AltaGas Canada

Annual Information Form

For the year ended December 31, 2018

March 6, 2019

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GENERAL INFORMATION

Unless otherwise noted, the information contained in this AIF dated March 6, 2019 is stated as at December 31, 2018 and all dollar amounts in this AIF are in Canadian dollars. Unless the context requires, all references to ACI or the Company herein refer to ACI and its subsidiaries on a consolidated basis and, when in reference to information prior to October 25, 2018, include reference to ACI and its subsidiaries and the business underlying the Acquired Assets on a combined carve-out basis prior to its separation from AltaGas. Financial information is presented in accordance with United States generally accepted accounting principles. For an explanation of certain terms and abbreviations used in this AIF see the "*Glossary*" of this AIF.

This AIF refers to certain terms commonly used in the rate-regulated utility industry, such as "rate-regulated", "rate base" and "return on equity". For a description of these terms, see information under the heading *"Business of Company – Utilities Business – Rate Regulated Overview"*. The terms "rate base" and "return on equity" are key performance indicators but are not considered non-GAAP measures. Rate base is an amount that a utility is required to calculate for regulatory purposes, and generally refers to net book value of the utility's assets for regulatory purposes. Return on equity is a percentage that is set or approved by a utility's regulator and represents the rate of return that a regulator allows the utility to earn on the equity component of the utility's rate base. The Company refers to the rate base and return on equity of its utility businesses because it believes that such terms assist in understanding the Company's business and are commonly used by investors and research analysts to help evaluate the performance of rate-regulated utilities.

FORWARD-LOOKING INFORMATION AND STATEMENTS

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

Specifically, such forward-looking statements included in this document include, but are not limited to, statements with respect to the following: the expected in-service date for the Atlantic Bridge Expansion Project; ACI's vision and objectives; the implementation and success of ACI's strategy as a whole and each of its business segments; timing of construction completion of, cost of and AUC decisions with regard to the Etizikom Lateral Project; expectations regarding the advancement of liquefied natural gas projects and their potential impact on capacity utilization in the Western System; expectations regarding arrangements in relation to the Kitimat, British Columbia to Summit Lake, British Columbia pipeline and proposed loop; duration of HGL's Customer Retention Program; expected success of financing plans and strategies, including maintenance of ACI's credit rating; the expected safety and reliability of ACI's operations; the expected good working relationships with stakeholders and governments; sources and terms of natural gas supply; the expected impacts on ACI's business of applicable environmental regulations and requirements; expected growth in each of ACI's business segments and the contributors to that growth; and targeted growth in ACI's rate-regulated utilities.

These statements involve known and unknown risks, uncertainties and other factors that may cause actual results, events and achievements to differ materially from those expressed or implied by such statements. Such statements reflect ACI's current expectations, estimates and projections based on certain material factors and assumptions at the time the statement was made. Material assumptions include: expected commodity supply, demand and pricing; volumes and rates; exchange rates; inflation; interest rates; credit ratings; regulatory approvals and policies; future operating and capital costs; project completion dates; capacity expectations; and the outcomes of significant commercial contract negotiations.

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: uncertainties faced by regulated companies; volume throughput and the impacts of commodity pricing, supply, composition and other market risks; natural gas demand; prevailing economic conditions; available electricity prices; legislative and regulatory environment; impacts of climate change and carbon taxing; cost of compliance with environmental regulation; weather, hydrology and climate changes; ACI's relationships with external stakeholders, including indigenous stakeholders; the potential for service interruptions; ACI's ability to update infrastructure on a timely basis; increased competition; loss of franchise grants; ACI's ability to economically and safely develop, contract and operate assets; ACI's dependence on certain partners; access to and use of capital markets; market value of ACI's securities; ACI's ability to service or refinance its debt and manage its credit ratings and risk; available electricity prices; underinsured losses; cybersecurity risks; failure to achieve benefits of business acquisitions; pension liabilities; impact of labour relations and reliance on key personnel; ability to maintain compliance with borrowing covenants; interest rate, exchange rate and counterparty risks; potential litigation; effects of decommissioning, abandonment and reclamation costs; risk associated with operations as a smaller entity; ongoing relationship with AltaGas; ACI's ability to pay dividends; potential volatility in market price of securities; and the other factors discussed under the heading "*Risk Factors*".

The Company believes the forward-looking statements are reasonable. However, such statements are not a guarantee that any of the actions, events or results of the forward-looking statements will occur, or if any of them do occur, their timing or what impact they will have on the Company's results of operations or financial condition. Many factors could cause ACI's or any particular business segment's actual results, performance or achievements to vary from those described in this AIF, 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 AIF as intended, planned, anticipated, believed, sought, proposed, estimated, forecasted, expected, projected or targeted and such forward-looking statements included in this AIF, 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 AIF. 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 AIF are expressly qualified by these cautionary statements.

Financial outlook information contained in this AIF about prospective results of operations, financial position or cash flow 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 AIF should not be used for purposes other than for which it is disclosed herein.

GLOSSARY

Unless the context otherwise requires, terms used in this AIF have the following meanings and references to agreements include any amendments, restatements, modifications or supplements in effect as of the date hereof:

"**ACEHL**" means AltaGas Canadian Energy Holdings Ltd.;

"**ACEHLP**" means AltaGas Canadian Energy Holdings Limited Partnership;

"**ACI**" or the "**Company**" means AltaGas Canada Inc.;

"**Acquired Assets**" has the meaning given to it under the heading "*General Development of the Business – 2018 – Acquisition of Assets from AltaGas";*

"**Acquired Indebtedness**" has the meaning given to it under the heading *"General Development of the Business – 2018 – Acquisition of Assets from AltaGas"*;

"**Acquisition**" has the meaning given to it under the heading "*General Development of the Business – 2018 – Acquisition of Assets from AltaGas*";

"**AHI**" means AltaGas Holdings Inc.;

"**AIF**" means this Annual Information Form;

"**AltaGas**" means AltaGas Ltd., including, where the context requires, the affiliates of AltaGas Ltd.;

"**Applicable Utilities Commission**" means the AUC, the BCUC, the NSUARB and the NWTPUB;

"**Atlantic Bridge Expansion Project**" means the construction of additional pipeline capacity and related facilities infrastructure by Enbridge Inc. to provide additional capacity on its Algonquin Gas Transmission and Maritimes & Northeast Pipeline systems to move natural gas to specific end use markets in the Canadian Maritime provinces targeting an in-service date in the second quarter of 2020;

"**AUC**" means the Alberta Utilities Commission;

"**AUGI**" means AltaGas Utilities Group Inc.;

"**AUI**" means AltaGas Utilities Inc.;

"**BC CPI**" means the Consumer Price Index for British Columbia, All Items (Not Seasonally Adjusted) as published by Statistics Canada;

"**BC Hydro**" means British Columbia Hydro Power Authority;

"**BCUC**" means British Columbia Utilities Commission;

"**Bear Mountain Wind Park**" means the 102 MW generating wind facility located near Dawson Creek, British Columbia;

"**BMWLP**" means Bear Mountain Wind Limited Partnership;

"**BMWPC**" means Bear Mountain Wind Power Corporation, the general partner of BMWLP;

"**Board of Directors**" means the board of directors of ACI, as from time to time constituted;

"**C&I**" means commercial and industrial;

"**CBCA**" means the *Canada Business Corporations Act*, R.S.C. 1985, c. C 44, and the regulations promulgated thereunder, each as amended;

"**CCIR**" has the meaning given to it under the heading "*Environmental Regulation – Climate Change*";

"**CMH Group**" means CMHLP and its general partners, AltaGas Renewable Energy Inc., AltaGas Renewable Energy #2 Inc. and Coast Mountain Hydro Corporation;

"**CMHLP**" means Coast Mountain Hydro Limited Partnership;

"**Coast GP**" means Northwest Hydro GP Inc., the general partner of Coast LP;

"**Coast LP**" means Northwest Hydro Limited Partnership;

"**COD**" means commercial operation date, being the first date on which a facility is considered substantially complete and selling power;

"**Common Shares**" means common shares of ACI;

"**CPI**" means the Consumer Price Index for Canada, All Items (Not Seasonally Adjusted) as published by Statistics Canada;

"**Customer Retention Program**" has the meaning given to it under the heading "*General Development of the Business – 2016 – Material Regulatory Developments and Applications – Nova Scotia*";

"**DBRS**" means DBRS Limited and its successors;

"**Degree Day**" means the amount that the daily mean temperature deviates below 15 degrees Celsius at AUI, below 18 degrees Celsius at HGL, such that a one degree difference equates to one Degree Day;

"**Demand Distribution**" has the meaning given to it under the heading "*Material Contracts*";

"**Distributable Securities**" has the meaning given to it under the heading "*Material Contracts*";

"**EH&S Management System**" means ACI's Environmental, Health & Safety Management System;

"**Etzikom Lateral Project**" has the meaning given to it under the heading "*General Development of the Business – 2018 – Material Regulatory Developments and Applications - Alberta*";

"**E&Y**" has the meaning given to it under the heading "*General – Audit Committee – External Auditor Service Fees by Category*";

"**Forrest Kerr**" means the 214 MW run-of-river hydroelectric facility, one of the three run-of-river hydroelectric facilities in northwest British Columbia that forms part of the Northwest Hydro Facilities;

"**GHG**" means greenhouse gas;

"**GHGRP**" has the meaning given to it under the heading "*Environmental Regulation – Climate Change*";

"**GJ**" means gigajoule or 1,000,000,000 joules;

"**Governance Agreement**" means the governance agreement between AltaGas and ACI effective as of October 18, 2018 governing various aspects of the relationship between the two companies, as further described under the heading "*Material Contracts*";

"**GWh**" means gigawatt-hour or 1,000,000,000 watt-hours; the watt-hour is equal to one watt of power flowing steadily for one hour;

"**HGL**" means Heritage Gas Limited;

"**Holder**" has the meaning given to it under the heading "*Material Contracts*";

"**Ikhil Joint Venture**" means the joint venture between ACI's subsidiary, Utility Group Facilities Inc., Inuvialuit Petroleum Company and ATCO Midstream NWT Ltd., which owns and operates two gas wells, a processing facility and a pipeline that delivers natural gas to Inuvik Gas and the Northwest Territories Renewable Energy Company;

"**Inuvik Gas**" means Inuvik Gas Ltd.;

"**Investor Liquidity Agreement**" means the investor liquidity agreement between ACI and AltaGas effective as of October 18, 2018, which affords AltaGas and any other permitted assignee with certain distribution rights, as further described under the heading "*Material Contracts*";

"**IPO**" means the initial public offering by ACI of its Common Shares completed on October 25, 2018;

"**km**" means kilometer;

"**Mcf**" means a thousand cubic feet of natural gas at standard imperial conditions of measurement;

"**McLymont Creek**" means the 72 MW run-of-river hydroelectric facility, one of the three run-of-river hydroelectric facilities in northwest British Columbia that forms part of the Northwest Hydro Facilities;

"**MTNs**" means medium term notes issued from time to time under the trust indenture dated November 15, 2018 between ACI and Computershare Trust Company of Canada;

"**MW**" means megawatt; one MW is 1,000,000 watts; the watt is the basic electrical unit of power;

"**Northeast System**" means the PNG(N.E.) distribution utility in the northeast part of British Columbia;

"**Northwest Hydro Facilities**" means the three run-of-river hydroelectric facilities in northwest British Columbia, being Forrest Kerr, McLymont Creek and Volcano Creek, approximately 10 percent of which is indirectly owned by ACI;

"**Northwest Transmission Line**" means the 344 km, 287 kilovolt northwest transmission line, owned by BC Hydro, from the Skeena substation near Terrace, British Columbia to a substation near Bob Quinn Lake, British Columbia;

"**NSUARB**" means the Nova Scotia Utility and Review Board;

"**NWTPUB**" means the Northwest Territories Public Utilities Board;

"**Offered Securities**" has the meaning given to it under the heading "*Material Contracts*";

"**Order**" has the meaning given to it under the heading "*General – Cease Trade Orders, Bankruptcies, Penalties and Sanctions*";

"**Over-Allotment Note**" means the unsecured promissory note dated October 18, 2018 issued by ACI to AltaGas bearing interest at 3.3 percent per annum in the principal amount of $35.9 million (adjusted to approximately $34.0 million following the exercise of the Over-Allotment Option in full);

"**Over-Allotment Option**" has the meaning given to it under the heading "*General Development of the Business* – 2018 – Initial Public Offering of Common Shares";

"**PBR**" means performance-based regulation;

"**Person**" means any individual, company (including any limited liability company), partnership, joint venture, association, trust, unincorporated organization or government or any agency or political subdivision thereof;

"**Piggy-Back Distribution**" has the meaning given to it under the heading "*Material Contracts*";

"**Piggy-Back Distribution Orderly Sale Numbers**" has the meaning given to it under the heading "*Material Contracts*";

"**PJ**" means Petajoule which is one million GJ;

"**PNG**" means Pacific Northern Gas Ltd.;

"**PNG(N.E.)**" means Pacific Northern Gas (N.E.) Ltd.;

"**Portland Xpress Expansion Project**" means the construction of additional pipeline capacity and related facilities infrastructure by several transmission pipeline companies, Union Gas Limited, TransCanada Pipeline Limited and

Portland Natural Gas Transmission System. This will enable the pipeline systems to move natural gas to specific end use markets in the Canadian Maritime provinces over a 3 year period which commenced service on November 1, 2018;

"**PPA**" means power purchase agreement;

"**Pre-FEED**" means a development of pre-defined design package to prove the feasibility in technical and economics. It is a basis of the front end engineering design or basic engineering;

"**Preferred Shares**" means preferred shares in the capital of the Company, issuable in one or more series;

"**Purchase and Sale Agreement**" means the purchase and sale agreement among ACI, AltaGas and AHI dated October 18, 2018 pursuant to which ACI acquired, for the purchase price of approximately $889.1 million, the Acquired Assets and certain indebtedness of AUGI and PNG;

"**Purchase Price Long-Term Note**" means the unsecured promissory note dated October 18, 2018 issued by ACI to AltaGas 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;

"**Purchase Price Short-Term Note**" means the unsecured promissory note dated October 18, 2018 issued by ACI to AltaGas bearing interest at 4.5 percent per annum in the principal amount of approximately $316.3 million;

"**RDA**" means revenue deficiency account;

"**RECs**" means Renewable Energy Credits;

"**Revolving Credit Facility**" has the meaning given to it under the heading "*Material Contracts*";

"**ROE**" means return on equity;

"**SEDAR**" means System for Electronic Document Analysis and Retrieval, at www.sedar.com;

"**Share Option**" means an option to purchase a Common Share granted under ACI's share option plan;

"**Shareholders**" mean the holders of Common Shares;

"**Term Loan**" has the meaning given to it under the heading "*Material Contracts*";

"**Transition Services Agreement**" means the transition services agreement between ACI and AltaGas effective as of October 18, 2018 pursuant to which AltaGas has agreed to provide or arrange for the provision of certain administrative services required by ACI, as further described under the heading "*Material Contracts*";

"**TSX**" means the Toronto Stock Exchange;

"**Volcano Creek**" means the 17 MW run-of-river hydroelectric facility, one of the three run-of-river hydroelectric facilities in northwest British Columbia that forms part of the Northwest Hydro Facilities; and

"**Western System**" means PNG's regulated natural gas transmission and distribution utility in the west central portion of northern British Columbia.

METRIC CONVERSION

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply by
Mcf	cubic meters	28.174
cubic meters	cubic feet	35.494
tonnes	long tons	0.984
feet	meters	0.305
GJ	Mcf	0.9482

To Convert From	To	Multiply by
meters	feet	3.281
miles	km	1.609
km	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

CORPORATE STRUCTURE

INCORPORATION

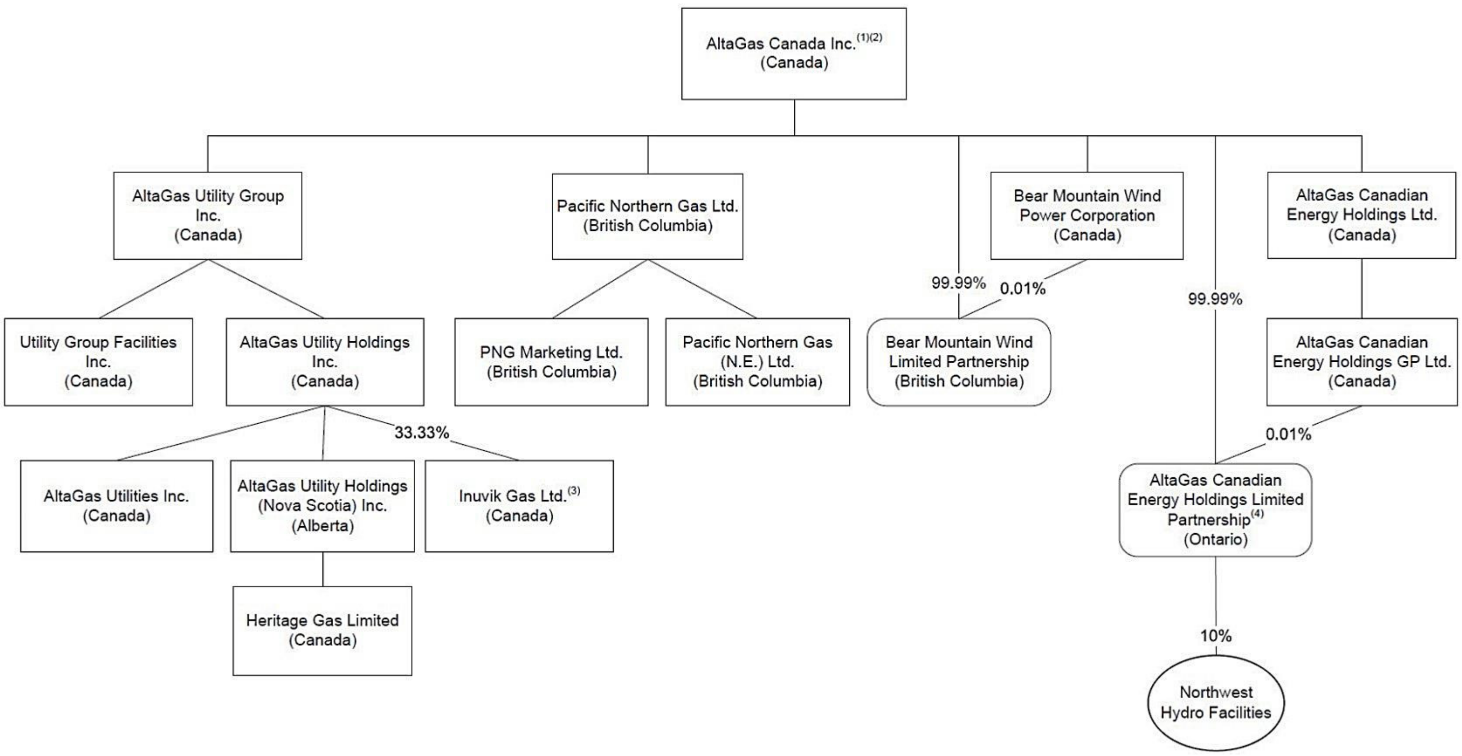
ACI was incorporated under the CBCA on October 27, 2011 as AltaGas Utility Holdings (Pacific) Inc. The Company was a wholly-owned subsidiary of AltaGas Ltd. until it completed the IPO. ACI maintains its head, principal and registered office in Calgary, Alberta currently located at 1700, 355 – 4th Avenue SW, Calgary, Alberta T2P 0J1. ACI is a public company, the Common Shares of which trade on the TSX under the symbol "ACI".

AMENDMENTS TO ARTICLES

On September 5, 2018, ACI amended its articles to, among other things, facilitate it becoming a public company, change its name to AltaGas Canada Inc., amend its authorized capital and consolidate its outstanding common shares on the basis of one post-consolidation share for every 28 pre-consolidation common shares.

INTERCORPORATE RELATIONSHIPS

The following organization diagram presents the name and the jurisdiction of incorporation of ACI's subsidiaries as at December 31, 2018.



Notes:
(1) Updated December 31, 2018.
(2) Unless otherwise stated, ownership is 100 percent.
(3) Ikhil Resources Ltd. (a wholly owned subsidiary of Inuvialuit Petroleum Corporation) and ATCO Midstream NWT Ltd. each own a 33.33 percent in Inuvik Gas Ltd.
(4) AltaGas Canadian Energy Holdings Limited Partnership holds an indirect 10 percent ownership in the Northwest Hydro Facilities through a limited partnership.

OVERVIEW OF THE BUSINESS

ACI is a Canadian corporation with diversified rate-regulated natural gas distribution and transmission utilities assets and long-term contracted renewable power generation assets. ACI has two business segments:

- Utilities, which owns and operates utility assets that deliver natural gas to end-users in Alberta, British Columbia and Nova Scotia. ACI also owns a one-third equity interest in the utility that delivers natural gas to end-users in Inuvik, Northwest Territories. In aggregate, the utilities have approximately $886 million of rate base as at December 31, 2018 and serve approximately 130,000 customers across Canada; and

- Renewable Energy, which includes the Bear Mountain Wind Park and an approximately 10 percent indirect interest in the entities that own the Northwest Hydro Facilities.

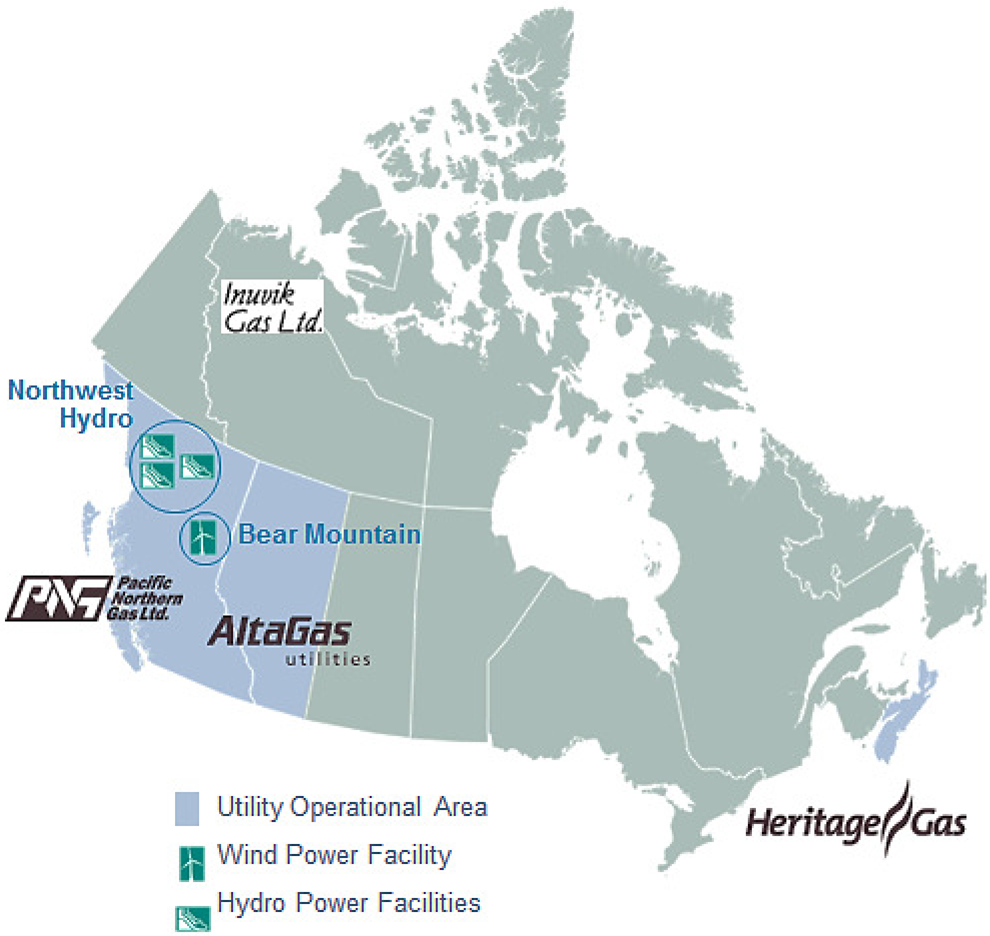
The Company also has a Corporate segment which primarily includes the cost of providing corporate services, financing and access to capital, and general corporate support.

