that mature on May 4, 2023. Borrowings are available by way of bankers' acceptances bearing interest at the three-month bankers' acceptance rate plus a spread and subject to stand-by fees. Interest and stand-by costs are due monthly. Optional repayments are allowed without penalty and there is no mandatory repayment prior to maturity. PNG has issued secured debentures for the five-year facility with the same collateral as PNG's other existing secured debentures. The external facility will be used to support PNG's capital spending program. The AltaGas facility can only be drawn once the external facility has been fully drawn;

(3) On May 4, 2018, the $25 million PNG operating credit facility was extended to November 4, 2019. The operating line is available for working capital purposes through cash draws in the form of prime-rate advances or bankers' acceptances and the issuance of letters of credit and is collateralized by a charge on PNG's accounts receivable and inventories;

(4) The $20 million AUGI unsecured, uncommitted, demand revolving operating credit facility with a Canadian chartered bank is available for general corporate purposes. Draws on the facility can be by way of prime rate loans, US prime rate loans, letters of credit, bankers' acceptances, and LIBOR loans.

On October 25, 2018, the Company executed:

- A $200 million unsecured revolving credit facility with a syndicate of lenders having a term of four years subject to customary extension provisions, which is available for general corporate purposes and was not materially drawn at Closing;
- A $250 million unsecured term loan with a syndicate of lenders having a term of two years, which was fully drawn at Closing with the proceeds utilized to pay for a portion of the unsecured promissory note bearing interest at 4.5 percent in the principal amount of $316.3 million; and
- A $35 million unsecured, uncommitted operating facility, which is available for general corporate purposes and was not materially drawn at Closing.

The borrowing options under the credit facility, term loan and operating facility include Canadian prime rate-based loans, U.S. base rate loans, bankers' acceptances and LIBOR loans. Further borrowing options under the operating facility include overdraft and letters of credit. Borrowings on the credit facility, term loan and operating facility bear fees and interest at rates relevant to the nature of the draw made and the Company credit rating.

Copies of these agreements are available for review on SEDAR at www.sedar.com.

In addition to the facilities executed on October 25, 2018, the Company continues to have available the PNG committed and operating credit facilities.

Letters of credit

Letters of credit of $7.8 million were issued and outstanding by AltaGas on behalf of the Company and its subsidiaries at September 30, 2018.

INVESTED CAPITAL

	Three months ended September 30, 2018			Three months ended September 30, 2017		
($ millions)	**Renewable Energy**	**Utilities**	**Total**	Renewable Energy	Utilities	Total
Invested capital:						
PP&E	**$ —**	**$ 21.9**	**$ 21.9**	$ —	$ 16.1	$ 16.1
Intangible assets	**—**	**1.8**	**1.8**	—	—	—
Invested capital	**—**	**23.7**	**23.7**	—	16.1	16.1
Disposals:						
PP&E	**—**	**(0.1)**	**(0.1)**	—	(0.1)	(0.1)
Net invested capital	**$ —**	**$ 23.6**	**$ 23.6**	$ —	$ 16.0	$ 16.0

	Nine months ended September 30, 2018			Nine months ended September 30, 2017		
($ millions)	**Renewable Energy**	**Utilities**	**Total**	Renewable Energy	Utilities	Total
Invested capital:						
PP&E	**$ —**	**$ 45.8**	**$ 45.8**	$ —	$ 32.8	$ 32.8
Intangible assets	**—**	**2.0**	**2.0**	—	—	—
Invested capital	**—**	**47.8**	**47.8**	—	32.8	32.8
Disposals:						
PP&E	**—**	**(0.3)**	**(0.3)**	—	(0.5)	(0.5)
Net invested capital	**$ —**	**$ 47.5**	**$ 47.5**	$ —	$ 32.3	$ 32.3

On an ongoing basis, the Company plans to fund its capital program with cash from operations, drawing on its credit facilities, future debt offerings, and future issuance of preferred shares.

Utilities segment

The Utilities segment planned capital expenditure for 2018 is approximately $80 million, which has received regulatory approval or is included in pending regulatory applications. The majority of the $47.8 million year-to-date spend relates to system betterment, replacement of transmission and distribution lines and new business installations. The capital expenditure plan includes approximately $4.5 million that PNG expects to spend in 2018 on the construction of a pipeline to facilitate the supply of product to a propane export terminal on Ridley Island.

Renewable Energy segment

There is no capital spending planned in connection with the Company's Renewable Energy assets.

COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

The Business has long-term natural gas purchase and transportation arrangements, service agreements, storage contracts and operating leases for office space and office equipment, all of which are transacted at market prices and in the normal course of business, the amount and timing of which are disclosed in note 20 to the Business' 2017 Annual Financial Statements.

The Business has an obligation to pay a minimum of $6.3 million over the next four years pursuant to a service and maintenance agreement with Enercon GmbH in respect of the Bear Mountain wind turbines.

In 2017, HGL 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 System. The PA with PNGTS was subject to HGL satisfying a condition precedent of obtaining regulatory approval by July 31, 2018 for the contract to proceed. On June 1, 2018, HGL received approval from the 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.

Guarantees

In October 2014, HGL 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. As at September 30, 2018 and December 31, 2017, two guarantees were outstanding that total US$91.7 million to stand by all payment obligations under the throughput service agreement.

Indemnifications

Under the terms of its gas transportation and supply agreements with certain customers, PNG has provided an indemnity for all damages, claims or actions arising from any act or accident in connection with the installation, presence, maintenance and operations of its property, plant and equipment, or in connection with the presence of gas deemed to be in its possession and control. PNG has $50 million of insurance coverage for third party liability with a $0.1 million deductible. PNG has also provided environmental indemnity to certain secured debenture holders for any losses arising from non-compliance by PNG with applicable environmental laws.

Contingencies

The Business is 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 Business does not believe that the resolution of such claims and actions will have a material impact on the Business' combined financial position or results of operations.

NON-GAAP FINANCIAL MEASURES

This MD&A contains references to certain financial measures used by the Business that do not have a standardized meaning prescribed by U.S. 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 U.S. GAAP. The non-GAAP measures and their reconciliation to U.S. GAAP financial measures are shown below. These non-GAAP measures provide additional information that Management believes is meaningful in describing the Business' 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 and normalized funds from operations throughout this MD&A have the meanings as set out in this section.

Normalized EBITDA

	Three months ended September 30		Nine months ended September 30	
($ millions)	**2018**	2017	**2018**	2017
Normalized EBITDA	**$ 15.9**	$ 16.5	**$ 70.1**	$ 70.5
Add (deduct):				
Unrealized gain (loss) on foreign exchange contract	**(0.3)**	(0.4)	**0.8**	(1.3)
Accretion expenses	**—**	—	**(0.1)**	—
Depreciation and amortization	**(7.6)**	(7.0)	**(22.0)**	(21.1)
Interest expense	**(7.2)**	(6.7)	**(20.9)**	(19.7)
Income tax expense	**(0.3)**	(0.5)	**(3.5)**	(3.8)
Net income after taxes	**$ 0.5**	$ 1.9	**$ 24.4**	$ 24.6

Normalized EBITDA is a measure of the Business' operating profitability prior to how business activities are financed, assets are amortized, or earnings are taxed. Normalized EBITDA is calculated using net income adjusted for pre-tax depreciation and amortization, interest expense, and income tax expense, accretion expenses, and foreign exchange gains (losses). 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 EBITDA as presented should not be viewed as an alternative to net income after taxes or other measures of income calculated in accordance with U.S. GAAP as an indicator of performance.

Normalized Net Income

	Three months ended September 30		Nine months ended September 30	
($ millions)	**2018**	2017	**2018**	2017
Normalized net income	**$ 0.8**	$ 2.3	**$ 23.6**	$ 25.9
Add (deduct):				
Unrealized gain (loss) on foreign exchange contract	**(0.3)**	(0.4)	**0.8**	(1.3)
Net income after taxes	**$ 0.5**	$ 1.9	**$ 24.4**	$ 24.6

Normalized net income represents net income after taxes adjusted for foreign exchange gains (losses). This measure is presented in order to enhance the comparability of results, as it reflects the underlying performance of the Business.