ACI's vision is to be the clean energy supplier of choice in each of the jurisdictions in which it operates through being a leader in safety, reliability, cost effectiveness and customer service. Through disciplined investments in its utilities and in contracted renewable power opportunities, the Company is committed to achieving long-term sustainable growth. Safety, customer service and earnings per common share are the primary measures of performance for the Company.

The Company's objective is to: (a) provide safe, reliable, clean and cost-effective energy to its customers; (b) create stable, consistent returns with strong organic growth for investors through the ownership of rate-regulated utilities and renewable power assets contracted through long-term PPAs with creditworthy counterparties; and (c) pay out a portion of its net income to the Shareholders on a quarterly basis.

The Company's strategy is focused on delivering safe, reliable, clean and cost-effective energy solutions to customers while achieving long-term profitable growth. Through the Company's diversified rate-regulated natural gas distribution and transmission utilities assets and long-term contracted renewable power generation assets, the Company expects to deliver low-risk, stable, predictable earnings and cash flows. The Company works to maintain strong relationships with regulators and be seen as a credible proponent for regulatory initiatives.

ACI'S GEOGRAPHIC FOOTPRINT



GENERAL DEVELOPMENT OF THE BUSINESS

Below is a summary of key general development of the business of ACI over the last three completed financial years.

2018

Acquisition of Assets from AltaGas (the "Acquisition")

On October 18, 2018, pursuant to the Purchase and Sale Agreement, ACI acquired the following assets from AltaGas for approximately $889.1 million (the "Acquired Assets") through the acquisition of: (a) all of the issued and outstanding common shares of AUGI; (b) all of the issued and outstanding common shares of BMWPC; (c) AltaGas' 99.99 percent partnership interest in BMWLP as a limited partner; (d) AltaGas' 99.99 percent partnership interest in ACEHLP as a limited partner; (e) all of the issued and outstanding common shares of ACEHL; and (f) 10 common shares in the capital of Coast GP:

- Rate-regulated natural gas distribution utility assets in Alberta and Nova Scotia owned by AUGI via its operating subsidiaries, AUI and HGL;
- Minority interests in entities (Inuvik Gas and Ikhil Joint Venture) providing natural gas to the Town of Inuvik, Northwest Territories;
- Fully contracted Bear Mountain Wind Park owned by BMWLP and BMWPC; and
- Approximately 10 percent indirect equity interest in the capital of Coast LP and Coast GP which indirectly own the Northwest Hydro Facilities by way of the CMH Group.

Pursuant to the Purchase and Sale Agreement, the Company also acquired on October 18, 2018 the indebtedness that AUGI and PNG owed to AltaGas and certain of its subsidiaries in the aggregate amount of approximately $481.6 million (the "Acquired Indebtedness").

The Company satisfied the purchase price of $889.1 million for the Acquired Assets and Acquired Indebtedness by issuing to AltaGas the following:

- 5,912,857 Common Shares;
- the Purchase Price Short-Term Note which was to be repaid upon closing of the IPO;
- the Over-Allotment Note which was to be repaid no later than 30 days after closing of the IPO; and
- the Purchase Price Long-Term Note.

The Purchase Price Short-Term Note, the Over-Allotment Note, and the Purchase Price Long-Term Note have been fully repaid as at December 31, 2018.

Initial Public Offering of Common Shares

On October 25, 2018, the Company completed its IPO, issuing 16,500,000 Common Shares at a price of $14.50 per Common Share for gross proceeds of $239.3 million.

In connection with the IPO, the Company granted to the underwriters of the IPO an over-allotment option (the "Over-Allotment Option"), exercisable at the underwriters' discretion at any time, in whole or in part, until 30 days following the closing of the IPO, to purchase at $14.50 per Common Share up to an additional 2,475,000 Common Shares (representing 15 percent of the Common Shares offered) to cover over-allotments, if any, and for market stabilization purposes. On November 21, 2018, the Over-Allotment Option was exercised in full for additional gross proceeds of $35.9 million.

Upon closing of the IPO and the exercise of the Over-Allotment Option, 30,000,000 Common Shares were issued and outstanding, of which AltaGas owned approximately 36.8 percent. The Company ceased to be a wholly-owned subsidiary of AltaGas upon completion of the IPO on October 25, 2018.

The net proceeds of the IPO were $223.7 million after deducting the underwriters' fee of $12.6 million and approximately $3.0 million in other expenses. The net proceeds from the exercise of the Over-Allotment Option were $34.0 million after deducting the underwriters' fee of $1.8 million and other expenses of $0.1 million. Pursuant to the Purchase and Sale Agreement, ACI used the net proceeds of the IPO, including the proceeds from the exercise of the Over-Allotment Option, to:

- Repay in full a note issued by ACI to AltaGas bearing interest at 5.0 percent per annum in the principal amount of $157.4 million issued in connection with a return on capital on the Common Shares immediately prior to the Acquisition;

- Repay a portion of the Purchase Price Short-Term Note with the remaining portion of the Purchase Price Short-Term Note being repaid using the proceeds of the Term Loan; and

- Repay in full the Over-Allotment Note. Per the terms of the Over-Allotment Note, if the Over-Allotment Option was exercised, the principal amount would be reduced by the amount of the underwriters' fee and other expenses of approximately $1.9 million. The Company repaid in full $34.0 million to AltaGas on November 21, 2018.

Filing of Base Shelf Prospectus and Issuance of MTNs

ACI filed with the securities commissions or similar regulatory authorities in each of the provinces of Canada on November 14, 2018 a final short form base shelf prospectus allowing ACI to offer and issue, from time to time: (a) Common Shares; (b) Preferred Shares; (c) subscription receipts (d) warrants to purchase securities; (e) notes or other types of unsecured debt securities which may be issuable in a series; (f) units comprising any combination of the foregoing; or (g) any combination of the foregoing, up to an aggregate offering price of $1,000,000,000 during the 25 month period that such short form base shelf prospectus, including any amendments, remains effective.

A prospectus supplement was filed on November 15, 2018 to the short form base shelf prospectus allowing ACI to offer and issue, from time to time, MTNs having maturities of not less than one year from the date of issue to be issued in denominations of $5,000 and multiples of $1,000 above such amount. The MTNs will either be interest bearing or non-interest bearing issued at par, a discount or at a premium. A pricing supplement was filed on December 3, 2018 and ACI issued $300 million of MTNs on December 5, 2018 with a coupon rate of 4.26 percent (4.269 percent yield to maturity) and maturity date of December 5, 2028. The net proceeds of approximately $298.6 million were used to partially repay the Purchase Price Long-Term Note.

Material Regulatory Developments and Applications

Alberta

Effective January 1, 2018, the AUC approved a second PBR plan term from 2018 to 2022 ("PBR 2"). Under the PBR 2 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. As revenues are generally decoupled from costs, a utility is incentivized to achieve cost efficiencies during the PBR plan term. In addition, the PBR 2 plan continues to allow for recovery of costs determined to flow through directly to customers, recovery of items related to material exogenous events, and re-opener threshold provisions that allow an application to be re-opened in order to address specific problems with the design or operation of the PBR plan. Incremental capital funding is largely determined formulaically based on historical capital additions with an additional mechanism available for cost recovery of specific capital projects that are extraordinary, not previously included rate base, and required by a third party ("Type 1 Capital Tracker"). As a result of its formulaic design, the PBR framework provides a level of regulatory certainty throughout the PBR period, allowing the utility to manage its costs and to allocate and plan capital spending accordingly.

On August 2, 2018, the AUC issued its decision on the 2018 generic cost of capital proceeding, approving a ROE of 8.5 percent for all Alberta utilities and a deemed capital structure for the utilities, with AUI set at 39 percent equity. The decision applies to 2018, 2019 and 2020.

On December 20, 2018, the AUC approved rates on an interim basis for the construction of 28 km of new pipeline to replace a lateral pipeline that is being abandoned by NOVA Gas Transmission Ltd. (the "Etzikom Lateral Project"). The Etzikom lateral pipeline serves approximately 1,715 of AUI's customers in southeast Alberta, including rural areas surrounding the City of Medicine Hat and extending south to the hamlet of Etzikom and surrounding rural areas. Construction of the Etzikom Lateral Project is expected to be completed in the fourth quarter of 2019 at a cost of approximately $10 million. AUI expects the AUC to issue a final decision on whether or not the project meets the Type 1 Capital Tracker Criteria under the PBR 2 plan in 2020. Any difference between interim-approved and actual approved revenue requirements are expected to be collected or refunded through 2021 annual PBR rates.

British Columbia

On October 9, 2018, PNG published a request for expressions of interest in a multi-lateral process, in which PNG identified 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, British Columbia, Kitimat, British Columbia and Prince Rupert, British Columbia areas, as well as on a proposed expansion of its pipeline system from Summit Lake to Kitimat, British Columbia (the "PNG Looping Project'). PNG has subsequently invited interested parties to participate in its multi-lateral process and execute binding agreements, which will include the payment of reservation fees to reserve existing PNG transportation capacity, as well as support agreements, for a pro-rata share of the project Pre-FEED development costs to assess feasibility of its expansion project. 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.

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Material Regulatory Developments and Applications

British Columbia

In November 2017, PNG submitted revenue requirements applications with the 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 the Western System, permanent delivery rate increases of approximately 6 percent for each of 2018 and 2019 for customers in the Northeast System (Fort St. John/Dawson Creek) service areas, as well as permanent delivery rate increases of approximately 18 percent for each of 2018 and 2019 for customers in the Northeast System (Tumbler Ridge) 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 and sought input from PNG on the transitional period to effect this accounting change. PNG requested and received BCUC approval on November 26, 2018 for a five year transition period for the inclusion of negative salvage accounting. The delivery rate increases noted above do not include the impact of negative salvage accounting. Taking into consideration negative salvage, the 2019 permanent delivery rates are decreased by approximately 0.3 percent for customers in the Western System, increased by approximately 7 percent in the Northeast System (Fort St. John/Dawson Creek) service areas and increased by approximately 20 percent in the Northeast System (Tumbler Ridge) service area.

Nova Scotia

In 2017, the *Gas Distribution Act* (Nova Scotia) was changed to enable the NSUARB to regulate long-term gas distribution contracts for recovery by the gas distribution utility. In 2017, HGL entered into a precedent agreement with Portland Natural Gas Transmission System that would provide transportation capacity to HGL, giving it access to gas supply in Dawn, Ontario which is a part of the Portland Xpress Expansion Project for a 22-year period beginning in the fall of 2018, enhancing security of supply and reducing gas price volatility. 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 went into effect on November 1, 2018.

2016

Material Regulatory Developments and Applications

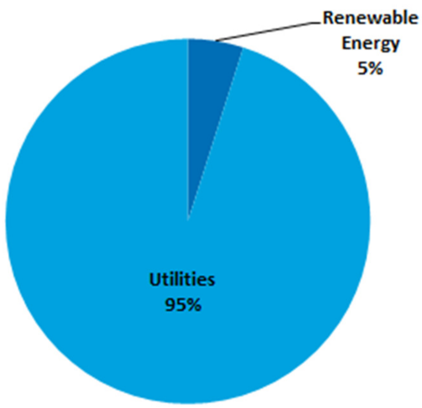
Nova Scotia

HGL filed a customer retention program application with the NSUARB on March 2, 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 previously approved distribution rates, a suspension of depreciation and a deferral of an additional 25 percent for operating, maintenance and administrative expenses while the program is in place (the “Customer Retention Program”). 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 for 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.

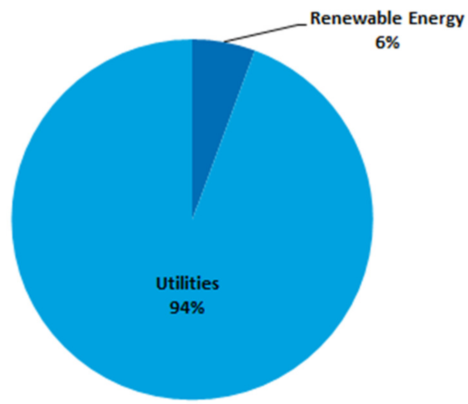
BUSINESS OF THE COMPANY

The revenue for ACI's assets for the year ended December 31, 2018 was approximately $309.1 million compared to $309.2 million for the year ended December 31, 2017.

Revenue by Business for 2018 [(1)]



Revenue by Business for 2017 [(1)]



Note:
(1) Excluding Corporate segment and intersegment eliminations

UTILITIES BUSINESS

ACI's Utilities business contributed revenue of $294.0 million for the year ended December 31, 2018 (2017 - $291.8 million), representing approximately 95 percent (2017 – 94 percent) of ACI's total revenue before Corporate segment and intersegment eliminations.

Rate Regulation Overview

The rates charged for natural gas distribution services are regulated in Canada and many other jurisdictions. The term "rate-regulated" is used to refer to a utility business whose rates for distribution, transmission or other services are subject to approval by a regulator. The Applicable Utilities Commissions are the regulators responsible for approving natural gas distribution rates in their respective jurisdictions.

In Canada, regulators generally use two different models for approving the rates charged by rate-regulated utilities: (a) a "cost of service" model; and (b) a "performance-based" model (sometimes also referred to as an "incentive-based" model).

In a cost of service model, a utility charges rates for its services that allow it the opportunity to recover the costs of providing its services, earn an allowed ROE and over time recover its invested capital. The costs of providing its services must be prudently incurred. Cost savings are typically passed on to customers in the form of lower rates reflected in future rate decisions.

In a performance-based model, a utility also charges rates for its services that allow it the opportunity to recover the costs of providing its services, earn an allowed ROE and over time recover its invested capital. However, the rates charged by the utility in a performance-based model assume that the utility becomes increasingly efficient over time, resulting in lower costs to provide the same service. If a utility achieves cost savings in excess of those established by the regulator, the utility may retain some or all of the benefits of those cost savings for a longer period of time, which may permit the utility to earn more than its allowed ROE during the performance term(s).

Value Drivers for a Rate Regulated Utility

Management believes the key drivers of value for a rate-regulated utility are:

- a skilled and experienced workforce delivering safe, reliable service;

- constructive and transparent relationships with the respective utility regulators;
- prudent capital investments which ultimately add to the utility's rate base;
- the utility's deemed capital structure and allowed ROE, as set by the regulator; and
- the ability to generate efficiencies and cost savings in the operations of the utility.

Safe, Reliable Service

The ability to provide safe, reliable service is a fundamental value driver for a utility. Utilities must develop operating practices and procedures, asset integrity management plans, natural gas supply strategies, workforce development plans and safety management plans, all driven towards safe delivery of their product in the short, medium and long-term. Success in this area attracts and retains customers to the business, builds the trust and confidence of the regulators, reduces repair, maintenance and emergency costs, and allows the utility to perform its obligations under its franchise agreements. See the heading "*Franchise Agreements and Approvals*".

Relationship with the Regulator

The ability of a utility to maintain constructive and transparent relationships with its regulator is a key driver of value. This relationship lays the foundation for all decisions made by the regulator in respect of the utility's business, including with respect to revenue requirements and ultimately the actual returns earned by the utility.

Rate Base and Capital Expenditures

The rate base of a rate-regulated utility generally refers to the net book value of the utility's assets for regulatory purposes. A utility's rate base must be calculated in accordance with the requirements of the utility's regulator and is generally approved by the regulator as part of the utility's rate application. The rate base for a natural gas utility in British Columbia, Alberta and Nova Scotia generally includes the gross cost of the Company's utility assets, less contributions paid by customers, less accumulated depreciation, plus an allowance for working capital. Utilities make capital investments to service new customers and to meet their obligations to deliver natural gas safely and reliably. Capital investments are included in a utility's rate base after the assets are placed into service. The rate base of a utility is reduced by depreciation of the utility's regulated assets being recorded in rates charged to customers. An increase in the utility's rate base will generally result in an increase in the utility's net income, all other things being equal.

Capital Structure and Return on Equity

Rate-regulated utilities have a "deemed" or approved capital structure that is set by the regulator. This is typically expressed as a ratio of debt-to-equity. For instance, in Alberta, the deemed capital structure for AUI set by the AUC is 61/39, which means that, for rate making purposes, AUI is considered to have a capital structure consisting of 61 perecnt debt and 39 percent equity. This capital structure is applied to the utility's rate base. As an example, if a utility has a rate base of $100 million and a 61/39 capital structure, this means the regulated assets of the utility are deemed to be capitalized with $61 million of debt and $39 million of equity. The deemed capital structure is important to a utility because it is used to calculate the dollar amount of a utility's net income that the utility is afforded the opportunity to earn through rates. A utility's deemed capital structure also reflects the regulator's view of the amount of debt that a utility should have in order to operate prudently.

A utility's ROE is the rate of return that a regulator allows the utility the opportunity to earn on the equity portion of the utility's rate base. ROE is expressed as a percentage. A utility's ROE represents the amount, over and above a utility's costs associated with providing services that a utility has the opportunity to earn as its net income after tax. A utility's allowed ROE is therefore a significant factor that affects the financial performance of rate-regulated utilities.

In order to calculate its allowed ROE as a dollar amount, the utility applies the allowable ROE percentage set by the regulator to the equity portion of its rate base. The equity portion of its rate base is, in turn, determined by multiplying the utility's rate base by the percentage of equity reflected in its deemed capital structure (i.e. 39 percent for AUI).

Operational Cost Savings and Efficiencies

Utilities seek greater efficiency and cost savings, including from economies of scale, productivity improvements or the use of new technology and systems. These cost savings are typically passed on to customers in the form of lower rates. In a cost of service model, this means the lower costs may be reflected in a lower revenue requirement approved by the regulator in the utility's next rate application. In other words, in a cost of service model without deferral mechanisms, cost savings, if any, are generally only retained by the utility until new rates are approved by the regulator. In a performance-based model for rates, the utility has the potential to retain some or all of the benefit of cost savings achieved in excess of those established by the regulator, thereby increasing its ROE during the performance term. The ability to demonstrate greater efficiency and cost savings in the operations of a utility is a key factor in a regulator's decision to approve rates. This, together with the utility's desire to increase profitability while keeping rates low, provides incentives for utilities to continue to seek more efficient ways to deliver their service to customers.

Rate Applications

Framework

The Applicable Utilities Commissions are the regulators that approve rates for utilities in their respective jurisdictions. In Alberta, rates are currently determined using a PBR methodology, with a potential for reverting back to cost of service at the end of the respective PBR term. In British Columbia and Nova Scotia, rates are typically set on a cost of service basis. In the Northwest Territories, rates are normally set on a cost of service basis, but are regulated on a light-handed complaint-based framework where competition exists within a franchise area. These models are reviewed and modified by the Applicable Utilities Commissions from time to time.

Application Process

A utility must file a rate application with the Applicable Utilities Commission to seek approval of its revenue requirement, which forms the basis for the rates to be charged for the approved period. The period between a utility's applications for rates may vary, and depends on the type of application process employed by the Applicable Utilities Commission.

A rate application is generally comprised of two phases: (a) to set the revenue requirement; and (b) to set specific rates to be charged to different classes of consumers and determine the terms and conditions of service.

A rate application is supported by pre-filed evidence, which contains details on the various categories of expenses proposed to be incurred by the utility, including, but not limited to, operations, maintenance and administration costs, depreciation and amortization, costs of debt and income taxes. A rate application will also include details on the capital expenditures proposed to be made based on available information and assumptions made at the time of the rate application. A utility must demonstrate to the Applicable Utilities Commission that capital investments are appropriate and prudent for inclusion in the utility's rate base and that the costs of providing service are also appropriate and prudent.

Rate applications for utilities such as PNG, AUI and HGL are generally based on "forward test years" whereby the utility must forecast and make assumptions regarding its expected costs and consumer demand during the periods covered by the rate application. The utility must support its application with information about prior or historical years and the current year.

Intervenors, such as consumer groups and other industry participants (including land owners and indigenous groups), and staff of the Applicable Utilities Commission, may also participate in the applicant's stakeholder activities, in technical conferences, and in the tribunal process itself, and they may also file questions and their own evidence. The parties may attempt to negotiate a full or partial settlement of the issues raised by the application. Unsettled issues are referred to a hearing in which the applicant is required to defend its rate application through written or oral submissions. After the completion of the hearing, the Applicable Utilities Commission issues a decision with reasons. The Applicable Utilities Commission will approve the final rate order or request revisions to better reflect its decision.

Applicable Utilities Commissions can instigate generic proceedings where topics are addressed for all utilities in the respective jurisdiction. The proceedings follow the same process as an individual utility application, however all utilities file evidence, take part in the hearing and are bound by the Applicable Utilities Commission's decision.

A utility may apply to the Applicable Utilities Commission for the approval of "deferral accounts" or "variance accounts", which are accounts used by the utility to record amounts due to, or amounts to be received from, rate payers at a future date. These type of accounts may be used to track, among other items, unforeseen capital expenditures or particular operation, maintenance and administration costs incurred during that period that were not included in the utility's last application for rates. The Applicable Utilities Commission will determine in connection with a subsequent rate application whether to allow a utility to include the assets produced from these capital expenditures in the utility's rate base or to recover such costs in rates.

Cost of Service Model

In a cost of service model for determining rates, a utility applies to the Applicable Utilities Commission for approval of its revenue requirement through a rate application. The revenue requirement covers the anticipated annual costs of providing the service, which includes an amount that represents the allowable ROE approved by the Applicable Utilities Commission.

Revenue Requirement

($)

Return on Equity	Calculated by multiplying the allowed ROE set by the Applicable Utilities Commission by the equity component of the utility's rate base.
Income Taxes	The allowance for the recovery of income taxes paid in respect of the regulated operations of the utility.
Cost of Debt	The approved cost of debt for the utility at the deemed capital structure.
Depreciation & Amortization	The depreciation on the rate base assets that is determined based on depreciation studies filed by a distribution utility, and approved by the Applicable Utilities Commission, which is net of any customer contribution amortization.
Operating Costs, Administrative Costs & Property Taxes	The costs associated with operating a utility that are determined to be prudent by the regulator.

The total revenue requirement is primarily collected through distribution rates. Other revenue generated by the utility through its regulated operations makes up the difference between the total revenue requirement and the amount collected through the distribution rates.

Performance-Based Model

The process for applying for distribution revenue requirements under a PBR framework differs from the process for applying for traditional cost of service revenue requirements in the following ways:

- under a PBR model, the revenue requirement is effectively decoupled from the utility's cost of providing service, and the utility must effectively manage its business to earn its allowed ROE over the period covered by the rate decision. Under this model, revenues earned from rates may not correspond to the utility's actual costs;

- the period covered by a PBR rate application in Alberta is typically five years, which is longer than the typical period covered by a cost of service rate application of one or two years;

- the utility applies for the "going-in rates" based on either a traditional cost of service rebasing model, a continuation of the rates in effect just prior to the new PBR period or as otherwise directed by the Applicable Utilities Commission;

- the revenue requirement for each of the subsequent years during the PBR period is generally determined based on a formula that multiplies the going-in rate by an inflation factor less certain productivity factors set by the regulator, multiplied by a factor for customer growth, plus a factor for capital funding. The revenue requirement in these subsequent years is set on the assumption that the utility is lowering its cost of service over the period covered by the rate decision due to efficiency or productivity improvements;

- certain capital expenses outside of the normal course of business or which cannot be foreseen are typically not included in PBR rates and are considered separately;

- the revenue requirement is also adjusted for the effect of other decisions of the regulator such as generic cost of capital proceedings; and

- the utility is permitted to retain all or a portion of the cost savings achieved in excess of those established by the regulator during the period covered by the rate decision, thereby allowing the utility to earn more than its allowed ROE.

Complaints-Based Model

Under a complaints-based model, a transmission or distribution utility does not file its rates for review or approval by the Applicable Utilities Commission. Rates are typically only reviewed upon the complaint of a ratepayer. Distribution providers in franchise areas with multiple providers in the Northwest Territories are typically regulated by the NWTPUB on a "light-handed" or complaints-based model.

Franchise Agreements and Approvals

In British Columbia, Alberta, Nova Scotia and the Northwest Territories, rate-regulated utilities may provide service within designated areas (i.e., franchise territories and areas), under the authority granted by franchise or operating agreements or otherwise granted as permits or approvals issued pursuant to applicable statutes by the Applicable Utilities Commissions. Franchise agreements or approvals grant the rate-regulated utility the exclusive right to provide utility services in the applicable franchise area.

Seasonality

The natural gas distribution business in Canada is highly seasonal, as the majority of natural gas demand occurs during the winter heating season that extends from November to March. Natural gas delivered during the winter heating season typically accounts for approximately two-thirds of annual natural gas deliveries, typically resulting in profitable first and fourth quarters and weaker second and third quarters. Accordingly, annualized individual quarterly revenues and earnings are not indicative of annual results.

Delivery rates for AUI and HGL are based on the 20-year rolling average Degree Days expected for the application period. Positive variances relative to expected levels lead to increased delivery volumes.

Delivery rates for PNG are set based on the 10-year rolling average Degree Days expected for the application period. PNG is authorized by the BCUC to maintain a rate stabilization adjustment mechanism regulatory account to mitigate the effect on its earnings of deliveries to certain customers caused principally by volatility in weather and the impact on deliveries. Balances in the account are recovered in customer rates over a two-year period based on forecast deliveries.

Competition

Natural gas competes with other forms of energy available to the Company's customers. The primary competitive factor is price. The commodity cost of natural gas has traditionally been volatile. When prices are high, the prospects of fuel-switching and increased energy conservation pose a risk to levels of demand for natural gas, as other energy sources can become more cost-competitive. It is anticipated that natural gas will continue to have a competitive advantage in British Columbia and Alberta, where virtually all potential customers in PNG and AUI's franchise areas are connected to natural gas. However, over time, material natural gas price increases may result in material decreases in the use of natural gas by customers. Within their respective current franchise areas, PNG and AUI have nearly achieved complete market saturation, with the exception of those consumers choosing alternate fuel sources or living in more remote areas where natural gas service is cost-prohibitive at this time.

In Nova Scotia, where customers face costs to convert to natural gas, there is competition from alternative energy sources. HGL is a relatively new utility having started with a single customer in 2003 and natural gas has a small share of the energy market. The dominant fuel source is oil, followed by electricity, then propane and wood fuel, used by smaller residential customers. In Nova Scotia, natural gas offers a competitive advantage relative to fuel oil and electricity due to its affordability, cleanliness, versatility, reliability and safety. HGL has responded to competitive propane prices in its small commercial rate class (500 to 4,999 GJ/year) by adjusting its distribution rates. The improving competitive position of natural gas relative to propane has allowed HGL to increase its distribution rates three times since the Customer Retention Program was put in place.

The rate-regulated utility sector is also affected by competition ranging from large utilities to independent power producers, as well as private equity and international conglomerates. In British Columbia and Alberta, the natural gas distribution market is dominated by a major distributor that serves a majority of customers. Although the Company holds a relatively small share of the overall market in its relevant jurisdictions, through its franchise agreements, permits and approvals, it has a monopoly within its noted service areas.

Utilities Business Key Utility Metrics

The following table summarizes the capital expenditures for the Utilities business for years ended December 31, 2018 and 2017.

	2018	2017
($ millions)		
New business	**19.1**	11.2
System betterment and gas supply	**42.6**	40.1
General plant	**10.0**	8.0
Total	**71.7**	59.3

The following table summarizes the nature of regulation applicable to each utility (other than Inuvik Gas):

Regulated Utility	Applicable Utilities Commission	$ Rate Base (% of the Company's Consolidated Rate Base) as at December 31, 2018	Allowed Common Equity (%)	Allowed ROE (%) 2017	Allowed ROE (%) 2018	Significant Features/Material Regulatory Development
AUI	AUC	$357 million (40%)	39	8.50	8.50	• Effective January 1, 2018, second generation PBR term 2018 – 2022 was approved. • Cost recovery and return on rate base through revenue per customer formula. • Generic cost of capital proceeding completed to establish allowed ROE and capital structure for 2018-2020. • Authorized to invest approximately $41 million per year over the five year plan term.
PNG	BCUC	$221 million (25%)				• Distribution rates approved under cost of service model. • Permanent rates approved for test year 2019 in the revenue requirements application. • Primarily protected from weather related volatility through revenue stabilization adjustment account.
Western System			46.50	9.50	9.50	
Northeast System (Fort St. John /Dawson Creek)			41.00	9.25	9.25	
Northeast System (Tumbler Ridge)			46.50	9.50	9.50	
HGL	NSUARB	$308 million (35%)	45	11.00	11.00	• Distribution rates approved under a cost of service model. • No regulatory lag; earn immediately on invested capital. • Revenue deficiency account of up to $50 million. • Customer Retention Program approved in September 2016 resulting in a decrease in distribution rates for certain commercial and residential customers and deferral of certain costs while the program is in place. • The incremental deferrals arising from the Customer Retention Program are allowed a return of 4 percent.

Regulatory Deferral Accounts

The Applicable Utilities Commissions have approved a number of deferral accounts for each of AUI, PNG and HGL to record costs and revenues for various items for recovery from customers, or refund to customers, over a future time period. The general purpose of a deferral account is to keep a company or its customers whole in respect of the subject matter of the deferral account. As at December 31, 2018, the Company's deferral accounts in assets were $216.4 million ($203 million at December 31, 2017) and were $31.0 million in respect of liabilities ($26.2 million at December 31, 2017). The period over which the accounts will be realized or settled depends upon the type of account. Recovery of deferral accounts may occur as quickly as the following month (as for certain deferral cost of gas amounts) or extend many decades (as for recovery of deferred income tax amounts).

Each of AUI, PNG and HGL have a gas cost variance account. The difference between the forecast gas cost charged to customers and the actual gas cost incurred is recorded in these accounts. If actual gas costs exceed forecast gas costs, the difference will be recovered from customers by an increase in future rates. If actual gas costs are lower than forecast gas costs, the difference will be refunded to customers through a reduction in future rates. In this way, customers, over time, pay the same cost for gas as is paid by the utility.

Each of AUI and PNG have an account with respect to recovery of deferred income taxes, which taxes reflect the future revenues required to fund the deferred tax liabilities. HGL is not yet subject to paying income taxes, as it has accumulated tax loss carryforwards which are used to reduce taxable income to zero. As such, income taxes are not yet reflected in HGL's distribution rates.

PNG forecasts the revenue it will receive from customers based on an annual forecast of gas deliveries to customers. As it is not possible to forecast deliveries to customers with complete accuracy for a variety of reasons, including the effect of weather on gas consumption, PNG is allowed by the BCUC to record the difference between forecast and actual use per account realized from residential and small commercial customers in a rate stabilization adjustment mechanism deferral account. If actual use per account exceeds forecast use per account, the resulting difference will be recorded in the rate stabilization adjustment mechanism deferral account and refunded to customers in future rates. If actual use per account is less than forecast use per account, the resulting revenue difference will be recorded in the rate stabilization adjustment mechanism deferral account and recovered from customers in future rates.

Alberta

AUI commenced operations as an Alberta, provincially regulated, natural gas distribution utility in 1954. Its head office is located in Leduc, Alberta. AUI delivers natural gas to residential, farm, and C&I consumers in more than 90 communities throughout Alberta. At the end of 2018, AUI served approximately 80,400 customers. AUI also owns transmission facilities, including, without limitation, high-pressure pipelines that deliver natural gas from gas sources to the distribution systems.

AUI operates in a mature market and has achieved nearly 100 percent saturation within its franchise areas, with the exception of a few consumers choosing alternate fuel sources or living in remote areas where natural gas service is cost-prohibitive. The Alberta natural gas distribution market is dominated by a major distributor that serves approximately 85 percent of natural gas consumers. AUI serves approximately 6 percent of Alberta customers, with the remaining market served by member-owned natural gas cooperatives and municipally owned systems. AUI expands its customer base through economic expansion and growth in its franchise areas and also pursues opportunities to develop service areas not currently served with natural gas. AUI pursues the acquisition of municipal and co-op systems as they become available.

Operations

AUI's distribution system consists of 21,016 km of pipeline. There are 691 small and mid-sized metering and pressure regulating stations throughout AUI's distribution network. AUI operates its gas distribution systems through a network of 14 district offices. AUI's market consists primarily of residential and small commercial consumers located in smaller population centres or rural areas of Alberta. The following table sets out, by customer category, AUI's gas deliveries:

The following table sets out, by customer category, AUI's gas deliveries:

	2018	2017
Deliveries: (PJ)		
Residential	**7.1**	6.7
Rural	**2.9**	2.7
Commercial	**5.4**	5.2
Small industrial (Rate 2 - Large General Services)	**1.4**	1.3
Large industrial (Rate 3 - Demand)	**2.6**	2.8
Producers	**1.0**	1.7
Total deliveries	**20.4**	20.4

The following table sets out, by customer category, AUI's customers:

	2018	2017
Customers at Year End:		
Residential	**58,779**	58,036
Rural	**13,945**	13,884
Commercial	**7,418**	7,383
Small industrial (Rate 2 - Large General Services)	**148**	153
Large industrial (Rate 3 - Demand)	**60**	60
Producers	**2**	2
Total customers	**80,352**	79,518

Under the *Municipal Government Act* (Alberta), municipal councils have the authority to grant a right, exclusive or otherwise, to a person to provide utility service in all or part of the municipality, for not more than 20 years. Under the *Municipal Government Act* (Alberta), AUI negotiates an initial franchise agreement with municipalities based on a standard template approved by the AUC. Each initial franchise agreement sets a negotiated initial term and also defines the rights and obligations of both the municipality and AUI.

The distribution franchise agreements granted to AUI under the *Municipal Government Act* (Alberta) are exclusive to AUI, granted under initial terms for a minimum of 10 years, and up to 20 years, and are typically renewed for periods of 10 years. If any franchise agreement is not renewed, it remains in effect until such time as either party, with the approval of the AUC, terminates it. Upon termination of a municipal franchise agreement, the municipality may purchase AUI's distribution facilities system within the municipality at a price to be agreed upon or, failing agreement, on a price to be fixed by the AUC. A prior Supreme Court of Canada decision supports a purchase price calculated at the full replacement cost, less loss in value of the system due to wear and tear and obsolescence.

As at December 31, 2018, AUI currently has 44 municipal distribution franchises granted pursuant to the *Municipal Government Act* (Alberta); nine permits granted by Indigenous and Northern Affairs Canada under the authority of the *Indian Act* (Canada); and 21 rural franchise approvals issued under the authority of the *Gas Distribution Act* (Alberta), with average remaining terms that vary from 3.3 years to perpetual and are renewed from time to time in the ordinary course of AUI's business. The top three municipalities contributing to AUI's total revenue in 2018 were the City of Leduc, City of Beaumont and Town of Drumheller, which collectively accounted for approximately 24 percent of AUI's total revenue and 21 percent of energy delivered in 2018

AltaGas has managed AUI's natural gas supply arrangements since November 1, 1999. AltaGas is under contract and receives a monthly fee that is escalated annually at the consumer price index for providing gas management services to AUI. AltaGas arranges for the purchase and transportation of the gas supply required to meet AUI's daily load requirements. AltaGas also provides support for third party retail gas suppliers that operate inside AUI's service area, tracking and balancing the gas flows and nominations to ensure that AUI's customers are not impacted.

AUI currently buys the majority of its natural gas under monthly and daily arrangements from a number of producers. The price paid for the natural gas on a monthly basis is based on market value provided in the Canadian Gas Price Reporter. AUI receives the majority of its natural gas from ATCO Gas and Pipelines Ltd.'s and NOVA Gas Transmission Ltd.'s Alberta gas transportation systems. Deliveries are made at various Alberta delivery points into the AUI system for delivery to its customers. AUI's natural gas supply and transportation arrangements are such that most of the third party transportation charges are paid by the natural gas customers. The cost of gas purchased is flowed through to the distribution customers and does not impact net income.

British Columbia

PNG's head office is located in Vancouver, British Columbia and its principal operating office is located in Terrace, British Columbia. PNG's wholly owned subsidiary, PNG(N.E.) has its main operating offices in Fort St. John, British Columbia and Dawson Creek, British Columbia.

PNG owns and operates the Western System, a regulated natural gas transmission and distribution utility within the west central portion of northern British Columbia. PNG(N.E.) owns and operates the Northeast System, a distribution utility in northeast British Columbia.

Substantially all of PNG's and PNG(N.E.)'s pipeline facilities are located across Crown land or privately-owned property under rights-of-way granted by the Crown or the owners in perpetuity or for so long as they are used for pipeline purposes. Approximately three kilometers of main pipelines and approximately nine kilometers of lateral transmission pipelines cross reserves established under the *Indian Act* (Canada), for which PNG has appropriate land rights. Compressor and metering stations are principally located on land owned by PNG. PNG owns its local offices in Terrace, Prince Rupert, Kitimat, Burns Lake, Smithers, Summit Lake, Dawson Creek, Tumbler Ridge and Fort St. John, British Columbia and leases office space in Vanderhoof and Vancouver, British Columbia.

All of the property and assets of PNG and PNG(N.E.) are subject to the lien of a deed of trust and mortgage dated as of April 15, 1982 between PNG and Computershare Trust Company of Canada, as trustee, as amended and supplemented from time to time, under which PNG's secured debentures have been issued.

All of PNG's and PNG(N.E.)'s residential customers, most of their commercial customers and a number of their smaller industrial customers continue to rely on PNG and PNG(N.E.) for arrangement of their gas supply, and such customers pay tariffs which include PNG's and PNG(N.E.)'s gas supply commodity and delivery costs. The large industrial customers, the majority of small industrial customers and a number of commercial customers purchase their own gas supply requirements from third party gas suppliers and contract for gas transportation service on the PNG and PNG(N.E.) pipeline systems. In addition, some of the smaller commercial customers purchase their gas supply requirements directly from gas marketers. Since PNG's income is earned from the distribution of natural gas and not from the sale of the commodity, distribution margin is not adversely affected by this practice as the gas commodity costs are passed through to customers without a mark-up.

In the Western System service area, PNG has a very high penetration of available energy customers. However, the joint venture partners of LNG Canada's export project at Kitimat, British Columbia announced a final investment decision with respect to the development of the project in October 2018. Although the project will have its own dedicated pipeline through Coastal GasLink Pipeline if it proceeds, the Company expects that economic spin-offs will be realized in the associated communities, including additional residential housing and business requirements in PNG's franchise areas, which could provide a basis for additional growth for the Company's business.

In the Northeast System service area, PNG(N.E.) continues to build out its distribution system to new communities and to capture new housing and commercial developments in its existing serviced communities.

Operations

PNG's transmission pipeline system in the Western System service area connects with the British Columbia pipeline system operated by Enbridge Westcoast Energy Inc. (formerly Spectra Energy) near Summit Lake, British Columbia, and extends 587 km to the west coast of British Columbia at Prince Rupert, British Columbia. The pipeline between Summit Lake, British Columbia and Terrace, British Columbia has been partially paralleled, or looped, with a second line to increase throughput capacity. PNG also owns and operates over 300 km of lateral transmission pipelines extending into the various communities served by PNG, the most significant being dual lines extending approximately 57 km into Kitimat, British Columbia. The Western System distribution system is comprised of approximately 960 km of distribution pipelines. Five compressor units maintain pressure on PNG's Western System transmission pipeline system (four of which are presently deactivated).

The Northeast System serves the Fort St. John and Dawson Creek areas of British Columbia through connections with the Enbridge Westcoast Energy Inc. pipeline system at several locations. The Northeast System also connects with pipelines owned by Canadian Natural Resources Limited to obtain supply for the Fort St. John area, a producer's pipeline to serve the Dawson Creek area, and a Canadian Natural Resources Limited gas supply pipeline to serve the Tumbler Ridge area of British Columbia. The entire Northeast System consists of approximately 243 km of transmission lines, 2,202 km of distribution lines and a gas processing plant near Tumbler Ridge with a capacity of 120,000 cubic meter of natural gas per day.

The following table sets out, by customer category, PNG's gas deliveries:

	2018	2017
Deliveries: (PJ)		
Residential	**3.1**	3.1
Commercial	**3.0**	3.0
Small industrial	**1.9**	2.4
Large industrial	**1.9**	1.5
Total deliveries	**9.9**	10.0

The following table sets out, by customer category, PNG's customers:

	2018	2017
Customers at Year End:		
Residential	**36,371**	36,218
Commercial	**5,437**	5,414
Small industrial	**47**	51
Large industrial	**2**	2
Total customers	**41,857**	41,685

Under the *Utilities Commission Act* (British Columbia), municipal councils and utilities negotiate franchise agreements, which are then subject to approval by the BCUC through a certificate of public convenience and necessity.

Under the *Community Charter* (British Columbia), a council of a municipality may enter into an agreement to grant an exclusive or limited franchise for the provision of gas, electrical or other energy supply system for terms of not more than 21 years. If any franchise agreement is not renewed, it remains in effect and the utility may not discontinue operations except on the approval of the BCUC. Furthermore, any disposition of a utility's property, franchises, licences, permits, concessions, privileges or rights also requires the approval of the BCUC.

PNG currently has exclusive franchise agreements with the municipalities of Prince Rupert, Port Edward, Kitimat, Terrace, Smithers, Burns Lake, Houston, Fort St. James, Fraser Lake and Vanderhoof, entitling it to supply and distribute natural gas within those municipalities. Each of the franchise agreements have a term of 21 years, expiring in 2032 (except in the cases of Port Edward, where the agreement expires on October 5, 2031, Prince Rupert and Fraser Lake, where both agreements expire in 2036, and Fort St. James, where the agreement expires June 30, 2038).

PNG also has an operating agreement with the municipality of Telkwa, British Columbia that entitles PNG to install and operate gas distribution facilities in the municipality. The initial term of this operating agreement has expired, and PNG is operating within ten year renewal terms which will expire in 2021. The operating agreement provides for an unlimited number of ten year renewal terms, which take effect automatically on the expiry of the preceding renewal term. If the parties cannot agree on alterations to an operating agreement for a renewal term, the BCUC may determine such alterations.

PNG(N.E.) has exclusive franchise agreements with the city of Fort St. John, the District of Taylor, the City of Dawson Creek, and the Village of Pouce Coupe for 21-year terms, expiring in 2018, 2033, 2036, and 2037, respectively. PNG(N.E.) currently has an interim operating agreement with the city of Fort St. John and is working on the renewal of the franchise agreement. PNG(N.E.) operates its gas distribution facilities in the Tumbler Ridge area pursuant to a certificate of public convenience and necessity issued by the BCUC. The franchise agreements with the District of Taylor and City of Fort St. John give the municipalities the right to purchase the distribution system within the municipality on expiry of the franchise agreement, at the fair market value of the assets as a going concern.

Tenaska Marketing Canada has managed most of PNG's natural gas supply arrangements since March 2013. Tenaska Marketing Canada's gas management services include gas supply planning and resource selection analysis, gas supply contract negotiation and administration, daily energy management services, and the monitoring and reporting of credit, hedging positions and gas prices. The contract expires on March 31, 2021. The cost of gas purchased is flowed through to the distribution customers and does not impact net income.

PNG meets its gas demand requirements using a balanced approach and contracts for supply from different counterparties for both daily and monthly priced supply. Most of the gas purchased by PNG is taken from the pooled gas stream available from the Enbridge Inc. pipeline system. This includes all of the supply to PNG's transmission line serving its Western System service area and most of the supply for the Fort St. John and Dawson Creek, British Columbia service areas. In addition, the Fort St. John system incorporates two interconnections with Canadian Natural Resources Limited's West Stoddart Pipeline and the Dawson Creek area connects to a producer's pipeline. In Tumbler Ridge, British Columbia, all of the gas supply is obtained in the form of raw gas production from Canadian Natural Resources Limited and PNG operates its own gas processing facilities.

PNG also includes natural gas storage in its gas supply portfolio and has a storage agreement with Tenaska Marketing Canada for storage at the Aitken Creek Gas Storage Facility of up to 1,000,000 GJs until March 31, 2019 to assist in managing gas supply during peak demand.

Nova Scotia

HGL is a greenfield natural gas distribution utility in Nova Scotia with a head office located in Dartmouth, Nova Scotia. HGL's franchise was granted in 2003 and gives it the exclusive right to distribute natural gas through its distribution system to all or part of seven counties in Nova Scotia, including the Halifax Regional Municipality until December 31, 2028.

For its regulated operations, HGL has approval from the NSUARB to use an RDA until it is fully recovered, subject to a cap of $50 million, 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 HGL's customer development stage, it is expected that the actual revenue billed will be less than the revenue required to earn the approved rates of return and, therefore, an 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 will be drawn down.

Natural gas currently provides less than 10 percent of total energy used in Nova Scotia, with electricity and fuel oil being the dominant energy sources. In 2018, HGL's customer base grew by 6 percent and ended the year at approximately 7,300 customers. HGL currently has approximately 4,100 residential and approximately 3,200 commercial customers representing approximately 29 percent of all homes and 43 percent of all commercial buildings that currently have access to natural gas. HGL is focused on increasing penetration levels within the area currently served by its existing network.

The following table sets out, by customer category, HGL's gas deliveries:

	2018	2017
Deliveries: (PJ)		
Residential	**0.3**	0.3
Small commercial	**2.3**	2.1
Large commercial	**2.5**	2.3
Industrial	**3.4**	3.3
Non-regulated compressed natural gas distribution	**1.1**	1.0
Total deliveries	**9.6**	9.0

The following table sets out, by customer category, HGL's customers:

	2018	2017
Customers at Year End:		
Residential	**4,100**	3,803
Small commercial	**2,938**	2,844
Large commercial	**241**	234
Industrial	**16**	15
Non-regulated compressed natural gas distribution	**3**	3
Total customers	**7,298**	6,899

Natural gas prices are very competitive with other energy sources in Nova Scotia for large commercial and industrial customers. HGL currently has a Customer Retention Program in place which was approved by the NSUARB in 2016 for commercial customers with consumption between 500 and 4,999 GJ per year (see *General Development of the Business – 2016 – Material Regulatory Developments and Applications – Nova Scotia*). In the fall of 2017, HGL implemented an increase to the distribution rates that were previously reduced as provided under the Customer Retention Program decision. An additional increase was made to distribution rates in the spring of 2018 and again in the fall of 2018 to partially restore the rates to previously approved cost of service levels. To date the program has been successful in curtailing the migration of customers to propane. Since the implementation of the Customer Retention Program HGL has continued to add residential and commercial customers, although at a slower pace than prior years. HGL estimates that the Customer Retention Program will be in place through to the end of 2020. The program has enabled HGL to remain competitive for this customer class during a period of low propane prices.

Operations

Under the *Gas Distribution Act* (Nova Scotia), a utility must apply for a franchise before the NSUARB, subject to approval by the Governor in Council. Franchises granted by the NSUARB provide the franchise holder the exclusive right to construct and operate a gas delivery system within the geographical area of the franchise (subject to limited exceptions) for a term of 25 years. Franchises are renewable by application to the NSUARB. In the event that a franchise is not renewed, the NSUARB may require the franchise holder to continue to provide service for such time as will allow users to convert to another energy source.

The franchise currently held by HGL is for a 25-year term, issued on February 7, 2003 for Cumberland, Colchester, Pictou, and Halifax Counties (now Halifax Regional Municipality), the Municipality of the District of East Hants, and the Goldboro area of Guysborough County. In addition, in 2014, HGL was granted the franchise rights for Antigonish County.

HGL's distribution system consists of approximately 460 km of pipeline mains infrastructure of which approximately 345 km is located in the Halifax Regional Municipality, approximately 60 km is located in Amherst, Nova Scotia 45 km in New Glasgow/Pictou area and approximately 10 km is located in Oxford, Nova Scotia.

Historically HGL has received much of its natural gas supply from the Sable Offshore Energy project and Encana's Deep Panuke project off the coast of Nova Scotia. In 2018 the natural gas supply from both of these projects ended with Deep Panuke ceasing operation in May 2018 and Sable Offshore Energy ceasing operation in December 2018. In anticipation of these declines, HGL entered into gas supply and transportation contracts to secure supply from other supply basins in North America and to provide relative price stability.