Normalized net income as presented should not be viewed as an alternative to net income after taxes or other measures of income calculated in accordance with U.S. GAAP as an indicator of performance.

Normalized Funds from Operations

	Three months ended September 30		Nine months ended September 30	
($ millions)	**2018**	2017	**2018**	2017
Normalized funds from operations	**$ 4.6**	$ 3.8	**$ 61.3**	$ 40.6
Add (deduct):				
Net change in operating assets and liabilities	**(0.2)**	6.2	**2.2**	7.5
Cash from operations	**$ 4.4**	$ 10.0	**$ 63.5**	$ 48.1

Normalized funds from operations is used to assist Management and investors in analyzing the liquidity of the Business without regard to changes in operating assets and liabilities in the period. Management uses this measure to understand the ability to generate funds for use in investing and financing activities.

Normalized funds from operations for the nine months ended September 30, 2018 includes a $20.3 million distribution from Northwest Hydro Limited Partnership that occurred concurrently with a change in the ownership of that entity.

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 U.S. GAAP as an indicator of liquidity.

RELATED PARTY TRANSACTIONS

The Business has historically been managed and operated in the normal course of business by AltaGas along with other AltaGas affiliates. Accordingly, certain shared costs have been allocated to the Business and reflected as expenses in the separate combined financial statements. Management of AltaGas and the Business consider the allocation methodologies used to be reasonable and appropriate reflections of the related expenses attributable to the Business for purposes of the separate combined financial statements; however, the expenses reflected in the Business' separate combined financial statements may not be indicative of the actual expenses that would have been incurred during the periods presented if the Business historically operated as a separate entity. In addition, the expenses reflected in the separate combined financial statements may not be indicative of expenses that will be incurred in the future by the Business. Significant transactions with AltaGas are discussed individually as follows:

Cash Management

The Business participates in AltaGas' centralized cash management programs. For certain of the Business' operating facilities, cash receipts are received and disbursements are made by AltaGas, with any excess cash being retained by AltaGas. For the purpose of these Interim Financial Statements, the net cash retained by AltaGas is reflected as Due from Related Party in the Combined Balance Sheets. Cash retained by AltaGas on behalf of the Business is not kept in specific accounts for the Business and is instead comingled with cash from other AltaGas entities.

Pension and Other Post-Employment Benefit Plans

The Business sponsors several pension and post-employment plans. In addition, the Business employees also participate in certain pension plan and post-employment benefit plans sponsored by AltaGas. There is no contractual agreement or stated policy between the Business and AltaGas for charging the costs of these plans (note that the Business comprises parts of multiple legal entities).

All obligations pursuant to these plans are obligations of AltaGas and as such are not included in the Business' Combined Balance Sheets. AltaGas allocates to the Business, the net periodic benefit costs associated with employees that are beneficiaries of pensions and other employment benefit costs. These costs are included in operating and administrative expenses in the Combined Statements of Income. AltaGas contributes to these plans. The amount contributed to these plans by AltaGas on the Business' behalf cannot be determined.

Derivatives

Derivatives that relate to the Business are entered into on behalf of the Business by another AltaGas entity.

Allocated Corporate Costs

Allocated costs include AltaGas charges including, but not limited to: board of directors, executive management, finance, accounting and tax, legal and compliance, office services and corporate resources, information technology and procurement. These costs are included in operating and administrative expenses in the Combined Statements of Income and have a pre-tax total of $2.3 million and $7.0 million for the three and nine month periods ended September 30, 2018, respectively ($2.1 million and $6.4 million for the three and nine month periods ended September 30, 2017, respectively). The costs were allocated to the Business based on similar methodology used to allocate costs within AltaGas, which is a combination of asset values, payroll expenses and earnings. Note that these expenses may have been different had the Business been a separate entity during the periods presented.

OUTSTANDING SECURITY DATA

The Company, PNG and the assets acquired pursuant to the Acquisition have share capital that, as at September 30, 2018, was owned directly or indirectly by AltaGas. Since the Interim Financial Statements were prepared in anticipation of a subsequent transaction and are not consolidated financial statements, AltaGas' interest in the equity of the combined entity has been presented as Net Parental Investment.

2018 OUTLOOK

The performance of the Business in 2018 will be dependent on a number of business environment and operational factors:

Business environment

- *Economic environment* – The jurisdictions in which the Business operates have experienced moderate growth to date in 2018, which is expected to continue during the remainder of the year. The Utilities segment is expected to achieve customer growth in line with such general economic conditions. The Renewable Energy segment is less susceptible to changes in the economic environment since all of its power is sold pursuant to PPAs in place.
- *Competitive environment* – The Utilities segment operates in competition with alternative fuel sources, notably in Nova Scotia. The ability to increase market penetration is closely tied to maintaining the competitiveness of burner-tip natural gas price relative to alternative energy sources. The Business expects to maintain market share during the remainder of 2018.
- *Regulatory environment* - The activities of the Utilities segment are regulated by the BCUC, AUC, NSUARB and the Northwest Territories Public Utilities Board. The performance of the Business is dependent upon approval of its regulatory applications by a supportive regulatory regime. The Business expects to maintain constructive relationships with its regulators.
- *Legislative environment* – The Business is subject to changes in both federal and provincial climate change legislation. Since compliance costs are recovered through customer billings, the financial impact of such legislative change is expected to be limited.

Operational

- *Sales volumes and generating capacity* – The sales volume of the Utilities segment and generating capacity of the Renewable Energy segment are subject to a number of internal and external factors including, but not limited to, weather, planned and unplanned outages and the general economic environment. The Business does not expect sales volumes or generating capacity to be significantly impacted by controllable factors during the remainder of 2018.
- *Operating and administrative expenses* – The Utilities segment's success in managing its operating and administrative expenses affords the Utilities segment the opportunity to earn its regulated return. The Business expects operating and administrative expenses to increase over time primarily due to inflation, although inflationary increases would generally be recovered through rate increases.
- *Interest expense* – Although the Business has floating rate debt, the majority of its financing is in the form of fixed rate debt and exposure to interest rate risk is therefore expected to be limited.
- *Income taxes* – The Business expects the statutory tax rate to remain at approximately 27 percent during the remainder of 2018, no tax rate changes having been enacted or announced to date during 2018. Taxes would generally be recovered through rates.
- *Accounting estimates* – A number of accounting estimates, which are detailed in the *Critical Accounting Estimates* section of this MD&A, are based on the current economic environment and outlook. Changes in market conditions that affect, for example, commodity prices or interest rates, could impact profitability, liquidity or asset valuation. The Business does not expect market conditions to change significantly during the remainder of 2018.

CRITICAL ACCOUNTING ESTIMATES

Since a determination of the value of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of the Business' Interim Financial Statements requires the use of estimates and assumptions that have been made using careful judgment. The Business' significant accounting policies are described in the note 2 to the Annual Financial Statements. Certain of these policies involve critical accounting estimates as a result of the requirement to make particularly subjective or complex judgments about matters that are inherently uncertain, and because of the likelihood that materially different amounts could be reported under different conditions or using different assumptions.

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

Regulatory Assets and Liabilities

AUI, HGL and PNG engage in the delivery and sale of natural gas and are regulated by the following regulatory agencies: AUC, NSUARB and BCUC, respectively.

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

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

Asset Impairment

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

The Business also tests goodwill for impairment annually or more frequently if events or changes in circumstances indicate that it is more likely than not that the fair value of a reporting unit is less than its carrying value. The Business has the option to first assess qualitative factors to determine whether it is necessary to perform the two-step goodwill impairment test. If the two-step goodwill impairment test is performed, the first step is to compare the fair value of the Business' reporting units to the carrying values. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value, goodwill impairment is measured as the excess of the carrying value amount of the reporting unit's allocated goodwill over the implied fair value of the goodwill. The fair value used in the quantitative impairment test of goodwill requires estimating future cash flows as well as appropriate discount rates. The Business assessed goodwill for impairment as at December 31, 2017 and determined that no write-down was required.

Revenue

Revenue includes natural gas sales that are recorded on the basis of estimates of customer usage from the last meter reading date to the end of the reporting period.