HGL has a 22-year contract with Portland Natural Gas Transmission System for natural gas transportation capacity from the Dawn Hub in Ontario to Nova Scotia on a pipeline path that consists of Union Gas Limited Pipeline, TransCanada pipeline, Portland Natural Gas Transmission System and the Maritimes and Northeast Pipeline system. This agreement enhances security of supply and reduces gas price volatility. The agreement provides for 3,915 GJ per day beginning November 1, 2018; 9,350 GJ per day beginning November 1, 2019; and 10,550 GJ per day beginning November 1, 2020 for the duration of the contract.

HGL purchases gas under negotiated contracts with wholesale gas marketers. During 2018, Emera Energy Inc. managed HGL's natural gas supply, and is contracted to continue to provide the service until October 2019. In 2018, HGL's supply was delivered via the TransCanada pipeline, the Portland Natural Gas Transmission system and the Maritimes & Northeast U.S. and Canadian pipeline systems from supply basins offshore Nova Scotia, central and western Canada and the United States. The cost of gas purchased is passed through to the distribution customers and does not impact net income.

In 2014, HGL executed a 20-year gas storage agreement with Alton Natural Gas Storage L.P., a wholly-owned subsidiary of AltaGas, for storage capacity at the Alton Natural Gas Storage Project in Nova Scotia. Construction for this facility is underway and HGL currently expects the first phase of storage service to commence in 2022.

Also in 2014, HGL signed an agreement with Enbridge Inc. for the Atlantic Bridge Expansion Project, on the Algonquin Gas Transmission pipeline system. The contract is a 15-year commitment for 10,000 GJ per day of transportation that provides HGL an opportunity to diversify suppliers and provide access to other supply basins until the end of its term. The Atlantic Bridge Expansion Project is expected to be in-service in 2020.

INUVIK GAS AND IKHIL JOINT VENTURE

AUGI has an approximate one-third interest in Inuvik Gas and the Ikhil Joint Venture natural gas reserves, which have historically supplied Inuvik Gas with natural gas for the Town of Inuvik. With the Ikhil Joint Venture 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 the Ikhil Joint Venture serving as a back-up.

Under the *Public Utilities Act* (Northwest Territories) and the *Cities Towns and Villages Act* (Northwest Territories), municipal councils have the authority to grant a utility the right to operate within a municipality. Where a utility plans to operate outside of a municipality, this authority rests with the Minister responsible for the *Public Utilities Act* (Northwest Territories). Under the *Cities Towns and Villages Act* (Northwest Territories), franchise agreements may not have initial terms greater than 20 years, and may be renewed for terms not to exceed 10 years. Upon expiry of a franchise, with the approval of the Minister under the *Cities Towns and Villages Act* (Northwest Territories), the municipality may purchase the property used in connection with a franchise on terms to be agreed to by the parties, or by arbitration under the *Arbitration Act* (Northwest Territories).

In December 2016, Inuvik Gas notified the Town of Inuvik of its intention to terminate the gas distribution franchise agreement effective December 2018. The franchise agreement was terminated on December 8, 2018. Through an in-person meeting in December 2018, Inuvik Gas agreed to continue to provide service to its customers in accordance with the previous franchise agreement and the NWTPUB approved terms and conditions of service as Inuvik Gas and the Town of Inuvik continue negotiations to transition ownership of Inuvik Gas to the Town of Inuvik. The Company and its joint venture partners will continue to own and operate the Ikhil Joint Venture.

RENEWABLE ENERGY BUSINESS

ACI's Renewable Energy business contributed revenue of $15.2 million for the year ended December 31, 2018 (2017 - $17.4 million), representing approximately 5 percent (2017 – 6 percent) of ACI's total revenue before Corporate segment and intersegment eliminations.

At December 31, 2018, ACI has installed power capacity from a combination of hydro and wind generation, as more particularly set forth in the below table.

Facility	Interest (%)	Nameplate Capacity	Installed Capacity	Type	Geographic Region	Contracted Expiry Date
Bear Mountain Wind Park	100	102	102	Wind	British Columbia, Canada	2034
Forrest Kerr(1)	10	195	214	Hydro	British Columbia, Canada	2074
McLymont Creek(1)	10	66	72	Hydro	British Columbia, Canada	2075
Volcano Creek(1)	10	16	17	Hydro	British Columbia, Canada	2074

(1) ACI owns a 10 percent indirect interest in the Northwest Hydro Facilities, which are comprised of Forrest Kerr, McLymont Creek and Volcano Creek.

The following chart provides a summary of the volumes sold for the last two years:

	2018	2017
Bear Mountain Wind Park power sold (GWh)	**143.7**	169.3
Northwest Hydro Facilities power sold (GWh) (1)	**101.4**	115.1

(1) Representing 10 percent of the total power sold by the Northwest Hydro Facilities.

Bear Mountain Wind Park

The Bear Mountain Wind Park, owned by the Company through BMWLP and BMWPC, is a 102 MW generating wind facility consisting of 34 turbines, a substation and transmission and collector lines, which are connected to the BC Hydro transmission grid. The Bear Mountain Wind Park is British Columbia's first fully-operational wind park, delivering enough electricity to power most of British Columbia's South Peace region.

The turbine manufacturer, Enercon GmbH of Germany, provides operating and maintenance services to BMWLP under a service agreement that expires in December 2021 on a fixed fee basis, escalating with reference to specified pricing indices. Enercon GmbH provides various warranties in respect of the turbines, including with respect to minimum levels of availability. Each of the 3 MW Enercon E-82 wind turbine generators supplied to the Bear Mountain Wind Park is 78 metres tall to the hub.

The Bear Mountain Wind Park was commissioned and fully connected to the British Columbia power grid in 2009. All of the power from the Bear Mountain Wind Park is sold to BC Hydro under a 25-year PPA expiring in 2034 with an escalation factor of 50 percent of CPI calculated at the beginning of each year. The facility is an EcoLogo certified facility and generates RECs. BMWLP has retained the green attributes and RECs and sells them, and intends to continue to sell them, to provide an additional revenue stream.

The Bear Mountain Wind Park covers approximately 25 hectares and, as the turbines require limited surface land space, the facility continues to be used for cattle grazing and by the public for hiking, snowmobiling, cross-country skiing and other recreational activities.

There are royalty agreements in place with Peace Energy Cooperative (a community-based group) and Aeolis Wind Renewable Energy Company for a total of 0.912 percent of the project revenues and for 28.5 percent of any revenues from the sale of RECs above a cumulative threshold amount.

Northwest Hydro Facilities

The Northwest Hydro Facilities, located in Tahltan First Nation territory approximately 1,000 kilometres northwest of Vancouver, British Columbia, are comprised of Forrest Kerr, McLymont Creek, Volcano Creek and all associated transmission and related facilities. Forrest Kerr is an approximately 214 MW run-of-river hydroelectric generating facility located on the Iskut River near its confluence with Forrest Kerr Creek that redirects a portion of the flow of the Iskut River through a tunnel to an underground powerhouse that houses nine Francis turbines to generate electricity. It achieved COD in October 2014. McLymont Creek is an approximately 72 MW run-of-river hydroelectric generating facility located on McLymont Creek near its confluence with the Iskut River the intake of which directs the water into a power tunnel where three Francis turbines generate electricity. It achieved COD in October 2015. Volcano Creek is an approximately

17 MW run-of-river hydroelectric generating facility that diverts a portion of the flow from Volcano Creek through a penstock (water pipeline) to move the water to a surface powerhouse where two Pelton turbines generate electricity. It achieved COD in December 2014.

The Northwest Hydro Facilities, with a combined installed capacity of approximately 303 MW, are contracted under three separate 60-year PPAs with BC Hydro that are fully indexed to BC CPI, meaning there is no direct commodity risk on contracted power. Each PPA expires 60 years from the facility's respective date of COD.

The cost of operating the Northwest Hydro Facilities is not material to the operation of the facilities, with minimal maintenance capital required.

The CMH Group is owned by Coast LP, its general partner Coast GP and the Tahltan First Nation. The Company's indirect ownership is through limited partnership units of Coast LP and common shares of Coast GP. Impact benefit agreements are in place for all three Northwest Hydro Facilities, supporting a cooperative and mutually beneficial relationship between the Tahltan First Nation and the CMH Group. In addition, CMHLP entered into an agreement with BC Hydro to contribute to the development of the Northwest Transmission Line. The Northwest Hydro Facilities are the anchor tenant for the Northwest Transmission Line.

The Company has agreed with AltaGas that it will not directly or indirectly dispose of any of its interest in Coast LP or Coast GP prior to November 1, 2028 without the prior consent of AltaGas.

Competition

Wind power generated from the Bear Mountain Wind Park is not currently exposed to power price volatility as the power generated is sold at a fixed price for 25 years, with an escalation factor of 50 percent of CPI calculated at the beginning of each year. Renewable energy sold from Forrest Kerr, McLymont Creek and Volcano Creek are sold at a predetermined price as contracted under the 60-year PPAs with BC Hydro. The PPAs for Forrest Kerr, McLymont Creek, and Volcano Creek are fully indexed to BC CPI.

Seasonality

The renewable energy business of ACI is cyclical due to the nature of wind and run-of-river hydroelectric resources, which fluctuate based on both seasonal patterns and annual weather variation. Typically, run-of-river hydroelectric facilities generate most of their electricity and revenues during May to October when increases in precipitation and snowpack melt starts feeding the watersheds and the rivers. Inversely, wind speeds are historically greater during the cold winter months when air density is at its peak. Accordingly, annualized individual quarterly revenues and earnings are not indicative of annual results.

CAPITAL STRUCTURE

DESCRIPTION OF CAPITAL STRUCTURE

The Company's authorized share capital consists of an unlimited number of Common Shares and such number of Preferred Shares issuable in series at any time as have aggregate voting rights either directly or on conversion or exchange that in the aggregate represent less than 50 percent of the voting rights attaching to the then issued and outstanding Common Shares. As at December 31, 2018, ACI had 30,000,000 Common Shares issued and outstanding and no Preferred Shares issued and outstanding.

The summary below of the rights, privileges, restrictions and conditions attaching to the Common Shares and the Preferred Shares is subject to, and qualified by reference to, ACI's articles and by-laws.

Common Shares

Holders of Common Shares are entitled to notice of, to attend and to one vote per share held at any meeting of the Shareholders (other than meetings of a class or series of shares of the Company other than the Common Shares as such). Subject to prior satisfaction of all preferential rights to dividends attached to shares of other classes of shares of the Company ranking in priority to the Common Shares in respect of dividends, the holders of Common Shares are entitled to receive dividends as and when declared by the Board of Directors on the Common Shares as a class. In the event of any liquidation, dissolution or winding-up of the Company, whether voluntary or involuntary, or any other distribution of the assets of the Company among the Shareholders for the purpose of winding-up its affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of shares of the Company ranking in priority to the Common Shares in respect of return of capital on dissolution, the holders of Common Shares are entitled to share rateably, together with the holders of shares of any other class of shares of the Company ranking equally with the Common Shares in respect of return of capital on dissolution, in such assets of the Company as are available for distribution. The Common Shares are not convertible into any other class of shares.

Preferred Shares

The Preferred Shares may at any time or from time to time be issued in one or more series. Before any shares of a particular series are issued, the Board of Directors shall, by resolution, fix the maximum number of shares that will form such series and shall, subject to the limitations set out herein, by resolution fix the designation, rights, privileges, restrictions and conditions to be attached to the Preferred Shares of such series. The Preferred Shares of each series will rank on parity with Preferred Shares of every other series with respect to accumulated dividends and return of capital and the holders of Preferred Shares will rank prior to the holders of Common Shares and any other shares of ACI ranking junior to the Preferred Shares with respect to the payment of dividends and the distribution of assets in the event of liquidation, dissolution or winding-up of ACI, whether voluntary or involuntary or any other distribution of the assets of ACI among its shareholders for the purpose of winding-up its affairs.

The rights, privileges, restrictions and conditions attaching to the Preferred Shares as a class may be repealed, altered, modified, amended or amplified or otherwise varied only with the sanction of the holders of the Preferred Shares given in such manner as may then be required by law, subject to a minimum requirement that such approval be given by resolution in writing executed by all holders of Preferred Shares entitled to vote on that resolution or passed by the affirmative vote of at least 66⅔ percent of the votes cast at a meeting of holders of Preferred Shares duly called for such purpose.

Medium Term Notes

ACI has issued senior unsecured notes in the form of MTNs. On December 5, 2018, ACI issued $300 million of MTNs with a coupon rate of 4.26 percent (4.269 yield to maturity) and maturity date of December 5, 2028. Details with respect to the issued and outstanding MTNs can be found in Note 11 to ACI's consolidated financial statements as at and for the year ended December 31, 2018 filed on SEDAR at www.sedar.com. The MTNs are not listed or quoted on any exchange.

GENERAL

EMPLOYEES

At December 31, 2018 there were 431 individuals employed by ACI.

Pursuant to the Transition Services Agreement AltaGas provides certain administrative services required by the Company, including: (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 provides such 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.

DIRECTORS AND EXECUTIVE OFFICERS

As at March 6, 2019: (a) the directors and executive officers of ACI, as a group, owned beneficially, directly or indirectly, or exercised control or direction over 214,807 of the outstanding Common Shares, or approximately 0.72 percent of the outstanding Common Shares; and (b) 30,000,000 Common Shares were issued and outstanding.

Directors

The number of directors of ACI is to be determined from time to time by resolution of the Board of Directors. The number of directors is currently seven, of which four are independent directors as defined under Canadian securities laws.

Pursuant to the Governance Agreement, AltaGas is currently entitled to nominate three individuals to serve on the Board of Directors based on its current ownership of Common Shares.

The term of office of any director continues until the annual meeting of Shareholders of ACI following the director's election or appointment or (if an election or appointment of a director is not held at such meeting or if such meeting does not occur) until the date on which the director's successor is elected or appointed, or earlier if the director dies or resigns or is removed or disqualified, or until the director's term of office is terminated for any other reason in accordance with the constating documents of ACI. The Shareholders are annually entitled to elect the Board of Directors.

The following table sets forth the names of the Directors of ACI on March 6, 2019, their municipalities of residence and their principal occupations within the last five years.

Name and Residence of Directors	**Principal Occupation During the Past Five Years**	**Director Since**
David W. Cornhill Calgary, Alberta, Canada Chair of the Board of Directors	Mr. Cornhill is Chair of the Board of Directors of ACI. Mr. Cornhill is also the Chairman of the board of directors of AltaGas and a founding shareholder of AltaGas (and its predecessors). He was Chief Executive Officer of AltaGas from 1994 until 2016 and served as interim co-chief executive officer from July to December 2018. Prior to forming AltaGas, Mr. Cornhill served in various capacities with Alberta and Southern Gas Co. Ltd, including Vice President, Finance and Administration, Treasurer and President and Chief Executive Officer.	September 5, 2018
Gregory A. Aarssen (1)(2) Chatham, Ontario, Canada	Mr. Aarssen is an entrepreneur and independent businessman and has been President of Aarssen Management Service Inc., since 1997. Mr. Aarssen was Co-President Gas of AltaGas from 2010 until his retirement in 2012, and prior thereto held senior roles with AltaGas and PremStar Energy Canada Inc.	September 5, 2018
Judith J. Athaide (1) Calgary, Alberta, Canada	Ms. Athaide is a Professional Engineer. She has been the President of The Cogent Group Inc., since 1999. Prior to co-founding The Cogent Group, Ms. Athaide held a variety of senior commercial and technical roles in the energy industry, including Vice-President, Bow Engineering and Project Execution of EnCana Leasehold Limited Partnership.	September 5, 2018
Amit Chakma (1) Calgary, Alberta, Canada	Mr. Chakma is a Professional Engineer. He is a Professor of Chemical Engineering and has served as the President of the Western University since 2009. Prior thereto, Mr. Chakma was Vice-President (Academic) and Provost, and a Professor of Chemical Engineering at the University of Waterloo.	September 5, 2018
William J. Demcoe (1) Calgary, Alberta, Canada	Mr. Demcoe is a Chartered Accountant and independent businessman. He has been President of Willbren & Company Ltd., since 1993. Prior thereto he held senior roles with various entities including Alberta Natural Gas Ltd., Alberta and Southern Gas Co. Ltd. and Consolidated Pipelines Ltd.	September 5, 2018
Corine R. K. Bushfield Calgary, Alberta, Canada	Ms. Bushfield is the Executive Vice President, Chief Administrative Officer of AltaGas, a position she has held since December 2016. Prior to joining AltaGas, Ms. Bushfield was the Senior Vice President and Chief Financial Officer of Long Run Exploration Ltd. from 2013 to 2016. She held various leadership positions at Encana Corporation from 2000 to 2013, including Vice President and Assistant Controller. Ms. Bushfield is a member of the Institute of Chartered Professional Accountants of Alberta.	September 5, 2018
Jared Green Calgary, Alberta, Canada	Mr. Green is the President and Chief Executive Officer of ACI. See *"Executive Officers"* below for Mr. Green's biography.	October 2017

Notes:
(1) Independent director
(2) Lead director

ACI has three standing committees of the Board of Directors: (1) Audit, (2) Compensation and Governance, (3) Environmental, Health & Safety ("EH&S"). The members of each of these committees, as of December 31, 2018, are identified below:

Director	Audit Committee (1)	Compensation and Governance Committee (2)	EH&S Committee
David Cornhill			
Gregory A. Aarssen			Member
Judith J. Athaide	Member	Member	Chair
Amit Chakma	Member	Chair	
William J. Demcoe	Chair	Member	
Corine R. K. Bushfield			Member
Jared Green			Member

Notes:

(1) All members of the Audit Committee are independent and financially literate.

(2) All members of the Compensation and Governance Committee are independent.

Executive Officers

The names, residence and position of each of the current executive officers of ACI, and the presidents of the utilities are as follows:

Name of Officer, Residence and Position	Principal Occupation During the Past Five Years
Jared Green Calgary, Alberta, Canada President and Chief Executive Officer	Prior to his current role as President and Chief Executive Officer, Mr. Green served as AltaGas' President, Canadian Utilities, with responsibility for PNG, AUI and HGL, plus its interest in Inuvik Gas. From 2014 to 2017, Mr. Green was President of ENSTAR Natural Gas Company and President of Cook Inlet Natural Gas Storage, AltaGas' Alaska utility and natural gas storage businesses. Mr. Green originally joined AltaGas in 2004 serving in progressively more senior roles through the organization, including Director of Business Development, Controller and Vice President Controller and Corporate Secretary of AUGI, which was a public company on the TSX, and as Vice President Controller, Utilities Division and Vice President Controller of AltaGas. Mr. Green is a Chartered Professional Accountant.
Shaun Toivanen Calgary, Alberta, Canada Executive Vice President, Chief Financial Officer and Corporate Secretary	Prior to his current role as Executive Vice President and Chief Financial Officer, Mr. Toivanen served as AltaGas' Vice President and Controller, from 2017 to 2018. Prior thereto, Mr. Toivanen served as the Vice President and Treasurer of AltaGas from 2011 to 2017. Mr. Toivanen served in various positions of increasing responsibility within the financial field, including Corporate Development, since joining AltaGas Ltd. in 2006. He is a Chartered Financial Analyst and a Chartered Professional Accountant.
Leigh Ann Shoji-Lee Vancouver, British Colombia, Canada Executive Vice President Utility Operations and President of PNG	Ms. Shoji-Lee is the Executive Vice President Utility Operations of ACI and the President of PNG. Ms. Shoji-Lee has been the President of PNG since 2016. From 2014 to 2016, she was Vice-President, Manufacturing and Shares Services for Britco LP. Prior thereto, Ms. Shoji-Lee was President and Chief Executive Officer of Canadian Utility Construction Corporation. She also held senior roles with BC Hydro and Union Gas Limited.
John Hawkins *Fall River, Nova Scotia, Canada* *President of HGL*	Mr. Hawkins is the President of HGL, a position he has held since June 2017. He was Vice President Engineering, Construction and Operations at HGL from 2014 to 2017. From 2000 to 2014, Mr. Hawkins held a variety of positions at Nova Scotia Power Inc. He is a Professional Engineer and currently serves on the board of directors of the Canadian Gas Association.
Mark Lowther *Leduc, Alberta, Canada* *President of AUI*	Mr. Lowther is the President of AUI, a position he has held since January 2019. Mr. Lowther joined AUI in 2008 and has held various positions, including Vice President Operations & Engineering, Vice President Corporate Services, and Director Distribution Operations. Mr. Lowther is a Professional Engineer and currently serves on the board of directors of the Canadian Gas Association.

CEASE TRADE ORDERS, BANKRUPTCIES, PENALTIES AND SANCTIONS

Cease trade orders

To the knowledge of ACI, no director or executive officer of ACI, nor any promoter of ACI is, as of March 6, 2019, or was within ten years before March 6, 2019, a director, chief executive officer or chief financial officer of any company (including ACI), that: (a) was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an ‘‘Order’’), and that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (b) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Bankruptcies

Other than as set out below, to the knowledge of ACI, no director or executive officer of ACI, nor any promoter of ACI or a Shareholder holding a sufficient number of securities of ACI to affect materially the control of ACI (nor any personal holding company of any of such Persons): (a) is, as of March 6, 2019, or has been within the ten years before March 6, 2019, a director or executive officer of any company (including ACI) that, while that Person was acting in that capacity, or within a year of that Person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (b) has, within the ten years before March 6, 2019, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or Shareholder.

John Hawkins, President of HGL, was a director of a private family business corporation from November 2005 until August 2010. An interim receiver in bankruptcy was appointed over such corporation's assets in September 2010 pursuant to the *Bankruptcy and Insolvency Act* (Canada). The Supreme Court of Nova Scotia issued a discharge order in respect of these matters on September 9, 2011 under the *Bankruptcy and Insolvency Act* (Canada) procedures.

Penalties or sanctions

To the knowledge of ACI, no director or executive officer of ACI, nor any promoter of ACI or a Shareholder holding a sufficient number of securities of ACI to affect materially the control of the ACI (nor any personal holding company of any of such Persons), has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

AUDIT COMMITTEE

Composition of the Audit Committee

The Audit Committee is currently comprised of three members, William J. Demcoe, Judith J. Athaide, and Amit Chakma. Mr. Demcoe is the chair of the Audit Committee. All of the members of the Committee are independent and financially literate as defined under Canadian securities law. Details of their relevant experience are below. For details of their principal occupation in the last five years, see *“General – Directors and Executive Officers – Directors”*.

Mr. Demcoe has over 30 years’ experience as an executive officer, including positions with Maryn International Ltd., Alberta Natural Gas Ltd., Alberta & Southern Gas Ltd., Consolidated Pipelines Ltd. and Consolidated Natural Gas Company Ltd. Mr. Demcoe was also an instructor at the University of Calgary, Faculty of Business and has past board experience. He holds a Master of Business Administration degree from the University of Chicago. He is a member of Financial Executives International and the Institute of Chartered Professional Accountants of Alberta.

Ms. Athaide has served on a number of private and public boards in the past 15 years, currently acting as a director of HSBC Canada, Computer Modelling Group Ltd., New Brunswick Power and PHX Energy Services Corp. She is a member of the Institute of Corporate Directors. Ms. Athaide holds a Bachelor of Science degree in Mechanical Engineering and a Masters of Business Administration degree, both from the University of Alberta, and a Bachelor of Commerce degree from the University of Manitoba.

Mr. Chakma holds a Ph.D. in Chemical Engineering and a Master of Applied Science, Chemical Engineering, both from the University of British Columbia. He also holds a Diplom-Ingenieur in Chemical Engineering, Gas Engineering Specialization from the Institut Algerien du Petrole, Algeria. He is a member of the Institute of Corporate Directors and has been a director of the Canadian Scholarship Trust since 2013. He serves on the audit committee of a non-profit organization.

Pre-Approval Policies and Procedures

As set forth in the Audit Committee's charter, the Audit Committee must pre-approve all non-audit services provided by the external auditor and has direct responsibility for overseeing the work of the external auditor.

Audit Committee Charter

The Mandate of the Audit Committee is attached hereto as Schedule A.

External Auditor Service Fees by Category

The fees billed by Ernst & Young LLP ("E&Y"), ACI's external auditors, during 2018 and 2017 were as follows:

Category of External Auditor Service Fee		**2018**		2017
Audit Fees[(1)]	$	**649,562**	$	643,156
Audit-Related Fees[(2)]		**78,050**		-
All Other Fees[(3)]		**96,428**		-
Total	$	**824,040**	$	643,156

Notes:

(1) Represents the aggregate fees for services related to the audit of annual financial statements of ACI, AUI, PNG and HGL, and annual pension audits of the ACI Salaried Employees' Pension Plan, AUI Bargaining Unit Pension Plan, and PNG Pension Plan. All fees billed in 2017 by E&Y have been paid by AltaGas.

(2) Represent the aggregate fees billed by E&Y for assurance and related services that were reasonably related to the performance of the audit or review of ACI's financial statements and were not reported under "Audit Fees". During 2018, the nature of the services provided included review of prospectuses and security filings, research of accounting and audit-related issues, and registration costs for the Canadian Public Accountability Board.

(3) Represent the aggregate fees billed by E&Y for products and services, other than those reported with respect to the other categories of service fees. During 2018, the nature of the services provided was for translation services.

RISK FACTORS

Set forth below is a summary of certain risk factors relating to ACI and the business of the Company. The risks described below are not an exhaustive list of all risks, nor should they be taken as a complete summary of all the risks associated with the applicable business being conducted. Security holders and prospective security holders of ACI should carefully review and consider the risk factors set out below in this AIF before making a decision on investment and should consult their own experts where necessary.

Risks Relating to the Company's Business, Industry and Operating Environment

The regulated operations of the Company are subject to the uncertainties faced by regulated companies

The Company is subject to uncertainties faced by regulated companies such as the approval by the Applicable Utilities Commissions of rates that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing services, including a fair return on and of rate base. Through the regulatory processes, the Applicable Utilities Commissions approve the ROE that the Company is allowed to earn and the deemed capital structure which may limit the Company's ability to make and implement independent management decisions, including, without limitation, setting rates charged to customers, determining methods of cost recovery and issuing debt. Rate applications that establish revenue requirements are subject to either a public hearing process which may be oral or written, or a negotiated settlement. Rates during this term will be determined through a review process which occurs on an annual basis. There can be no assurance that the rate orders issued will permit the Company to recover all costs actually incurred and to earn the expected rate of return. A failure to obtain rates that recover the costs of providing service or provide a reasonable opportunity to earn an expected ROE and capital structure as applied for may adversely affect the business carried on by the Company, the undertaking or timing of proposed upgrades or expansion projects, ratings assigned by rating agencies, the issue and sale of securities, and other matters which may, in turn, have a material adverse effect on the Company's results of operations and financial position. See information under the heading "*Business of the Company – Utilities Business – Rate Regulation Overview*".

The ability of the Company to recover the actual costs of providing services and to earn the approved rates of return is impacted by achieving the forecasts established in the rate-setting process. The cost for upgrading existing facilities and adding new facilities requires the approval of the Applicable Utilities Commissions for inclusion in the rate base. There is no assurance that capital projects perceived as required by management will be approved by the Applicable Utilities Commissions or that conditions to such approval will not be imposed. Actual costs could exceed the approved forecasts if, for example, the Company incurs operations, maintenance and administration costs above those included in the Company's approved revenue requirement, higher capital expenditures than those approved in rate decisions, or additional financing charges because of increased debt amounts or higher interest rates. There is no assurance that the Applicable Utilities Commissions would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in demand or in the Company's costs. Conversely, if costs are lower than the forecasts established in the rate-setting process, the Applicable Utilities Commissions may review the approved rate in light of the realized cost efficiencies.

There is legislation in the jurisdictions where the Company conducts its business to impose administrative monetary penalties on the Company, upon finding contravention of an Applicable Utilities Commission order, rule, or standard. The penalty amount varies depending on the nature of the violation and it is not recoverable from customers.

Changes in law, including in the regulatory environment, may be beyond the Company's control and may significantly affect the Company's business, results of operations and financial conditions.

Natural gas demand is impacted by a number of factors

Natural gas demand is impacted by a number of factors, including the weather, economic conditions, the number of customers, the customer mix, the availability and price of natural gas and alternative forms of energy and energy efficiency measures taken by customers.

Weather

The natural gas distribution business is highly seasonal with the majority of natural gas demand occurring during the winter heating season, the length of which varies in each jurisdiction. Natural gas distribution revenue during the winter typically accounts for the largest share of annual natural gas distribution revenue.

The Applicable Utilities Commissions set rates based upon an allowed capital structure, an allowed ROE, an approved rate base and costs expected to be incurred and sales volumes which assume normal weather conditions. As customers are billed on an actual volume basis, the ability of PNG, AUI, HGL and Inuvik Gas to recover the actual costs of providing service and to earn the approved rates of return depend on achieving the forecasts approved in the regulatory rate-setting process. As a result, the Company receives the benefit or loss related to colder or warmer than predicted weather on a multi-year average, except for PNG which has a rate stabilization arrangement for residential and small commercial customers.

Customer Additions/Mix

A general and extended decline in the economy of the Company's service areas would be expected to have the effect of reducing demand for energy over time. Energy sales are influenced by economic factors such as changes in employment levels, personal disposable income, energy prices, housing starts and customer growth. New customer additions in the applicable utility's service area are typically a result of population growth and new housing starts, which are affected by the state of the local economy. The Company is also affected by changes in trends in housing starts in Canada from single family dwellings to multi-family dwellings, for which natural gas has a lower penetration rate. The growth of new multi-family housing starts continues to significantly outpace that of new single-family housing starts. Natural gas and crude oil prices are closely correlated with natural gas and crude oil exploration and production activity in certain of the Company's service territories. The level of these activities can influence energy demand, which could have a material adverse effect on the Company.

Alternative Energy Sources

Natural gas competes with other forms of energy available to the Company's customers. The primary competitive factor is price. The commodity cost of natural gas has traditionally been volatile. When prices are high, the prospects of fuel-switching and increased energy conservation pose a risk to levels of demand for natural gas, as other energy sources can become more cost-competitive.

Natural gas competes with oil and propane in Nova Scotia, but currently maintains a competitive advantage in terms of pricing and environmental benefits when compared with alternative sources of energy available in the Company's franchise areas.

It is anticipated that natural gas will continue to have a competitive advantage in British Columbia and Alberta, where virtually all potential customers in PNG and AUI's franchise areas are already connected to natural gas. However, over time, natural gas price increases may result in material decreases in the use of natural gas by customers. Within its current franchise areas, PNG and AUI have nearly achieved complete market saturation, with the exception of those consumers choosing alternate fuel sources or living in more remote areas where natural gas service is cost-prohibitive at this time.

In Nova Scotia, where customers face costs to convert to natural gas, there is significant competition from alternative energy sources. In Nova Scotia, natural gas currently has a small share of the energy market. The dominant fuel source is oil, followed by electricity, used by small commercial and residential consumers, then propane and wood fuel, used by smaller residential consumers. Natural gas is priced competitively against all options except propane for some small commercial customers. Natural gas is more efficient and provides environmental advantages when compared to the other forms of fuel in the market.

Climate Change

In addition to the seasonality associated with the Company's natural gas distribution business, the average daily temperature in each of the Company's operating areas may gradually increase and thereby cause a corresponding decrease in the consumption of natural gas by the Company's residential customers. As weather-sensitive usage represents the most significant component of the Company's natural gas deliveries, any prolonged and material increase in temperature would negatively impact the Company's natural gas deliveries.

The Company is subject to numerous laws, regulations and guidelines governing the management, transportation and disposal of hazardous substances and other waste materials and otherwise relating to the protection of the environment and health and safety, for which the Company incurs compliance costs

The process of obtaining environmental permits and approvals, including any necessary environmental assessment, can be lengthy, contentious and expensive. Potential environmental damage and costs could arise due to a variety of events, including severe weather and other natural disasters, human error or misconduct, or equipment failure. However, there can be no assurance that such costs will be recoverable through rates and, if substantial, unrecovered costs could have a material adverse effect on the Company's results of operations and financial position.

The Company is exposed to environmental risks that owners and operators of properties in the jurisdictions in which they operate generally face. These risks include the responsibility of any current or previous owner or operator of a contaminated site for remediation of the site, whether or not such Person actually caused the contamination. In addition, environmental and safety laws make owners, operators and Persons in charge of management and control of facilities subject to prosecution or administrative action for breaches of environmental and safety laws, including the failure to obtain certificates of approval. If actual consumption materially falls below projected levels, the Company's revenue could be materially adversely affected. It is not possible to predict with absolute certainty the position that a regulatory authority will take regarding matters of non-compliance with environmental and safety laws. Changes in environmental, health and safety laws could also lead to significant increases in costs and lower revenues to the Company.

The trend in environmental regulation has been to impose more restrictions and limitations on activities that may impact the environment, including use of water, the generation and disposal of wastes, the use and handling of chemical substances, and conducting environmental impact assessments and remediation. It is possible that other developments may lead to increasingly strict environmental and safety laws, regulations and enforcement policies and claims for damages to property or persons resulting from the Company's operations, any one of which could result in substantial costs or liabilities to the Company. Any regulatory changes that impose additional environmental restrictions or requirements on the Company or its customers could adversely affect the Company through increased operating and capital costs.

The Company is exposed to various operational risks, such as pipeline leaks; accidental damage to mains and service lines; corrosion in pipes; pipeline or equipment failure; other issues that can lead to outages and/or leaks; and any other accidents involving natural gas, that could result in significant operational disruptions and/or environmental liability.

Natural gas transmission, distribution and storage has inherent potential risks and there can be no assurance that substantial costs and liabilities will not be incurred. Potential environmental damage and costs could materialize due to some type of severe weather event or major equipment failure and there can be no assurance that such costs would be recoverable. Unrecovered costs could have a material adverse effect on the Company's results of operations and financial position.

While the Company maintains insurance, the insurance is subject to coverage limits as well as time sensitive claims discovery and reporting provisions and there can be no assurance that the possible types of liabilities that may be incurred by the Company will be covered by insurance. See "*Risk Factors — Risks Relating to the Company's Business, Industry and Operating Environment — There can be no assurance that the Company will be able to obtain or maintain adequate insurance in the future at rates it considers reasonable*" below.

Some of the Company's significant facilities may be subject to future provincial or federal climate change regulations or both to manage greenhouse gas emissions

The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The Company's business could also be indirectly impacted by laws and regulations that affect its customers or suppliers; to the extent such changes result in reductions in the use of natural gas by its customers or limit the operations of, or increase the costs faced by producers. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation, development and transportation of fossil fuels. Given the evolving nature of the debate related to climate change and the control of greenhouse gas emissions and resulting requirements, it is difficult to predict the impact on the Company and its operations and financial condition.

The acquisition, ownership and operation of natural gas businesses and assets require numerous permits, approvals and certificates from federal, provincial and local government agencies and indigenous peoples

For various reasons, including requirements for increased stakeholder participation and consultation, the Company may not be able to obtain or maintain all required regulatory approvals to own and operate its natural gas business or to make desirable acquisitions. If there is a delay in obtaining any required regulatory approval or if the Company fails to maintain or obtain any required approval or fails to comply with any applicable law, regulation or condition of an approval, the operation of its assets and the distribution of natural gas could be prevented or become subject to additional costs, any of which could have a material adverse effect on the Company's results of operations and financial position.

The natural gas distribution business, and its associated infrastructure, is subject to physical risks such as fires, floods, explosions, leaks, sabotage, terrorism, natural disasters and equipment malfunction, many of which are beyond the control of the Company

The occurrence or continuation of any of these events could impair the Company's ability to deliver natural gas to, or on behalf of, its customers or increase the costs associated with such delivery. Additionally, the occurrence of any of these events may negatively impact the Company's reputation, cause loss of life or personal injury, result in loss of or damage to equipment, property, information technology systems, related data and control systems or cause environmental damage. The Company attempts to manage those risks over which it has control by acknowledging their likelihood and by timing its capital expenditures and operational decisions to proactively anticipate and take preventative steps to decrease that likelihood to the greatest extent possible. Notwithstanding such efforts, such risks may still be realized and negatively impact the Company and its financial affairs.

A major natural disaster or severe weather conditions and other natural events could severely damage the Company's natural gas transmission, distribution and storage systems

A major natural disaster, such as an earthquake, fire or flood, could severely damage the Company's natural gas transmission, distribution and storage systems. In addition, the facilities of the Company could be exposed to the effects of severe weather conditions and other natural events. Although the Company's facilities have been constructed, operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. Furthermore, many of these facilities are located in remote areas which make it more difficult to perform maintenance and repairs if such assets are damaged by weather conditions or other natural events. The Company operates facilities in remote and mountainous terrain with a risk of loss or damage from forest fires, floods, washouts, landslides, avalanches and similar natural events. PNG has insurance against storm damage and other natural disasters. AUI has insurance for its high pressure distribution and transmission piping and all above ground facilities. HGL insures its above ground assets and Halifax Harbour pipelines, but does not insure its natural gas distribution systems. In the event of a large uninsured loss caused by severe weather conditions or other natural disasters, application would be made to the Applicable Utilities Commissions for the recovery of these costs through higher rates to offset any loss. However, there can be no assurance that any Applicable Utilities Commission would approve any such application. Losses resulting from repair costs and lost revenues could substantially exceed insurance coverage and any increased rates. Furthermore, the Company could be subject to claims from its customers for damages caused by the failure to transmit or distribute natural gas to them in accordance with the Company's contractual obligations. Thus, any major damage to the Company's facilities could result in lost revenues, repair costs and customer claims that are substantial in amount, and could, therefore, have a material adverse effect on the Company's results of operations and financial position.

Adequate supplies of natural gas may not be available to satisfy committed obligations of the Company's businesses as a result of economic events, natural occurrences or counterparty failure to perform

AUI and PNG are supplied by gas reserves located in the region in which they have been granted franchises for natural gas distribution. HGL is supplied by gas from other regions, transported through pipeline infrastructure. For each of the Company's businesses, supply estimates differ for the supply regions. The supply is dependent on a number of variables, including the ability of the reservoirs to maintain production levels, natural gas prices sufficient in the region to incent producers to continue to explore for more natural gas and the cost to producers of exploring for and producing natural gas in the region. If adequate supply of natural gas cannot be maintained, this could have a material adverse effect on the Company's business, financial position and cash flow.

As the Ikhil Joint Venture natural gas reserves have depleted, a propane air mixture system producing synthetic natural gas is currently the main source of energy supply for Inuvik Gas. Future costs of propane deliveries could impact the competitive position of Inuvik Gas. The increased price of propane could adversely affect the Company through increased operating and capital costs.

The Company's regulated assets require on-going maintenance, replacement and expansion

The Company's regulated assets require on-going maintenance, replacement and expansion. Accordingly, to ensure the continued performance of such physical assets, the Company determines expenditures that should be made to maintain, replace and expand the assets. The Company could experience service disruptions and increased costs if it is unable to maintain, replace or expand its rate base. The inability to recover, through approved rates, the costs of capital expenditures that the Company believes are necessary to maintain, replace, expand and remove its regulated assets, the failure by the Company to properly implement or complete approved capital expenditure programs or the occurrence of significant unforeseen equipment failures could have a material adverse effect on the Company's results of operations and financial position.

The Company continually updates its capital expenditure programs and assesses current and future operating, maintenance, replacement, expansion and removal expenses that will be incurred in the ongoing operation of its business. Management's analysis is based on assumptions as to costs of services and equipment, regulatory requirements, revenue requirement approvals, and other matters, which involve some degree of uncertainty. If actual costs exceed regulatory-approved capital expenditures, it is uncertain as to whether such additional costs, if found imprudent, will receive regulatory approval for recovery in future rates. The inability to recover these additional costs could have a material adverse effect on the Company's results of operations and financial position.

Increased competition could adversely affect the performance of the Company

The Company competes with other infrastructure companies as well as traditional energy companies, which may have greater financial and other resources for new business. The Company competes with other renewable power companies primarily for development and acquisition opportunities, and with other power companies for access to transmission and distribution networks.

Franchise grants may not be renewed upon their expiry

Most of the Company's natural gas distribution businesses operate within a franchise territory that has been granted under the terms of franchise and other agreements. This means that there is virtually no competition for natural gas distribution within such service areas during the terms of the agreements. This enables the applicable utility to grow organically for the term of the franchise with little threat of competition other than from alternative energy sources. There are ongoing risks that the various franchise grants will not be renewed upon their expiry. The consequence of expiry differs depending upon the jurisdiction in which the franchise is granted, but in some cases may result in the loss of revenue from the franchise area after the franchise agreement expires, which could have a material adverse effect on the Company's business, financial position and cash flow.

The Town of Inuvik may not accept ownership of Inuvik Gas

On December 7, 2016, Inuvik Gas notified the Town of Inuvik of its intention to terminate the gas distribution franchise agreement effective December 2018. That franchise agreement was terminated on December 8, 2018. Inuvik Gas agreed to continue to provide service to its customers in accordance with the previous franchise agreement and the NWTPUB approved terms and conditions of service as Inuvik Gas and the Town of Inuvik continue negotiations to transition ownership to the Town of Inuvik. However, if the Town of Inuvik does not accept ownership, the Company will continue to own its interest in Inuvik Gas and provide natural gas service to its customers indefinitely, which could impact the Company's ability to pursue other opportunities.

The operation and maintenance of the Company's and the CMH Group's renewable power facilities involve risks that may materially and adversely affect the Company's business

The revenue generated by the Company's and the CMH Group's renewable power facilities is dependent on the amount of electricity generated by them. The ability of the Company's and the CMH Group's renewable power facilities to generate the amount of power expected is an important determinant in the amount of revenues that will be received by the Company and the CMH Group. A number of different factors, including: equipment failure due to wear and tear, latent defect, design error, operator error, slow response to outages due to underperforming monitoring systems, changes in wind or water flows, and vandalism or theft could adversely affect the amount of power produced, and thus the revenues and cash available for distribution. Unplanned outages or prolonged downtime for maintenance and repair typically increase operation and maintenance expenses and reduce revenues as a result of selling less electricity. Although the Company's and the CMH Group's renewable power facilities have generally operated in accordance with expectations, there can be no assurance that they will continue to do so. To the extent that a facility's equipment requires longer than forecasted down times for maintenance and repair, or suffers disruptions of renewable power for other reasons, the Company's and the CMH Group's business, operating results, financial condition or prospects could be adversely affected.

There can be no assurance that the Company's or the CMH Group's maintenance program will be able to detect potential failures in its facilities prior to occurrence or eliminate all adverse consequences in the event of failure. In addition, weather related interference, work stoppages and other unforeseen problems may disrupt the operation and maintenance of the Company's and the CMH Group's renewable power facilities and may materially and adversely affect the Company or the CMH Group.

While the Company and the CMH Group may maintain an inventory of, or otherwise make arrangements to obtain, spare parts to replace critical equipment and maintain insurance for property damage to protect against certain operating risks, these protections may not be adequate to cover lost revenues or increased expenses and penalties which could result if the Company or the CMH Group is unable to operate its generation facilities at a level necessary to comply with sales contracts.

The Company's and the CMH Group's revenues may be reduced upon expiration or termination of PPAs

The Company and the CMH Group sell power under long-term PPAs. These PPAs and any replacement PPAs may be subject to termination in certain circumstances, including default by the facility owner or operator. When a PPA expires or is terminated, it is possible that the price received by the relevant facility for power under subsequent selling arrangements may be reduced significantly. It is also possible that PPAs negotiated in replacement of the initial PPAs may not be at prices that permit the continued operation of the affected facility or plant on a profitable basis. If this occurs, the affected facility or plant may be forced to permanently cease operations.

The Company and the CMH Group are each party to significant third party contracts and the failure of such third parties to fulfill their contractual obligations could have a material adverse effect on the Company or the CMH Group

The Company and the CMH Group sell all of their power to third parties under long-term PPAs. If, for any reason, any of the purchasers of power under such PPAs are unable or unwilling to fulfill their contractual obligations under the relevant PPA, or if they refuse to accept delivery of power pursuant to the relevant PPA, the Company's and the CMH Group's assets, liabilities, business, financial condition, results of operations and cash flow could be materially and adversely affected as they may not be able to replace the agreement with another agreement on equivalent terms and conditions. External events, such as a severe economic downturn, could impair the ability of some counterparties to the PPAs or some end use customers to pay for electricity received.

In addition, the Company and the CMH Group will enter into contracts with third parties for materials and generation equipment, which often require deposits to be made prior to equipment being delivered and other goods and services being provided. Should one or more of these third parties be unable to meet their obligations under the contracts, such an occurrence would result in possible loss of revenue, delay in return to service and increase in operating costs.

The Company or the CMH Group could suffer lost revenues or increased expenses and penalties if the Company or the CMH Group are unable to operate their renewable power facilities at a level necessary to comply with its PPAs

The ability of the Company's and the CMH Group's renewable power facilities to generate the maximum amount of power which can be sold under PPAs is an important determinant of the revenues of the Company and the CMH Group. Under certain PPAs, if the renewable power facility delivers less than the required quantity of electricity in a given contract year, penalty payments may be payable to the relevant purchaser by the Company or the CMH Group. The payment of any such penalties by the Company or the CMH Group could materially adversely affect the revenues and profitability of the Company or the CMH Group.

The Company and the CMH Group are subject to extensive government regulation, incentive mechanisms and supervision, which may impact the Company's and the CMH Group's financial performance, limit their flexibility and, in the event of non-compliance, could result in adverse actions by regulatory authorities against them

The market for renewable power is heavily influenced by federal, provincial and local government regulations and policies in respect of tariffs, market structure and penalties. These regulations and policies often relate to the encouragement of renewable power development, electricity pricing and interconnection.

The Company's and the CMH Group's inability to predict, influence or respond appropriately to changes in law or regulatory frameworks could adversely impact the Company's or the CMH Group's results of operations. Furthermore, changes in laws, regulations or changes in the application or interpretation of regulatory provisions in jurisdictions where the Company and the CMH Group operate, could adversely affect the Company's and the CMH Group's businesses. These include, but are not limited to: (a) changes in applicable PPA rates, including changes in the timing of PPA rate increases or decreases; (b) adverse changes in laws, regulations or policies or their interpretation; and (c) other changes related to licensing or permitting, which affect the Company's and the CMH Group's ability to conduct its respective businesses in an orderly fashion.

Any of the foregoing events may result in lower revenues, higher costs and/or lower margins for the affected projects, which would adversely affect the Company's or the CMH Group's results of operations.

The Company and the CMH Group hold permits and licences from various regulatory authorities for the construction and operation of their renewable power facilities. These permits and licences are critical to the operation of the Company's and the CMH Group's businesses. The majority of these permits and licenses are long-term in nature, reflecting the anticipated useful life of the renewable power facilities. In some cases these permits may need to be renewed prior to the end of the anticipated useful life of such renewable power facilities and there is no guarantee that such renewals will be granted. These permits and licences require the Company's and the CMH Group's compliance with the terms thereof. In addition, delays may occur in obtaining necessary government approvals required for future power projects.

The Company may have restricted access to capital and increased borrowing costs

As the Company's future capital expenditures and certain short-term indebtedness repayment obligations will be financed out of cash generated from operations, borrowings and possible future equity and/or debt sales, the Company's ability to finance such expenditures is dependent on, among other factors, the overall state of capital markets and investor demand for investments in the energy infrastructure industry generally and the Company's securities in particular.

To the extent that external sources of capital become unavailable or available on onerous terms or otherwise limited, the Company's ability to make capital investments, maintain existing assets and repay indebtedness may be impaired, and its assets, liabilities, business, financial condition, results of operations and dividends may be materially and adversely affected as a result.

If cash flow from operations is lower than expected or capital costs for these projects exceed current estimates, or if the Company incurs major unanticipated expenses related to construction, development or maintenance of its existing assets, the Company may be required to seek additional capital to maintain its capital expenditures at planned levels. Failure to obtain financing necessary for the Company's capital expenditure and indebtedness repayment plans may result in a delay in the Company's capital program or a decrease in dividends.

Changes in general economic conditions may have a material adverse effect on the Company or the CMH Group

Adverse changes in general economic and market conditions could negatively impact demand for electricity, revenue, operating costs, timing and extent of capital expenditures, the net recoverable value of plant, property and equipment, results of financing efforts, credit risk and counterparty risk, which could cause the Company or the CMH Group to suffer a material adverse effect.