Asset Retirement Obligations

The Business records liabilities relating to asset retirement obligations when there is a legal obligation. In estimating the obligations, Management is required to make assumptions regarding inflation and discount rates, ultimate amounts and timing of settlements, and expected changes in environmental laws and regulation.

Income Taxes

The Business is subject to the provisions of the Income Tax Act (Canada) for purposes of determining the amount of income that will be subject to tax in Canada. The determination of the Business' provision for income taxes requires the application of these complex rules.

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

If Management's interpretation of tax legislation differs from that of tax authorities, or timing of reversals is not as anticipated, the provision for income taxes could increase or decrease in future periods. See note 13 to the 2017 Annual Financial Statements.

Pension Plans and Post-Retirement Benefits

The determination of pension plan obligations and expense is based on a number of actuarial assumptions. Critical assumptions include the expected long-term rate-of-return on plan assets, the discount rate applied to pension plan obligations, and the expected rate of compensation increase. For post-retirement benefit plans, which provide for certain health care premiums and life insurance benefits for qualifying retired employees and which are not funded, critical assumptions in determining post-retirement obligations and expense are the discount rate and the assumed health care cost trend rates. Notes 2 and 19 to the 2017 annual Combined Financial Statements include information on the assumptions used for the purposes of recording the funding status of the plans and the associated expenses.

Depreciation and Amortization

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

Loss Contingencies

The Business is subject to various legal claims and actions arising in the normal course of business. Liabilities for loss contingencies are determined on a case-by-case basis and are accrued for when it is probable that a liability has been incurred and the amount can be reasonably estimated. Significant judgement is required to determine the probability of having incurred the liability and the estimated amount. Estimates are reviewed regularly and updated as new information is received. As at September 30, 2018, no provisions on loss contingencies have been recorded by the Business. However, due to the inherent uncertainty of the litigation process, the resolution of any particular contingencies could have a material adverse effect on the Business' results of operations or financial position.

Fair Value of Financial Instruments

Fair value is defined as the amount of consideration that would be agreed upon in an arms-length transaction, other than a forced sale or liquidation, between knowledgeable, willing parties who are under no compulsion to act. The best evidence of fair value is a quoted bid or ask price, as appropriate, in an active market. Fair value based on unadjusted quoted prices in an active market requires minimal judgment by Management. Where bid or ask prices in an active market are not available, Management's judgment on valuation inputs is necessary to determine fair value. The Business uses derivative instruments to manage fluctuations in foreign exchange rates. The Business estimates forward prices based on published sources adjusted for factors specific to the asset or liability, including currency exchange. The forward curves used to mark these derivative instruments to market are vetted against public sources. Changes in estimates and assumptions about these inputs could affect the reported fair value.

ADOPTION OF NEW ACCOUNTING STANDARDS AND FUTURE ACCOUNTING CHANGES

Effective January 1, 2018, the Business 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”). The Business 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 6 for further details. The Business does not expect the application of ASC 606 to have a material impact on its combined 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. The provisions of this ASU did not have a material impact on the Business’ combined 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 the Business’ combined 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 the Business’ combined 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 adoption of this ASU did not have a material impact on the Business’ combined financial statements;

- 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. The Business 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. The Business early adopted this ASU. The adoption of this ASU did not have a material impact on the Business’ combined 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 the Business’ combined 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. The Business 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, $nil million and $0.6 million of net benefit cost associated with other components were reclassified from the line item “Operating and administrative” to “Other loss” on the Combined Statement of Income for the three and nine months ended September 30, 2017. The Business applied the change related to the capitalization of the service cost prospectively. The adoption of this ASU did not have a material impact on the Business’ combined 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 the Business’ combined 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. The Business early adopted this ASU. The adoption of this ASU did not have a material impact on the Business’ combined 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. The Business early adopted this ASU. The adoption of this ASU did not have a material impact on the Business’ combined 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. The Business 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 combined financial statements, but expects that the new standard will have an impact on the Company’s balance sheet as all operating leases will need to be reflected on the balance sheet upon adoption. In addition, the Business 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. The Business is currently assessing the impact of this ASU on its combined 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 the Business plans to adopt this ASU effective July 1, 2018. The adoption of this ASU is not expected to have a material impact on the Business’ combined 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 the Business' combined financial statements.

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

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

In August 2018, FASB issued ASU No. 2018-15 "Intangibles – Goodwill and Other – Internal – Use Software: Customer's Accounting for Implementation Costs Incurred in a cloud Computing Arrangement (CCA) that is a Service Contract". The amendments in this ASU align the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software (and hosting arrangements that include an internal use software license). The amendments in this update are effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on the Business' combined financial statements.

RISK MANAGEMENT

Risks associated with financial instruments

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

Foreign Exchange Risk

The Business is exposed to foreign exchange risk as changes in foreign exchange rates may affect future cash flows. As a result, the Business' earnings and cash flows are exposed to fluctuations resulting from changes in foreign exchange rates. The Business may enter into foreign exchange forward derivatives to manage the risk of fluctuating cash flows due to variations in foreign exchange rates. Details concerning the Business' outstanding foreign exchange forward contracts at September 30, 2018 and December 31, 2017 are provided in note 7 to the Interim Financial Statements.

Interest Rate Risk

The Business is exposed to interest rate risk as changes in interest rates may impact future cash flows and the fair value of its financial instruments. The Business manages its interest rate risk by holding a mix of both fixed and floating interest rate debt. In addition, from time to time, the Business may enter into interest rate swap agreements to fix the interest rate on a portion of its banker's acceptances issued under its credit facilities.

Credit Risk

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

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

The Business' maximum credit exposure consists primarily of the carrying value of the non-derivative financial assets and the fair value of derivative financial assets. The Business does not have concentration of credit risk with a single counterparty.

Liquidity Risk

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

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Since the Company became a reporting issuer subsequent to September 30, 2018, it is not required to make any certifications regarding the disclosure controls and procedures and internal control over financial reporting in place as at September 30, 2018.

DEFINITIONS

CPI means Consumer Price Index
GJ means gigajoule
GW means gigawatt
GWh means gigawatt hour
MW means megawatt
MWh megawatt hour
PJ means petajoule; one million gigajoules
PP&E means property, plant and equipment
US$ means United States dollar

Combined Balance Sheets

(condensed and unaudited)

As at *($ millions)*	**September 30, 2018**	December 31, 2017
ASSETS		
Current assets		
Accounts receivable, net of allowances	**$ 26.5**	$ 62.0
Inventory	**1.7**	1.7
Due from related party *(note 11)*	**134.9**	134.2
Regulatory assets	**1.5**	0.8
Foreign exchange asset *(note 7)*	**0.5**	—
Prepaid expenses and other current assets	**4.8**	2.3
	169.9	201.0
Property, plant and equipment	**952.4**	933.5
Intangible assets	**16.6**	16.4
Goodwill	**119.1**	119.1
Regulatory assets	**209.1**	202.2
Investments accounted for by the equity method *(note 5)*	**123.0**	139.6
	$ 1,590.1	$ 1,611.8
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	**$ 33.8**	$ 66.1
Short-term advances due to related party *(note 10)*	**69.8**	69.8
Short-term debt	**6.0**	9.1
Current portion of long-term debt *(note 4)*	**8.0**	8.0
Current portion of long-term debt due to related parties *(note 10)*	**—**	55.0
Customer deposits	**11.4**	9.8
Regulatory liabilities	**9.3**	4.2
Foreign exchange liability *(note 7)*	**—**	0.3
	138.3	222.3
Long-term debt *(note 4)*	**25.3**	25.8
Long-term debt due to related parties *(note 10)*	**440.2**	385.2
Asset retirement obligations	**1.3**	1.2
Deferred income taxes	**123.9**	121.6
Regulatory liabilities	**21.4**	22.0
Future employee obligations	**28.9**	29.6
	$ 779.3	$ 807.7

As at *($ millions)*	**September 30, 2018**	December 31, 2017
Net parental investment		
Net parental investment	**$ 811.4**	$ 804.7
Accumulated other comprehensive income (AOCI)	**(0.6)**	(0.6)
Total net parental investment	**810.8**	804.1
	$ 1,590.1	$ 1,611.8

Subsequent events *(note 2)*
Commitments and contingencies *(note 9)*

See accompanying notes to the condensed interim Combined Financial Statements.

Combined Statements of Income

(condensed and unaudited)

($ millions)	Three months ended September 30 2018	Three months ended September 30 2017	Nine months ended September 30 2018	Nine months ended September 30 2017
REVENUE *(note 6)*				
Regulated operations	**$ 38.6**	$ 40.5	**$ 198.8**	$ 206.0
Services	**2.6**	3.6	**9.4**	10.6
Sales	**1.1**	1.4	**4.0**	4.5
Other revenue (expense)	**1.8**	—	**1.6**	(0.2)
Unrealized gains (losses) on foreign exchange contract	**(0.3)**	(0.4)	**0.8**	(1.3)
	43.8	45.1	**214.6**	219.6
EXPENSES				
Cost of sales, exclusive of items shown separately	**9.8**	11.4	**78.9**	89.5
Operating and administrative	**21.7**	21.7	**68.8**	65.5
Accretion expenses	**—**	—	**0.1**	—
Depreciation and amortization	**7.6**	7.0	**22.0**	21.1
	39.1	40.1	**169.8**	176.1
Income from equity investments	**3.3**	4.3	**4.1**	5.2
Other loss	**—**	(0.2)	**—**	(0.6)
Foreign exchange loss	**—**	—	**(0.1)**	—
Interest expense				
Short-term debt	**(0.2)**	(0.2)	**(0.3)**	(0.5)
Long-term debt	**(7.0)**	(6.5)	**(20.6)**	(19.2)
Income before income taxes	**0.8**	2.4	**27.9**	28.4
Income tax expense (recovery)				
Current	**0.9**	1.6	**3.4**	4.4
Deferred	**(0.6)**	(1.1)	**0.1**	(0.6)
Net income after taxes	**0.5**	1.9	**24.4**	24.6

See accompanying notes to the condensed interim Combined Financial Statements.

Combined Statements of Comprehensive Income

(condensed and unaudited)

		Three months ended September 30				Nine months ended September 30		
($ millions)		**2018**		2017		**2018**		2017
Net income after taxes	**$**	**0.5**	$	1.9	**$**	**24.4**	$	24.6
Total other comprehensive income (OCI), net of taxes		**—**		—		**—**		—
Comprehensive income, net of taxes	**$**	**0.5**	$	1.9	**$**	**24.4**	$	24.6

See accompanying notes to the condensed interim Combined Financial Statements.

Combined Statements of Changes in Net Parental Investment

(condensed and unaudited)

	Three months ended September 30		Nine months ended September 30	
($ millions)	**2018**	2017	**2018**	2017
Net parental investment				
Balance, beginning of period	**$ 809.8**	$ 766.7	**$ 804.7**	$ 742.0
Net income after taxes	**0.5**	1.9	**24.4**	24.6
Net transfers from (to) AltaGas Ltd. *(note 11)*	**1.1**	1.6	**(17.7)**	3.6
Balance, end of period	**$ 811.4**	$ 770.2	**$ 811.4**	$ 770.2
AOCI				
Balance, beginning of period	**$ (0.6)**	$ (0.5)	**$ (0.6)**	$ (0.5)
Other comprehensive income	**—**	—	**—**	—
Balance, end of period	**$ (0.6)**	$ (0.5)	**$ (0.6)**	$ (0.5)
Total net parental investment	**$ 810.8**	$ 769.7	**$ 810.8**	$ 769.7

See accompanying notes to the condensed interim Combined Financial Statements.

Combined Statements of Cash Flows

(condensed and unaudited)

($ millions)	Three months ended September 30 2018	2017	Nine months ended September 30 2018	2017
Cash from operations				
Net income after taxes	**$ 0.5**	$ 1.9	**$ 24.4**	$ 24.6
Items not involving cash:				
Depreciation and amortization	**7.6**	7.0	**22.0**	21.1
Accretion expenses	**—**	—	**0.1**	—
Deferred income tax expense (recovery)	**(0.6)**	(1.1)	**0.1**	(0.6)
Income from equity investments	**(3.3)**	(4.3)	**(4.1)**	(5.2)
Unrealized losses (gains) on foreign exchange contract *(note 7)*	**0.3**	0.4	**(0.8)**	1.3
Other	**(0.2)**	(0.1)	**(1.0)**	(0.6)
Net distributions from equity investments	**0.3**	—	**20.6**	—
Changes in operating assets and liabilities *(note 12)*	**(0.2)**	6.2	**2.2**	7.5
	$ 4.4	$ 10.0	**$ 63.5**	$ 48.1
Investing activities				
Acquisition of property, plant and equipment	**$ (19.6)**	$ (16.9)	**$ (38.1)**	$ (29.4)
Acquisition of intangible assets	**(2.0)**	—	**(2.1)**	(0.1)
Proceeds from disposition of assets, net of transaction costs	**0.1**	0.5	**0.2**	0.5
	$ (21.5)	**$** (16.4)	$ **(40.0)**	$ (29.0)
Financing activities				
Net issuance (repayment) of short-term debt	**$ 6.0**	$ —	**$ (3.0)**	$ (6.1)
Net issuance (repayment) of advances due to a related party	**11.4**	7.8	**(0.8)**	(12.5)
Repayment of long-term debt	**(0.5)**	(7.9)	**(0.6)**	(7.9)
Issuance of long-term debt due to related parties	**—**	6.0	**—**	6.0
Receipt (repayment) of net parental investment *(note 11)*	**0.2**	0.5	**(19.1)**	1.4
	$ 17.1	$ 6.4	**$ (23.5)**	$ (19.1)
Change in cash and cash equivalents	**—**	—	**—**	—
Cash and cash equivalents, beginning of period	**—**	—	**—**	—
Cash and cash equivalents, end of period	**$ —**	$ —	**$ —**	$ —

See accompanying notes to the condensed interim Combined Financial Statements.

Notes to the Condensed Interim Combined Financial Statements (unaudited)

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

1. OVERVIEW OF THE BUSINESS

Formation of the Company

AltaGas Canada Inc. ("the Business" or "the Company") was incorporated under the Canada Business Corporations Act on October 27, 2011 as AltaGas Utility Holdings (Pacific) Inc., a wholly owned subsidiary of AltaGas Ltd ("AltaGas"). Prior to the transactions described in note 2, the Company owned rate-regulated natural gas distribution utility assets in British Columbia through its subsidiary, Pacific Northern Gas Ltd. On September 5, 2018, the name of the Company was changed to AltaGas Canada Inc. Subsequent to the transactions described in note 2, the Company is a reporting issuer listed on the Toronto Stock Exchange with ownership interests in rate-regulated natural gas distribution utilities and renewable power assets.

Basis of Preparation

These unaudited condensed interim Combined Financial Statements of the Business were prepared from the historical accounting records of AltaGas to include Canadian utility and power assets controlled by AltaGas at September 30, 2018 in anticipation of the transactions described in note 2. The Combined Financial Statements include the assets, liabilities, and operations of AltaGas Canada Inc., AltaGas Utility Group Inc. ("AUGI"), Bear Mountain Wind Power Corporation, Bear Mountain Wind Limited Partnership ("Bear Mountain"), AltaGas Canadian Energy Holdings Ltd., AltaGas Canadian Energy Holdings GP Ltd., AltaGas Canadian Energy Holdings Limited Partnership, Pacific Northern Gas Ltd. ("PNG"), Pacific Northern Gas (NE) Ltd., PNG Marketing Ltd., Utility Group Facilities Inc., AltaGas Utility Holdings Inc., AltaGas Utilities Inc., AltaGas Utility Holdings (Nova Scotia) Inc., Inuvik Gas Ltd., and Heritage Gas Limited, which are subsidiaries of AltaGas, as well as various other assets owned directly or indirectly by AltaGas. Intercompany transactions and balances are eliminated. Investments in unconsolidated companies that the Business has significant influence over, but not control, are accounted for using the equity method.