Negative public or community response to wind and/or hydroelectric facilities could adversely affect the Company's or the CMH Group's projects

Negative public or community response to wind and/or hydroelectric power facilities could adversely affect the Company's and the CMH Group's ability to develop and operate their renewable power facilities. In particular, with respect to the development and operation of wind projects, public concerns and objections often center around the noise generated by wind turbines and the impact such turbines have on wildlife, including birds and bats and in respect of hydroelectric power facilities centered around water quality, the effect on water flows and reservoirs, any hazardous substances that may be released in the water in the course of its operations and the impact the facilities have on fish passage. While public opposition is usually of greatest concern during the development stage of renewable assets, which is when the public has the ability to provide comments and appeal regulatory permits, continued opposition could have an impact on operations. This type of negative response could lead to legal, public relations and other challenges that impede the Company's or the CMH Group's ability to meet their development and construction targets, achieve commercial operations for a facility on schedule and generate revenues. The Company expects this type of opposition to continue. An increase in opposition to the Company's or the CMH Group's requests for permits or successful challenges or appeals to permits issued to them could materially adversely affect the Company's operations and financial position. Legal requirements, changes in scientific knowledge and public complaints regarding issues such as noise generated by wind turbines could impact the operation of the Company's or the CMH Group's renewable power assets in the future as well as their respective reputations.

Unexpected changes in the cost of maintenance or in the cost and durability of components for the Company's or the CMH Group's renewable power facilities may adversely affect their results of operations

Unexpected increases in the Company's or the CMH Group's cost structure that are beyond the control of the Company or the CMH Group could materially adversely impact their respective financial performance. Examples of such costs include, but are not limited to unexpected increases in the cost of procuring materials and services required for maintenance activities and unexpected replacement or repair costs associated with equipment underperformance or lower-than-anticipated durability. Such increase in the Company's or the CMH Group's cost structure might not be recoverable from customers through increased rates.

The industries in which the Company operates have certain inherent risks related to worker health and safety and the environment that could cause the Company to suffer unanticipated expenditures or to incur fines, penalties or other consequences material to its business and operations

The ownership and operation of the Company's regulated utilities and renewable power assets carries an inherent risk of liability related to worker health and safety and the environment, including the risk of government imposed orders to remedy unsafe conditions and/or to remediate or otherwise address environmental contamination, potential penalties for contravention of health, safety and environmental laws, licences, permits and other approvals, and potential civil liability. Compliance with health, safety and environmental laws (and any future changes) and the requirements of licences, permits and other approvals will remain material to the Company's businesses. The occurrence of any of these events or any changes, additions to or more rigorous enforcement of, health, safety and environmental laws, licences, permits or other approvals could have a significant impact on operations and/or result in additional material expenditures. As a consequence, no assurances can be given that additional environmental and workers' health and safety issues relating to presently known or unknown matters will not require unanticipated expenditures, or result in fines, penalties or other consequences (including changes to operations) material to its business and operations.

A major natural disaster or severe weather conditions and other natural events could severely damage the Company's and the CMH Group's renewable power facilities and operations

A major natural disaster, such as an earthquake, fire or flood, could severely damage the Company's and the CMH Group's renewable power facilities and operations. In addition, the facilities of the Company and the CMH Group could be exposed to the effects of severe weather conditions and other natural events. Although the Company's and the CMH Group's facilities have been constructed, operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. Furthermore, many of these facilities are located in remote areas which make it more difficult to perform maintenance and repairs if such assets are damaged by weather conditions or other natural events. The Company and the CMH Group operate facilities in remote and mountainous terrain with a risk of loss or damage from forest fires, floods, washouts, landslides, avalanches and similar natural events. Losses resulting from repair costs and lost revenues could substantially exceed insurance coverage and any increased rates. Thus, any major damage to the Company's and the CMH Group's facilities could result in lost revenues, repair costs and customer claims that are substantial in amount, and could, therefore, have a material adverse effect on the Company's and the CMH Group's results of operations and financial position.

The Company's and the CMH Group's renewable power facilities rely on national and regional transmission systems and related facilities that are owned and operated by third parties and have both regulatory and physical constraints that could impede access to electricity markets

The Company's and the CMH Group's renewable power facilities depend on electric transmission systems and related facilities owned and operated by third parties to deliver the electricity the Company and the CMH Group generate to delivery points where ownership changes and the Company or the CMH Group is paid. These grids operate with both regulatory and physical constraints which in certain circumstances may impede access to electricity markets. There may be instances in system emergencies in which the Company's or the CMH Group's renewable power facilities are physically disconnected from the power grid, or their production curtailed, for short periods of time. Most of the Company's and the CMH Group's PPAs do not provide for payments to be made if electricity is not delivered.

The Company's and the CMH Group's renewable power facilities may also be subject to changes in regulations governing the cost and characteristics of use of the transmission and distribution systems to which their renewable power facilities are connected. The Company's or the CMH Group's renewable power facilities in the future may not be able to secure access to this interconnection or transmission capacity at reasonable prices, in a timely fashion or at all, which could then cause delays and additional costs in attempting to negotiate or renegotiate PPAs or to construct new projects. In addition, the Company or the CMH Group may not benefit from preferential arrangements in the future. Any such increased costs and delays could delay the COD of the Company's or the CMH Group's new projects and negatively impact the Company's or the CMH Group's revenues and financial condition.

Run-of-river infrastructure failures may result in lost generating capacity, increased maintenance and repair costs and other liabilities

A natural or man-made disaster, and certain other events, could potentially cause infrastructure failures that could impact the Northwest Hydro Facilities, and result in a loss of generating capacity, damage to the environment or damage and harm to third parties or the public. Additionally, significant seasonal variations in the river flow could significantly impact the water flow available to generate sufficient electricity necessary for power generation and economic viability. Such failures could require the CMH Group to incur significant expenditures of capital and other resources, or expose the CMH Group to significant liabilities for damages. There can be no assurance that the CMH Group's safety program will be able to detect potential infrastructure failures prior to occurrence or eliminate all adverse consequences in the event of failure. Other safety regulations could change from time to time, potentially impacting the CMH Group's costs and operations. The consequences of infrastructure failures could have a material adverse effect on the CMH Group and the Company. The CMH Group attempts to manage this risk by following preventative maintenance procedures and obtaining insurance coverage; however, in the event of a sufficiently large infrastructure failure, insurance coverage, if available, may not be adequate and the CMH Group and the Company may suffer a material adverse effect.

A significant increase in water rental costs could result in a material adverse effect

The CMH Group is required to make rental payments for water rights in respect of the Northwest Hydro Facilities. Significant increases in water rental costs in the future or changes in the way that governmental authorities in British Columbia regulate water supply could have a material adverse effect on the CMH Group's business, operating results, financial condition or prospects.

The CMH Group may be adversely affected if its supply of water is materially reduced

The Northwest Hydro Facilities require continuous water flow for their operation. Shifts in weather or climate patterns, seasonal precipitation, the timing and rate of melting, run off, and other factors beyond the control of the CMH Group, may reduce the water flow to the Northwest Hydro Facilities. Any material reduction in the water flow to Northwest Hydro Facilities would limit the CMH Group's ability to produce and market electricity from these facilities and could have a material adverse effect on the CMH Group. There is an increasing level of regulation respecting the use, treatment and discharge of water, and respecting the licensing of water rights in British Columbia. Any such change in regulations could have a material adverse effect on the CMH Group.

Variation in wind levels may negatively impact the amount of electricity generated at the Company's wind facilities

Wind is naturally variable. Therefore, the level of electricity production from the Bear Mountain Wind Park will also be variable. In addition, the strength and consistency of the wind resource at the Bear Mountain Wind Park may vary from what the Company anticipates due to a number of factors including: the extent to which site-specific historic wind data and wind forecasts accurately reflects actual long-term wind speeds, strength and consistency; the potential impact of climatic factors; the accuracy of assumptions relating to, among other things, weather, icing and soiling of wind turbines, site access, wake and line losses and wind shear; the potential impact of topographical variations; and the potential for electricity losses to occur before delivery.

A reduced amount of wind at the location of the Bear Mountain Wind Park over an extended period may reduce the production from such facility, as well as any environmental attributes that accrue to the Company and reduce the Company's revenues and profitability.

There can be no assurance that the Company will be able to obtain or maintain adequate insurance in the future at rates it considers reasonable

The Company maintains insurance coverage with respect to potential liabilities and the accidental damage to or loss of certain of its assets, in amounts and with such insurers as is considered appropriate, taking into account all relevant factors, including the practices of owners of similar assets and operations. It is anticipated that such insurance coverage will be maintained. However, there can be no assurance that the Company will be able to obtain or maintain adequate insurance in the future at rates it considers reasonable. Further, there can be no assurance that available insurance will cover all losses or liabilities that might arise in the conduct of the Company's business. The occurrence of a significant uninsured claim or a claim in excess of the insurance coverage limits maintained by the Company or a claim that falls within a significant self-insured retention could have a material adverse effect on the Company's results of operations and financial position.

In the event of an uninsured loss or liability in respect of its regulated assets, the Company would apply to the Applicable Utilities Commissions to recover the loss (or liability) through an increased tariff. However, there can be no assurance that any Applicable Utilities Commission would approve any such application, in whole or in part. Any major damage to the Company's facilities could result in repair costs, increased insurance premiums and customer claims that are substantial in amount and which could have a material adverse effect on the Company's results of operations and financial position.

The Company operates in territories in which indigenous peoples have land and rights claims

Indigenous peoples have claimed rights to a substantial portion of the lands in Canada. The Company and the CMH Group operate in territories in which such claims have been advanced. Such claims, if successful, could have a material adverse effect on the development of natural gas projects and power development and generation in the jurisdictions in which they operate, which could have a materially adverse effect on the power produced by the Company's and the CMH Group's facilities or on the operation or development of facilities for natural gas distribution and renewable power.

The Company and the CMH Group have concluded agreements with many indigenous communities. These agreements support an approach of active engagement with indigenous communities that serves to ensure the identification of issues and facilitates constructive problem-solving. Further, the Company and the CMH Group have taken a proactive approach to enhance the economic participation of indigenous groups in its operations where feasible and reasonable. The agreements and the measures taken by the Company and the CMH Group strengthen relationships between the parties while respecting the ever evolving regulatory and judicial relationship between Canada's governments and indigenous people.

However, the Company and the CMH Group cannot predict whether future indigenous land claims and the assertion of other rights will affect their ability to conduct their business and operations as currently undertaken or as may be undertaken in the future in such regions. Furthermore, any failure to reach an agreement, or a conflict or disagreement, with, an indigenous group could have a material adverse effect on the Company's or the CMH Group's business, financial condition and results of operations.

The ability of the Company to operate effectively is dependent upon information systems and infrastructure

The ability of the Company to operate effectively is dependent upon managing and maintaining information systems and infrastructure that support the operation of distribution, transmission storage facilities and power generation; provide customers with billing and consumption information; and support the financial and general operating aspects of the business. The reliability of the communication infrastructure and supporting systems are also necessary to provide important safety information. System failures could have a material adverse effect on the Company.

A cyber security breach of the Company's critical infrastructure could have a material adverse effect on the Company's results of operations and financial position

The Company's business processes are increasingly reliant upon information systems automation provided by infrastructure, technologies and data. A failure of these information systems could lead to the impairment of business processes, and there is a risk of cascading failure of information systems leading to the impairment of multiple business processes. The risk of cyber-attack targeting information systems is increasing, with strong evidence of the energy industry being specifically targeted.

Security breaches of the Company's information technology infrastructure, including, without limitation, cyber-attacks and cyberterrorism, or other failures of the Company's information technology infrastructure could result in operational outages, delays, damage to assets, the environment or to the Company's reputation, diminished customer confidence, lost profits, lost data (including confidential information), increased regulation and other adverse outcomes, including, without limitation, material legal claims and liability or fines or penalties under applicable laws and adversely affect its business operations and financial results.

The Company's cyber security strategy focuses on information technology security risk management which includes, without limitation, continuous monitoring, ongoing cyber security communications and training for staff, conducting third-party vulnerability and security tests, threat detection and an incident response protocol. However, there is no assurance that the Company will not suffer a cyber-attack or an information technology failure notwithstanding the implementation of this strategy and the measures taken pursuant to that strategy, including, without limitation, as set forth above and the occurrence of any of these cyber events could adversely affect the Company's financial condition and results of operations.

Additionally, the Company must be able to protect its infrastructure against physical damage, security breaches and service disruption from any of a variety of causes. Theft, vandalism, and other disruptions could jeopardize the security of information stored in and transmitted through the Company's systems and network infrastructure, and could result in significant set-backs, potential liabilities and deter future customers. While the Company has systems, policies, hardware, practices, and procedures designed to prevent or limit the effect of the failure, interruptions or security breaches of its facilities and infrastructure, there can be no assurance that these measures will be sufficient and that such failures, interruptions or security breaches will not occur or, if they do occur, that they will be adequately addressed in a timely manner.

Business acquisitions involve numerous risks and the failure to realize anticipated benefits of acquisitions and dispositions could negatively affect the Company's results of operations

The Company may consider acquisitions and dispositions of assets in the ordinary course of business. Achieving the benefits of acquisitions, including the Acquisition, depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Company's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. The integration of acquired businesses, including the business underlying the Acquired Assets, may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. The Company may also enter into other industry related activities or new geographical areas or acquire different utility-related assets that may result in unexpected or significantly increased risk to the Company, which could materially adversely affect the Company's business and financial condition. Additionally, management will continually assess the value and contribution of the various properties and assets within its portfolio. In this regard, certain assets may be periodically disposed of so the Company can focus its efforts and resources more efficiently. Depending on the state of the market for such assets, certain assets of the Company, if disposed of, may realize less than what the market may expect for such disposition or their carrying value on the financial statements of the Company.

The Company maintains defined benefit pension plans and supplemental pension arrangements. There is no certainty that the plan assets will be able to earn the assumed rate of returns

The Company is subject to obligations under defined benefit pension plans and supplemental pension arrangements. Future payments under the plans are intended to be fixed. Market driven changes impacting the performance of the plan assets may result in material variations in actual return on plan assets from the assumed return on the assets causing material changes in net benefit costs. Net benefit cost is impacted by, among other things, the discount rate, changes in the expected mortality rates of plan members, the amortization of experience and actuarial gains or losses, and expected return on plan assets. Market driven changes impacting other assumptions, including the assumed discount rate, may also result in future contributions to pension plans that differ significantly from current estimates as well as causing material changes in net benefit cost.

There is also measurement uncertainty associated with net benefit cost, future funding requirements, the net accrued benefit asset and projected benefit obligation due to measurement uncertainty inherent in the actuarial valuation process.

Net benefit cost variances from forecasts for rate-setting purposes are recovered through future rates using regulatory deferral accounts approved by the Applicable Utilities Commissions. There can be no assurance that such deferral mechanisms will exist in the future as they are dependent on future regulatory decisions and orders. An inability to flow through these costs could have a material adverse effect on the Company's results of operations and financial position.

The Company relies on a few key employees whose absence or loss could disrupt its operations and have a material adverse effect on its business

The Company's success depends in large measure on certain key personnel. Many key responsibilities within the Company's business have been assigned to a small number of employees. The loss of their services could disrupt the Company's operations. In addition, the Company does not maintain "key person" life insurance policies on any of its employees. As a result, the Company is not insured against any losses resulting from the death of its key employees. The competition for qualified personnel is the rate-regulated utility and renewable power industry is intense and there can be no assurance that the Company will be able to continue to attract and retain all personnel necessary for the development and operation of the business.

The inability to attract, develop and retain skilled workforces could have a material adverse effect on the Company

The ability of the Company to deliver service in a cost-effective manner is dependent on the ability of the Company to attract, develop and retain skilled workforces. Like other infrastructure companies across Canada, the Company is faced with demographic challenges relating to such skilled workforces. The inability to attract, develop and retain skilled workforces could have a material adverse effect on the Company. The Company also competes with other utilities for a limited pool of personnel with requisite industry knowledge and experience.

The Company employs members of labour unions that have entered into collective bargaining agreements with the Company and there can be no assurance that current relations will continue in future negotiations

The Company employs members of labour unions that have entered into collective bargaining agreements with the Company. The provisions of such collective bargaining agreements affect the flexibility and efficiency of the business carried on by the Company. The inability to maintain, or to renew, the collective bargaining agreements on acceptable terms could result in increased labour costs or service interruptions arising from labour disputes, that are not provided for in approved rates and that could have a material adverse effect on the Company's results of operations and financial position.

The Company maintains credit arrangements and is required to comply with various covenants in respect of those arrangements

The Company maintains a number of debt arrangements as part of its capital structure. The Company's indebtedness could have significant effects on its business. For example, it could: (a) increase the Company's vulnerability to adverse changes in general economic, industry and competitive conditions; (b) require the Company to dedicate a substantial portion of its cash flow from operations to make payments on its indebtedness, thereby reducing the availability of its cash flow to fund the payment of dividends as well as to fund working capital, capital expenditures and other general corporate purposes; and (c) restrict the Company from exploiting new business opportunities.

The Company is required to comply with customary positive and negative covenants under its current and future credit arrangements and in the event that the Company does not comply with these covenants, the Company's access to capital could be restricted or repayment could be required. Events beyond the Company's control may contribute to the failure of the Company to comply with such covenants. A failure to comply with any of the covenants could result in an event of default which, if not cured or waived, would permit acceleration of the indebtedness pursuant to the applicable credit arrangements and would prevent dividends from being paid to Shareholders and a material reduction in the value of the Common Shares. Compliance with the terms of the covenants under the Company's credit arrangements could adversely impact the free cash flow of the Company.

The Company's business plan is subject to the availability of additional debt financing to refinance existing debt obligations and to finance expansion, which financing may not be available, or may not be available on favourable terms. The Company's ability to refinance debt obligations and access financing will be subject to conditions in credit markets which are beyond the Company's control, and will also be affected by credit ratings, if any, assigned to the Company and its debt. If the Company is not able to raise capital to replace existing debt on maturity or to pay required capital expenditures or finance acquisitions, this could impede its growth and could materially adversely affect the business, financial condition and results of operations of the Company.

The Company is exposed to interest rate risks associated with floating rate debt and refinancing of its long-term debt

Regulated interest expense variances from forecast for rate-setting purposes are recovered through future rates using a regulatory deferral account approved by the Applicable Utilities Commissions. There can be no assurance that such deferral mechanisms will exist in the future as they are dependent on future regulatory decisions and orders. An inability to flow through these costs could have a material adverse effect on the Company's results of operations and financial position.

The Company is subject to various credit risks

Financial instruments, which subject the Company to credit risk, consist primarily of accounts receivable. Accounts receivable credit risk is reduced due to a large and diversified customer base, customer deposits for at-risk customers and the ability to recover the majority of uncollectible accounts through approved rates.

The Company may be subject to foreign exchange risk

The Company is exposed to changes in the Canadian dollar. Substantially all of the Company's revenues are paid in Canadian dollars, while a portion of its purchases of supplies and services are obtained from foreign suppliers. A sustained decrease in the value of the Canadian dollar relative to the currencies of the Company's foreign suppliers may have a material negative impact on the results of operations and financial position of the Company.

The Company may become subject to legal proceedings

In the normal course of the Company's operations, it may become involved in, be named as a party to or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to actual or alleged violations of law, common law damages claims, personal injuries, property damage, property taxes, land rights, the environment and contract disputes. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Company, which could have a material adverse effect on the Company. Even if the Company prevails in any such legal proceeding, the proceedings could be costly and time-consuming and would divert the attention of management and key personnel from the Company's business operations, which could adversely affect the Company.

The Company will be responsible for compliance with all applicable laws and regulations regarding the decommissioning, abandonment and reclamation of its facilities at the end of their economic life, the costs of which may be substantial

It is not possible to predict these costs with certainty since they will be a function of regulatory requirements at the time of decommissioning, abandonment and reclamation. The Company may, in the future, determine it prudent or be required by applicable laws or regulations to establish and fund a reclamation reserve fund to provide for payment of future decommissioning, abandonment and reclamation costs, which could decrease funds available to service debt obligations in the future or for payment of dividends on the Common Shares. In addition, such reserve, if established, may not be sufficient to satisfy such future decommissioning, abandonment and reclamation costs.

Risks Related to the Company's Structure and Organization

AltaGas' Shareholdings and Provision of Transitional Services

AltaGas is a significant Shareholder and, as such, is able to exert significant influence on the Company through its voting rights, including the right to vote for the election of directors to the Board of Directors. In addition, pursuant to the Governance Agreement, AltaGas has the right, in certain circumstances, to nominate a certain number of directors based on the level of its retained interest in the Company and to nominate directors for election to the Board of Directors. As a result, AltaGas is able to exercise influence over the management, administration, strategy and growth of the Company.

Until June 30, 2020, unless earlier terminated by the Company upon notice to AltaGas, the Company is depending on AltaGas to provide certain services to the Company pursuant to the Transition Services Agreement. AltaGas personnel and support staff that provide services to the Company under the Transition Services Agreement are not required to have as their primary responsibility the administration of the Company or to act exclusively for the Company and the Transition Services Agreement does not require any specific individuals to be provided by AltaGas.

AltaGas has experienced departures of key employees in the past and this could also happen in the future. The Company cannot predict the impact that any such departures may have on the Company's ability to achieve its objectives, particularly during the term of the Transition Services Agreement.

Conflicts of Interest with AltaGas

The Transition Services Agreement, the Governance Agreement, the Investor Liquidity Agreement and the Company's other arrangements with AltaGas do not impose any duty on AltaGas to act in the best interest of the Company, and AltaGas is not prohibited from engaging in other business activities that may compete with those of the Company. The Company's ownership structure involves a number of relationships that may give rise to conflicts of interest between AltaGas, on the one hand and the Company and the Shareholders, on the other hand. In certain instances, the interests of AltaGas may differ from the interests of the Company and its Shareholders, including with respect to the reinvestment of returns generated by the Company's activities, future acquisitions or strategic decisions, and the appointment of outside advisors and service providers. It is possible that conflicts of interest may arise between the Company and AltaGas and that such conflicts may not be resolved in a manner that is in the best interests of the Company or its Shareholders.

Under the Transition Services Agreement, AltaGas does not assume any responsibility other than to provide or arrange for the provision of the services described in the Transition Services Agreement in a reasonable and prudent manner and in accordance with applicable laws. AltaGas, its affiliates and associates and each of their respective directors, officers, employees and agents are not, either directly or indirectly, liable, answerable or accountable to the Company or any of its Shareholders, for any loss or damage resulting from the performance or non-performance of services described in the Transition Services Agreement (including any mistake or error of judgment), unless such loss or damage resulted from the gross negligence or willful misconduct of such party. Under the Transition Services Agreement, the Company has agreed to indemnify AltaGas, its affiliates and their respective directors, officers, employees and agents from and against any liabilities, obligations, losses, damages, costs, expenses and charges suffered by an indemnified Person arising out of or otherwise relating to any act or omission of AltaGas, its affiliates and their respective directors, officers, employees and agents in connection with the provisions of the services described in the Transition Services Agreement by AltaGas, except to the extent that the claims, liabilities, losses, damages, costs or expenses are determined to have resulted from gross negligence or willful misconduct of AltaGas, its affiliates and their respective directors, officers, employees and agents.

Pursuant to the Governance Agreement, AltaGas has the right to appoint or nominate for election, as the case may be, a certain number of directors of the Company, based on the level of its retained interest in the Company. Currently, three of the directors are nominees of AltaGas. The directors are required to act honestly and in good faith with a view to the best interests of the Company. The interests of AltaGas may conflict with those of other Shareholders.