Historically, combined financial statements have not been prepared for the Business as it has not operated as a separate business. These unaudited condensed interim Combined Financial Statements reflect the Combined Balance Sheets, the Combined Statements of Income, the Combined Statements of Comprehensive Income, the Combined Statements of Changes in Net Parental Investment, and the Combined Statements of Cash Flows in a manner consistent with how AltaGas managed the Business and as though the Business had been a separate company for all periods presented. All material assets and liabilities specifically attributable to the Business have been presented in the Combined Balance Sheets; all material revenues and expenses specifically identified to the Business and allocations of overhead expenses have been presented in the separate Combined Statements of Income and the Combined Statements of Comprehensive Income.

Expenses related to shared assets and liabilities and overhead expenses have been allocated to the Business on a reasonable basis as described in note 11. These overhead expenses include finance, accounting and tax, legal and compliance, office services and corporate resources, information technology, procurement and other administrative functions.

Transactions between AltaGas and the Business have been identified as related party transactions. It is possible that the terms of the transactions with AltaGas and its affiliates are not the same as those that would result from transactions among unrelated parties. In the opinion of the Company's management, all adjustments have been reflected that are necessary for a fair presentation in the combined financial statements. Also, the Company's management believes that the allocations have been made on a reasonable basis and have been consistently applied for each period presented. The combined financial statements may not necessarily reflect the financial position, results of operations, or cash flows that the Business might have reported in the periods presented had it existed as a separate business during the periods presented.

2. SUBSEQUENT EVENTS

Subsequent events have been reviewed through October 30, 2018, the date on which these unaudited condensed interim Combined Financial Statements were approved for issue by the Board of Directors.

Acquired Assets and Acquired Indebtedness (collectively, “the Acquisition”)

On October 18, 2018 (the “Acquisition Date”), the Company acquired, pursuant to a Purchase and Sale Agreement, the business conducted by AltaGas using direct and indirect interests in the following assets (“the Acquired Assets”):

- Rate-regulated natural gas distribution utility assets in Alberta and Nova Scotia;
- Minority interests in entities (Inuvik Gas Ltd and Ikhil Joint Venture) providing natural gas to the Town of Inuvik, Northwest Territories;
- Wind power assets located near Dawson Creek, British Columbia; and
- A 10% indirect equity interest in three run-of-river hydroelectric power generation assets in British Columbia (“Northwest Hydro Limited Partnership”).

Since AltaGas controlled the Company at the Acquisition Date, the business conducted using the Acquired Assets was transferred at its carrying value.

On the same date, the Company acquired the indebtedness that AUGI and PNG had with AltaGas and certain of its subsidiaries (“the Acquired Indebtedness”) in the amount of $481.6 million.

The Company acquired the Acquired Assets and Acquired Indebtedness from AltaGas for $889.1 million which was satisfied by issuing to AltaGas:

- 5,912,857 common shares;
- An unsecured promissory note bearing interest at 4.5% per annum in the principal amount of $316.3 million to be repaid upon closing of the Initial Public Offering described below;
- An unsecured promissory note bearing interest at 3.3% per annum in the principal amount of $35.9 million to be repaid no later than 30 days after closing of the Initial Public Offering; and
- An unsecured promissory note bearing interest at 4.5% per annum in the principal amount of $351.2 million with a term of 30 months, the interest to be increased by 0.25% on the 18 and 24 month anniversaries of the issuance date.

Prior to the Acquisition:

- The Company paid an eligible dividend of $31.0 million to AltaGas;
- Bear Mountain distributed cash of $64.6 million to AltaGas; and
- AUGI repaid indebtedness of $28.4 million to AltaGas.

Initial Public Offering of Common Shares

On October 18, 2018, the Company filed a final long form prospectus in connection with its offering of 16,500,000 common shares (“the Offering”) issued pursuant to the terms of an Underwriting Agreement at a price of $14.50 per common share (“the Offering Price”).

On October 25, 2018, the Company completed the Offering and issued 16,500,000 common shares at the Offering Price for gross proceeds of $239.3 million.

The Company has granted to the Underwriters an option ("the Over-Allotment Option"), exercisable at the Underwriters' discretion at any time, in whole or in part, until 30 days after the closing of the Offering to purchase at the Offering Price up to an additional 2,475,000 common shares (representing 15% of the common shares offered) to cover over-allotments.

Upon closing of the Offering and the exercise or otherwise of the Over-Allotment Option, 30,000,000 common shares will be issued and outstanding. AltaGas will own 45% of the outstanding common shares, assuming no exercise of the Over-Allotment Option and the resulting conversion of indebtedness, and 36.8% of the outstanding common shares if the Over-Allotment Option is exercised in full.

The net proceeds of the Offering were $223.7 million after deducting the Underwriters' fee of $12.6 million and other expenses of the Offering, estimated to be $3.0 million. If the Over-Allotment Option is exercised in full, the net proceeds are expected to be approximately $257.7 million after deducting the Underwriters' fee of $14.4 million and other expenses of the Offering, estimated to be $3.0 million**.**

Pursuant to the Purchase and Sale Agreement, the Company used the net proceeds of the Offering (excluding any proceeds from the Over-Allotment Option) to:

- Repay in full a note issued to AltaGas bearing interest at 5.0% per annum in the principal amount of $157.4 million which resulted from a return on capital on the Company's common shares prior to the Acquisition;
- Repay a portion of the unsecured promissory note bearing interest at 4.5% per annum issued to AltaGas in the principal amount of $316.3 million.

The Company intends to use the net proceeds, if any, from the exercise of the Over-Allotment Option to repay all or a portion of the unsecured promissory note bearing interest at 3.3% per annum issued to AltaGas in the principal amount of $35.9 million.

On October 25, 2018, the Company executed:

- A $200 million unsecured revolving credit facility with a syndicate of lenders having a term of four years subject to customary extension provisions, which is available for general corporate purposes and was not materially drawn at Closing;
- A $250 million unsecured term loan with a syndicate of lenders having a term of two years, which was fully drawn with the proceeds utilized to pay for a portion of the unsecured promissory note bearing interest at 4.5% in the principal amount of $316.3 million; and
- A $35 million unsecured, uncommitted demand operating facility, which is available for general corporate purposes and was not materially drawn at Closing

The borrowing options under the credit facility, term loan and operating facility include Canadian prime rate-based loans, U.S. base rate loans, bankers' acceptances and LIBOR loans. Further borrowing options under the operating facility include overdraft and letters of credit. Borrowings on the credit facility, term loan and operating facility bear fees and interest at rates relevant to the nature of the draw made and the Company's credit rating.

Transition Services Agreement

On October 18, 2018, the Company entered into a Transition Services Agreement with AltaGas pursuant to which AltaGas will provide certain day-to-day services required by the Company, to include: (a) general administrative and corporate services, including accounting, tax, finance, legal and regulatory, payroll, corporate human resources and pension management, environmental, health and safety administration, procurement, enterprise resource planning and information technology; (b) credit support services; and (c) accounting, budgeting and engineering services in respect of the Ikhil Joint Venture. AltaGas will provide the services on a cost recovery basis only. The Transition Services Agreement will operate until June 30, 2020, subject to earlier termination in certain circumstances, and is extendable by mutual agreement of the parties.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These unaudited condensed interim Combined 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 Combined Financial Statements do not include all of the information and disclosures required in the annual Combined Financial Statements and should be read in conjunction with the Business' 2017 annual audited Combined Financial Statements prepared in accordance with U.S. GAAP which were included in Appendix FS to the Business' final long form prospectus dated October 18, 2018 filed pursuant to its Initial Public Offering, which is available on SEDAR. In management's opinion, these unaudited condensed interim Combined Financial Statements include all adjustments that are of a recurring nature and necessary to present fairly the financial position of the Business.

Pursuant to National Instrument 52-107, "Acceptable Accounting Principles and Auditing Standards" (NI 52-107), U.S. GAAP reporting is permitted by Canadian securities laws for companies subject to reporting obligations under U.S. securities laws. However, given that the Business is not subject to such reporting obligations and could not therefore rely on the provisions of NI 52-107 to that effect, the Company sought and obtained exemptive relief from the securities regulators in Alberta and Ontario to permit it to prepare its financial statements in accordance with U.S. GAAP. The exemption will terminate on or after the earlier of January 1, 2024, the date upon which the Company ceases to have activities subject to rate regulation, or the effective date prescribed for a mandatory application of International Financial Reporting Standards for rate-regulated accounting.