Future Changes in Relationship with AltaGas

The arrangements between the Company and AltaGas do not require AltaGas to maintain any ownership level in the Company following the expiry of the 12 month lock-up period under the Governance Agreement. Accordingly, after such time, AltaGas may transfer all or a substantial portion of its interest in the Company to the public through secondary offerings (including pursuant to its rights under the Investor Liquidity Agreement), or to a third party, including in a merger or consolidation or sale of Common Shares, without the consent of the Company or its Shareholders, subject to market conditions, AltaGas' requirements for capital or other circumstances that may arise in the future. Certain of the rights and obligations under the Governance Agreement, may also be assignable to a transferee of the Common Shares (other than in respect of transfers made pursuant to a public offering), upon notice to the Company. Accordingly, there can be no assurance as to who may hold and exercise such rights in the future. The interests of a transferee of the Common Shares may be different from AltaGas' and may not align with those of other Shareholders. The Company cannot predict with any certainty the effect that any such transfer would have on the trading price of the Common Shares or the Company's ability to raise capital in the future. As a result, the future of the Company would be uncertain and the Company's business and financial condition may suffer.

The Company conducts its business through other entities

The Company conducts its business through its ownership of corporations and partnerships and a substantial portion of its assets are the shares of and other interests in its subsidiaries. As a result, Shareholders are subject to the risks attributable to the Company's subsidiaries. The Company conducts substantially all of its business through its subsidiaries, which generate substantially all of its revenues. Consequently, the Company's cash flows and ability to complete current or desirable future enhancement opportunities are dependent on the earnings of its subsidiaries and the distribution of those earnings to the Company. The ability of these entities to pay dividends and other distributions depends on their operating results and is subject to applicable laws and regulations which require that solvency and capital standard be maintained by such entities and contractual restrictions contained in the instruments governing their debts. The ability of PNG to distribute cash to the Company is subject to PNG's compliance with its obligations under the certain of its debt arrangements, and in the future any debt obligations incurred by subsidiaries directly may limit their ability to contribute to the Company's cash flow. In the event of a bankruptcy, liquidation of reorganization of any of the Company's subsidiaries, holders of indebtedness and other creditors will generally be entitled to payment of their claims from the assets of such subsidiaries before any assets are made available for distribution to the Company.

The Company has conducted past operations within a larger vehicle

The Company's assets had been part of AltaGas for a number of years. In the past, the Company's assets operated in the context of AltaGas' business as a whole. Accordingly, employees of the Company had access to AltaGas' resources, including AltaGas' systems, business contacts, financial resources, senior management and other expertise and resources. Other than for the limited purpose and limited time specified in the Transition Services Agreement, the Company does not have the same access to AltaGas' expertise and resources. There can be no assurance that the Company will have similar expertise or resources through internal sources or by contracting services with third parties, or if such expertise or resources can be obtained on the same basis, or at the same or lesser cost, as provided historically by AltaGas.

Although the Company expects to benefit from the experience that management and employees have gained while working at AltaGas or at other infrastructure companies, the Company may be less successful in implementing its business strategy. As a result, the Company may experience significant fluctuations in its results, which may vary from those projected by management. No assurance can be given that the Company will be successful in implementing its business strategy or that it will achieve expected future results which could materially adversely affect the Company's business and financial condition.

The Company may be subject to both transition and growth-related risks

The Company may be subject to both transition and growth-related risks, including capacity constraints and pressure on its internal systems and controls. The Company did not act as the parent of a public utility and power generator prior to completion of the Acquisition, and although it believes that it has adequate staff and resources (including services provided by AltaGas pursuant to the Transition Services Agreement), it may lack sufficient resources to operate as a stand-alone company. The historical financial and operating results of the Company, the Acquired Assets and its underlying business while it was under the management of AltaGas may not be indicative of future results. In particular, the Company is responsible for managing substantial regulatory functions and related accounting functions that will require significant employee resources. The ability of the Company to manage both its transition to a stand-alone company and future growth effectively requires it to continue to implement and improve financial and operational systems and to expand, train and manage its employee base. The inability of the Company to deal with this transition and growth may have a material adverse effect on the Company's business and financial condition.

The Company is a minority securityholder of Coast GP and Coast LP

The unanimous shareholder agreement governing Coast GP and the limited partnership agreement governing Coast LP governing the operations of the CMH Group provide governance rights to the shareholders and partners thereto. As an approximate indirect 10 percent securityholder, the Company has very limited rights outside the right to receive regular distributions and does not have the ability to direct such entities and the CMH Group and accordingly any decisions made by the major securityholders may negatively impact the Company.

A Person may be restricted from acquiring a significant number of Common Shares without regulatory approval

Pursuant to certain laws and regulations regarding public utilities in the jurisdictions in which the Company operates, a Person may be restricted from acquiring a significant number of Common Shares without approval of the Applicable Utilities Commissions.

The Company depends on certain partners that may have objectives which conflict with the objectives of the Company and such differences could have a negative impact on the Company

The Company is a party to the unanimous shareholder agreement governing Coast GP and the limited partnership agreement governing Coast LP governing the operation of the Northwest Hydro Facilities. Certain of the other parties to the unanimous shareholder agreement governing Coast GP and the limited partnership agreement governing Coast LP may have or develop interests or objectives which are different or even conflict with the objectives of the Company. Any such differences could have a negative impact on the success of the Northwest Hydro Facilities. The Company and the CMH Group are sometimes required, through the permitting and approval process, to notify and consult with various stakeholder groups, including landowners, indigenous peoples and municipalities. Any unforeseen delays in this process may negatively impact the ability of the Company or the CMH Group to complete any given facility on time or at all.

Risks Related to the Common Shares

The market price for the Common Shares may be volatile

The market price for Common Shares may be volatile and subject to wide fluctuations in response to numerous factors, many of which are beyond the Company's control, including the following: (a) actual or anticipated fluctuations in the Company's results of operations; (b) recommendations by securities research analysts; (c) changes in the economic performance or market valuations of other companies that investors deem comparable to the Company; (d) the loss or resignation of executive officers and other key personnel of the Company; (e) sales or perceived sales of additional Common Shares; (f) significant acquisitions or business combinations, strategic partnerships, joint ventures or capital commitments by or involving the Company or its competitors which prove to be ill considered; and (g) trends, concerns, technological or competitive developments, regulatory changes and other related issues in the industries in which the Company operates or the Company's target markets.

Financial markets have experienced significant price and volume fluctuations in recent years that have particularly affected the market prices of equity securities of companies and that have, in many cases, been unrelated to the operating performance, underlying asset values or prospects of such companies. Accordingly, the market price of the Common Shares may decline even if the Company's operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause decreases in asset values which may result in impairment losses. Certain institutional investors may base their investment decisions on consideration of the Company's environmental, governance and social practices and performance against such institutions' respective investment guidelines and criteria, and failure to meet such criteria may result in limited or no investment in the Common Shares by those institutions, which could adversely affect the trading price of the Common Shares.

The Company's cash dividend payments are not guaranteed

The payment of dividends under the Company's expected dividend policy is not guaranteed and could fluctuate with the performance of the Company. The Board of Directors has the discretion to determine the amount of dividends to be declared and paid to Shareholders. The Company may alter its dividend policy at any time and the payment of dividends will depend on, among other things, results of operations; financial condition; current and expected future levels of earnings; operating cash flow; liquidity requirements; market opportunities; income taxes; maintenance and growth capital expenditures; debt repayments; legal, regulatory and contractual constraints; working capital requirements; tax laws and other relevant factors. The Company's short and long-term borrowings may prohibit the Company from paying dividends at any time at which a default or event of default would exist under such debt, or if a default or event of default would exist as a result of paying the dividend.

Over time, the Company's capital and other cash needs may change significantly from its current needs, which could affect whether the Company pays dividends and the amount of any dividends it may pay in the future. If the Company pays dividends at the level currently anticipated under the proposed dividend policy, it may not retain a sufficient amount of cash to finance growth opportunities, meet any large unanticipated liquidity requirements or fund its operations in the event of a significant business downturn. The Board of Directors may amend, revoke or suspend the Company's dividend policy at any time. A decline in the market price or liquidity, or both, of the Common Shares could result if the Board of Directors establishes large reserves that reduce the amount of quarterly dividends paid or if the Company reduces or eliminates the payment of dividends, which could result in losses to Shareholders.

The Company is dependent on the operations of its facilities and the facilities of the CMH Group for its cash availability. The actual amount of cash available for dividends to Shareholders will depend upon numerous factors relating to each of the Company's assets, including: rates of return, customer base, demand for natural gas, the strength and consistency of the wind resources at the Bear Mountain Wind Park, the availability of water flows in respect of the Northwest Hydro Facilities, profitability, changes in revenues, fluctuations in working capital, capital expenditure levels, applicable laws, compliance with contracts and contractual restrictions contained in the instruments governing any indebtedness. Any reduction in the amount of cash available for distribution from its assets will reduce the amount of cash available for the Company to pay dividends to Shareholders.

The Common Share price could decline due to the potential for share issuances by the Company for other purposes

The Board of Directors may issue an unlimited number of Common Shares without any vote or action by the Shareholders, subject to the rules of any stock exchange on which the Company's securities may be listed from time to time. The Company may make future acquisitions or enter into financings or other transactions involving the issuance of securities. If the Company issues any additional equity, the percentage ownership of existing Shareholders will be reduced and diluted and the price of the Common Shares could decline. In addition, pursuant to the Governance Agreement, the Company may be required to issue Common Shares to AltaGas upon the completion of an acquisition involving the issuance of Common Shares in order for AltaGas to maintain its then-current shareholding percentage in the Company. It could be required to do this even if the Company does not have use for the proceeds of such sale of shares to AltaGas.

There may be an effect on the market price of the Common Shares arising from future sales of Common Shares by AltaGas

Following the expiry of the 12 month lock-up period under the Governance Agreement, AltaGas will not be restricted, subject to compliance with applicable laws, from selling all or a portion of the Common Shares it holds through the market or pursuant to a private placement transaction or a public offering under the Investor Liquidity Agreement. The sale of a large number of shares on the market by AltaGas, or the market's perception that AltaGas may proceed to sell a large number of shares, could adversely affect prevailing market prices for the Common Shares

ENVIRONMENTAL AND SAFETY POLICIES AND SOCIAL RESPONSIBILITY

Values

ACI operates in a safe, reliable manner and maintains positive relationships with its customers and in the communities that we live, work and operate, which includes, without limitation, building mutually beneficial working relationships with Indigenous peoples and working closely with governments and regulatory agencies to help meet long term project success. ACI strives for clear, transparent, communication to customers, employees, regulators, Shareholders and all stakeholders.

Safety and environmental stewardship are core values at ACI and integral to how ACI operates. All aspects of ACI’s business operates with the highest regard for the safety of its customers, communities, employees, and contractors. ACI employees and contractors are responsible for acting safely, continually improving practices and procedures to enhance safety and reliability, and for encouraging the same behaviors in others. ACI provides low carbon energy solutions to its customers and always looks for ways to minimize the company environmental footprint by operating the business prudently and in an environmentally responsible fashion.

Board of Directors

The Board of Directors has established the EH&S Committee to oversee the development of the environment, health and safety programs for ACI and the EH&S Committee shall be responsible for a continuing assessment of environment, health and safety matters and for making recommendations to the Board of Directors regarding ACI's approach to environment, health and safety.

Corporate Social Responsibility

ACI is committed to operating in an environmentally and socially responsible manner. ACI has a number of social and environmental policies, procedures and practices in place. Notably, ACI's Code of Business Ethics, which applies to directors, officers, employees, contractors, consultants, representatives and agents of ACI, sets out fundamental principles for the ethical conduct of its business. The Board of Directors has adopted a whistleblower policy. The Board of Directors believes that providing a forum for employees, clients, contractors, officers and directors to raise concerns about ethical conduct and treating all complaints with the appropriate level of seriousness fosters a culture of ethical conduct.

Diversity Policy

The Board has adopted a policy on diversity and gender diversity, which aims to set out the key considerations for the approach of the Board of Directors towards Board of Directors composition, including the Board of Directors approach for achieving diversity and gender diversity on the Board of Directors. The Board of Directors is committed to growth and development with respect to diversity among its members.

Environmental Protection

Protecting the environment and minimizing impact are critical for ACI to maintain a sustainable business. To help ensure the responsibility and accountability for environmental protection, ACI educates all such individuals in environmental safeguarding to ensure those working on ACI's behalf are made aware of their responsibilities. By maintaining an emergency response system and regularly conducting emergency response exercises, ACI is prepared to respond and minimize environmental impact if an incident were to occur. Best management practices are employed across all ACI businesses to assure compliance with regulatory requirements.

ACI's Health and Safety Management and Environmental Management Codes of Conduct provide the standard for performance across the enterprise. EH&S Management Systems within ACI's companies are effectively monitored and continually improved to ensure minimum standards and components are met, and various actions and accountabilities are assigned. A Plan-Do-Check-Act cycle, forms the basis for continual improvement.

ENVIRONMENTAL REGULATION

ACI faces uncertainties related to future environmental laws and regulations affecting its business and operations. Existing environmental laws and regulations may be revised or interpreted more strictly, and new laws or regulations may be adopted or become applicable to ACI, which may result in increased compliance costs or additional operating restrictions, each of which could reduce ACI's earnings and adversely affect ACI's business.

ACI is subject to extensive federal, provincial and municipal regulation relating to the protection of the environment that governs, among other things, environmental assessments, discharges to water, land and air, and the generation, storage, transportation, disposal and release of various hazardous substances. Estimated environmental liabilities will be reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimated changes are accounted for prospectively. ACI is also subject to environmental regulation governing the construction and operation of ACI's assets, which requires ACI to obtain operating licences and permits. To ensure compliance, ACI works closely with local and regional authorities to address all environmental matters and to comply with licensing and permitting requirements. In addition to the license and permit requirements, legislation may require that end of life assets be abandoned, remediated, and reclaimed to the satisfaction of federal, provincial, or municipal authorities. Failure to comply with applicable environmental legislation can result in civil or criminal penalties, environmental contamination clean-up, and government orders affecting future operations. ACI may also be subject to opposition from special interest groups resulting in regulatory process delays, which can impact schedules and increase cost.

CLIMATE CHANGE

Changes in laws and regulations relating to GHG emissions could require ACI, in addition to complying with monitoring and reporting requirements applicable to its operations, to do one or more of the following: (a) comply with stricter emissions standards for internal combustion engines; (b) take additional steps to control transmission and distribution system leaks; (c) retrofit existing ACI equipment with pollution controls or replace such equipment; or (d) reduce ACI's GHG emissions or, depending on the requirements enacted, acquire emissions offsets, credits or allowances or pay taxes on the emissions emitted in connection with its operations. ACI's business could also be indirectly impacted by laws and regulations that affect its customers or suppliers to the extent such changes result in reductions in the use of natural gas by its customers or limit the operations of, or increase the costs of goods and services acquired from ACI suppliers.

AUI is subject to the *Climate Leadership Act* (Alberta) which was enacted introducing an initial economy-wide carbon levy of $20 per tonne effective January 1, 2017, and increasing to $30 per tonne in January 2018. All fuel consumption, including gasoline and natural gas, is subject to the levy.

AUI is also subject to the *Carbon Competitiveness Incentive Regulation* (Alberta) ("CCIR") and the Greenhouse Gas Reporting Program ("GHGRP") under the *Canadian Environmental Protection Act* (Federal), both of which require annual reporting of greenhouse gas emissions. Unlike the previous regulation, which set emission intensity reduction requirements, the CCIR imposes an output-based benchmark on competitors in the same emitting industry for facilities that emit over 100,000 tonnes of specified gases, or facilities that have opted-in to the CCIR. The CCIR requires these emitters to submit quarterly and final reports on their emissions under the *Specified Gas Reporting Regulation* (Alberta). The aim is to reduce annual GHG emissions by 20 megatonnes by 2020 and 50 megatonnes by 2030. The information submitted is used by the provincial government to inform policy development and for analysis/reporting purposes. The GHGRP collects information on greenhouse gas emissions from facilities across Canada. It is a mandatory program for facilities that emit 10,000 tonnes or more of GHG's of Carbon Dioxide Equivalent per year. The information collected by the GHGRP helps the Federal Government assess its overall environmental performance and contributes to policy and strategy development related to climate change. The reporting thresholds for both of these programs were reduced from 50,000 tonnes to 10,000 tonnes for the 2017 operating year (reporting in 2018) which resulted in an increase in regulatory reporting obligations.

The Federal Government also enacted the *Greenhouse Gas Pollution Pricing Act* on June 21, 2018 to implement a carbon pricing system beginning in 2019, to be applied in provinces and territories whose carbon pricing system does not align with the federal benchmark. Currently, those provinces and territories are listed in Schedule 2 of the *Greenhouse Gas Pollution Pricing Act*, and include Ontario, New Brunswick, Manitoba, Prince Edward Island, Saskatchewan, Yukon and Nunavut. Alberta has signaled its intent to maintain carbon pricing levels at $30 per tonne, and it remains uncrertain whether Alberta will be subject to the federal carbon pricing system in future years. The federal government has also proposed regulations setting out requirements for facilities to produce emissions information under the *Greenhouse Gas Pollution Pricing Act*.

The federal carbon pollution pricing scheme is composed of two elements, (a) a carbon levy applied to fossil fuels set at $20 per tonne of carbon emitted, increasing to $50 per tonne in 2022; and (b) an output based pricing system for industrial facilities that emit 50,000 tonnes of carbon dioxide equivalent (CO2e) per year or more, with an opt-in capability for smaller facilities with emissions below the threshold.

PNG is subject to the *Carbon Tax Act* (British Columbia), which is currently set at $35 per tonne of CO2e emissions generated primarily through the combustion of fossil fuels consumed in the course of PNG's operations. In September 2017, the British Columbia government announced in its budget that starting on April 1, 2018; carbon tax rates will increase annually by $5 per tonne of CO2e emissions until rates equal $50 per tonne in 2021. With these increases, British Columbia will exceed the carbon pricing requirements expected in the Pan Canadian Framework on Clean Growth and Climate Change.

Effective Date	BC Carbon Tax Rate ($/tonne CO2e)
Prior to 2018	$30
April 1, 2018	$35
April 1, 2019	$40
April 1, 2020	$45
April 1, 2021	$50

PNG operates under and complies with the requirements set forth by the *Carbon Tax Act* (British Columbia). The carbon tax is recovered from customers through regular customer billings

On February 15, 2018, the Quantification, Reporting and Verification of Greenhouse Gas Emissions Regulations made under the *Environment Act* (Nova Scotia) came into effect. Among the companies subject to the reporting requirements are those which own facilities that generate 50,000 tonnes or more of greenhouse gas emissions per year from the distribution of natural gas, as well as natural gas distributors and fuel suppliers that deliver natural gas for consumption in Nova Scotia that, when combusted, produces 10,000 tonnes or more of greenhouse gas emissions per year.

HGL is a mandatory participant in the cap and trade program for greenhouse gas emissions that began on January 1, 2019. The program sets annual limits on the amount of GHG emissions allowed from certain activities in the province each year. The province will allocate free emission allowances to fuel suppliers like HGL equal to 80 percent of the suppliers' verified GHG emissions each year. Remaining allowances must be obtained through auctions of emission allowances that occurs a number of times in each calendar year.

DIVIDENDS

Dividends are declared at the discretion of the Board of Directors and dividend levels are reviewed periodically by the Board of Directors, giving consideration to the ongoing sustainable net income and cash flow of the business, its maintenance and growth capital programs and any debt repayment requirements of ACI. The Company targets to pay a portion of its ongoing net income through regular quarterly dividends made to Shareholders.

ACI's payment of dividends may be limited by covenants under its credit agreements, including, without limitation, in circumstances when a default or event of default exists or would be reasonably expected to exist upon or as a result of making such dividend payment. In the event of liquidation, dissolution or winding-up of ACI, the preferred shareholders have priority in the payment of dividends over the common shareholders.

The table below shows the cash dividends paid by ACI on Common Shares:

$ per common share		**2018**
December 31, 2018	**$**	0.1744

In connection with the Acquisition, the Company paid an eligible dividend in the approximate amount of $31.0 million to AltaGas and effected a return capital on the Common Shares in the amount of approximately $157.4 million.

MARKET FOR SECURITIES

The following chart provides the reported high and low trading prices and volume of Common Shares, traded on the TSX under the symbol ACI, traded by month from October 25, 2018 to December 31, 2018 as reported by the TSX:

Month	High	Low	Volume Traded
October	14.65	14.10	1,817,910
November	14.60	14.06	1,063,778
December	17.14	14.58	1,671,445

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTIONS ON TRANSFER

The following table sets forth the number of securities of each class of securities of the Company that, to the knowledge of the Company, are in escrow or subject to a contractual restriction on transfer and the percentage that number represents of the outstanding securities of that class.

Designation of Class	Number of Securities Held in Escrow or that are Subject to a Contractual Restriction on Transfer(1)(2)	Percentage of Class
Common Shares	11,025,000	36.75%

Notes:

(1) Each of the Company and AltaGas has agreed that it will not, without the prior consent of RBC Dominion Securities Inc. and TD Securities Inc., on behalf of the underwriters of the IPO, which consent shall not be unreasonably withheld, issue, in the case of the Company, and sell, in the case of AltaGas, or offer, grant any option to purchase or agree to issue or sell, as applicable, any equity securities of the Company or other securities convertible into, or exchangeable or exercisable for, equity securities of the Company for a period of 180 days from the date of the closing of the IPO.

(2) Under the Governance Agreement, AltaGas has also agreed that, for a period of 12 months from the date of the closing of the IPO, it will not, directly or indirectly, without the prior written consent of the Company, sell, offer, grant any option to purchase or agree to sell any equity securities of the Company or other securities convertible into, or exchangeable or exercisable for, equity securities of the Company held by AltaGas at the date of the Governance Agreement to any Person other than to an affiliate of AltaGas.

CREDIT RATINGS

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities and are indicators of the likelihood of payment and of the capacity and willingness of a company to meet its financial commitment on an obligation in accordance with the terms of an obligation.

This information concerning ACI's credit ratings relates to ACI's financing costs, liquidity and operations. The availability of ACI's funding options may be affected by certain factors, including the global capital markets environment and outlook as well as ACI's financial performance. ACI's access to capital markets at competitive rates is influenced by ACI's credit rating and rating outlook, as determined by credit rating agencies such as DBRS, and if ACI's ratings were downgraded, ACI's financing costs and future debt issuances could be unfavorably impacted.

DBRS is one of several rating agencies that provide credit ratings. The ratings for debt instruments range from a high of AAA to a low of D.

On October 26, 2018, DBRS finalized ACI's provisional Issuer Rating of BBB(high) with a Stable trend. On December 3, 2018, DBRS assigned a rating of BBB(high) with a Stable trend to ACI's MTNs.

According to the DBRS rating system, debt securities rated BBB are the in the fourth highest of ten rating categories and are of adequate credit quality. The capacity for the payment of financial obligations is considered acceptable, but may be vulnerable to future events. "High" or "Low" designations are used to indicate the relative standing of the security being rated within a particular rating category.

The credit ratings assigned by DBRS are not recommendations to purchase, hold or sell the securities in as much as such ratings do not comment as to market price or suitability for a particular investor. There can be no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by DBRS at any time in the future if, in their judgment, circumstances so warrant. The credit ratings on a security may not reflect the potential impact of all risks related to the value of the security.

Except as set forth above, DBRS have not announced that it is reviewing or intends to revise or withdraw the ratings on ACI.

ACI provides an annual fee to DBRS for credit rating services. ACI has paid DBRS its respective fees in connection with the provision of the above ratings.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts entered into by ACI within the most recently completed financial year, or before the most recently completed financial year but which are still material and are still in effect, are the following:

(a) Investor Liquidity Agreement

The Investor Liquidity Agreement provides that AltaGas and any direct or indirect transferee of AltaGas who shall become party to the Investor Liquidity Agreement (each a "Holder") may, at any time and from time to time, make a written request to the Company to file a prospectus in any jurisdiction or jurisdictions of Canada in which the Company is at the relevant time a reporting issuer (a "Demand Distribution") in respect of the distribution of all or part of the Common Shares then held by the Holder ("Distributable Securities"), subject to certain restrictions as discussed below. Upon receipt by the Company of a Demand Distribution, the Company is required to use its reasonable commercial efforts to file a prospectus in order to permit the offer and sale or other disposition or distribution in Canada of all or any portion of the Distributable Securities.

The Demand Distribution rights are subject to certain limitations, including that: (a) each Holder is entitled to a maximum of one Demand Distribution in any six month period; (b) other than in respect of a shelf prospectus, the Company is not obligated to file a prospectus in respect of a Demand Distribution within 60 days after the effective date of a previously filed prospectus; or (c) the Company is not obligated to file a prospectus in respect of a Demand Distribution unless the request is for a number of Distributable Securities with a market value that is equal to at least $50 million as of the date of such request for a Demand Distribution or such amount as is sufficient to permit a Holder to effect a distribution of all of its remaining Distributable Securities.

If at any time the Company proposes to, or reasonably contemplates that it will, file a preliminary prospectus with respect to the distribution of any Common Shares to the public, then the Company will, at that time, give prompt notice of the proposed distribution to each Holder, which notice will offer each Holder the opportunity to qualify for distribution such number of Distributable Securities as such Holder may request. The Company will use commercially reasonable efforts to include in such prospectus such Distributable Securities as the Holders may request (a "Piggy-Back Distribution"), unless the Company, with the assistance of its underwriter or agent, if applicable, determines, acting reasonably, that qualifying such Piggy-Back Distribution exceeds the number of Common Shares that can be sold in an orderly manner in such offering within a price range acceptable to the Company ("Piggy-Back Distribution Orderly Sale Number"). The Company shall then include in such distribution: (a) first, the number of Common Shares that is proposed to be qualified for distribution by such preliminary prospectus by the Company as specified in its notice to the Holder; and (b) second, such Distributable Securities that are equal to (X) the Piggy-Back Distribution Orderly Sale Number less (Y) the number of Common Shares that are proposed to be qualified for distribution by such preliminary prospectus by the Company as specified in its notice to the Holder, subject to certain conditions.

The Investor Liquidity Agreement continues in force until the earlier of the date on which: (a) there are no longer any outstanding Distributable Securities; (b) the Holders, collectively, beneficially own, directly or indirectly, less than 10 percent of the issued and outstanding Common Shares (on a non-diluted basis) on the last date of the last preceding financial year end of ACI; or (c) the Investor Liquidity Agreement is terminated by written agreement of all parties to the Investor Liquidity Agreement.

(b) Governance Agreement

Under the Governance Agreement, AltaGas is entitled to nominate three of the members of the Board for so long as the percentage of outstanding Common Shares (on a non-diluted basis) beneficially owned directly or indirectly by AltaGas is not less than 30 percent of the issued and outstanding Common Shares; nominate two of the members of the Board for so long as the percentage of outstanding Common Shares (on a non-diluted basis) beneficially owned directly or indirectly by AltaGas is not less than 20 percent of the issued and outstanding Common Shares; and nominate one of the members of the Board for so long as the percentage of outstanding Common Shares (on a non-diluted basis) beneficially owned directly or indirectly by AltaGas is not less than 10 percent of the issued and outstanding Common Shares. So long as AltaGas in entitled to nominate three members of the Board of Directors, one of such members shall, if requested by AltaGas, be the Chair of the Board of Directors. The nominees of AltaGas to the Board of Directors may be directors, officers or employees of AltaGas or its affiliates, or other persons, at AltaGas' discretion. Subject to any requirements of the CBCA, AltaGas is entitled to nominate for appointment or election to the Board of Directors a replacement director for any vacancy on the Board of Directors, provided AltaGas remains, at that time, entitled to appoint such director. The Governance Agreement provides that such rights are premised on a Board of Directors of up to seven directors, and if the size of the Board of Directors is increased to more than seven directors, then AltaGas is entitled to nominate such number of additional representatives to the Board of Directors as are necessary such that AltaGas' minimum rights to nominees to the Board of Directors (as a percentage of the total number of directors on the Board of Directors) is proportionately maintained.

Under the Governance Agreement, the Company also provides AltaGas with certain rights to participate in future offerings of securities by the Company. Provided AltaGas beneficially owns, directly or indirectly, not less than 10 percent of the issued and outstanding Common Shares (on a non-diluted basis) and subject to limited exceptions, if the Company proposes to, or reasonably anticipates that it will, issue any securities (the "Offered Securities"), the Company will promptly first offer AltaGas the opportunity to subscribe for and acquire that number of Offered Securities equal in amount to AltaGas' then outstanding proportionate interest in the Common Shares (on a non-diluted basis) or any such lesser amount as AltaGas may elect to subscribe for at the subscription price as determined by the Board. If any of the Offered Securities are not subscribed for by AltaGas within the applicable periods provided for in the Governance Agreement, the Company may proceed to offer such unsubscribed Offered Securities within a 60 day period after the expiration of such applicable period to any Person, provided the price at which such Offered Securities are issued is not less than the subscription price offered to AltaGas and the terms of payment for such Offered Securities are not more favourable to such Person than the terms of payment offered to AltaGas. Furthermore, such rights apply to any Offered Securities issued by the Company for proceeds other than cash, including in connection with any acquisition, business combination or similar transaction, and AltaGas shall be offered the right to subscribe for such number of Common Shares, at a market-based price, to entitle AltaGas to maintain its proportionate ownership of Common Shares, or such lesser amount as AltaGas may elect. AltaGas is also entitled to subscribe for, no more than once per fiscal quarter and at a market-based price, such number of additional Common Shares to allow AltaGas to maintain its proportionate ownership of Common Shares (on a non-diluted basis), or such lesser amount as AltaGas may determine, after giving effect to issuances of Common Shares by the Company pursuant to compensation plans or similar plans.

Under the Governance Agreement, AltaGas has also agreed that, for a period of 12 months from the date of the closing of the IPO, it will not, directly or indirectly, without the prior written consent of the Company, sell, offer, grant any option to purchase or agree to sell any equity securities of the Company or other securities convertible into, or exchangeable or exercisable for, equity securities of the Company held by AltaGas at the date of the Governance Agreement to any Person other than to an affiliate of AltaGas.

The Governance Agreement continues in force until the earlier of: (a) the date on which the Governance Agreement is terminated by the written agreement of AltaGas and the Company; or (b) the date on which AltaGas beneficially owns, directly or indirectly, less than 10 percent of the issued and outstanding Common Shares (on a non-diluted basis) on the last date of the preceding financial year of the Company.

(c) The Purchase Price Long-Term Note

Prior to December 31, 2018, the Purchase Price Long-Term Note was repaid in full.

(d) Transition Services Agreement

Pursuant to the Transition Services Agreement AltaGas provides or arranges for the provision of certain administrative services required by the Company. The services provided 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 and its personnel are obligated to devote as much time as is reasonably necessary for the proper discharge of services under the Transition Services Agreement. Under the Transition Services Agreement, the Company has agreed to indemnify AltaGas, its affiliates and their respective directors, officers, employees and agents from and against any liabilities, obligations, losses, damages, costs, expenses and charges suffered by an indemnified Person arising out of or otherwise relating to any act or omission of AltaGas, its affiliates and their respective directors, officers, employees and agents in connection with the provisions of the services provided for in the Transition Services Agreement by AltaGas, except to the extent that the claims, liabilities, losses, damages, costs or expenses are determined to have resulted from gross negligence or willful misconduct of AltaGas, its affiliates and their respective directors, officers, employees and agents.

AltaGas is providing the services under the Transition Services Agreement on a cost recovery basis only. The Transition Services Agreement will operate until June 30, 2020, subject to earlier termination in certain circumstances. The Transition Services Agreement is extendable by mutual agreement of the parties.

(e) Revolving Credit Facility

On October 25, 2018, the Company entered into a $200 million unsecured revolving credit facility with a syndicate of lenders, with a term of four years subject to customary extension provisions (the "Revolving Credit Facility"). This facility was made available for general corporate purposes. The borrowing options under the Revolving Credit Facility include Canadian prime rate based loans, U.S. base rate loans, bankers' acceptances, LIBOR loans and letters of credit. Borrowings on the Revolving Credit Facility bear fees and interest at rates relevant to the nature of the draw made and the Company's corporate credit rating. The Revolving Credit Facility includes customary covenants for a transaction of this nature, including, without limitation: (a) the ratio of consolidated net debt to capitalization will not exceed 65 percent at the end of any fiscal quarter; and (b) the ratio of consolidated earnings before interest, tax, depreciation and amortization to interest expense will not be less than 2.5:1.0 at the end of any fiscal quarter.

(f) Term Loan

On October 25, 2018, the Company entered into a $250 million unsecured term loan with a syndicate of lenders, with a term of two years (the "Term Loan"). The Term Loan was fully drawn on October 25, 2018 with the proceeds utilized to pay for a portion of the Purchase Price Short Term Note. The borrowing options under the Term Loan include Canadian prime rate based loans, U.S. base rate loans, bankers' acceptances and LIBOR loans. Borrowings on the Term Loan are expected to bear fees and interest at rates relevant to the nature of the draw made and the Company's corporate credit rating. The Term Loan includes customary covenants for a transaction of this nature, including, without limitation: (a) the ratio of consolidated net debt to capitalization will not exceed 65 percent at the end of any fiscal quarter; and (b) the ratio of consolidated earnings before interest, tax, depreciation and amortization to interest expense will not be less than 2.5:1.0 at the end of any fiscal quarter.

(g) MTN Trust Indenture

The trust indenture between ACI and Computershare Trust Company of Canada dated November 15, 2018, as supplemented, related to the issuance and sale of MTNs pursuant to ACI's medium term note program.

The foregoing descriptions are summaries of the noted material contracts. The full text of each material contract is available on SEDAR at www.sedar.com.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as has already been disclosed herein with regard to AltaGas in connection with the Acquisition and IPO, ACI is not aware of any material interest, direct or indirect, of any director or officer of ACI, any director or officer of a corporation that is an insider or subsidiary of ACI, or any other insider of ACI, or any associate or affiliate of any such person, in any transaction since the commencement of ACI's last three completed financial years, or in any proposed transaction, that has materially affected or would materially affect ACI or any of its subsidiaries. See ‘‘*Material Contracts*”.

CONFLICTS OF INTEREST

Certain directors of the Company are engaged in, and may continue to be engaged in, other activities in the industries in which the Company operates from time to time. The Governance Agreement does not prohibit AltaGas from competing with the Company and its affiliates. Certain directors of the Company are also directors and/or officers of AltaGas.

The CBCA provides that in the event that a director or an officer is a party to, or is a director or an officer of, or has a material interest in any Person who is a party to, a material contract or material transaction or proposed material contract or proposed material transaction, such director or officer shall disclose the nature and extent of his or her interest and shall refrain from voting to approve such contract or transaction, unless otherwise provided under the CBCA. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the CBCA.

The Transition Services Agreement, the Governance Agreement, the Investor Liquidity Agreement and the Company's other arrangements with AltaGas do not impose any duty on AltaGas to act in the best interest of the Company, and AltaGas is not prohibited from engaging in other business activities that may compete with those of the Company. The Company's ownership may give rise to conflicts of interest between the Company and the Shareholders, on the one hand, and AltaGas, on the other hand. In certain instances, the interests of AltaGas may differ from the interests of the Company and its Shareholders, including with respect to future acquisitions or strategic decisions. It is possible that conflicts of interest may arise between the Company and AltaGas and that such conflicts may not be resolved in a manner that is in the best interests of the Company or its Shareholders.

As of March 6, 2019, the Company is not aware of any existing or potential material conflicts of interest between the ACI and any director or officer of the ACI.

PROMOTER

AltaGas may have been considered a promoter of the Company within the meaning of Canadian securities laws at a time in the most recently completed financial year. As of March 6, 2019, AltaGas holds 11,025,000 Common Shares, representing 36.75 percent of the issued and outstanding Common Shares. A portion of these Common Shares were acquired pursuant to the Purchase and Sale Agreement pursuant to which the Company acquired the Acquired Assets and certain indebtedness.

AltaGas and the Company have entered into certain contracts as described under the heading "*Material Contracts*" and are parties to certain gas services agreements and various operational agreements providing for, among other things, the short term sale and purchase of natural gas, the supply of natural gas, natural gas management services, natural gas supply management services, natural gas transportation services, retailer distribution services, electricity supply for various facilities, natural gas storage services, travel booking services, sublease of office space and pension administrative services and other contracts whereby certain value will be received by AltaGas either directly or indirectly from the Company and, in return for such value, the Company will pay consideration to AltaGas.

LEGAL PROCEEDINGS

ACI is not aware of any material legal proceedings to which ACI or its affiliates was a party or to which their property was subject during ACI's most recently completed financial year and ACI is not aware of any such material legal proceedings being contemplated.

REGULATORY ACTIONS

ACI is not aware of any (i) penalties or sanctions imposed against it by a court relating to securities legislation or by a securities regulatory authority during its most recently completed financial year, or (ii) other penalties or sanctions imposed by a court or regulatory body against it that would likely be considered important to a reasonable investor in making an investment decision. There were no settlement agreements entered into by ACI before a court relating to securities legislation or with a securities regulatory authority during ACI's most recently completed financial year.

INTERESTS OF EXPERTS

The auditors of ACI are Ernst & Young LLP, Chartered Accountants, 2200 – 215 2nd Street SW, Calgary, Alberta T2P 1M4. Ernst & Young LLP is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Professional Accountants of Alberta.

ADDITIONAL INFORMATION

Additional information, including, without limitation, directors' and officers' remuneration and indebtedness, principal holders of ACI's securities, Share Options and interests of insiders in material transactions, where applicable, will be contained in ACI's management information circular for ACI's first annual meeting of Shareholders involving the election of directors.

Additional financial information is contained in ACI's audited consolidated financial statements as at and for the year ended December 31, 2018 and management's discussion and analysis as at and for the year ended December 31, 2018.

The Company routinely files all required documents through the SEDAR system and on its own website. Internet users may retrieve such material through the SEDAR website www.sedar.com. ACI's website is located at www.altagascanada.ca, but ACI's website is not incorporated by reference into this AIF.

TRANSFER AGENTS AND REGISTRARS

The registrar and transfer agent for the Common Shares is Computershare Investor Services Inc., 600, 530 - 8th Avenue SW, Calgary, Alberta T2P 3S8, Tel: 1-800-564-6253.

The registrar and trustee for MTNs is Computershare Trust Company of Canada, 600, 530 - 8th Avenue SW, Calgary, Alberta T2P 3S8, Tel: 1-800-564-6253

SCHEDULE A: AUDIT COMMITTEE MANDATE

I. CONSTITUTION

The Board of Directors (the ''Board'') of AltaGas Canada Inc. (the ''Company'') has established an Audit Committee (the ''Committee'') to serve as the Audit Committee of the Board. Such Committee shall be in compliance with the guidelines for corporate governance of the Toronto Stock Exchange (''TSX'') and any other regulatory or legal authority having jurisdiction over ACI.

The Committee shall assist the Board with its oversight of: the quality and integrity of ACI's financial statements, financial disclosure and internal controls over financial reporting; ACI's compliance with relevant legal and regulatory requirements; the qualifications, independence and performance of the external auditor and internal auditor; certain policies of ACI; and other matters set out herein or delegated by the Board from time to time.

II. MEMBERSHIP

The Board shall elect from its members not less than three Directors to serve on the Committee (the ''Members'') and shall appoint one such Member as Chair of the Committee.

Every Member must be:

- independent (in accordance with National Instrument 52-110 —*Audit Committees* of the Canadian Securities Administrators (''NI 52-110'')); and
- financially literate (in accordance with NI 52-110).

No Member shall be an officer or employee of ACI or any subsidiary or affiliate of ACI. Any Member may be removed or replaced at any time by the Board and shall cease to be a Member upon ceasing to be a Director of ACI.

Each Member shall hold office until the Member resigns or is replaced, whichever first occurs. Where a vacancy occurs at any time in the membership of the Audit Committee, it may be filled by the Board on the recommendation of the Compensation and Governance Committee, provided that the proposed Member meets the above criteria. Provided the Committee includes three Members, it may continue to act in the event of a vacancy. When appointing a Member to the Committee, the Board shall take into consideration the number of other audit committees upon which the proposed Member sits.

The Corporate Secretary of ACI shall be secretary to the Committee unless the Committee directs otherwise.

III. MEETINGS

The Committee shall convene no less than four times per year at such times and places designated by its Chair or whenever a meeting is requested by a Member, the Board, or an officer of ACI. A minimum of 24 hours' notice of each meeting, plus a copy of the proposed agenda, shall be given to each Member. Members of management of ACI or any subsidiary or affiliate of ACI shall attend whenever requested to do so by a Member.

A meeting of the Committee shall be duly convened if a majority of Members are present. Where the Members consent, and proper notice has been given or waived, Members may participate in a meeting of the Committee by means of such telephonic, electronic or other communication facilities as permits all persons participating in the meeting to communicate adequately with each other, and a Member participating in such a meeting by any such means is deemed to be present at that meeting. In the absence of the Chair of the Committee, the Members may choose one of the Members to be the chair of the meeting.

The external auditor will be given notice of and be provided the opportunity to attend every meeting of the Committee.

The Committee will hold in camera sessions without management present, including with internal and external auditors, as may be deemed appropriate by the Members.

Minutes shall be kept of all meetings of the Committee by the Corporate Secretary or designate of the Corporate Secretary.

IV. DUTIES AND RESPONSIBILITIES OF THE CHAIR

The Chair of the Committee is responsible for:

1. providing leadership to the Committee and assisting the Committee in reviewing and monitoring its responsibilities;
2. duly convening Committee meetings and designating the times and places of those meetings;
3. working with management, the Chair of the Board and the Lead Director on the development of agendas;
4. reviewing material for Committee meetings prior to it being made available to Members;
5. ensuring Committee meetings are conducted in an efficient, effective and focused manner;
6. ensuring the Committee has sufficient information to permit it to properly make decisions when decisions are required;
7. advising the Committee of any finance, accounting or misappropriation matters brought to the Chair's attention;
8. advising other committee Chairs or the Chair of the Board of any matters which may affect the organization and influence the Board or Committee's responsibilities; and
9. reporting to the Board on the activities, decisions and recommendations of the Committee after each meeting.

V. DUTIES AND RESPONSIBILITIES OF THE COMMITTEE

The Committee shall, as permitted by and in accordance with the requirements of the *Canada Business Corporations Act*, the Articles and By-laws of ACI and any legal or regulatory authority having jurisdiction, periodically assess the adequacy of procedures for the public disclosure of financial information and review on behalf of the Board and report to the Board the results of its review and its recommendation regarding all material matters of a financial reporting and audit nature including, but not limited to, the following main subject areas:

1. oversight of external auditors, including:
   a) appointment, compensation, retention and termination of external auditors, who shall report directly to the Committee, provided that the appointment of the auditor shall be subject to shareholder approval;
   b) review and approval of the terms of the external auditors' annual engagement letter, including the proposed audit fee;
   c) regular discussions with external auditors in the absence of management on matters of interest, including matters that the external auditors recommend bringing to the attention of the Board;
   d) at least annually, obtain and review reports of external auditors delineating all relationships between the external auditors and ACI required by applicable audit professional regulatory standards, discuss with the external auditors any relationships or services that may impact the objectivity and independence of the external auditors and determine external auditor independence;
   e) review and pre-approve the audit plans (and any changes) of the external audit firm and all non-audit work undertaken by the external audit firm, ensuring that except in exceptional circumstances non-audit related fees represent less than half of the total fees billed by the external audit firm and ensuring that non-audit fees do not include charges for services that are either likely to impair the independence of the auditor or relate to tax services for senior executives of ACI;
   f) resolution of any disagreements between management and the auditor regarding financial reporting;
   g) assessment of the effectiveness and performance of the external audit firm;
   h) review and approval of ACI's hiring policies re: current and former partners and employees of the external audit firm; and
   i) ensure management provides adequate funding to the Committee so that it may independently engage and remunerate the external auditor and any advisors;

2. oversight of internal auditors, including:
   a) at least annually, review the internal audit plan, including the degree of coordination between such plan and the audit plans of the external auditor;
   b) obtain and review reports periodically from the head of the internal audit function regarding the activities of the internal audit function, including any significant disagreements between internal auditors and management; and
   c) discuss the responsibilities, budget and staffing of ACI's internal audit function and review the performance of the internal audit function;

3. oversight of financial reporting, including
   a) financial statements, including management's discussion and analysis;
   b) annual and interim press releases regarding financial results;
   c) reports to shareholders and others;
   d) filings to securities regulators;
   e) public disclosure documents containing audited or unaudited financial information (for example, but not limited to, press releases, prospectuses, annual information form, management information circular);
   f) review of the financial aspects of any transactions of ACI that involve related parties (other than wholly-owned subsidiaries); and
   g) review of litigation, claims and contingencies in consultation with management and legal counsel as appropriate;

4. oversight of financial reporting processes and internal control over financial reporting and disclosure controls, including:
   a) review of the adequacy and effectiveness of the accounting and internal control policies, including internal controls over financial reporting, of ACI and procedures through inquiry and discussions with the external auditors, management and the internal auditor, including about the extent to which the scope of the internal and external audit plans can be relied upon to detect weakness in internal control policies, fraud or other illegal acts;
   b) review of the adequacy and effectiveness of the disclosure control policies and procedures of ACI;
   c) review of the effectiveness of procedures for the receipt, retention and resolution of complaints regarding accounting, internal accounting controls or auditing matters, and the confidential, anonymous submission by employees of concerns regarding questionable accounting, internal accounting controls, financial reporting or auditing matters and review and, as necessary,
   d) investigate any reports alleging material violations of federal, provincial or state securities or any similar other law or a material breach of fiduciary duties by directors, officers, employees or agents of ACI arising under such laws; and
   e) review and discuss with management and the independent auditor the certification and reports of management and the independent auditor required in ACI's periodic reports concerning ACI's internal control over financial reporting and disclosure controls and procedures, the adequacy of such controls and any remedial steps being undertaken to address any material weaknesses or significant deficiencies in internal control over financial reporting;

5. oversight of finance matters, including:
   a) review of analyses by management and the external auditor regarding significant financial reporting issues and judgments made in connection with the preparation of ACI's consolidated financial statements;
   b) review of Company's policy on dividends;
   c) review the issuance of equity or debt securities by ACI;
   d) review and recommend for approval to the Board the management information circular with respect to matters related to the auditor or affecting the capital of ACI; and
   e) review and recommend to the Compensation and Governance Committee, for further recommendation or approval, the calculations of financial metrics used in the determination of employee incentive compensation plans; monitor finance integration and financial risk management programs associated with major acquisitions;

6. oversight of risk management, including:

a) review of ACI's major risks, a review of the method of risk analysis by ACI, review of the strategies, policies and practices in place for risk management; and
b) review of ACI's cyber risk and data security, and insurance program; and

7. oversight of policies applicable to the Committee's mandate, and compliance therewith, including:
   - Code of Business Ethics as it relates to the matters covered by this Mandate;
   - Whistleblower Policy;
   - Disclosure Policy; and
   - Other policies that may be established from time to time relating to accounting, financial reporting, disclosure controls and procedures, internal controls over financial reporting and audits.

VI. OTHER DUTIES

The Committee shall have the following other duties:

1) meet regularly with management to discuss areas of concern and coordinate its activities with the Chief Financial Officer;
2) review at least annually the succession planning in the accounting and finance groups;
3) meet separately with senior management, the internal auditors, the external auditors and, as is appropriate, internal and external legal counsel and independent advisors in respect of matters not elsewhere listed concerning any other audit, finance and risk matter;
4) review at least annually the relevance and adequacy of this Mandate and provide recommendations to the Compensation and Governance Committee of the Board; and
5) such other duties not mentioned herein but otherwise required pursuant to any applicable legal or regulatory authority.

VII. OUTSIDE EXPERTS AND ADVISORS

The Committee is authorized, when deemed necessary or desirable, to engage independent counsel, outside experts and other advisors, at ACI's expense, to advise the Committee on any matter.

VIII. RELIANCE

Absent actual knowledge to the contrary (which shall be promptly reported to the Board), each member of the Committee shall be entitled to rely on (i) the integrity of those persons or organizations within and outside ACI from which it receives information, (ii) the accuracy of the financial and other information provided to the Committee by such persons or organizations, and (iii) representations made by management and the external auditor, as to any information technology, internal audit and other non-audit services provided by the external auditor to ACI and its subsidiaries.

IX. COMMITTEE TIMETABLE

The major activities of the Committee will be outlined in an annual schedule.

AltaGas Canada Inc.
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