USE OF ESTIMATES AND MEASUREMENT UNCERTAINTY

The preparation of combined 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: 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 the Business operates, 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 combined financial statements of future periods.

SIGNIFICANT ACCOUNTING POLICIES

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

ADOPTION OF NEW ACCOUNTING STANDARDS

Effective January 1, 2018, the Business 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”). The Business 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 6 for further details. The Business does not expect the application of ASC 606 to have a material impact on its combined 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. The provisions of this ASU did not have a material impact on the Business’ combined 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 the Business’ combined 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 the Business’ combined 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 adoption of this ASU did not have a material impact on the Business’ combined financial statements;

- 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. The Business 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. The Business early adopted this ASU. The adoption of this ASU did not have a material impact on the Business’ combined 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 the Business’ combined 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. The Business 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, $nil million and $0.6 million of net benefit cost associated with other components were reclassified from the line item “Operating and administrative” to “Other loss” on the Combined Statement of Income for the three and nine months ended September 30, 2017. The Business applied the change related to the capitalization of the service cost prospectively. The adoption of this ASU did not have a material impact on the Business’ combined 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 the Business’ combined 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. The Business early adopted this ASU. The adoption of this ASU did not have a material impact on the Business’ combined 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. The Business early adopted this ASU. The adoption of this ASU did not have a material impact on the Business’ combined 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. The Business 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 combined 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, the Business 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. The Business is currently assessing the impact of this ASU on its combined 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 the Business plans to adopt this ASU effective July 1, 2018. The adoption of this ASU is not expected to have a material impact on the Business’ combined 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 the Business’ combined financial statements.

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

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

In August 2018, FASB issued ASU No. 2018-15 “Intangibles – Goodwill and Other – Internal – Use Software: Customer’s Accounting for Implementation Costs Incurred in a cloud Computing Arrangement (CCA) that is a Service Contract”. The amendments in this ASU align the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software (and hosting arrangements that include an internal use software license). The amendments in this update are effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on the Business’ combined financial statements.

4. LONG-TERM DEBT

As at	Maturity date	**September 30, 2018**	December 31, 2017
Debenture notes			
PNG 2018 Series Debenture - 8.75% [(a)]	15-Nov-2018	**$ 7.0**	$ 7.0
PNG 2025 Series Debenture - 9.30% [(a)]	18-Jul-2025	**12.5**	13.0
PNG 2027 Series Debenture - 6.90% [(a)]	2-Dec-2027	**14.0**	14.0
		$ 33.5	$ 34.0
Less debt issuance costs		**(0.2)**	(0.2)
		33.3	33.8
Less current portion		**(8.0)**	(8.0)
		$ 25.3	$ 25.8

(a) Collateral for the Secured Debentures consists 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.

5. INVESTMENTS ACCOUNTED FOR BY THE EQUITY METHOD

Description	Location	Ownership Percentage	September 30, 2018	December 31, 2017
Inuvik Gas Ltd.	Canada	33.33%	**$ —**	$ —
Northwest Hydro Limited Partnership	Canada	10%	**123.0**	139.6
			$ 123.0	$ 139.6

Summarized financial information, assuming a 100% ownership interest in the equity investments listed above, is as follows:

	Three months ended September 30 2018	Three months ended September 30 2017	Nine months ended September 30 2018	Nine months ended September 30 2017
Revenues	**$ 51.2**	$ 60.0	**$ 93.2**	$ 102.7
Expenses	**(17.6)**	(17.0)	**(51.0)**	(50.0)
	$ 33.6	$ 43.0	**$ 42.2**	$ 52.7

As at	September 30, 2018	December 31, 2017
Current assets	**$ 46.4**	$ 235.0
Property, plant and equipment	**$ 1,095.8**	$ 1,088.0
Intangible assets	**$ 246.9**	$ 249.5
Current liabilities	**$ (23.0)**	$ (33.0)
Long-term liabilities	**$ (135.8)**	$ (142.8)

During the nine months ended September 30, 2018, a distribution of $20.3 million was received from Northwest Hydro Limited Partnership that occurred concurrently with a change in ownership of that entity.

6. REVENUE

The following table disaggregates revenue by major sources:

	Three months ended September 30, 2018		
	Renewable Energy	**Utilities**	**Total**
Revenue from contracts with customers			
Gas sales and transportation services	**$ —**	**$ 38.6**	**$ 38.6**
Other	**—**	**0.1**	**0.1**
Total revenue from contracts with customers	**$ —**	**$ 38.7**	**$ 38.7**
Other sources of revenue			
Revenue from alternative revenue programs [(a)]	**$ —**	**$ 0.7**	**$ 0.7**
Leasing revenue	**2.9**	**—**	**2.9**
Risk management activities	**—**	**(0.3)**	**(0.3)**
Other	**—**	**1.8**	**1.8**
Total revenue from other sources	**$ 2.9**	**$ 2.2**	**$ 5.1**
Total revenue	**$ 2.9**	**$ 40.9**	**$ 43.8**

(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.

	Nine months ended September 30, 2018		
	Renewable Energy	**Utilities**	**Total**
Revenue from contracts with customers			
Gas sales and transportation services	**$ —**	**$ 198.8**	**$ 198.8**
Other	**—**	**1.2**	**1.2**
Total revenue from contracts with customers	**$ —**	**$ 200.0**	**$ 200.0**
Other sources of revenue			
Revenue from alternative revenue programs [(a)]	**$ —**	**$ (1.1)**	**$ (1.1)**
Leasing revenue	**10.4**	**—**	**10.4**
Risk management activities	**—**	**0.8**	**0.8**
Other	**—**	**4.5**	**4.5**
Total revenue from other sources	**$ 10.4**	**$ 4.2**	**$ 14.6**
Total revenue	**$ 10.4**	**$ 204.2**	**$ 214.6**

(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.

Revenue Recognition

The Business' revenue recognition policy by major sources of revenue is as follows:

Renewable Energy segment

The majority of revenue earned is through power purchase agreements which are accounted for as operating leases.

Utilities segment

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, the Business 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.

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 September 30, 2018:

	Remainder of 2018	2019	2020	2021	2022	> 2022	Total
Gas sales and transportation services	$ 2.6	$ 5.5	$ 12.3	$ 16.3	$ 16.1	$ 15.9	**$ 68.7**
	$ 2.6	$ 5.5	$ 12.3	$ 16.3	$ 16.1	$ 15.9	**$ 68.7**

The Business 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 the Business 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 gas sales and transportation service contracts contain variable consideration whereby uncertainty related to the associated variable consideration will be resolved (usually on a daily basis) as gas is delivered or as service is provided.

7. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

The Business' financial instruments consist of accounts receivable, due from related party, foreign exchange contracts, accounts payable and accrued liabilities, short-term advances due to related party, current portion of long-term debt, long-term debt and long-term debt due to related parties.

Fair Value Hierarchy

The Business 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. The Business uses derivative instruments to manage fluctuations in foreign exchange rates. The Business estimates forward prices based on published sources adjusted for factors specific to the asset or liability, including currency exchange. The forward curves used to mark-to-market these derivative instruments are vetted against public sources.

Level 3 - fair values are based on inputs for the asset or liability that are not based on observable market data. The Business uses valuation techniques when observable market data is not available.

	September 30, 2018				
	Carrying Amount	**Level 1**	**Level 2**	**Level 3**	**Total Fair Value**
Financial assets					
Foreign exchange asset - current	**$ 0.5**	**$ —**	**$ 0.5**	**$ —**	**$ 0.5**
	$ 0.5	**$ —**	**$ 0.5**	**$ —**	**$ 0.5**
Financial liabilities					
Current portion of long-term debt	**$ 8.0**	**$ —**	**$ 8.3**	**$ —**	**$ 8.3**
Long-term debt	**25.3**	**—**	**29.7**	**—**	**29.7**
Long-term debt due to related parties	**440.2**	**—**	**443.1**	**—**	**443.1**
	$ 473.5	**$ —**	**$ 481.1**	**$ —**	**$ 481.1**

	December 31, 2017				
	Carrying Amount	Level 1	Level 2	Level 3	Total Fair Value
Financial liabilities					
Foreign exchange liability - current	$ 0.3	$ —	$ 0.3	—	$ 0.3
Current portion of long-term debt	8.0	—	8.5	—	8.5
Current portion of long-term debt due to related parties	55.0	—	54.1	—	54.1
Long-term debt	25.8	—	31.5	—	31.5
Long-term debt due to related parties	385.2	—	395.8	—	395.8
	$ 474.3	$ —	$ 490.2	$ —	$ 490.2

Foreign Exchange

The Business has entered into foreign exchange forward derivatives to manage the risk of fluctuating cash flows due to variations in foreign exchange rates. As at September 30, 2018, the Business had outstanding foreign exchange forward contracts for US$10.3 million at an average rate of $1.24 Canadian per U.S. dollar. As at December 31, 2017, the Business had outstanding foreign exchange forward contracts for US$31.6 million at an average rate of $1.26 Canadian per U.S. dollar.

8. 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 September 30, 2018		Three months ended September 30, 2017	
	Defined Benefit	**Post-retirement Benefits**	Defined Benefit	Post-retirement Benefits
Current service cost [a]	**$ 1.6**	**$ 0.2**	$ 1.3	$ 0.2
Interest cost [b]	**1.0**	**0.1**	1.0	0.1
Expected return on plan assets [b]	**(1.4)**	**(0.1)**	(1.3)	(0.1)
Amortization of regulatory asset [b]	**0.4**	**—**	0.3	—
Net benefit cost recognized	**$ 1.6**	**$ 0.2**	$ 1.3	$ 0.2

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

	Nine months ended September 30, 2018		Nine months ended September 30, 2017	
	Defined Benefit	**Post-retirement Benefits**	Defined Benefit	Post-retirement Benefits
Current service cost [(a)]	**$ 4.8**	**$ 0.5**	$ 4.0	$ 0.5
Interest cost [(b)]	**3.1**	**0.4**	3.1	0.4
Expected return on plan assets [(b)]	**(4.3)**	**(0.2)**	(3.8)	(0.2)
Amortization of net actuarial loss [(b)]	**—**	**—**	0.1	—
Amortization of regulatory asset [(b)]	**1.1**	**—**	0.9	0.1
Net benefit cost recognized	**$ 4.7**	**$ 0.7**	$ 4.3	$ 0.8

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

9. COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

The Business has long-term natural gas purchase and transportation arrangements, service agreements and operating leases for office space and office equipment, all of which are transacted at market prices and in the normal course of business, the amount and timing of which is disclosed in note 20 to the Business' 2017 annual audited Combined Financial Statements.

The Business has an obligation to pay a minimum of $6.3 million over the next four years pursuant to a service and maintenance agreement with Enercon GmbH in respect of the Bear Mountain wind turbines.

In 2017, HGL 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 System. The PA with PNGTS was subject to HGL satisfying a condition precedent of obtaining regulatory approval by July 31, 2018 for the contract to proceed. On June 1, 2018, HGL received approval from the Nova Scotia Utility and Review Board 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.

Guarantees

On October 2014, HGL, a company included in the Business, entered into a throughput 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. At September 30, 2018 and December 31, 2017, two guarantees were outstanding that total US$91.7 million to stand by all payment obligations under the transportation agreement.

Contingencies

The Business is 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 Business does not believe that the resolution of such claims and actions will not have a material impact on the Business' combined financial position or results of operations.

10. RELATED PARTY TRANSACTIONS

In the normal course of business, the Business transacts with AltaGas, subsidiaries, affiliates and joint ventures. As at September 30, 2018, there were no significant changes in the nature of the related party transactions described in note 21 of the 2017 Audited Combined Financial Statements.

Long-Term Debt Due to Related Parties

The Business entered into borrowing agreements with the Parent and certain subsidiaries of AltaGas:

As at	Maturity date		**September 30, 2018**		December 31, 2017
Medium-term notes (MTNs)					
Debenture - 4.14%	1-Jun-2020	**$**	**20.0**	$	20.0
Debenture - 4.48%	15-Mar-2024		**40.0**		40.0
Debenture - 3.91%	15-Jan-2025		**15.0**		15.0
Debenture - 3.76%	7-Apr-2026		**10.0**		10.0
Debenture - 4.20%	7-Apr-2026		**45.0**		45.0
Debenture - 5.21%	13-Jan-2044		**20.0**		20.0
Debenture - 4.88%	15-Aug-2044		**20.0**		20.0
Debenture - 5.03%	4-Oct-2047		**30.0**		30.0
Shareholder loan [(a)]	1-Jan-2020		**176.0**		176.0
Shareholder loan [(b)]	2-Dec-2027		**55.0**		—
Revolving loan [(c)]	7-Jun-2018		**—**		55.0
Other related party loan [(d)]	1-Jan-2020		**9.2**		9.2
		$	**440.2**	$	440.2
Less current portion			**—**		(55.0)
		$	**440.2**	$	385.2

(a) Unsecured loan from AltaGas which is due on January 1, 2020 and bears interest at 7.25%.
(b) Unsecured loan from AltaGas which is due on December 2, 2027 and bears interest at 4.15%.
(c) $70 million, 5 year Revolver due June 7, 2018 with draws available by way of bankers' acceptances bearing interest at the three-month BA rate plus 1.75% and subject to a stand-by fee of 0.35%.
(d) Unsecured loan from AltaGas which is due on January 1, 2020 and bears interest at 6.00%.

On May 4, 2018, PNG completed financing of $55 million of revolving 5-year credit facilities, $30 million with AltaGas and $25 million with another counterparty. Borrowings are available by way of bankers' acceptances bearing interest at the three-month BA rate plus a spread and subject to stand-by fees. Interest and stand-by costs are due monthly. Optional repayments are allowed without penalty and there is no mandatory repayment prior to maturity. PNG has issued Secured Debentures for the 5-year facility with the same collateral as the PNG's other existing Secured Debentures. No amounts had been drawn on these facilities as at September 30, 2018.

On May 4, 2018, PNG refinanced its term loan facility with AltaGas with a $55 million fully drawn non-amortizing credit facility that matures on December 2, 2027. The debt obligation of $55 million on the existing term loan facility was applied against the new facility. PNG has issued Secured Debentures for this new facility with the same collateral as its other existing Secured Debentures. Interest and stand-by costs are due semi-annually and amounted to $0.9 million for the nine months ended September 30, 2018, and has been included in finance fees, of which $0.6 million is outstanding and included in accrued liabilities. Optional repayments are allowed without penalty and there is no mandatory repayment prior to maturity.

Short-Term Advances Due to Related Parties

At September 30, 2018, the Business had short-term advances of $69.8 million (December 31, 2017 - $69.8 million) due to AltaGas which are unsecured, non-interest bearing and due on demand.

11. RELATIONSHIP WITH PARENT AND CORPORATE ALLOCATIONS

The Business has historically been managed and operated in the normal course of business by AltaGas along with other AltaGas affiliates. Accordingly, certain shared costs have been allocated to the Business and reflected as expenses in the combined financial statements. Management of AltaGas and the Business consider the allocation methodologies used to be reasonable and appropriate reflections of the related expenses attributable to the Business for purposes of the combined financial statements; however, the expenses reflected in the Business' combined financial statements may not be indicative of the actual expenses that would have been incurred during the periods presented if the Business historically operated as a separate entity. In addition, the expenses reflected in the combined financial statements may not be indicative of expenses that will be incurred in the future by the Business.

Prior to the transactions described in note 2, significant transactions with AltaGas were as follows:

Cash Management

The Business participates in AltaGas' centralized cash management programs. For certain of the Business' operating facilities, cash receipts are received and disbursements are made by AltaGas, with any excess cash being retained by AltaGas. For the purpose of these Combined Financial Statements, the net cash retained by AltaGas is reflected as Due from Related Party in the Combined Balance Sheets. Cash retained by AltaGas on behalf of the Business is not kept in specific accounts for the Business and is instead comingled with cash from other AltaGas entities.

Pension and Other Post-Employment Benefit Plans

The Business sponsors several pension and post-employment plans. In addition, the Business employees also participate in certain pension plan and post-employment benefit plans sponsored by AltaGas. There is no contractual agreement or stated policy between the Business and AltaGas for charging the costs of these plans (note that the Business comprises parts of multiple legal entities).

All obligations pursuant to these plans are obligations of AltaGas and as such are not included in the Business' Combined Balance Sheets. AltaGas allocates to the Business, the net periodic benefit costs associated with employees that are beneficiaries of pensions and other employment benefit costs. These costs are included in operating and administrative expenses in the Combined Statements of Income. AltaGas contributes to these plans. The amount contributed to these plans by AltaGas on the Business' behalf cannot be determined.

Derivatives

Derivatives that relate to the Business are entered into on behalf of the Business by another AltaGas entity.

Allocated Corporate Costs

Allocated costs include AltaGas charges including, but not limited to: board of directors, executive management, finance, accounting and tax, legal and compliance, office services and corporate resources, information technology and procurement. These costs are included in operating and administrative expenses in the Combined Statements of Income and have a pre-tax total of $2.3 million and $7.0 million for the three and nine month periods ended September 30, 2018, respectively (three and nine months ended September 30, 2017 - $2.1 million and $6.4 million, respectively). The costs were allocated to the Business based on similar methodology used to allocate costs within AltaGas, which is a combination of asset values, payroll expenses and earnings. Note that these expenses may have been different had the Business been a separate entity during the periods presented.

12. SUPPLEMENTAL CASH FLOW INFORMATION

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

	Three months ended September 30		Nine months ended September 30	
	2018	2017	**2018**	2017
Source (use) of cash:				
Accounts receivable	**$ 9.2**	$ 8.3	**$ 35.3**	$ 34.1
Inventory	**(0.7)**	(0.7)	**—**	(0.6)
Other current assets	**(0.2)**	0.9	**(2.5)**	0.2
Regulatory assets (current)	**(0.4)**	1.0	**(0.7)**	0.9
Accounts payable and accrued liabilities	**(10.8)**	(1.4)	**(36.9)**	(32.4)
Customer deposits	**3.1**	3.8	**1.7**	1.7
Regulatory liabilities (current)	**3.1**	(1.0)	**5.0**	2.7
Other operating assets and liabilities	**(3.5)**	(4.7)	**0.3**	0.9
Changes in operating assets and liabilities	**$ (0.2)**	$ 6.2	**$ 2.2**	$ 7.5

13. 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.

14. SEGMENTED INFORMATION

The Business owns and operates a portfolio of assets and services used to move energy from the source to the end-user. The following describes the Business' three reporting segments:

Renewable Energy	–	the 102MW Bear Mountain Wind Park, and a 10% equity investment in Northwest Hydro Limited Partnership, which indirectly owns and operates three run-of-river hydroelectric power generation assets in northwest British Columbia.
Utilities	–	rate-regulated natural gas distribution assets in Alberta, British Columbia and Nova Scotia.
Corporate	–	cash balances managed on behalf of the Business by AltaGas.

The following tables show the composition by segment:

	Three months ended September 30, 2018			
	Renewable Energy	**Utilities**	**Corporate**	**Total**
Revenue	**$ 2.9**	**$ 40.9**	**$ —**	**$ 43.8**
Cost of sales	**(0.1)**	**(9.7)**	**—**	**(9.8)**
Operating and administrative	**(1.5)**	**(20.2)**	**—**	**(21.7)**
Depreciation and amortization	**(1.8)**	**(5.8)**	**—**	**(7.6)**
Income (loss) from equity investments	**3.4**	**(0.1)**	**—**	**3.3**
Interest expense	**—**	**(7.2)**	**—**	**(7.2)**
Income (loss) before income taxes	**$ 2.9**	**$ (2.1)**	**$ —**	**$ 0.8**
Net additions to:				
Property, plant and equipment[(a)]	**$ —**	**$ 21.9**	**$ —**	**$ 21.9**
Intangible assets	**$ —**	**$ 1.8**	**$ —**	**$ 1.8**

(a) Net additions to property, plant, and equipment, and intangible assets may not agree to changes reflected in the Combined Statement of Cash flow due to classification differences.

	Nine months ended September 30, 2018			
	Renewable Energy	**Utilities**	**Corporate**	**Total**
Revenue	**$ 10.4**	**$ 204.2**	**$ —**	**$ 214.6**
Cost of sales	**(0.2)**	**(78.7)**	**—**	**(78.9)**
Operating and administrative	**(4.2)**	**(64.6)**	**—**	**(68.8)**
Accretion expenses	**—**	**(0.1)**	**—**	**(0.1)**
Depreciation and amortization	**(5.4)**	**(16.6)**	**—**	**(22.0)**
Income (loss) from equity investments	**4.2**	**(0.1)**	**—**	**4.1**
Foreign exchange loss	**—**	**—**	**(0.1)**	**(0.1)**
Interest expense	**—**	**(20.9)**	**—**	**(20.9)**
Income (loss) before income taxes	**$ 4.8**	**$ 23.2**	**$ (0.1)**	**$ 27.9**
Net additions to:				
Property, plant and equipment[(a)]	**$ —**	**$ 45.5**	**$ —**	**$ 45.5**
Intangible assets	**—**	**2.0**	**—**	**$ 2.0**

(a) Net additions to property, plant, and equipment, and intangible assets may not agree to changes reflected in the Combined Statement of Cash flow due to classification differences.

(b)

	Three months ended September 30, 2017			
	Renewable Energy	Utilities	Corporate	Total
Revenue	$ 4.1	$ 41.0	$ —	$ 45.1
Cost of sales	(0.1)	(11.3)	—	(11.4)
Operating and administrative	(1.4)	(20.3)	—	(21.7)
Depreciation and amortization	(1.8)	(5.2)	—	(7.0)
Income from equity investments	4.3	—	—	4.3
Other loss	—	(0.2)	—	(0.2)
Interest expense	—	(6.7)	—	(6.7)
Income (loss) before income taxes	$ 5.1	$ (2.7)	$ —	$ 2.4
Net additions to:				
Property, plant and equipment[(a)]	$ —	$ 16.0	$ —	$ 16.0
Intangible assets	$ —	$ —	$ —	$ —

(a) Net additions to property, plant, and equipment, and intangible assets may not agree to changes reflected in the Combined Statement of Cash flow due to classification differences.

	Nine months ended September 30, 2017			
	Renewable Energy	Utilities	Corporate	Total
Revenue	$ 12.0	$ 207.6	$ —	$ 219.6
Cost of sales	(0.2)	(89.3)	—	(89.5)
Operating and administrative	(3.8)	(61.7)	—	(65.5)
Depreciation and amortization	(5.4)	(15.7)	—	(21.1)
Income (loss) from equity investments	5.3	(0.1)	—	5.2
Other loss	—	(0.6)	—	(0.6)
Interest expense	—	(19.7)	—	(19.7)
Income before income taxes	$ 7.9	$ 20.5	$ —	$ 28.4
Net additions to:				
Property, plant and equipment[(a)]	$ —	$ 32.3	$ —	$ 32.3
Intangible assets	$ —	$ —	$ —	$ —

(a) Net additions to property, plant, and equipment, and intangible assets may not agree to changes reflected in the Combined Statement of Cash flow due to classification differences

The following table shows goodwill and total assets by segment:

	Renewable Energy	Utilities	Corporate	Total
As at September 30, 2018				
Goodwill	**$ —**	**$ 119.1**	**$ —**	**$ 119.1**
Segmented assets	**$ 275.6**	**$ 1,179.6**	**$ 134.9**	**$ 1,590.1**
As at December 31, 2017				
Goodwill	$ —	$ 119.1	$ —	$ 119.1
Segmented assets	$ 297.8	$ 1,179.8	$ 134.2	$ 1,611.8